Unitil
Unitil Service Corp.

ORIGINAL
N.H.P.U.C. Case No. DG 10-250
Exhibit No. #1
Witness Panel #1
DO NOT REMOVE FROM FILE

VIA HAND DELIVERY

September 15, 2010

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit St., Suite 10
Concord, New Hampshire 03301

Re: **Northern Utilities, Inc. -- DG 10-   , 2010 / 2011 Winter Season Cost of Gas and Associated Charges Filing**

Dear Ms. Howland:

Northern Utilities, Inc. ("Northern" or the "Company") hereby submits an original and seven copies of the Exhibits and Direct Testimony of James D. Simpson, Francis X. Wells and Joseph F. Conneely in support of the Company's 2010-2011 Winter Season Cost of Gas filing and other associated proposed tariff changes.

Northern respectfully requests approval for the following Tariffs:

Forty-seventh Revised Page 38 (CGA);
Fifty-first Revised Page 39 (CGA);
Fourteenth Revised Page 56 (LDAC);
Forty-sixth Revised Page 94 (Rate Summary);
Forty-sixth Revised Page 95 (Rate Summary);
Fortieth Revised Page 96 (Rate Summary);
Tenth Revised Page 154 (Appendix A);
Ninth Revised Page 169 (Appendix C); and
Third Revised Page 170-b (Appendix D).

The above listed tariffs are issued September 15, 2015 by Mark H. Collin, Treasurer, to be effective November 1, 2010.

Forty-seventh Revised Page 38 (CGA) is the statement of the Company's anticipated direct and indirect costs of gas.

Fifty-first Revised Page 39 (CGA) contains the calculations of the proposed Cost of Gas Adjustment Rates for Residential and General Service Firm Sales Customers.

Fourteenth Revised Page 56 (LDAC) contains proposed rates for the Company's RLIAP rate DSM rate and ERC Rate, all of which are components of the Company's Local Distribution Adjustment Clause rate. Support for the ERC Component was filed under separate cover on September 15, 2010.

Frederick J. Stewart
Manager Regulatory Services

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Hampton, NH 03842-1720

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Forty-sixth Revised Pages 94, 95 & 96 (Rate Summaries) have been updated to reflect the proposed CGA and the proposed LDAC.

Tenth Revised Page 154 (Appendix A), Schedule of Administrative Fees and Charges: the Supplier Balancing Charge has been updated to reflect the Company's latest balancing resources and associated capacity costs, and the Peaking Service Demand Charge has been updated to reflect the Company's Peaking resources and associated costs, as discussed in the Testimony of James D. Simpson and shown in Schedule 10A.

Ninth Revised Page 169 (Appendix C) contains the proposed Capacity Allocators.

Third Revised Page 170-b (Appendix D) contains the Firm Sales Service Re-Entry Fee Bill Adjustment. Support for this charge was provided to the Commission in the Company's annual report filed under separate cover on September 15, 2010.

The proposed 2010 / 2011 Winter Season Cost of Gas Adjustment (CGA) for residential customers is $1.1177 per therm, $0.1041 per therm or 10.3 percent higher than the 2009 / 2010 Winter Season CGA. The typical bill for a residential heating customer for the 2010 / 2011 Winter Season is projected to be $1,453.04; this is higher than the 2009 / 2010 Winter Season bill of $1,341.35 by $111.69 or 8.3 percent.

Also included in the filing behind Tab Schedule 15 is a revised reconciliation of the 2009 / 2010 Winter Season gas costs and recoveries. The revision was made necessary by changes to the Adjusted Target Volumes (ATV) reconciliation.

The Company will submit to the Commission its revised 2010 / 2011 Winter Season CGA reflecting then current costs a few weeks before the November 1, 2010 effective date.

Please be advised that Susan Geiger, Esq. of Orr & Reno has been engaged to represent Northern in this proceeding.

If you have any questions or need additional information, please contact me or Susan Geiger.

Very Truly Yours,

Frederick J. Stewart

Enclosures

CC: Edward Damon, Staff Counsel
Meredith Hatfield, OCA
Kenneth Traum, OCA
Susan Geiger, Orr & Reno
James D. Simpson, CEA

NORTHERN UTILTIES, INC. - NEW HAMSHIRE DIVISION
Winter Season 2010-2011 Cost of Gas Filing

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N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2010 - April 30, 2011

	Column A	Column B	Column C
1	**ANTICIPATED DIRECT COST OF GAS**		
2	**Purchased Gas for Sales Service:**		
3	Demand Costs:	$ 1,944,296	
4	Supply Costs:	$ 5,408,538	
5			
6	**Storage & Peaking Gas for Sales Service:**		
7	Demand, Capacity:	$ 13,538,806	
8	Commodity Costs:	$ 7,629,178	
9			
10	**Hedging (Gain)/Loss**	$ 1,054,446	
11			
12	**Interruptible Sendout Cost**	$ -	
13			
14	**Inventory Finance Charge**	$ 10,094	
15			
16	**Capacity Release, Asset Management, PNGTS Cost,**	$ (1,771,080)	
17	**PNGTS Refund**		
18	**Adjustment for Actual Costs**	$ -	
19			
20	**Total Anticipated Direct Cost of Gas**		$ 27,814,277
21			
22	**ANTICIPATED INDIRECT COST OF GAS**		
23	**Adjustments:**		
24	Prior Period Under/(Over) Collection	$ 2,527,403	
25	Prior Period Adjustment (ATV Reconciliation)	$ -	
26	Interest	$ 99,945	
27	Refunds	$ -	
28	Interruptible Margins	$ -	
29	Total Adjustments		$ 2,627,348
30			
31	**Working Capital:**		
32	Total Anticipated Direct Cost of Gas	$ 27,814,277	
33	Working Capital Percentage	0.190%	
34	Working Capital Allowance	$ 52,847	
35			
36	Plus: Working Capital Reconciliation (Acct 182.11)	$ (83,069)	
37			
38	Total Working Capital Allowance		$ (30,222)
39			
40	**Bad Debt:**		
41	Total Anticipated Direct Cost of Gas	$ 27,814,277	
42	Plus: Prior Period Under/(Over) Collection	$ 2,527,403	
43	Plus: Prior Period Adjustment (ATV Reconciliation)	$ -	
45	Plus: Total Working Capital	$ (30,222)	
46	Subtotal	$ 30,311,459	
47			
48	Bad Debt Percentage	0.450%	
49	Bad Debt Allowance	$ 136,402	
50	Plus: Bad Debt Reconciliation (Acct 182.16)	$ (2,655)	
51	Total Bad Debt Allowance		$ 133,747
52			
53	**Local Production and Storage Capacity**		$ 686,673
54			
55	**Miscellaneous Overhead-79.11% Allocated to Winter Season**		$ 98,333
56			
57	**Total Anticipated Indirect Cost of Gas**		$ 3,515,879
58			
59	**Total Cost of Gas**		$ 31,330,157
60			
61			
62			

N.H.P.U.C No.10 **Summary**
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2010 - April 30, 2011

	Column A	Reference **Column D**
1	<u>**ANTICIPATED DIRECT COST OF GAS**</u>	
2	**Purchased Gas for Sales Service:**	
3	Demand Costs:	Schedule 1A, LN 71
4	Supply Costs:	Schedule 1B, LN 15
5		
6	**Storage & Peaking Gas for Sales Service:**	
7	Demand, Capacity:	Schedule 1A, LN 71
8	Commodity Costs:	Schedule 1B, LN 16 + Schedule 1B, LN 17
9		
10	**Hedging (Gain)/Loss**	Schedule 1B, LN 15
11		
12	**Interruptible Sendout Cost**	-(Schedule 1B, LN 22)
13		
14	**Inventory Finance Charge**	Schedule 22, LN 105
15		
16	**Capacity Release, Asset Management, PNGTS Cost,**	-(Schedule 1A, LN 76)
17	**PNGTS Refund**	
18	**Adjustment for Actual Costs**	
19		
20	**Total Anticipated Direct Cost of Gas**	Sum (LN 3 : LN 18)
21		
22	<u>**ANTICIPATED INDIRECT COST OF GAS**</u>	
23	**Adjustments:**	
24	Prior Period Under/(Over) Collection	Schedule 3, LN 105: April
25	Prior Period Adjustment (ATV Reconciliation)	
26	Interest	LN 44
27	Refunds	Company Analysis
28	<u>Interruptible Margins</u>	-(Schedule 1A, LN 77)
29	Total Adjustments	Sum (LN 24 : LN 28)
30		
31	**Working Capital:**	
32	Total Anticipated Direct Cost of Gas	LN 20
33	Working Capital Percentage	NHPUC No. 10 Section 4.06.1
34	Working Capital Allowance	LN 32 * LN 33
35		
36	Plus: Working Capital Reconciliation (Acct 182.11)	Company Analysis
37		
38	Total Working Capital Allowance	Sum (LN 34 : LN 36)
39		
40	**Bad Debt:**	
41	Total Anticipated Direct Cost of Gas	LN 20
42	Plus: Prior Period Under/(Over) Collection	LN 24
43	Plus: Prior Period Adjustment (ATV Reconciliation)	LN 25
45	Plus: Total Working Capital	LN 38
46	Subtotal	Sum (LN 41 : LN 45)
47		
48	Bad Debt Percentage	NHPUC No. 10 Section 4.06.1
49	Bad Debt Allowance	LN 48 * LN 46
50	Plus: Bad Debt Reconciliation (Acct 182.16)	Company Analysis
51	Total Bad Debt Allowance	LN 49 + LN 50
52		
53	**Local Production and Storage Capacity**	Schedule 1B, LN 84
54		
55	**Miscellaneous Overhead-79.11% Allocated to Winter S**	Schedule 1B, LN 83
56		
57	**Total Anticipated Indirect Cost of Gas**	Sum (LN 29 : LN 55)
58		
59	**Total Cost of Gas**	LN 57 + LN 20
60		
61		
62		

CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: November 1, 2010 - April 30, 2011

Column A		**Column B**	**Column C**	
Total Anticipated Direct Cost of Gas		$ 27,814,277		
Projected Prorated Sales (11/01/10 - 04/30/11)		28,028,950		
Direct Cost of Gas Rate			$ 0.9923	per therm
Demand Cost of Gas Rate		$ 13,712,022	$ 0.4892	per therm
Commodity Cost of Gas Rate		$ 14,102,256	$ 0.5031	per therm
Total Direct Cost of Gas Rate		$ 27,814,277	$ 0.9923	per therm
Total Anticipated Indirect Cost of Gas		$ 3,515,879		
Projected Prorated Sales (11/01/10 - 04/30/11)		28,028,950		
Indirect Cost of Gas			$ 0.1254	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/2010			**$ 1.1177**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/10		COGwr	**$ 1.1177**	**per therm**
	Maximum (COG+25%)		**$ 1.3971**	
COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10		COGwl	**$ 1.0019**	**per therm**
	Maximum (COG+25%)		**$ 1.2524**	
C&I HLF Demand Costs Allocated per SMBA	$ 712,743			
PLUS: Residential Demand Reallocation to C&I HLF	$ 12,540			
C&I HLF Total Adjusted Demand Costs	$ 725,283			
C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	2,402,246			
Demand Cost of Gas Rate	**$ 0.3019**			
C&I HLF Commodity Costs Allocated per SMBA	$ 1,378,807			
PLUS: Residential Commodity Reallocation to C&I HLF	$ 1,419			
C&I HLF Total Adjusted Commodity Costs	$ 1,380,226			
C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	2,402,246			
Commodity Cost of Gas Rate	**$ 0.5746**			
Indirect Cost of Gas	**$ 0.1254**			
Total C&I HLF Cost of Gas Rate	**$ 1.0019**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/10		COGwh	**$ 1.1398**	**per therm**
	Maximum (COG+25%)		**$ 1.4248**	
C&I LLF Demand Costs Allocated per SMBA	$ 6,495,498			
PLUS: Residential Demand Reallocation to C&I LLF	$ 114,281			
C&I LLF Total Adjusted Demand Costs	$ 6,609,778			
C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	12,591,463			
Demand Cost of Gas Rate	**$ 0.5249**			
C&I LLF Commodity Costs Allocated per SMBA	$ 6,157,247			
PLUS: Residential Commodity Reallocation to C&I LLF	$ 6,338			
C&I LLF Total Adjusted Commodity Costs	$ 6,163,585			
C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	12,591,463			
Commodity Cost of Gas Rate	**$ 0.4895**			
Indirect Cost of Gas	**$ 0.1254**			
Total C&I LLF Cost of Gas Rate	**$ 1.1398**			

63	CALCULATION OF FIRM SALES COST OF GAS RATE	
64	Period Covered: November 1, 2010 - April 30, 2011	
65		
66	**Column A**	**Column D**
67		
68	Total Anticipated Direct Cost of Gas	LN 20
69	Projected Prorated Sales (11/01/10 - 04/30/11)	Company Analysis
70	**Direct Cost of Gas Rate**	LN 68 / LN 69
71		
72	**Demand Cost of Gas Rate**	Column B : SUM (LN 3 , LN 7 , LN 16)
73	**Commodity Cost of Gas Rate**	Column B : SUM (LN 4 , LN 8 , LN 10 , LN 12 , LN 14)
74	**Total Direct Cost of Gas Rate**	SUM (LN 72 : LN 73)
75		
76	Total Anticipated Indirect Cost of Gas	LN 57
77	Projected Prorated Sales (11/01/10 - 04/30/11)	Company Analysis
78	**Indirect Cost of Gas**	LN 76 / LN 77
79		
80		
81	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE**	LN 74 + LN 78
82		
83	**RESIDENTIAL COST OF GAS RATE - 11/01/10**	Company Analysis
84		LN 83 * 1.25
85		
86		
87	**COM/IND LOW WINTER USE COST OF GAS RATE - 11**	Company Analysis
88		LN 87 * 1.25
89		
90	C&I HLF Demand Costs Allocated per SMBA	Schedule 10A, LN 169
91	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 26, LN 16
92	C&I HLF Total Adjusted Demand Costs	Sum (LN 90 : LN 91)
93	C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	Company Analysis
94	**Demand Cost of Gas Rate**	LN 92 / LN 93
95		
96	C&I HLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 139
97	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 26, LN 26
98	C&I HLF Total Adjusted Commodity Costs	Sum (LN 96 : LN 97)
99	C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	Company Analysis
100	**Commodity Cost of Gas Rate**	LN 98 / LN 99
101		
102	**Indirect Cost of Gas**	LN 78
103		
104	**Total C&I HLF Cost of Gas Rate**	Sum (LN 94, LN 100, LN 102)
105		
106		
107	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11**	Company Analysis
108		LN 107 * 1.25
109		
110	C&I LLF Demand Costs Allocated per SMBA	Schedule 10A, LN 170
111	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 26, LN 17
112	C&I LLF Total Adjusted Demand Costs	Sum (LN 110 : LN 111)
113	C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	Company Analysis
114	**Demand Cost of Gas Rate**	LN 112 / LN 113
115		
116	C&I LLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 140
117	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 26, LN 27
118	C&I LLF Total Adjusted Commodity Costs	Sum (LN 116 : LN 117)
119	C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	Company Analysis
120	**Commodity Cost of Gas Rate**	LN 118 / LN 119
121		
122	**Indirect Cost of Gas**	LN 78
123		
124	**Total C&I LLF Cost of Gas Rate**	Sum (LN 114, LN 120, LN 122)

Northern Utilities, Inc.

New Hampshire Division

Winter Season 2010-2011
Proposed Cost of Gas Adjustment

To be Effective November 1, 2010

Filed September 15, 2010

Unitil
Northern Utilities, Inc.

Prefiled Testimony of James D. Simpson

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2010 / 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 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 my time at Bay State, 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 NUI-JDS-1 of 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 / 2010 Winter Cost of Gas ("COG") proceeding, Docket No. DG 09-167, the 2009 Summer Cost of Gas proceeding, Docket No. DG 09-052, and the 2010 Summer Cost of Gas proceeding, Docket No. DG 10-050. In addition, while I 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 prepared direct testimony in this proceeding.

A. Francis X. Wells, Senior Energy Trader for Unitil; Joseph F. Conneely, Senior Regulatory Analyst for Unitil; and I are sharing the responsibility in this proceeding for describing and explaining the proposed 2010 / 2011 Winter New Hampshire Division COG rate adjustment that the Company is proposing to make effective November 1, 2010. 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 Maine and New Hampshire divisions. Mr. Wells will also describe the impact of the Company's Hedging Program for the 2010 / 2011 Winter period. Mr. Conneely will discuss the calculation of the 2010 / 2011 Environmental Response Cost Rate Adjustment, and typical bill analyses for the proposed Winter New Hampshire Division COG rates.

I will describe and explain the calculation of the COG that Northern Utilities proposes to bill from November 1, 2010 to April 30, 2011. I will also discuss the New Hampshire 2009 / 2010 Winter Cost-of-Gas Reconciliation Filing.

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.

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 2009 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 22	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Schedule 21	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Schedule 23	Supporting Detail to Proposed Tariff Sheets

II. COST OF GAS FACTOR

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

Q. Please explain how the projected fixed capacity-related costs, i.e. (a) pipeline reservation and gas supply demand charges, (b) underground storage capacity costs and (c) peaking resource capacity costs are allocated between Northern's Maine and New Hampshire divisions.

A. 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 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

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[1] Pipeline, storage, and peaking

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.

As I will explain in more detail in the following responses, I used the MPR methodology to allocate total Northern annual demand costs to the Maine and New Hampshire divisions for the 2010 / 2011 Winter period, i.e. November 2010 through April 2011, and for the 2011 Summer COG, i.e. May through October 2011.

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

A. I have prepared Schedule 21 to explain how I calculated the MPR factors and then how I used these factors to allocate total Northern annual demand costs for the period November 2010 through October 2011 ("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) These 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); the MPR allocators are based

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

on design year sendout volumes for each resource type. (3) The fixed capacity costs that are allocated to each month in Step 2 are then allocated to the Maine and New Hampshire divisions according to design year total firm sendout as shown in Lines 58 through 90. The last column of Pages 2 and 4 of Schedule 21 are descriptions of the sources of data and explanations of the calculations that I have included in Schedule 21 and 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.[3] 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. As shown on Schedule 21, Line 7, Northern Utilities' share of litigation costs that have been incurred by the PNGTS Shippers Group ("PSG") in the PNGTS rate case, RP08-306 from September, 2009 to mid-August 2010 is $326,567. For the purpose of incorporating the PNGTS Litigation Expense, which is discussed in Mr. Well's testimony, into the cost of gas rates, I have reflected these costs as an offset to Asset Management revenues throughout the attachments to my testimony. Mr. Wells has also provided an estimate refunds from the PNGTS rate cast RP08-306. I have added the sales customers' portion of the PNGTS refund to the Asset Management revenues, net of the PNGTS litigation costs.

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

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 the Storage demand costs, as shown on Line 39, and subtracted from the Pipeline demand costs, as shown on Line 53.

Northern fixed capacity costs that have been allocated to each month are summarized and consolidated on Lines 50 through 56. Lines 50, 51 and 52 repeat the Pipeline, Storage, and Peaking capacity costs from Lines 22, 40, and 49. Line 53 shows the credit to Pipeline capacity costs that is related to the Injection Fees that have been added to the Storage capacity costs. In addition, (a) $1/5^{th}$ 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 PSG 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 PSG 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 Asset Management revenues allocated to each month are then allocated to the Maine and New Hampshire divisions according to the design year total sendout for Maine and New Hampshire, 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 firm sales and transportation customers that are subject to the assigned capacity requirements under Design conditions from May 2009 through April 2010.

As shown on Line 90 of Schedule 21, 48.95% of total Northern demand costs from November 2010 through October 2011 will be allocated to New Hampshire and the remaining 51.05%, as shown on Line 81, will be allocated to Maine.

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

Q. Please explain how the projected annual demand-related costs that are allocated to New Hampshire are then assigned to be recovered in the 2010 / 2011 Winter period and the 2011 Summer period.

A. I have prepared Schedule 1A to show detailed support for the allocation of New Hampshire 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 New Hampshire less the capacity assignment revenues from New Hampshire transportation customers. The Winter and Summer rates that will be charged to New Hampshire firm sales customers from November 2010 through October 2011 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 2011[6], 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 that Remaining 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 show the calculation of the PR factor that is used to allocate (a) Remaining Net Pipeline Demand costs and (b) Storage and Peaking costs related to Firm Sales customers to the twelve months, November 2010 through October 2011. 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 six Peak months, November 2010 through April 2011. These PR factors are summarized by type of capacity cost in lines 61 through 65. Line 61 of Schedule 1A shows that one twelfth of the Net annual base use pipeline demand costs are allocated to each

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4 These direct demand costs are adjusted by Capacity Release and Asset Management revenues net of PNGTS litigation costs and the PNGTS refund (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 demand costs are allocated to seasons.

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

month and Lines 68 through 84 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 demand costs to be recovered in the 2010 / 2011 Winter COG rates, $13,712,022, is shown on Line 80, Winter total column, of Schedule 1A.

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

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Winter 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' prorata 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' 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 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 daily base use, shown on Lines 35 to 48; base sendout, shown on Lines 49 to 64; and remaining sendout, shown on Lines 66 to 80. These base and remaining sendout values for each class are used to allocate the Winter period demand costs to New Hampshire division firm sales classes.

I have prepared Schedule 10A to show the allocation of Winter 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 Winter period month as shown in Schedule 1A, Lines 69 through 80 and (b) the Rate Class allocators as shown Schedule 10B, Lines 49 to 80. 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. 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 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 2010 / 2011 Winter period variable gas costs between Maine and New Hampshire.

Q. Please explain Schedule 22 in 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 11, and 18 through 20 of Schedule 22. The pipeline commodity costs shown on Lines 11 and 18 are based on projected NYMEX prices as of July 22, 2010. 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 Maine and New Hampshire 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 through 37; these price-triggered hedging gains and losses are directly assigned to New Hampshire. Schedule 22 also shows the allocation of (a) Commodity costs (Maine: Lines 65, 67, 68, and 69; New Hampshire: Lines 74, 76, 77, and 78); and (b) hedging

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7 Variable costs include Pipeline usage / commodity charges, Pipeline fuel retention, Storage commodity injection and withdrawal charges, and Storage Fuel retention.

gains and losses (Lines 66 and 75) to Maine and New Hampshire. Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 99 to 101); the allocation of these costs to Maine and New Hampshire (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).

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[8]. These inventory finance costs were calculated based on forecasted inventory activity calculations; I have prepared Schedule 14 to show these calculations.

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 2010, the Company does not incur inventory finance costs on the Washington 10 inventories, and the

[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 99 through 101. Total 2010 / 2011 inventory finance costs allocated to New Hampshire, $10,094 (Line 105) are recovered in the Peak period, as shown on Line 71 of Schedule 22.

Company anticipates contracting for similar terms beginning April 1, 2011. For this reason, no inventory finance costs were calculated for Washington 10 Storage, 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[9] 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[10] to each rate class. A summary of all commodity costs allocated to New Hampshire firm sales classes is shown on Lines 99 to 140.

E. Refunds

Q. Are there any refunds included in this filing?

A. Yes, as I have previously described in this testimony, a refund from PNGTS has been included in this filing.

F. 2009 – 2010 Winter Period Reconciliation

Q. Please explain the 2009 / 2010 Winter period over and under-collections.

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

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

A. The 2009 / 2010 Winter Period Cost of Gas (COG) Adjustment Reconciliation (Form III), which was filed with the Commission on July 30, 2010, provides a detailed explanation of the Winter undercollection of $2,527,403 a as of April 30, 2010

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 2010 / 2011 Winter period?

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

H. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division Cost of Gas factors for the 2010 / 2011 Winter period.

A. The Summary Schedule, which is a copy of COG tariff pages 38 and 39, has been prepared to explain the calculation of the proposed 2010 / 2011 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 2010 / 2011 Winter period COG 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 2010 / 2011 Winter period, the projected Average Cost of Gas is $1.1177 per therm (Line 83), which is the sum of the Average Direct Cost of

Gas, \$0.9923 per therm (Line 74), and the Average Indirect Cost of Gas, \$0.1254 per therm (Line 78).

Q. What are the major components of the 2010 / 2011 Winter 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	\$1,944,296	3
2	Purchased Gas Supply Costs	\$5,408,538	4
3	Storage and Peaking Capacity Costs	\$13,538,806	7
4	Storage and Peaking Commodity Costs	\$7,629,178	8
5	Hedging (Gain) / Loss	\$1,054,446	10
6	Interruptible Costs	\$0	12
7	Capacity Release, Asset Management, PNGTS Cost, PNGTS Refund	\$(1,771,080)	16
8	Total Anticipated Direct Cost of gas	\$27,814,277	20

Q. What are the major components of the 2010 / 2011 Winter 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	\$2,527,403	24
2	Interest	\$99,945	26
3	Refunds	\$0	27
4	Interruptible Margins	\$0	28
5	Working Capital Allowance	\$(30,222)	38

6	Bad Debt Allowance	$133,747	51
7	Local Production and Storage	$686,673	53
8	Miscellaneous Overhead	$98,333	55
9	Total Anticipated Indirect Cost of Gas	$3,515,879	57

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

The total Working Capital allowance, $(30,222) shown on Line 38 of the Summary Schedule is the sum of the current period working capital allowance, $52,847 (Line 34), plus the prior period Working Capital reconciliation balance, $(83,069) (Line 36).

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

A. The Bad Debt allowance of $133,747 (Line 51) is the sum of the current period bad debt allowance, $136,402 (Line 49), plus the prior period Working Capital reconciliation balance, $(2,655) (Line 50).

A. Summary Analyses

Q. How does the proposed 2010 / 2011 Winter period COG rate compare with the actual 2009 / 2010 Winter period gas costs?

A. I have prepared Schedule 9 to compare the proposed 2010 / 2011 Winter average COG rate with actual 2009 / 2010 Winter gas costs. Schedule 9 indicates that the projected 2010 / 2011 Winter period average COG rate ($1.1177 per therm) is $0.0599 per therm higher than the actual 2009 / 2010 Winter period Total Adjusted Cost ($1.0579 per therm). The overall change in the proposed 2010 / 2011 Winter rate compared to the actual 2009 / 2010 Winter average cost of gas is primarily due to (1) increases in demand costs, which are largely offset by (2) decreases in commodity costs. The difference between Winter 2009 / 2010 actual average Direct Gas Costs and Winter 2010 /2011 projected average Direct Gas Costs, on Line 15 is $0.0557 per therm, which is the result of (a) an increase of $0.1437 per therm in pipeline and storage demand costs (Line 6); (b) a decrease of $0.0261 in pipeline, storage and peaking commodity costs (lines 8 and 10) and (c) a decrease of $0.0665 per therm in hedging losses (line 12). The small difference between Winter 2009 / 2010 actual average Indirect Gas Costs and Winter 2010 /2011 projected average Indirect Gas Costs, on Line 31 is $0.0043 per therm.

III. ANCILLARY RATES

A. Supplier Balancing Charge

Q. Have you updated the Supplier Balancing Charge for the period November 1, 2010 through October 31, 2011?

A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1, 2010, $0.75 per MMBtu, is unchanged from the currently effective Supplier Balancing Charge. I have prepared Schedule xx to support the updated Supplier Balancing Charge.

IV. FINAL MATTERS

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

A. Yes. The Company plans to file a revised calculation of its 2010 / 2011 Winter Period COG to reflect updated gas cost projections and/or other information a few weeks prior to the effective date of November 1, 2010.

Q. Does this conclude your testimony?

A. Yes it does.

Prefiled Testimony of Francis X. Wells

Unitil
Northern Utilities, Inc.

**NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD
COST OF GAS FILING
PREFILED TESTIMONY OF
FRANCIS X. WELLS**

I. INTRODUCTION

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

A. My name is Francis X. Wells. I am Senior Energy Trader for Unitil Service Corp. ("Unitil"). My business address is 6 Liberty Lane West, Hampton, NH.

Q. Please describe your relevant educational and work experience.

A. I received my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined Unitil in September 1996, assisting in the planning and operation of both electric power and natural gas supply portfolios. Since January 2001, I have worked as a Senior Energy Trader in the Energy Contracts Department. I have responsibilities in the areas of (1) energy supply acquisition, including natural gas supply procurement, electric default service purchasing; (2) regulatory testimony and reporting; (3) budgeting for both natural gas and electric supply, and (4) long-term supply planning.

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

A. Yes. I have testified as Northern's gas supply witness before the Commission in Northern's Cost of Gas Factor ("COG") filings since Unitil Corporation acquired Northern in December 2008. I have also testified numerous times before the Commission on behalf of Northern's affiliate, Unitil Energy Systems, Inc. on electric supply related matters.

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

A. First, I will provide an overview of Northern's sales and sendout projections for the 2010-2011 Winter Period.

Second, I will provide a summary of Northern's natural gas supply portfolio, which will be used to meet these supply requirements.

Third, I will provide a detailed forecast of the gas supply cost forecast, based on the sendout forecast and the natural gas supply portfolio. The gas supply cost forecast includes the following items:

- Fixed Demand Costs, including reservation and demand charges for supply contracts, transportation contracts and storage contracts that are part of Northern's wholesale portfolio of contracts and any projected offsets due to Northern's capacity assignment program or the optimization of Northern's portfolio through capacity release contracts or asset management contracts. The Fixed Demand Cost forecast is updated once annually, for COG rates effective November 1 each year.

- Variable Commodity Costs, including any variable supply and transportation or storage charges to be incurred to deliver natural gas commodity to meet Northern's projected sendout requirements.

- Gains or Losses of Northern's Hedging Program

- Projected Storage Inventory costs and balances

Finally, I will also provide support to the Company's proposal to recover approximately $184,000 in external legal and consulting costs rising from Northern's opposition to proposed rate increases by Portland Natural Gas Transmission System under FERC Docket No. RP08-306 ("2008 PNGTS Rate Case") and FERC Docket No. RP10-729 ("2010 PNGTS Rate Case").

I have provided these materials to James Simpson, Vice President of Concentric Energy Advisors, who used them as inputs to calculate the proposed COG. He also discusses the impact that the proposed COG will have on the bills of the Company's typical customers.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast metered distribution deliveries[1] for the Company's residential, small commercial and larger industrial/commercial classes, the Company has utilized time-series techniques to develop two forecast models: use-per-meter and the number of meters. The growth rates for customers (meters) and use-per-meter from these models are applied to the most recent data normalized for weather; the forecast monthly billed deliveries for each customer class was calculated by multiplying forecast customers times forecast use-per-customer. Forecast deliveries for the large commercial customers with special contracts were developed separately for each of these customers.[2]

Q. Please provide the forecast distribution deliveries, meter counts and use-per-meter figures utilized in this COG filing and a comparison of this forecast to weather normalized data for prior periods.

A. I have prepared Table 1, below, which provides a summary of the company's forecast of total billed distribution deliveries for the upcoming 2010-2011 Peak Period.

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[1] In my testimony I use the term "deliveries" to refer to the volumes or quantities of gas that are distributed to the premises of sales customers and transportation customers. I use the term "sales customer" to refer to a gas customer that receives bundled distribution and gas supply service from Northern. Finally, I use the term "transportation customer" to refer to a gas customer that receives distribution service from Northern and gas supply service from a competitive retail supplier.

[2] When forecasting the Large General rate classes (G42 & T42, G52 & T52 and Special Contracts), the Company utilizes individual customer forecasts through the first full calendar year of the forecast. Thereafter, the Company relies on its forecast of use-per-meter and the number of meters for each rate class. Since this COG filing relies solely on forecast data within the first calendar year, the Large General forecast is based on the individual forecasts.

Table 3. 2010-2011 Winter New Hampshire Division Metered Usage Forecast Compared to Prior Years (All Units in Dth)

Month	2010-11 Forecast[1]	2009-10 Actual[2]	2010-11 minus 2009-10	Percent Change	2008-09 Actual[3]	2010-11 minus 2008-09	Percent Change
Nov	542,536	525,777	16,759	3.19%	549,450	-6,913	-1.26%
Dec	770,259	785,751	-15,492	-1.97%	792,007	-21,748	-2.75%
Jan	1,015,419	1,050,941	-35,522	-3.38%	990,236	25,183	2.54%
Feb	1,015,501	974,983	40,518	4.16%	991,088	24,413	2.46%
Mar	878,056	868,777	9,279	1.07%	894,108	-16,052	-1.80%
Apr	677,756	697,010	-19,254	-2.76%	678,954	-1,198	-0.18%
Season	4,899,527	4,903,238	-3,712	-0.08%	4,895,842	3,685	0.08%

Note 1: Company Forecast.
Note 2: Actual Weather-Normalized Data.
Note 3: Actual Weather-Normalized Data.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2010-2011 Gas Year in Attachment 1 to Schedule 10B. Page 1 of Attachment 1 to Schedule 10B provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate classes, heating residential rate classes and commercial and industrial rate classes, respectively. The top section of each page provides the 2010-2011 Gas Year distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2009-2010 and 2008-2009 Gas Years. The changes in the distribution deliveries from the prior period are explained in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Attachment 1 to Schedule 10B provides a calculation of the use-per-meter, which have been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. Please provide an overview of the process for converting the forecast distribution deliveries forecast to a sales service deliveries forecast.

A. In order to prepare this COG filing, Northern reduced its total distribution deliveries forecast to reflect only the distribution deliveries to those customers taking sales service. My commodity cost forecast, which I present later, reflects only the projected costs to serve Northern's sales service obligations. Customers electing transportation-only service reflect a substantial portion of Northern's total distribution deliveries and the cost of gas for these customers is determined by the private contractual arrangements between the customers and their retail marketer.

I estimated the percentage of total distribution deliveries supplied through Sales Service ("Sales Service Percentage") for each rate class based upon the most recent 12 months of historical distribution and sales service deliveries data available at the time of the analysis.

I converted the billed distribution deliveries forecast to a calendar-month distribution deliveries forecast by utilizing the same model used by the Company to develop the billed distribution deliveries forecast. Using this model, I replaced the projected bill cycle data for monthly days and effective degree days with calendar month days and effective degree days. For each rate class, I multiplied by projected Sales Service Percentage times the projected calendar-month distribution deliveries forecast to calculate the sales service deliveries forecast. Having converted the billed distribution service deliveries to calendar month Sales Service deliveries, I then calculated the city-gate supply required to serve the Sales Service deliveries.

Attachment 2 to Schedule 10B provides my back-up calculations for this analysis. On Pages 1 and 2 of Attachment 2 to Schedule 10B, I present my calculation of the calendar month and billed sales service deliveries by rate class, using the methodology I discuss above. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the New Hampshire Division. I have also prepared Schedule 13, which provides annual summary data for sales service and transportation service deliveries by rate class.

On Page 3 of Attachment 2 to Schedule 10B, I present my calculations of the city-gate receipts. First, I estimated Company Use by multiplying the forecast Total Deliveries and the estimated ratio of Company-Use to Total Deliveries. Then, I added Company Use to the total Calendar Sales Service Deliveries, calculated on Page 1 ("Sales Service plus Company Use"). Then, I added an estimate for Lost and Unaccounted for Gas. Each of the estimates used in these calculations was based on the recent history of actual data.

Q. Please summarize the Company's forecast of sales service deliveries and city-gate receipts required to meet the projected sales service deliveries.

A. I have prepared Table 2, below, which provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries and City-Gate Receipts to meet the Sales Service Deliveries[3] for the upcoming Peak Period. The detailed calculations can be found in Attachment 2 to Schedule 10B.

Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary

Month	Total Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-10	586,642	304,710	312,051
Dec-10	851,652	472,252	483,928
Jan-11	1,045,034	638,023	652,778
Feb-11	912,462	542,998	555,527
Mar-11	892,658	525,753	537,934
Apr-11	599,363	319,160	326,540
Winter	4,887,810	2,802,895	2,868,758

III. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its sales customers.

A. I have prepared Table 3, below, which provides an overview of the sources of supply available to Northern through its portfolio of long-term contracts, including transportation contracts, storage contracts, peaking supply contracts and an exchange agreement with Bay State Gas Company.

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[3] When I use the term "City-Gate Receipts to meet the Sales Service Requirements", I refer to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, Maritimes and Northeast, L.L.C and Tennessee Gas Pipeline and the Company's LNG facility.

Table 3. Northern Capacity by Source of Supply

Supply Source:	Northern Deliverable Capacity (Dth per Day)
Chicago (Interconnection of Alliance and Vector Pipelines)	6,433
Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)	1,095
Niagara (Interconnection of TransCanada and Tennessee Pipelines)	3,280
Tennessee Production Area	13,089
Washington 10 Storage*	32,835
Tennessee Firm Storage - Market Area	2,640
Peaking Supply 1	4,975
Peaking Supply 2*	52,735
Lewiston LNG	10,000
Total Deliverable Capacity	127,082

* indicates that the capacity is deliverable only during the months of November through March on a firm basis.

I have prepared a capacity path diagram and capacity path detail for each of the supply sources listed above (except the Lewiston LNG, which feeds directly into Northern's distribution system), showing the transportation, storage and long-term supply contracts required to provide the Northern Deliverable Capacity listed each source of supply. This information is found in Schedule 12.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited, Transportation ("TransCanada"), Vector Pipeline L.P. ("Vector"), Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P. ("Iroquois") and Texas Eastern Transmission System, L.P. ("Texas Eastern" or "TETCO"). The gas supply portfolio also includes long-term storage contracts with Washington 10 Storage Corporation ("Washington 10" or "W10"), Tennessee and Texas Eastern, as well as long-term peaking supply contracts, Distrigas of Massachusetts Corporation ("Peaking Supplier 1") and FPL Energy Power Marketing, Inc. ("Peaking Supplier 2"). Finally, as I mentioned previously, the gas supply portfolio consists of an exchange agreement with Bay State Gas Company ("BSG Exchange" or "Bay State Exchange Agreement"). Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which is capable of producing approximately 10,000 Dth per day and storing approximately 12,000 Dth of LNG.

I have prepared the capacity path diagrams and capacity path details in Schedule 12 in order to show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, in order to move natural gas supplies from the sources of supply listed in Table 3 to Northern's distribution system. Each of these contractual arrangements represents a segment in one or more capacity paths. The capacity path diagrams show how each segment in the path is interconnected within the path.

The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

Q. Has the Company entered into any long-term releases of capacity?

A. Yes. The Company has found that some of its Algonquin and Texas Eastern transportation contracts were not highly utilized by Northern, but were highly valued in the market-place. Northern has permanently released the Algonquin and Texas Eastern contracts contributing to the majority of costs for the capacity paths, listed in Table 4, below.[4] These releases are at the maximum allowable rates, benefiting customers by fully recovering the costs of the released contracts. As a result, capacity from these supply sources is no longer deliverable. For completeness, Pages 9 and 10 of Schedule 12 also contains capacity path diagrams and capacity path details of these released capacity paths in order to provide a complete picture of the portfolio.

Table 4. Released Capacity	
Supply Source:	Northern Deliverable Capacity (Dth per Day)

[4] Northern has the right to a single recall of its permanent releases of Algonquin contract number 93201A1C and Texas Eastern contract number 800384.

Texas Eastern Production and Storage & Algonquin (Centerville, NJ)	286
Texas Eastern Zone M3	965
Total Released Capacity	1,251

Q. What updates have been made to Northern's capacity portfolio since the last Winter COG filing?

A. Northern has elected not to renew 1,196 GJ of TransCanada capacity from Empress, Alberta to the interconnection of TransCanada and PNGTS at East Hereford. At current TransCanada demand rates, the annual projected demand cost for this capacity is approximately $750,000 per year.

Northern has recently entered into a new contract with Granite. Contract 10-010-FT-NN contains a renewal clause, allowing the contract to continue on a year-to-year basis. Each party shall have the right to terminate the agreement effective November 1 of each year with a one-year notice provision.

Northern has also entered into an amendment of the Bay State Exchange, which will become effective for the upcoming peak season. The effect of this amendment is to define the volume of natural gas to be exchanged as the lower of the volumes desired by each party to the Bay State Exchange (Northern and Bay State). The purpose of this amendment is to provide more flexibility and control of monthly and daily gas supply purchasing.

Q. Please describe the Company's process for procuring its gas supply commodity supplies.

A. Northern's practice is to secure its gas supply commodity supplies through annual requests-for-proposal ("RFP") for terms beginning April 1 and running through March 31 each year. Northern concluded an RFP during the month of March 2010 for the supplies necessary to meet its projected requirements for the period beginning April 2010 through March 2011. These supplies include summer re-fill of underground storage and projected baseload supplies through March 2011. The Company entered into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers.

Q. What steps has Northern taken since the 2010 Summer COG proceeding to better match the Adjusted Target Volumes ("ATV") for the non-daily metered transportation customers with the actual consumption for these customers?

A. Effective August 1, 2010 Northern has implemented revised consumption factors used to estimate the ATV for most of its non-daily metered transportation customers.[5] This project was completed by compiling a two-year history of bill cycle consumption and weather data for all customers eligible for non-daily metered transportation service. The raw bill cycle consumption data was reviewed to clean the data of errors, duplications and inconsistencies. The total

[5] This includes T40, G41, T41, G50, T50, G51 and T51 customers for both the New Hampshire and Maine Divisions. This includes approximately 5,000 total customers, of which approximately 1,700 are New Hampshire Division customers.

Effective Degree Days ("EDD") were calculated for each bill cycle for each customer. Finally, weather-sensitive and non-weather sensitive coefficients were calculated for each customer based upon the bill cycle consumption and weather data. Following the calculation of the new factors, Northern communicated to the retail marketers with non-daily metered pools in order to ensure a smooth transition to the new ATV consumption factors. Since August 1, Northern has observed a significant reduction in the amount of gas it requires retail marketers serving non-daily metered to deliver. Northern also now monitors the monthly variance between the ATV deliveries and the aggregate consumption of non-daily metered transportation customers in order to ensure the accuracy of the ATV and to estimate the costs or revenues associated with the seasonal ATV reconciliation so that this item be accounted for in the determination of monthly COG recovery balances.

IV. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Simpson to calculate the 2010-2011 Winter COG.

A. I have provided Mr. Simpson the following cost estimates for the period beginning November 2010 through October 2011, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities

- Northern's commodity costs
- Impact of Northern's financial hedging program

The allocation of Northern's fixed demand, commodity and hedging costs to the New Hampshire Division was performed by Mr. Simpson. The figures I present in my testimony relate to total company costs, inclusive of both the New Hampshire and Maine Divisions.

In addition, I also prepared the estimates of New Hampshire Division Capacity Assignment program demand revenues.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 5, below, titled, "Summary of Estimated Fixed Demand Costs."

Table 5. Summary of Estimated Fixed Demand Costs November 1, 2010 through October 31, 2011			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 6,979,327	Schedule 5A, Page 2 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 23,000,956	Schedule 5A, Page 2 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,008,911	Schedule 5A, Page 3 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,578,485	Schedule 5A, Page 2 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 4,582,488	Schedule 5A, Page 4, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (2,931,530)	Schedule 5A, Page 5 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 36,218,638	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Schedule 5A. On page 1 of the Attachment, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 2 of Schedule 5A, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 3 and 4 of Schedule 5A provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 5 of Schedule 5A, I forecast the capacity release and asset management revenue the Company expects to receive for the

2010-2011 Gas Year. Support for the pipeline, storage and supply contract rates used in Schedule 5A can be found in the Attachment to Schedule 5A.

Q. Please compare the Demand Cost estimates for the upcoming gas year (2010-2011) to the Demand Cost estimates provided for the current gas year in Docket No. DG 09-167.

A. The Demand Cost estimates for the upcoming gas year are $36.2 million compared to estimated Demand Cost estimates of $27.1 million provided in Docket No. DG 09-167. These projected increase of $9.1 million is explained by the following.

1. $3.4 million of the increase in estimated demand costs are due to the PNGTS increase in tariff rates, proposed in the rate case, filed in FERC Docket RP10-729.

2. $2.1 million of the increase are due to increases in TransCanada demand costs. Rates increased substantially on January 1, 2010. This increase in TransCanada demand costs is net of the savings to the Company by turning back the Empress, Alberta to East Hereford capacity, discussed previously.

3. $1.9 million of the increase in estimated demand costs are due to the Granite increase in tariff rates, proposed in the rate case, filed in FERC Docket RP10-896.

4. $1.4 million of the increase in the estimated demand costs are due to the decrease in projected asset management and capacity

release demand revenue due to the lower values offered by bidders in the March 2010 RFP.

5. $0.3 million of the increase is due to peaking supply contract demand cost increases, stipulated by these long-term agreements.

Q. Please provide the Northern's forecast of Capacity Assignment Demand Revenues for the New Hampshire Division.

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed calculations of this figure in Schedule 5B. On page 1 of Schedule 5B, I present a summary of the Company's forecast of New Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Schedule 5B, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Schedule 5B. The 2010-2011 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $2,600,137.

Q. Please describe Northern's process for forecasting commodity costs.

A. I base the Company's commodity cost forecast on Northern's projected city-gate receipts for sales service customers, which I calculated in Attachment 2 to Schedule 10B, and the supply sources available to Northern, which I presented in Schedule 12. I forecast supply prices at each supply source, utilizing NYMEX natural gas contract price data and a forecast of the adder to NYMEX for the price of supply at each supply source available to Northern through its portfolio. I also forecast variable fuel retention factors and rates for Northern's transportation and storage contracts. Then, I utilized the Sendout® natural gas supply cost model to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.

Q. Please present the Company's commodity cost forecast for the 2010-2011 Winter Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter Period in Table 6, below.

Table 6. Contracts Ranked on a Per-Unit Cost Basis
November 1, 2010 through April 30, 2011

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes (Dth)	Delivered Cost per Dth
Peaking Supply 1	$2,404,468	602,041	$3.9939
Washington 10 Storage	$11,577,747	2,559,895	$4.5227
Tennessee Storage	$707,503	147,681	$4.7908
Chicago	$1,667,801	301,862	$5.5251
Niagara	$1,035,386	184,693	$5.6060
Tennessee Production	$7,768,412	1,375,093	$5.6494
LNG	$111,223	18,872	$5.8934
Pittsburgh, NH	$1,240,066	199,100	$6.2284
Peaking Supply 2	$21,557	2,670	$8.0723
Total System	$26,534,162	5,391,907	$4.9211

In summary, projected delivered commodity costs equal approximately $26.5 million at an average delivered rate of approximately $4.92 per Dth. This table can also be found in Schedule 2. In support of Table 6 and Schedule 2, I prepared Schedule 6A to show the monthly forecasted commodity cost by supply option. Page 1 of Schedule 6A provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of the Schedule 6A provides monthly delivered volumes (Dth) by supply source. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

The detailed calculations of the delivered commodity cost are found in Schedule 6B. For each supply source, I have provided the detailed monthly calculations for supply cost, fuel losses and variable transportation charges, which will be incurred by Northern in order to deliver its supplies to Northern's city-gates for ultimate consumption by our customers. Support of the supply prices and variable transportation charges found in the Schedule 6B are found in the Attachment to Schedule 6B.

I based my commodity cost forecast on NYMEX prices as of July 22, 2010. Mr. Simpson has updated the commodity costs in the proposed COG rates to reflect updated NYMEX prices as of September 2, 2010.

Q. Please provide projected monthly supply volumes and capacity utilization calculations for both Northern's normal weather and design weather scenarios for the upcoming 2010-11 Winter period.

A. Please refer to Schedules 11A, 11B and 11C. Schedule 11A provides monthly supply volumes for Northern's normal weather scenario. The data in Schedule 11A is also found in Schedule 6A. Schedule 11B provides monthly supply volumes for Northern's design cold weather scenario. The volumes is Schedule 11B were those used by Mr. Simpson to calculated the capacity cost allocators between New Hampshire and Maine. Schedule 11C calculates the capacity utilization of all supply resources in both normal and design cold weather scenarios.

Q. Please provide Northern's Design Day Report for the upcoming Winter Period.

A. Northern's Design Day Report is found in Schedule 11D.

Q. Please provide an overview of the changes in Northern's hedging program since the last Peak COG filing.

A. Northern has made four substantive changes to its hedging program: 1) the adoption of a portfolio approach to hedging whereby Northern would combine its physically hedged supplies with its financial hedges to begin each peak season with approximately 70 percent of the supply requirements available under a fixed-price. The remaining supply (approximately 30%) would be purchased at market prices throughout the peak period; 2) the introduction of a price ceiling calculated pursuant to a formula, above which purchases of futures contracts would be postponed; 3) elimination of the price-based component of the existing hedging program; and 4) the introduction of a process under which futures contracts that appreciate in value above a specified percentage would be sold. Northern has also made an administrative change to the hedging program in that seasonal hedging plans are established and filed with the Commission as part of the Summer COG filings, rather than semi-annually.

Q. Please provide the results of the hedging program related to the Company's proposed COG rates.

A. I have also calculated the gains or losses of the NYMEX natural gas contracts purchased by the Company in accordance with its hedging program. Based upon the July 22, 2010 NYMEX natural gas settlement price data, Northern projects a hedging loss of approximately $546,240 for time-based hedges for the coming peak season. Time-based hedges are allocated between the New Hampshire and Maine Divisions on the basis of the projected commodity allocators. I have also provided the Commission a projection of the hedging loss due to price-based hedges of approximately $396,920. Since the Maine Public Utilities Commission suspended the price-triggered hedging strategy in its Order in Docket No. 2008-93 dated September 23, 2009, Northern procured price-triggered hedging using only New Hampshire supply requirements. Thus, price-based hedges are 100% allocated to the New Hampshire Division. Please refer to Schedule 7 for the monthly hedging calculations.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2010 through October 2011.

A. Please refer to Schedule 14. The results are based upon the Company's Sendout® analysis, which I provided to Mr. Simpson.

VI. PNGTS Rate Case Litigation Update & Proposed Cost Recovery

Q. What is the current status of the litigation opposing proposed rate increases by Portland Natural Gas Transmission System ("PNGTS")?

A. The Initial Decision of the Administrative Law Judge in FERC Docket No. RP08-306-000 ("2008 Rate Case") was issued on December 24, 2009. Briefs on Exceptions to the Initial Decision and Briefs Opposing Exceptions have been filed with the FERC. Although no specific timeframe for an order from FERC is established, an order is expected approximately six months after the briefs were submitted, which would be in the October 2010 timeframe. PNGTS rates since September 2008 have been billed subject to refund at the rate proposed in April 2008. The FERC order would establish the rates applicable to the refund period as well as the prospective rates, at least until December 1, 2010 when rates from RP10-729 go into effect.

Q. What is the impact of the Initial Decision in FERC Docket No. RP08-306-000, should it be upheld by the FERC?

A. The Initial Decision was very favorable to Northern and the PNGTS Shipper Group ("PSG"), with PNGTS losing on most significant issues including treatment of bankruptcy revenues, capacity for purposes of the at-risk condition (affirmed at 210,840 Dth), return on equity, treatment of interruptible transportation revenues, negative salvage rate, depreciation rates, and type of cost levelization model. Should the final order from FERC uphold the Initial Decision in RP08-306, Northern estimates a refund of approximately $1.2M dollars, $628,298 of which would be credited to the New Hampshire Division, would be due. Please refer to Schedule 5C for the back-up calculations for this amount.

Q: Please identify the costs incurred to oppose PNGTS proposed rate increases that Northern proposes to recover.

A: Northern proposes to recover costs of $183,943, which is the New Hampshire Division's share of the $376,840 in external legal and consulting costs that Northern has incurred opposing the 2008 and 2010 PNGTS rate cases and since September 1, 2009. The proposed 2010-2011 fixed proportional responsibility allocators were used to assign these costs by state for costs incurred from September 2009 through August 2010, which are presented to the Commission with this filing. Please see Schedule 5D, which lists the legal and consulting fees Northern seeks to recover. Northern has compiled the invoices, supporting these amounts and will provide these materials to the Commission Staff. Northern is not proposing to recover costs for expenses that were paid before December 1, 2008 or the costs of internal resources. In this Cost of Gas filing, Northern has reflected these costs as a deduction from Asset Management revenues.

Q: In making this request for inclusion of these extraordinary legal and consulting costs in the cost of gas rates for the coming winter season, does Northern intend to establish any precedent for such future treatment?

A: No. With this request, Northern intends to recover the costs to oppose the 2008 PNGTS rate case that have been incurred since September 1, 2009 and does not intend to establish any precedent with regard to the manner of recovery of similar costs in the future. Northern would address the recovery of similar future costs at such future time.

Q. Does Northern anticipate future litigation with PNGTS regarding firm transportation rates?

A. Yes. On May 12, 2010, PNGTS filed a new rate case which has been docketed RP10-729 ("2010 Rate Case"). The proposed new rates represent a 47 percent increase over current rates. Northern has intervened as a member of PSG and has begun incurring additional legal and consulting costs. On June 11, 2010, FERC ordered suspending the proposed new rates until December 1, 2010, when they go into effect subject to refund.

Q. Does this conclude your testimony?

A. Yes it does.

Prefiled Testimony of Joseph F. Conneely

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
2010 / 2011 WINTER SEASON PROPOSED
COST OF GAS ADJUSTMENT
PREFILED TESTIMONY OF
JOSEPH F. CONNEELY

I. INTRODUCTION

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

A. My name is Joseph F. Conneely. 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 that provides managerial, financial, regulatory and engineering services to Unitil Corporation's principal subsidiaries Firchburg Gas and Electric Light Company, d/b/a Unitil ("FG&E"), Granite State Gas Transmission, Inc. ("Granite"), Northern Utilities, Inc. d/b/a Unitil ("Northern"), and Unitil Energy Systems, Inc. ("UES") (together "Unitil"). In this capacity I am responsible for managing and filing reporting requirements.

Q. Please summarize your professional and educational background.

A. I graduated from Saint Anselm College, Manchester, New Hampshire in 1999 with a Bachelor of Arts degree in Financial Economics. Before joining Unitil, I worked for the Royal Bank of Scotland- Sempra Energy Trading Corp. joint venture ("RBS") in Greenwich, Connecticut as a senior electricity and natural gas trader. Prior to working for RBS, I was employed as a mid-term electricity and natural gas trader at Morgan Stanley in New York City. Before this position at Morgan Stanley, I ran an every trading book at Shell Gas and Energy Trading North America in La Jolla, California. I joined Unitil in November 2008.

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

A. No, this is my first time testifying before the New Hampshire Commission. I have previously testified before the Maine Public Utilities Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to introduce and describe Northern's proposed changes to its Local Delivery Adjustment Clause tariff (Page No. 56). Northern is proposing changes to its rates for effect November 1, 2010 for the following items: Residential Low Income Assistance Program ("RLIAP") rate; Demand Side Management ("DSM") rate and Environmental Response Cost ("ERC") rate. I will also discuss the impact that the proposed Cost of Gas ("COG") would have on bills on the Company's typical residential customer.

Q. Please describe the proposed change to the RLIAP rate.

A. Northern is proposing to decrease the RLIAP rate from $0.0055 to $0.0043 per therm effective November 1, 2010.

Q. Could you describe the reason for the proposed change to the RLIAP rate?

A. Yes. The Residential Low-Income Assistance Program has been in effect since 2005. Northern is not proposing any program changes at this time; however, Northern is proposing to change the RLIAP rate in order to eliminate a currently projected over-collected balance as of October 31, 2010 of $28,893, as shown on Schedule 16 RLIAP A. Estimated program costs and recoveries are provided in Schedule 16 RLIAP B, Schedule 2 and are based on actual results for the 12-month period ending August 2010.

Q. What changes are being proposed for the DSM charges?

A. The Company is proposing to increase the DSM charge for the residential classes from $0.0185 to $0.0355 per therm, and increase the charge for the commercial and industrial customer classes from $0.0054 to $0.0160 per therm effective November 1, 2010.

Q. Please describe the reason for these proposed changes to the DSM rates.

A. The proposed changes to the DSM rates are necessitated by the implementation of Northern's current energy efficiency program budget. That budget is provided in Schedule 16 DSM A. Information regarding the development of the proposed DSM rate for the residential classes is provided in Schedule 16 DSM B.

Schedule 16 DSM C provides the support for the proposed DSM rate for the commercial and industrial classes.

Q. Please describe the change to Northern's ERC rate that is proposed for effect November 1, 2010.

A. The current ERC rate is $0.0057 per therm. Northern proposes to decrease this charge to $0.0056 per therm.

Q. Please explain the calculation of the proposed ERC rate.

A. During the period July 1, 2009 through June 30, 2010, ERC expenses totaled $189,634. Northern is allowed to recover one-seventh of the actual response costs incurred by the Company in a twelve-month period ending June 30 of each year until fully amortized, plus any insurance and third-party expenses for the year. Any insurance and third-party recoveries, or other benefits for the year, are used to reduce the unamortized balance. The $367,188 shown on Schedule 1 in the Environmental Response Cost filing is comprised of the following:

1/7th ERC costs incurred July 2009 - June 2010	$ 27,091
1/7th ERC costs incurred July 2008 - June 2009	$ 18,247
1/7th ERC costs incurred July 2007 - June 2008	$ 33,280
1/7th ERC costs incurred July 2006 - June 2007	$ 26,686
1/7th ERC costs incurred July 2005 - June 2006	$ 90,352
1/7th ERC costs incurred July 2004 - June 2005	$ 129,871
1/7th ERC costs incurred July 2003 - June 2004	$ 41,661
Total	$367,188

The prior period reconciliation of ERC costs, an over collection of $36,705, is included in the annual ERC costs resulting in net ERC costs to be recovered from customers during the period of November 2010 through October 2011 of $330,483. Dividing these recoverable ERC costs by total annual sales of 58,898,383 therms yields an ERC rate of $0.0056 per therm. This calculation is illustrated in Schedule 16 ERC.

Q. Have you prepared typical bill analyses showing the impacts of the proposed COG and LDAC rate changes for effect on November 1, 2010 for typical gas customers?

A. Yes, Schedule 8 provides the analyses.

Q. Does this conclude your testimony?

A. Yes, it does.

Tariff Pages

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
New Hampshire Division
Winter 2010-2011 Cost of Gas - Compliance Filing

Compliance Tariff Sheets

Forty-seventh Revised Page No. 38 Statement of anticipated Cost of Gas
Fifty-first Revised Page No. 39 Calculation of proposed Cost of Gas Adjustment
Fourteenth Revised Page No. 56 Company's proposed LDAC Rates
Forty-sixth Revised Page No. 94 Rate Summary
Forty-sixth Revised Page No. 95 Rate Summary
Fortieth Revised Page No. 96 Rate Summary
Tenth Revised Page 154 Appendix A
Ninth Revised Page 169 Appendix C
Third Revised Page 170-b Appendix D

Northern Utilities, Inc.
New Hampshire Division

CHECK SHEET

The title page and pages i-171 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

Pages	Revision	Proposed
Title	Original	
i	Original	
ii	Third Revised	
iii	Second Revised	
iv	Second Revised	
v	Second Revised	
1	Original	
2	Original	
3	Original	
4	Original	
5	Original	
6	Original	
7	Original	
8	Original	
9	Original	
10	First Revised	
11	Original	
12	Original	
13	Original	
14	Original	
15	Original	
16	First Revised	
17	First Revised	
18	Third Revised	
19	Third Revised	
20	Fourth Revised	
20.1	Original	
21	Third Revised	
21.1	Original	
22	Second Revised	
23	Second Revised	
24	Second Revised	
25	Second Revised	
26	Second Revised	
27	Second Revised	
28	Second Revised	
29	Second Revised	
30	Second Revised	
31	Second Revised	
32	Fourth Revised	
33	Second Revised	
34	Second Revised	
35	Second Revised	
36	Second Revised	
37	Third Revised	
37.1	Second Revised	
37.2	First Revised	
38	Forty-sixth Revised	Forty-seventh Revised
39	Fiftieth Revised	Fifty-first Revised

CHECK SHEET

The title page and pages i-171 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

Pages	Revision	Proposed
40	Twenty-fourth Revised	
41	First Revised	
42	First Revised	
43	Second Revised	
44	Third Revised	
45	Second Revised	
46	First Revised	
47	First Revised	
48	First Revised	
49	First Revised	
50	First Revised	
51	First Revised	
52	First Revised	
53	Second Revised	
54	Second Revised	
55	Second Revised	
55-a	First Revised	
55-b	First Revised	
55-c	Original	
55-d	Original	
55-e	Original	
56	Thirteenth Revised	Fourteenth Revised
57	Second Revised	
58	Original	
59	Third Revised	
60	Second Revised	
60-a	Original	
61	Third Revised	
62	First Revised	
63	Third Revised	
64	First Revised	
65	Original	
66	Original	
67	Original	
68	Original	
69	Original	
70	Second Revised	
71	Original	
72	Second Revised	
73	Original	
74	Second Revised	
75	Original	
76	Second Revised	
77	Original	
78	Second Revised	
79	Original	
80	Second Revised	
81	Original	
82	Second Revised	

CHECK SHEET

The title page and pages i-171 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

Pages	Revision	Proposed
83	Original	
84	Second Revised	
85	Original	
86	Second Revised	
87	Original	
88	Second Revised	
89	Original	
90	Second Revised	
91	Original	
92	Second Revised	
93	Original	
94	Forty-fifth Revised	Forty-sixth Revised
95	Forty-fifth Revised	Forty-sixth Revised
96	Thirteenth Revised	Fortieth Revised
97	First Revised	
98	First Revised	
99	Eleventh Revised	
99-a	Eighteenth Revised	
100	Original	
101	Original	
102	Original	
103	Original	
104	First Revised	
105	Original	
106	Original	
107	Original	
108	Original	
109	Original	
110	Original	
111	Original	
112	Original	
113	Original	
114	Original	
115	Original	
116	Original	
117	Original	
118	Original	
119	Original	
120	Original	
121	First Revised	
122	First Revised	
122-a	Original	
123	Original	
124	First Revised	
125	First Revised	
126	First Revised	
127	First Revised	
128	First Revised	
129	First Revised	

CHECK SHEET

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130	First Revised	
131	First Revised	
132	First Revised	
133	First Revised	
134	First Revised	
135	First Revised	
136	First Revised	
137	First Revised	
138	First Revised	
139	First Revised	
140	First Revised	
141	First Revised	
142	First Revised	
143	First Revised	
144	First Revised	
145	First Revised	
146	First Revised	
147	First Revised	
148	First Revised	
149	First Revised	
150	First Revised	
151	First Revised	
152	First Revised	
152-a	Original	
153	Second Revised	
154	Ninth Revised	Tenth Revised
155	Original	
156	Original	
157	Original	
158	Original	
159	Original	
160	Original	
161	Original	
162	Original	
163	Original	
164	Original	
165	Original	
166	Original	
167	Original	
168	Original	
169	Eighth Revised	Ninth Revised
170	Original	
170-a	Original	
170-b	Second Revised	Third Revised
171	First Revised	

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1,2010 - April 30, 2011

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$1,944,296	
Supply Costs:	$5,408,538	
Storage & Peaking Gas:		
Demand, Capacity:	$13,538,806	
Commodity Costs:	$7,629,178	
Hedging (Gain)/Loss	$1,054,446	
Interruptible Included Above	$0	
Inventory Finance Charge	$10,094	
Capacity Release, Asset Management, PNGTS Cost	($1,771,080)	
PNGTS Refund		
Total Anticipated Direct Cost of Gas		$27,814,277
ANTICIPATED INDIRECT COST OF GAS		
Adjustments:		
Prior Period Under/(Over) Collection	$2,527,403	
Prior Period Adjustment (ATV Reconciliation)	$0	
Interest	$99,945	
Refunds	$0	
Interruptible Margins	$0	
Total Adjustments		$2,627,348
Working Capital:		
Total Anticipated Direct Cost of Gas	$27,814,277	
Working Capital Percentage	0.19%	
Working Capital Allowance	$52,847	
Plus: Working Capital Reconciliation (Acct 182.11)	($83,069)	
Total Working Capital Allowance		($30,222)
Bad Debt:		
Total Anticipated Direct Cost of Gas	$27,814,277	
Plus: Prior Period Under/(Over) Collection	$2,527,403	
Plus: Interest	$0	
Plus: Total Working Capital	($30,222)	
Subtotal	$30,311,459	
Bad Debt Percentage	0.45%	
Bad Debt Allowance	$136,402	
Plus: Bad Debt Reconciliation (Acct 182.16)	($2,655)	
Total Bad Debt Allowance		$133,747
Local Production and Storage Capacity		$686,673
Miscellaneous Overhead-25.15% Allocated to Winter Season		$98,333
Total Anticipated Indirect Cost of Gas		$3,515,879
Total Cost of Gas		$31,330,157

Issued: September 15, 2010
Effective Date: November 1, 2010

Issued By: [signature]
Treasurer

Authorized by NHPUC Order No. ______, in Docket No. DG 10-___, dated __________, 2010.

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2010 - April 30, 2011

(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$27,814,277		
Projected Prorated Sales (11/01/10-04/30/11)	28,028,950		
Direct Cost of Gas Rate		$0.9923	per therm
Demand Cost of Gas Rate	$13,712,022	$0.4892	per therm
Commodity Cost of Gas Rate	$14,102,256	$0.5031	per therm
Total Direct Cost of Gas Rate	$27,814,278	$0.9923	per therm
Total Anticipated Indirect Cost of Gas	$3,515,879		
Projected Prorated Sales (11/01/10-04/30/11)	28,028,950		
Indirect Cost of Gas		$0.1254	per therm
TOTAL PERIOD AVERAGE COST OF GAS		**$1.1177**	**per therm**

RESIDENTIAL COST OF GAS RATE - 11/01/10	**COGwr**	**$1.1177**	**per therm**
	Maximum (COG+25%)	**$1.3971**	

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10	**COGwl**	**$1.0019**	**per therm**
	Maximum (COG+25%)	**$1.2524**	

C&I HLF DEMAND COSTS ALLOCATED PER SMBA	$712,743
PLUS: RESIDENTIAL DEMAND RELOCATION TO C7I HLF	$12,540
C&I HLF TOTAL ADJUSTED DEMAND COSTS	$725,283
C&I HLF PROJECTED PRORATED SALES (11/1/10-04/30/11)	2,402,246
DEMAND COST OF GAS RATE	**$0.3019**
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	$1,378,807
PLUS: RESIDENTIAL COMMODITY COSTS	$1,419
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	$1,380,226
C&I HLF PROJECTED PRORATED SALES (11/01/10-04/30/11)	2,402,246
COMMODITY COST OF GAS RATE	**$0.5746**
INDIRECT COST OF GAS	**$0.1254**
TOTAL C&I HLF COST OF GAS RATE	**$1.0019**

COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/10	**COGwh**	**$1.1398**	**per therm**
	Maximum (COG+25%)	**$1.4248**	

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$6,495,498
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	$114,281
C&I LLF TOTAL ADJUSTED DEMAND COSTS	$6,609,779
C&I LLF PROJECTED PRORATED SALES (11/01/10-04/30/11)	12,591,463
DEMAND COST OF GAS RATE	**$0.5249**
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$6,157,247
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	$6,338
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	$6,163,585
C&I LLF PROJECTED PRORATED SALES (11/1/10-04/30/11)	12,591,463
COMMODITY COST OF GAS RATE	$0.4895
INDIRECT COST OF GAS	**$0.1254**
TOTAL C&I LLF COST OF GAS RATE	**$1.1398**

Issued: September 15, 2010
Effective Date: November 1, 2010
Authorized by NHPUC Order No. ___, in Docket No. DG 10-___, dated ___, 2010.

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Treasurer

Local Delivery Adjustment Clause

Rate Schedule	RLIAP	DSM	ERC	ITM	WLNG	CCE	RCE	LDAC
Residential Heating	$0.0043	$0.0355	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0454
Residential Non-Heating	$0.0043	$0.0355	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0454
Small C&I	$0.0043	$0.0160	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0259
Medium C&I	$0.0043	$0.0160	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0259
Large C&I	$0.0043	$0.0160	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0259
No Previous Sales Service								

Issued: September 15, 2010

Effective: With Service Rendered On and After November 1, 2010

Authorized by NHPUC Order No. ______ in Docket N. DG 10-___, dated __________, 2010

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Title: Treasurer

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

WINTER SEASON RESIDENTIAL RATES

	Winter Season November 2010- April 2011		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**				
	Monthly Customer Charge		$9.50	**$9.50**	**$9.50**
	First 50 therms		$0.4102	**$0.4556**	**$1.5733**
	All usage over 50 therms		$0.2990	**$0.3444**	**$1.4621**
	LDAC		**$0.0454**		
	Gas Cost Adjustment:				
	Cost of Gas		**$1.1177**		
Residential Heating Low Income	**Tariff Rate R 10:**				
	Monthly Customer Charge		$3.80	**$3.80**	**$3.80**
	First 50 therms		$0.1641	**$0.2095**	**$1.3272**
	All usage over 50 therms		$0.1196	**$0.1650**	**$1.2827**
	LDAC		**$0.0454**		
	Gas Cost Adjustment:				
	Cost of Gas		**$1.1177**		
Residential Non-Heating	**Tariff Rate R 6:**				
	Bi-monthly Customer Charge		$19.00	**$19.00**	**$19.00**
	First 20 therms		$0.4067	**$0.4521**	**$1.5698**
	All usage over 20 therms		$0.3082	**$0.3536**	**$1.4713**
	Monthly Customer Charge		$9.50	**$9.50**	**$9.50**
	First 10 therms		$0.4067	**$0.4521**	**$1.5698**
	All usage over 10 therms		$0.3082	**$0.3536**	**$1.4713**
	LDAC		**$0.0454**		
	Gas Cost Adjustment:				
	Cost of Gas		**$1.1177**		
Residential Non-Heating Low Income	**Tariff Rate R 11:**				
	Bi-monthly Customer Charge		$13.80	**$13.80**	**$13.80**
	First 20 therms		$0.3084	**$0.3538**	**$1.4715**
	All usage over 20 therms		$0.2335	**$0.2789**	**$1.3966**
	Monthly Customer Charge		$6.90	**$6.90**	**$6.90**
	First 10 therms		$0.3084	**$0.3538**	**$1.4715**
	All usage over 10 therms		$0.2335	**$0.2789**	**$1.3966**
	LDAC		**$0.0454**		
	Gas Cost Adjustment:				
	Cost of Gas		**$1.1177**		

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

WINTER SEASON C&I RATES

	Winter Season November 2010-April 2011	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$18.70	$18.70	$18.70
	First 75 therms	$0.3077	$0.3336	$1.4734
	All usage over 75 therms	$0.2007	$0.2266	$1.3664
	LDAC	$0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	$1.1398		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$18.70	$18.70	$18.70
	First 75 therms	$0.3018	$0.3277	$1.3296
	All usage over 75 therms	$0.1969	$0.2228	$1.2247
	LDAC	$0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	$1.0019		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$60.30	$60.30	$60.30
	All usage	$0.1942	$0.2201	$1.3599
	LDAC	$0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	$1.1398		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$60.30	$60.30	$60.30
	First 1300 therms	$0.1862	$0.2121	$1.2140
	All usage over 1300 therms	$0.1467	$0.1726	$1.1745
	LDAC	$0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	$1.0019		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$254.00	$254.00	$254.00
	All usage	$0.1725	$0.1984	$1.3382
	LDAC	$0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	$1.1398		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$254.00	$254.00	$254.00
	All usage	$0.1262	$0.1521	$1.1540
	LDAC	$0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	$1.0019		

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

WINTER SEASON DELIVERY RATES

	Winter Season November 2010-April 2011		Tariff Rates	Total Delivery Rates (Includes LDAC)
C&I Low Annual/High Winter	**Tariff Rate T 40:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3077	**$0.3336**
	All usage over 75 therms		$0.2007	**$0.2266**
	LDAC		**$0.0259**	
C&I Low Annual/Low Winter	**Tariff Rate T 50:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3018	**$0.3277**
	All usage over 75 therms		$0.1969	**$0.2228**
	LDAC		**$0.0259**	
C&I Medium Annual/High Winter	**Tariff Rate T 41:**			
	Monthly Customer Charge		$60.30	**$60.30**
	All usage		$0.1942	**$0.2201**
	LDAC		**$0.0259**	
C&I Medium Annual/Low Winter	**Tariff Rate T 51:**			
	Monthly Customer Charge		$60.30	**$60.30**
	First 1300 therms		$0.1862	**$0.2121**
	All usage over 1300 therms		$0.1467	**$0.1726**
	LDAC		**$0.0259**	
C&I High Annual/High Winter	**Tariff Rate T 42:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		$0.1725	**$0.1984**
	LDAC		**$0.0259**	
C&I High Annual/Low Winter	**Tariff Rate T 52:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		$0.1262	**$0.1521**
	LDAC		**$0.0259**	
C&I Interruptible Transportation	**Tariff Rate IT:**			
	Monthly Customer Charge		$170.21	**$170.21**
	First 20,000 therms		$0.0407	**$0.0407**
	All usage over 20,000 therms		$0.0347	**$0.0347**

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.75 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$13.84 per MMBtu** per MDPQ per month for November 2010 through April 2011.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Supplier Services and Associated Fees:

SERVICE	PRICING
Pool Administration (required) **Non-Daily Metered Pools only**	• $0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• $0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• $1.50/customer/month billed @ marketer level
Customer Administration (required)	• $10/customer/switch billed @ marketer level

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, 2010 through October 31, 2011.

Commercial and Industrial

	High Winter Use	Low Winter Use
Pipeline:	6.89%	64.97%
Storage:	33.75%	12.70%
Peaking:	59.37%	22.34%

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX D

Firm Sales Service Re-Entry Fee Bill Adjustment (continued)

The Re-Entry Fee shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Firm Sales Service Re-Entry Fee Unit Charge shall be applicable for the period of November 1, 2010 through October 31, 2011.

Effective Dates:	**November 1, 2010 – October 31, 2011**
Annual Average Unit Cost:	$ 311.63
25% - Annual Charge for Re-Entry Fee:	$ 77.91
Monthly Unit Charge for Re-Entry Fee:	$ 6.49

Anticipated Cost of Gas

New Hampshire Division

Period Covered: ~~May 1, 2010 -October 31, 2010~~ November 1, 2010 - April 30, 2011

(Col 1)	(Col 2)		(Col 3)	
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 474,873~~	$ 1,944,296		
Supply Costs:	~~$ 4,171,677~~	$ 5,408,538		
Storage & Peaking Gas:				
Demand, Capacity:	~~$ 583,148~~	$ 13,538,806		
Commodity Costs:	~~$ 26,514~~	$ 7,629,178		
Hedging (Gain)/Loss	~~$ 343,585~~	$ 1,054,446		
Interruptible Included Above	~~$~~	$ -		
Inventory Finance Charge	~~$~~	$ 10,094		
Capacity Release, Asset Management, PNGTS Cost	~~$~~	$ (1,771,080)		
PNGTS Refund				
Total Anticipated Direct Cost of Gas			~~$ 5,599,797~~	27,814,277
ANTICIPATED INDIRECT COST OF GAS				
Adjustments:				
Prior Period Under/(Over) Collection	~~$ (536,749)~~	$ 2,527,403		
Prior Period Adjustment (ATV Reconciliation)	~~$ 433,436~~			
Interest	~~$ (17,510)~~	$ 99,945		
Refunds	~~$~~			
~~Capacity Reserve Charge Revenue~~	~~$ (90,228)~~			
Interruptible Margins	$ -			
Total Adjustments			~~$ (120,823)~~	$ 2,627,348
Working Capital:				
Total Anticipated Direct Cost of Gas	~~$ 5,599,797~~	$ 27,814,277		
Working Capital Percentage	0.190%			
Working Capital Allowance	~~$ 10,640~~	$ 52,847		
Plus: Working Capital Reconciliation (Acct 182.11)	~~$ (8,299)~~	$ (83,069)		
Total Working Capital Allowance			~~$ 2,341~~	$ (30,222)
Bad Debt:				
Total Anticipated Direct Cost of Gas	~~$ 5,599,797~~	$ 27,814,277		
~~Less: Capacity Reserve Charge Revenue~~	~~$~~			
Plus: Prior Period Under/(Over) Collection	~~$ (536,749)~~	$ 2,527,403		
Plus: Interest	~~$ 433,436~~			
Plus: Total Working Capital	~~$ 2,341~~	$ (30,222)		
Subtotal	~~$ 5,498,825~~	$ 30,311,459		
Bad Debt Percentage	0.450%			
Bad Debt Allowance	~~$ 24,745~~	$ 136,402		
Plus: Bad Debt Reconciliation (Acct 182.16)	~~$ (4,888)~~	$ (2,655)		
Total Bad Debt Allowance			~~$ 19,857~~	$ 133,747
Local Production and Storage Capacity			$ -	
Miscellaneous Overhead-25.15% Allocated to Winter Season			~~$ 31,261~~	$98,333
Total Anticipated Indirect Cost of Gas			~~$ (67,365)~~	$3,515,879
Total Cost of Gas			~~$ 5,532,433~~	$ 31,330,157

Issued: ~~April 30, 2010~~ September 15, 2010

Effective Date: ~~May~~ November 1, 2010

Authorized by NHPUC Order No._______, in Docket No. DG ~~09~~-10-____, dated___________, ~~2009~~ 2010.

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Treasurer

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: ~~May 1, 2010 - October 31, 2010~~ November 1, 2010 - April 30, 2011

(Col 1)	(Col 2)		(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 5,599,798~~	$27,814,277		
Projected Prorated Sales (~~05/01/10 - 10/31/10~~ 11/1/10 - 04/30/11)	~~8,452,584~~	28,028,950		
Direct Cost of Gas Rate			~~$ 0.6625~~	$0.9923 per therm
Demand Cost of Gas Rate	~~$ 1,058,022~~	$13,712,022	~~$ 0.1252~~	$0.4892 per therm
Commodity Cost of Gas Rate	~~$ 4,541,776~~	$14,102,256	~~$ 0.5373~~	$0.5031 per therm
Total Direct Cost of Gas Rate	~~$ 5,599,798~~	$27,814,277	~~$ 0.6625~~	$0.9923 per therm
Total Anticipated Indirect Cost of Gas	~~$ (67,365)~~	$3,515,879		
Projected Prorated Sales (~~05/01/10 - 10/31/10~~ 11/1/10 - 04/30/11)	~~8,452,584~~	28,028,950		
Indirect Cost of Gas			~~$ (0.0080)~~	$0.1254 per therm
TOTAL PERIOD AVERAGE COST OF GAS			~~$ 0.6545~~	$1.1177 per therm
~~Period Ending Over-collection as determined on 5/25/10[1]~~	~~$ (457,966)~~			
~~PROJECTED SALES (05/01/10 - 10/31/10)~~	~~7,949,035~~			
~~PER UNIT CHANGE IN COST OF GAS (06/01/10 - 10/31/10)~~	~~$ (0.0576)~~			
~~Period Ending Under-collection as determined on 6/24/10[2]~~	~~$ 551,768~~			
~~PROJECTED SALES (07/01/10 - 10/31/10)~~	~~4,209,415~~			
~~PER UNIT CHANGE IN COST OF GAS (07/01/10 - 10/31/10)~~	~~$ 0.1311~~			

~~[1] Over-collection w/o rate adjustment as contained in NUI's COG Report dated May 25, 2010~~
~~[2] Under-collection w/o rate adjustment as contained in NUI's COG Report dated June 24, 2010~~

RESIDENTIAL COST OF GAS RATE - ~~07/01/10~~ 11/01/10	COGwr	~~$ 0.7280~~	$1.1177 per therm
	Maximum (COG+25%)	~~$ 0.8184~~	$1.3971
~~RESIDENTIAL COST OF GAS RATE - 05/01/10~~		~~$ 0.6545~~	
~~CHANGE IN PER UNIT COST~~		~~$ (0.0576)~~	
~~RESIDENTIAL COST OF GAS RATE - 06/01/10~~		~~$ 0.5969~~	
~~CHANGE IN PER UNIT COST~~		~~$ 0.1311~~	
~~RESIDENTIAL COST OF GAS RATE - 07/01/10~~		~~$ 0.7280~~	

COM/IND LOW WINTER USE COST OF GAS RATE - ~~07/01/10~~ 11/01/10	COGwl	~~$ 0.6810~~	$1.0019 per therm
	Maximum (COG+25%)	~~$ 0.7594~~	$1.2524
~~COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/10~~		~~$ 0.6075~~	
~~CHANGE IN PER UNIT COST~~		~~$ (0.0576)~~	
~~COM/IND LOW WINTER USE COST OF GAS RATE - 06/01/10~~		~~$ 0.5499~~	
~~CHANGE IN PER UNIT COST~~		~~$ 0.1311~~	
~~COM/IND LOW WINTER USE COST OF GAS RATE - 07/01/10~~		~~$ 0.6810~~	
C&I HLF Demand Costs Allocated per SMBA	$712,743		
PLUS: Residential Demand Relocation to C&I HLF	$12,540		
C&I HLF Total Adjusted Demand Costs	$725,283		
C&I HLF Projected Prorated Sales (11/01/10-04/20/11)	2,402,246		
Demand Cost of Gas Rate	$0.3019		
C&I HLF Commodity Costs Allocated per SMBA	$1,378,807		
PLUS: Residential Commodity Reallocation to C&I HLF	$1,419		
C&I HLF Total Adjusted Commodity Costs	$1,380,226		
C&I HLF Projected Prorated Sales (11/01/10-04/30/11)	2,402,246		
Commodity Cost of Gas Rate	$0.5746		
Indirect Cost of Gas	$0.1254		
Total C&I HLF Cost of Gas Rate	$1.0019		

COM/IND HIGH WINTER USE COST OF GAS RATE - ~~07/01/10~~ 11/01/10	COGwh	~~$ 0.7640~~	$1.1398 per therm
	Maximum (COG+25%)	~~$ 0.8631~~	$1.4248
~~COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/10~~		~~$ 0.6905~~	
~~CHANGE IN PER UNIT COST~~		~~$ (0.0576)~~	
~~COM/IND HIGH WINTER USE COST OF GAS RATE - 06/01/10~~		~~$ 0.6329~~	
~~CHANGE IN PER UNIT COST~~		~~$ 0.1311~~	
~~COM/IND HIGH WINTER USE COST OF GAS RATE - 07/01/10~~		~~$ 0.7640~~	
C&I LLF Demand Costs Allocated per SMBA	$6,495,498		
PLUS: Residential Demand Reallocation to C&I LLF	$114,281		
C&I LLF Total Adjusted Demand Costs	$6,609,779		
C&I LLF Projected Prorated Sales (11/01/10-04/30/11)	12,591,463		
Demand Cost of Gas Rate	$0.5249		
C&I LLF Commodity Costs Allocated per SMBA	$6,157,247		
PLUS: Residential Commodity Reallocation to C&I LLF	$6,338		
C&I LLF Total Adjusted Commodity Costs	$6,163,585		
C&I LLF Projected Prorated Sales (11/01/10-04/30/11)	12,591,463		
Commodity Cost of Gas Rate	$0.4895		
Indirect Cost of Gas	$0.1254		
Total C&I LLF Cost of Gas Rate	$1.1398		

Issued: ~~June 25, 2010~~ September 15, 2010
Effective Date: ~~July 1, 2010~~ November 1, 2010
Authorized by NHPUC Order No. ~~25,097~~___, in Docket No. DG 10-~~050~~___, dated ~~April 29, 2010~~___.

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Treasurer

N.H.P.U.C. No. 10 - Gas
Northern Utilities, Inc.

~~Thirteenth~~ Fourteenth Revised Page ~~No.~~ 56
Superseding ~~Twelfth~~ Thirteenth Revised Page ~~No.~~ 56

Local Delivery Adjustment Clause

Rate Schedule	RLIAP	DSM	ERC	ITM	WLNG	CCE	RCE	LDAC
Residential Heating	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0355	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0297~~ $0.0454
Residential Non-Heating	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0355	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0297~~ $0.0454
Small C&I	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0160	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0166~~ $0.0259
Medium C&I	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0160	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0166~~ $0.0259
Large C&I	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0160	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0166~~ $0.0259
No Previous Sales Service								

Issued: ~~October 15, 2009~~ September 15, 2010
Effective: With Service Rendered On and After November 1, ~~2009~~ 2010
Authorized by NHPUC Order No. ______ in Docket N. DG-~~09~~ 10-___, dated __________, ~~2009~~ 2010

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Title: Treasurer

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

~~SUMMER~~ WINTER SEASON RESIDENTIAL RATES

~~Summer~~ Winter Season ~~May 2010 - October 2010~~ November 2010- April 2011			Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**				
	Monthly Customer Charge		$9.50	$9.50	$9.50
	First 50 therms		$0.4102	~~$0.4399~~ $0.4556	~~$1.1679~~ $1.5733
	All usage over 50 therms		$0.2990	~~$0.3287~~ $0.3444	~~$1.0567~~ $1.4621
	LDAC		~~$0.0297~~ $0.0454		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.1177		
Residential Heating Low Income	**Tariff Rate R 10:**				
	Monthly Customer Charge		$3.80	$3.80	$3.80
	First 50 therms		$0.1641	~~$0.1938~~ $0.2095	~~$0.9218~~ $1.3272
	All usage over 50 therms		$0.1196	~~$0.1493~~ $0.1650	~~$0.8773~~ $1.2827
	LDAC		~~$0.0297~~ $0.0454		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.1177		
Residential Non-Heating	**Tariff Rate R 6:**				
	Bi-monthly Customer Charge		$19.00	$19.00	$19.00
	First 20 therms		$0.4067	~~$0.4364~~ $0.4521	~~$1.1644~~ $1.5698
	All usage over 20 therms		$0.3082	~~$0.3379~~ $0.3536	~~$1.0659~~ $1.4713
	Monthly Customer Charge		$9.50	$9.50	$9.50
	First 10 therms		$0.4067	~~$0.4364~~ $0.4521	~~$1.1644~~ $1.5698
	All usage over 10 therms		$0.3082	~~$0.3379~~ $0.3536	~~$1.0659~~ $1.4713
	LDAC		~~$0.0297~~ $0.0454		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.1177		
Residential Non-Heating Low Income	**Tariff Rate R 11:**				
	Bi-monthly Customer Charge		$13.80	$13.80	$13.80
	First 20 therms		$0.3084	~~$0.3381~~ $0.3538	~~$1.0661~~ $1.4715
	All usage over 20 therms		$0.2335	~~$0.2632~~ $0.2789	~~$0.9912~~ $1.3966
	Monthly Customer Charge		$6.90	$6.90	$6.90
	First 10 therms		$0.3084	~~$0.3381~~ $0.3538	~~$1.0661~~ $1.4715
	All usage over 10 therms		$0.2335	~~$0.2632~~ $0.2789	~~$0.9912~~ $1.3966
	LDAC		~~$0.0297~~ $0.0454		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.1177		

Issued: ~~June 25,~~ September 15, 2010
Effective: With Service Rendered On and After ~~July~~ November 1, 2010
Authorized by NHPUC Order No. ~~25,097~~___, in Docket No. DG 10-~~050~~___, dated ~~April 29~~___, 2010

Issued by:
Title: Treasurer

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

~~SUMMER~~ WINTER SEASON C&I RATES

~~Summer~~Winter Season ~~May 2010 - October 2010~~ November 2010-April 2011		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$18.70	$18.70	$18.70
	First 75 therms	$0.3077	~~$0.3243~~ $0.3336	~~$1.0883~~ $1.4734
	All usage over 75 therms	$0.2007	~~$0.2173~~ $ 0.2266	~~$0.9813~~ $1.3664
	LDAC	~~$0.0166~~ $0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.764~~ $1.1398		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$18.70	$18.70	$18.70
	First 75 therms	$0.3018	~~$0.3184~~ $0.3277	~~$0.9994~~ $1.3296
	All usage over 75 therms	$0.1969	~~$0.2135~~ $0.2228	~~$0.8945~~ $1.2247
	LDAC	~~$0.0166~~ $0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.681~~ $1.0019		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$60.30	$60.30	$60.30
	All usage	~~$0.1124~~ $0.1942	~~$0.1290~~ $0.2201	~~$0.8930~~ $1.3599
	LDAC	~~$0.0166~~ $0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.764~~ $1.1398		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$60.30	$60.30	$60.30
	First ~~1000~~ 1300 therms	~~$0.1112~~ $0.1862	~~$0.1278~~ $0.2121	~~$0.8088~~ $1.2140
	All usage over ~~1000~~ 1300 therms	~~$0.078~~ $0.1467	~~$0.0946~~ $0.1726	~~$0.7756~~ $1.1745
	LDAC	~~$0.0166~~ $0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.681~~ $1.0019		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$254.00	$254.00	$254.00
	All usage	~~$0.0964~~ $0.1725	~~$0.1130~~ $0.1984	~~$0.8770~~ $1.3382
	LDAC	~~$0.0166~~ $0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.764~~ $1.1398		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$254.00	$254.00	$254.00
	All usage	~~$0.0653~~ $0.1262	~~$0.0819~~ $0.1521	~~$0.7629~~ $1.1540
	LDAC	~~$0.0166~~ $0.0259		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.681~~ $1.0019		

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

~~SUMMER~~ WINTER SEASON DELIVERY RATES

~~Summer~~ Winter Season ~~May 2010 - October 2010~~ November 2010-April 2011			Tariff Rates	Total Delivery Rates (Includes LDAC)
C&I Low Annual/High Winter	**Tariff Rate T 40:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3077	**~~$0.3243~~ $0.3336**
	All usage over 75 therms		$0.2007	**~~$0.2173~~ $0.2266**
	LDAC		**~~$0.0166~~ $0.0259**	
C&I Low Annual/Low Winter	**Tariff Rate T 50:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3018	**~~$0.3184~~ $0.3277**
	All usage over 75 therms		$0.1969	**~~$0.2135~~ $0.2228**
	LDAC		**~~$0.0166~~ $0.0259**	
C&I Medium Annual/High Winter	**Tariff Rate T 41:**			
	Monthly Customer Charge		$60.30	**$60.30**
	All usage		~~$0.1124~~ $0.1942	**~~$.1290~~ $0.2201**
	LDAC		**~~$0.0166~~ $0.0259**	
C&I Medium Annual/Low Winter	**Tariff Rate T 51:**			
	Monthly Customer Charge		$60.30	**$60.30**
	First ~~1000~~ 1300 therms		~~$0.1112~~ $0.1862	**~~$0.1278~~ $0.2121**
	All usage over ~~1000~~ 1300 therms		~~$0.078~~ $0.1467	**~~$0.0946~~ $0.1726**
	LDAC		**~~$0.0166~~ $0.0259**	
C&I High Annual/High Winter	**Tariff Rate T 42:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		~~$0.0964~~ $0.1725	**~~$0.1130~~ $0.1984**
	LDAC		**~~$0.0166~~ $0.0259**	
C&I High Annual/Low Winter	**Tariff Rate T 52:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		~~$0.0653~~ $0.1262	**~~$0.0819~~ $0.1521**
	LDAC		**~~$0.0166~~ $0.0259**	
C&I Interruptible Transportation	**Tariff Rate IT:**			
	Monthly Customer Charge		$170.21	**$170.21**
	First 20,000 therms		$0.0407	**$0.0407**
	All usage over 20,000 therms		$0.0347	**$0.0347**

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.75 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$~~16.49~~13.84 per MMBtu** per MDPQ per month for November ~~2009~~ 2010 through April ~~2010~~ 2011.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Supplier Services and Associated Fees:

SERVICE	PRICING
Pool Administration (required) **Non-Daily Metered Pools only**	• $0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• $0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• $1.50/customer/month billed @ marketer level
Customer Administration (required)	• $10/customer/switch billed @ marketer level

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, ~~09~~2010 through October 31, ~~2010~~2011.

Commercial and Industrial

	High Winter Use	Low Winter Use
Pipeline:	~~6.09~~ 6.89%	~~53.98~~ 64.97%
Storage:	~~32.91~~ 33.75%	~~16.13~~ 12.70%
Peaking:	~~60.99~~ 59.37%	~~29.89~~ 22.34%

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX D

Firm Sales Service Re-Entry Fee Bill Adjustment (continued)

The Re-Entry Fee shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Firm Sales Service Re-Entry Fee Unit Charge shall be applicable for the period of November 1, ~~2009~~ 2010 through October 31, ~~2010~~2011.

Effective Dates:	**November 1, ~~2009~~ 2010 – October 31, ~~2010~~2011**
Annual Average Unit Cost:	$ ~~231.48~~ 311.63
25% - Annual Charge for Re-Entry Fee:	$ ~~57.87~~ 77.91
Monthly Unit Charge for Re-Entry Fee:	$ ~~4.823~~ 6.49

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

Line	NH Division Total Annual Demand Cost Allocation	
1	**Resource**	**Costs**
2	Pipeline & Product Demand	$ 2,740,726
3	Storage	$ 13,405,151
4	Peaking	$ 3,015,206
5	Total Gross Demand Cost	$ 19,161,083
6		
7	Capacity Assignment Demand Revenue Estimate	$ 2,600,137
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 19,161,083
9	Capacity Assignment as % of Total Gross Demand Cost	13.57%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 371,913
14	Storage	$ 1,819,064
15	Peaking	$ 409,160
16	Total Capacity Assignment Credit	$ 2,600,137
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,368,813
21	Storage	$ 11,586,088
22	Peaking	$ 2,606,046
23	Total Net Demand Cost (Less Capacity Assignment)	$ 16,560,946
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,564
28	Less 13.57% NH Transp. Capacity Assignment	(1,569)
29	Net Pipeline MDQ	9,995
30		
31	Net Pipeline MDQ	9,995
32	Less: Firm Sales Base Use	2,932
33	Remaining Pipeline MDQ	7,063
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$237.00
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,368,813
40	Less: Base Pipeline Use	$ 694,919
41	Remaining Pipeline Use	$ 1,673,893

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH Division Total Annual Demand Cost Allocation

1	**Resource**	
2	Pipeline & Product Demand	Schedule 25, LN 84 + Schedule 25, LN 87
3	Storage	Schedule 25, LN 85
4	Peaking	Schedule 25, LN 86
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Attachment NUI-FXW-5
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		
13	Pipeline & Product Demand	LN 2 * LN 9
14	Storage	LN 3 * LN 9
15	Peaking	LN 4 * LN 9
16	Total Capacity Assignment Credit	Sum (LN 13 : LN 15)
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		
20	Pipeline & Product Demand	LN 2 - LN 13
21	Storage	LN 3 - LN 14
22	Peaking	LN 4 - LN 15
23	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 16
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DE**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 13.57% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

42 **NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**
43 (Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)
44

Line	All Months	Nov	Dec	Jan	Feb	Mar	Apr
46	Remaining Load for All Months	2,254,019	3,941,629	5,629,208	4,743,608	4,482,254	2,398,238
47	Rank	6	4	1	2	3	5
48	% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
49	PR	3.91%	6.85%	15.73%	2.32%	3.20%	0.51%
50	CumPR	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%

51

Line	Peak Months Only	Nov	Dec	Jan	Feb	Mar	Apr
53	Remaining Load for Peak Months Only	2,254,019	3,941,629	5,629,208	4,743,608	4,482,254	2,398,238
54	Rank	6	4	1	2	3	5
55	% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
56	PR	6.67%	6.85%	15.73%	2.32%	3.20%	0.51%
57	CumPR	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%

58
59 **DEMAND COST PR ALLOCATORS**

Line		Nov	Dec	Jan	Feb	Mar	Apr
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
62	Pipeline - Remaining	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%
63	Storage & Peaking	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%
64	Capacity Release	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%
65	Interr. Margins & Off Sys Sales	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%

66
67 **DEMAND COSTS ALLOCATED TO MONTHS**

Line		Nov	Dec	Jan	Feb	Mar	Apr
69	Pipeline - Base	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 57,910
70	Pipeline - Remaining	$ 98,866	$ 222,178	$ 577,963	$ 314,622	$ 275,764	$ 107,443
71	Total Pipeline	$ 156,776	$ 280,088	$ 635,873	$ 372,532	$ 333,674	$ 165,353
72							
73	Storage & Peaking	$ 838,236	$ 1,883,740	$ 4,900,270	$ 2,667,531	$ 2,338,074	$ 910,955
74							
75	Less Credits to Demand Cost						
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 118,194	$ 248,666	$ 625,108	$ 346,478	$ 305,364	$ 127,269
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
79							
80	Total Direct Demand Costs	$ 876,817	$ 1,915,161	$ 4,911,035	$ 2,693,586	$ 2,366,384	$ 949,039

81

Line	
82	Indirect Demand Costs/(Credits)
83	Miscellaneous Overhead
84	Local Production & Storage
85	Subtotal

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT**											
43	(Based on NH Firm Sales Sendout for Remaining Temperatur											
44												
45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**		
46	Remaining Load for All Months	774,180	192,941	28,476	91,816	286,081	932,290	25,754,739	23,448,955	2,305,784		
47	Rank	8	10	12	11	9	7					
48	% Max Month	13.75%	3.43%	0.51%	1.63%	5.08%	16.56%					
49	PR	1.08%	0.18%	0.04%	0.10%	0.18%	0.40%	34.53%				
50	CumPR	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%		
51												
52	**Peak Months Only**							**Total**	**Winter**	**Summer**		
53	Remaining Load for Peak Months Only							23,448,955				
54	Rank											
55	% Max Month											
56	PR							35.30%				
57	CumPR							100.00%	100.00%	0.00%		
58												
59	**DEMAND COST PR ALLOCATORS**											
60		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**		
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%		
62	Pipeline - Remaining	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%		
63	Storage & Peaking	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%		
64	Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%		
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%		
66												
67	**DEMAND COSTS ALLOCATED TO MONTHS**											
68		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**	**Winter**	**Summer**
69	Pipeline - Base	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 694,919	$ 347,460	$ 347,460	50.00%	50.00%
70	Pipeline - Remaining	$ 26,645	$ 5,425	$ 706	$ 2,418	$ 8,502	$ 33,361	$ 1,673,893	$ 1,596,836	$ 77,057	95.40%	4.60%
71	Total Pipeline	$ 84,555	$ 63,335	$ 58,616	$ 60,328	$ 66,412	$ 91,271	$ 2,368,813	$ 1,944,296	$ 424,516	82.08%	17.92%
72												
73	Storage & Peaking	$ 225,908	$ 45,995	$ 5,983	$ 20,500	$ 72,087	$ 282,854	$ 14,192,133	$ 13,538,806	$ 653,327	95.40%	4.60%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$1,771,080	$ 1,771,080	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 310,463	$ 109,330	$ 64,598	$ 80,828	$ 138,499	$ 374,125	$ 14,789,865	$ 13,712,022	$ 1,077,843	92.71%	7.29%
81												
82	Indirect Demand Costs/(Credits)											
83	Miscellaneous Overhead							$ 124,297	$ 98,333	$ 25,964	79.11%	20.89%
84	Local Production & Storage							$ 686,673	$ 686,673	$ -	100.00%	0.00%
85	Subtotal							$ 810,970	$ 785,006	$ 25,964	96.80%	3.20%

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

LN	Description	Calculation
42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT**	
43	(Based on NH Firm Sales Sendout for Remaining Temperatur	
44		
45	**All Months**	
46	Remaining Load for All Months	Schedule 10B, LN 80
47	Rank	Rank LN 46
48	% Max Month	LN 46 / MAX Month LN 46
49	PR	The difference between LN 48 for the month and LN 48 for next highest rank
50	CumPR	Cumulative Values, LN 49
51		
52	**Peak Months Only**	
53	Remaining Load for Peak Months Only	LN 46
54	Rank	Rank LN 53
55	% Max Month	LN 53 / MAX Month LN 53
56	PR	The difference between LN 55 for the month and LN 55 for next highest rank
57	CumPR	Cumulative Values, LN 56
58		
59	**DEMAND COST PR ALLOCATORS**	
60		
61	Pipeline - Base	1/12
62	Pipeline - Remaining	LN 50
63	Storage & Peaking	LN 50
64	Capacity Release	LN 57
65	Interr. Margins & Off Sys Sales	LN 57
66		
67	**DEMAND COSTS ALLOCATED TO MONTHS**	
68		
69	Pipeline - Base	LN 40 * LN 61
70	Pipeline - Remaining	LN 41 * LN 62
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & Peaking	LN 63 * (Sum LN 21 : LN 22)
74		
75	Less Credits to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	LN 64 * Sum (Schedule 25 LN 88, Schedule 25 LN 89)
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79		
80	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 78)
81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

New Hampshire PNGTS Refund, Litigation Costs and Asset Management

		Total	Capacity Assigned	Sales
1	Asset Management	($1,223,716)	($71,945)	($1,151,771)
2	PNGTS Litigation	$183,943	$13,187	$170,756
3	PNGTS Refund	($628,298)	($45,043)	($583,255)
4	PNGTS litigation net of Refund	($444,355)	($31,856)	($412,499)
5	Asset Management plus PNGTS			($1,564,270)
6	Capacity Release Revenues			($206,811)
7	Total NH Cap Rel and Asset Management			($1,771,080)

Notes
1 Capacity Assigned values from Schedule 5B page 1
2 Total PNGTS Litigation and Refund valuse from Schedule 5B page 6
3 Total Asset Management revenues from Schedule 25, line 9 x line 89

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	2,630,286	1,300,278	1,054,110	882,830	2,011,250	3,096,575	18,510,394	10,975,329
2	New Hampshire Sales Storage	0	2,892,662	4,786,814	4,052,994	2,656,366	13,697	14,402,533	14,402,533
3	New Hampshire Sales Peaking	490,224	646,340	686,856	619,446	711,724	155,128	3,355,263	3,309,718
4	Total New Hampshire Firm Sales Sendout	3,120,510	4,839,280	6,527,780	5,555,270	5,379,340	3,265,400	36,268,190	28,687,580
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	3,120,510	4,839,280	6,527,780	5,555,270	5,379,340	3,265,400	36,268,190	28,687,580
9	Total Firm Sales	3,047,100	4,722,517	6,380,229	5,429,979	5,257,529	3,191,596	35,429,591	28,028,950
10	Difference (LAUF & Company Use)	73,410	116,763	147,551	125,291	121,811	73,804	838,599	658,630
11	Percent Difference	2.35%	2.41%	2.26%	2.26%	2.26%	2.26%	2.31%	2.30%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 1,222,161	$ 649,388	$ 550,433	$ 463,086	$ 1,029,074	$ 1,494,396	$ 9,134,158	$ 5,408,538
15	New Hampshire Hedging (Gains) Losses	$ 221,115	$ 206,683	$ 125,504	$ 155,583	$ 151,036	$ 194,526	$ 1,089,835	$ 1,054,446
16	New Hampshire Total Storage	$ -	$ 1,258,945	$ 2,089,644	$ 1,767,251	$ 1,160,872	$ 6,417	$ 6,283,128	$ 6,283,128
17	New Hampshire Total Peaking	$ 197,883	$ 260,037	$ 276,274	$ 248,940	$ 299,647	$ 63,270	$ 1,370,306	$ 1,346,050
18	New Hampshire Inventory Finance Charge	$ 970	$ 1,697	$ 2,423	$ 2,042	$ 1,929	$ 1,032	$ 10,094	$ 10,094
19	Total New Hampshire Sales Variable Costs	$ 1,642,129	$ 2,376,749	$ 3,044,278	$ 2,636,902	$ 2,642,557	$ 1,759,640	$ 17,887,520	$ 14,102,256
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,421,015	$ 2,170,067	$ 2,918,774	$ 2,481,319	$ 2,491,522	$ 1,565,114	$ 16,797,685	$ 13,047,810
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 1,642,129	$ 2,376,749	$ 3,044,278	$ 2,636,902	$ 2,642,557	$ 1,759,640	$ 17,887,520	$ 14,102,256
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	0.4646	0.4994	0.5222	0.5245	0.5117	0.4826	$ 0.4935	$ 0.4928
27	New Hampshire Hedging (Gains) Losses	0.0841	0.1590	0.1191	0.1762	0.0751	0.0628	$ 0.0589	$ 0.0961
28	New Hampshire Storage Excld Inventory Finance Costs	0.0000	0.4352	0.4365	0.4360	0.4370	0.4685	$ 0.4363	$ 0.4363
29	New Hampshire Peaking Excld Inventory Finance Costs	0.4037	0.4023	0.4022	0.4019	0.4210	0.4079	$ 0.4084	$ 0.4067
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	0.0020	0.0005	0.0004	0.0004	0.0006	0.0061	$ 0.0006	$ 0.0006
31	Weighted Average Cost per Dth Sendout	0.5262	0.4911	0.4664	0.4747	0.4912	0.5389	$ 0.4932	$ 0.4916
32									
33	New Hampshire Interruptible Cost / Therm	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	866,491	897,651	898,572	811,662	897,086	867,162	10,513,451	5,238,625
37	Base Commodity Cost Excld Hedging	$ 402,615	$ 448,307	$ 469,215	$ 425,755	$ 459,002	$ 418,489	$ 5,226,141	$ 2,623,383
38	Base Hedging Commodity Cost	$ 72,841	$ 142,684	$ 106,985	$ 143,041	$ 67,367	$ 54,475	$ 605,987	$ 587,394
39	Remaining Commodity Excld Hedging	$ 1,018,400	$ 1,721,760	$ 2,449,559	$ 2,055,564	$ 2,032,520	$ 1,146,625	$ 11,571,544	$ 10,424,427
40	Remaining Hedging Commodity	$ 148,273	$ 63,999	$ 18,519	$ 12,542	$ 83,669	$ 140,051	$ 483,848	$ 467,052
41	Total Commodity Excld Hedging	$ 1,421,015	$ 2,170,067	$ 2,918,774	$ 2,481,319	$ 2,491,522	$ 1,565,114	$ 16,797,685	$ 13,047,810
42	Total Hedging	$ 221,115	$ 206,683	$ 125,504	$ 155,583	$ 151,036	$ 194,526	$ 1,089,835	$ 1,054,446
43	Total Commodity (Incl Hedging)	$ 1,642,129	$ 2,376,749	$ 3,044,278	$ 2,636,902	$ 2,642,557	$ 1,759,640	$ 17,887,520	$ 14,102,256

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Schedule 22, LN 9 * LN 60 * 10
2	New Hampshire Sales Storage	Schedule 22, LN 3 * LN 60 * 10
3	New Hampshire Sales Peaking	Schedule 22, LN 4 * LN 60 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Schedule 22, LN 7 * 10
7		
8	Total Firm Sendout	LN 4
9	Total Firm Sales	Schedule 10B, LN 11
10	Difference (LAUF & Company Use)	LN 8 - LN 9
11	Percent Difference	LN 10 / LN 8
12		
13	**Variable Costs**	
14	New Hampshire Sales Pipeline Commodity	Schedule 22, LN 74 * 10
15	New Hampshire Hedging (Gains) Losses	Schedule 22, LN 75 * 10
16	New Hampshire Total Storage	Schedule 22, LN 76 * 10
17	New Hampshire Total Peaking	Schedule 22, LN 77 * 10
18	New Hampshire Inventory Finance Charge	Schedule 22, LN 80 * 10
19	Total New Hampshire Sales Variable Costs	Sum LN 14 : LN 18
20	Total New Hampshire Sales Variable Costs Excld Hedges	LN 19 - LN 15
21		
22	New Hampshire Interruptible Commodity Costs	Schedule 22, LN 78
23	Total New Hampshire Commodity Costs	LN 19
24		
25	**Supply Cost/Therm**	
26	New Hampshire Sales Pipeline Commodity Excld Hedges	LN 14 / LN 1
27	New Hampshire Hedging (Gains) Losses	LN 15 / LN 1
28	New Hampshire Storage Excld Inventory Finance Costs	LN 16 / LN 2
29	New Hampshire Peaking Excld Inventory Finance Costs	LN 17 / LN 3
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	LN 18 / Sum (LN 2 : LN 3)
31	Weighted Average Cost per Dth Sendout	LN 19 / LN 8
32		
33	New Hampshire Interruptible Cost / Therm	LN 22 / LN 6
34		
35	**Commodity Costs**	
36	Base Commodity, therms	Schedule 10B, LN 64
37	Base Commodity Cost Excld Hedging	Min (LN 26 * LN 36), LN 19
38	Base Hedging Commodity Cost	Min (LN 27 * LN 36), (LN 19 - LN 37)
39	Remaining Commodity Excld Hedging	LN 20 - LN 37
40	Remaining Hedging Commodity	LN 15 - LN 38
41	Total Commodity Excld Hedging	LN 37 + LN 39
42	Total Hedging	LN 38 + LN 40
43	Total Commodity (Incl Hedging)	LN 41 + LN 42

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes
November 1, 2010 through April 30, 2011

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Peaking Supply 1	$2,404,468	602,041	$3.9939
Washington 10 Storage	$11,577,747	2,559,895	$4.5227
Tennessee Storage	$707,503	147,681	$4.7908
Chicago	$1,667,801	301,862	$5.5251
Niagara	$1,035,386	184,693	$5.6060
Tennessee Production	$7,768,412	1,375,093	$5.6494
LNG	$111,223	18,872	$5.8934
Pittsburgh, NH	$1,240,066	199,100	$6.2284
Peaking Supply 2	$21,557	2,670	$8.0723
Total System	$26,534,162	5,391,907	$4.9211

Peak Period

Northern Utilities

NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

	Sales Revenues		Summer						Winter						
			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
2	Residential Heat & Non Heat								1,414,484	2,062,233	2,986,351	2,524,748	2,503,078	1,544,347	13,035,240
3	Sales HLF Classes								350,675	424,947	465,570	408,229	429,473	323,352	2,402,246
4	Sales LLF Classes								1,281,941	2,235,337	2,928,309	2,497,002	2,324,978	1,323,897	12,591,463
5	Total								3,047,100	4,722,517	6,380,229	5,429,979	5,257,529	3,191,596	28,028,950
6	Rates														
7	Residential Heat & Non Heat CGA								$1.1177	$1.1177	$1.1177	$1.1177	$1.1177	$1.1177	
8	Sales HLF Classes CGA								$1.1177	$1.1177	$1.1177	$1.1177	$1.1177	$1.1177	
9	Sales LLF Classes CGA								$1.1177	$1.1177	$1.1177	$1.1177	$1.1177	$1.1177	
10	Revenues														
11	Residential Heat & Non Heat								$ (1,580,968)	$ (2,304,958)	$ (3,337,844)	$ (2,821,911)	$ (2,797,690)	$ (1,726,117)	$ (14,569,488)
12	Sales HLF Classes								$ (391,950)	$ (474,963)	$ (520,367)	$ (456,278)	$ (480,022)	$ (361,410)	$ (2,684,990)
13	Sales LLF Classes								$ (1,432,825)	$ (2,498,436)	$ (3,272,971)	$ (2,790,899)	$ (2,598,627)	$ (1,479,720)	$ (14,073,479)
14	Total Sales Revenues								$ (3,405,743)	$ (5,278,357)	$ (7,131,182)	$ (6,069,087)	$ (5,876,340)	$ (3,567,247)	$ (31,327,957)

15

16			Summer						Winter						
17	Gas Costs and Credits		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18			May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline		$ 165,006	$ 165,006	$ 165,006	$ 165,006	$ 165,006	$ 165,006	$ 144,690	$ 149,541	$ 165,006	$ 165,006	$ 165,006	$ 165,006	$ 1,944,296
21	Storage		$ 513,332	$ 513,332	$ 513,332	$ 513,332	$ 513,332	$ 513,332	$ 1,212,196	$ 1,537,673	$ 1,564,703	$ 1,564,703	$ 1,564,703	$ 513,332	$ 11,037,302
22	Peaking		$ 147,181	$ 147,181	$ 147,181	$ 147,181	$ 147,181	$ 147,181	$ 272,618	$ 272,618	$ 303,525	$ 303,525	$ 303,525	$ 147,181	$ 2,486,078
23	Total Demand Costs		$ 825,520	$ 825,520	$ 825,520	$ 825,520	$ 825,520	$ 825,520	$ 1,629,504	$ 1,959,832	$ 2,033,234	$ 2,033,234	$ 2,033,234	$ 825,520	$ 15,467,675
24	NUI Commodity Costs														
25	NUI Total Pipeline Volumes								499,368	256,695	197,401	162,786	371,174	573,323	2,060,747
26	Pipeline Costs Modeled in Sendout™								$ 2,759,757	$ 1,490,684	$ 1,187,524	$ 978,909	$ 2,173,072	$ 3,121,720	$ 11,711,666
27	NYMEX Price Used for Forecast								$ 4.9050	$ 5.1720	$ 5.3370	$ 5.3060	$ 5.2100	$ 5.0180	
28	NYMEX Price Used for Update								$ 4.0250	$ 4.3590	$ 4.5430	$ 4.5380	$ 4.4720	$ 4.3990	
29	Increase/(Decrease) NYMEX Price								$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	
30	Increase/(Decrease) in Pipeline Costs								$ (439,444)	$ (208,693)	$ (156,737)	$ (125,020)	$ (273,927)	$ (354,887)	
31	Updated Pipeline Costs								$ 2,320,313	$ 1,281,991	$ 1,030,787	$ 853,889	$ 1,899,146	$ 2,766,833	
32	Interruptible Volumes - NH								0	0	0	0	0	0	
33	Average Supply Cost ($/MMBtu)								$ 4.65	$ 4.99	$ 5.22	$ 5.25	$ 5.12	$ 4.83	
34	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Updated Pipeline Costs								$ 2,320,313	$ 1,281,991	$ 1,030,787	$ 853,889	$ 1,899,146	$ 2,766,833	
36	New Hampshire Allocated Percentage								52.67%	50.65%	53.40%	54.23%	54.19%	54.01%	
37	NH Updated Pipeline Costs								$ 1,222,161	$ 649,388	$ 550,433	$ 463,086	$ 1,029,074	$ 1,494,396	$ 5,408,538
38	Hedging (Gain)/Loss Estimate														
39	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
40	NYMEX NG Futures Contracts								7	8	4	5	5	9	
41	Average Purchase Price								$ 6.3850	$ 6.6363	$ 6.9913	$ 6.9020	$ 6.7130	$ 6.1778	
42	NYMEX Price Used for Forecast								$ 4.9050	$ 5.1720	$ 5.3370	$ 5.3060	$ 5.2100	$ 5.0180	
43	NYMEX Price Used for Update								$ 4.0250	$ 4.3590	$ 4.5430	$ 4.5380	$ 4.4720	$ 4.3990	
44	Increase/(Decrease) NYMEX Price								(0.8800)	(0.8130)	(0.7940)	(0.7680)	(0.7380)	(0.6190)	
45	NUI Futures Hedging (Gain)/Loss - Allocate								$ 165,200	$ 182,180	$ 97,930	$ 118,200	$ 112,050	$ 160,090	$ 835,650
46	New Hampshire Allocated Percentage								52.67%	50.65%	53.40%	54.23%	54.19%	54.01%	
47	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 87,015	$ 92,283	$ 52,294	$ 64,103	$ 60,716	$ 86,466	$ 442,876

Peak Period

Northern Utilities

NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

			Summer						Winter						
	Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
48	Price Triggered NYMEX Contracts (NH Only)														
49	NYMEX NG Futures Contracts								6	5	3	4	4	6	
50	Average Purchase Price								$ 6.2600	$ 6.6470	$ 6.9833	$ 6.8250	$ 6.7300	$ 6.2000	
51	NYMEX Price Used for Forecast								$ 4.9050	$ 5.1720	$ 5.3370	$ 5.3060	$ 5.2100	$ 5.0180	
52	NYMEX Price Used for Update								$ 4.0250	$ 4.3590	$ 4.5430	$ 4.5380	$ 4.4720	$ 4.3990	
53	Increase/(Decrease) NYMEX Price								(0.8800)	(0.8130)	(0.7940)	(0.7680)	(0.7380)	(0.6190)	
54	NUI Futures Hedging (Gain)/Loss - Allocate								$ 134,100	$ 114,400	$ 73,210	$ 91,480	$ 90,320	$ 108,060	$ 611,570
55	New Hampshire Allocated Percentage								100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
56	NH Futures Hedging (Gain)/Loss, Price Triggered								$ 134,100	$ 114,400	$ 73,210	$ 91,480	$ 90,320	$ 108,060	$ 611,570
57	NH Commodity Costs														
58	Pipeline Excl Hedging								$ 1,222,161	$ 649,388	$ 550,433	$ 463,086	$ 1,029,074	$ 1,494,396	$ 5,408,538
59	Hedging (Gain)/Loss Estimate								$ 221,115	$ 206,683	$ 125,504	$ 155,583	$ 151,036	$ 194,526	$ 1,054,446
60	Storage								$ -	$ 1,258,945	$ 2,089,644	$ 1,767,251	$ 1,160,872	$ 6,417	$ 6,283,128
61	Peaking								$ 197,883	$ 260,037	$ 276,274	$ 248,940	$ 299,647	$ 63,270	$ 1,346,050
62	Total Commodity Costs								$ 1,641,159	$ 2,375,052	$ 3,041,855	$ 2,634,860	$ 2,640,628	$ 1,758,608	$ 14,092,162
63	Inventory Finance Charge		$ 628	$ 915	$ 1,129	$ 1,034	$ 1,005	$ 976	$ 1,018	$ 978	$ 877	$ 658	$ 462	$ 414	$ 10,094
64	Asset Management and Capacity Release														
65	NUI AMA Revenue		$ (206,417)	$ (206,417)	$ (206,417)	$ (206,417)	$ (206,417)	$ (206,417)	$ (212,417)	$ (212,417)	$ (212,417)	$ (212,417)	$ (212,417)	$ (206,417)	$ (2,507,000)
66	PNGTS Litigation Cost		$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 31,403	$ 376,840
67	NUI Capacity Release		$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (35,377)	$ (424,530)
68	NUI AMA Rev & Cap. Release Subtotal		$ (210,391)	$ (210,391)	$ (210,391)	$ (210,391)	$ (210,391)	$ (210,391)	$ (216,391)	$ (216,391)	$ (216,391)	$ (216,391)	$ (216,391)	$ (210,391)	$ (2,554,690)
69	NH AMA Revenue		$ (80,531)	$ (80,531)	$ (80,531)	$ (80,531)	$ (80,531)	$ (80,531)	$ (83,460)	$ (83,460)	$ (83,460)	$ (83,460)	$ (83,460)	$ (80,531)	$ (981,015)
70	NH Capacity Release		$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (17,234)	$ (206,811)
	NH PNGTS Refund											($583,255)			
71	NH Total Asset Management and Capacity Release		$ (97,765)	$ (97,765)	$ (97,765)	$ (97,765)	$ (97,765)	$ (97,765)	$ (100,694)	$ (100,694)	$ (100,694)	$ (683,949)	$ (100,694)	$ (97,765)	$ (1,771,080)

Peak Period

Northern Utilities

NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

			Summer						Winter						
	Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
72															
73	**Total Anticipated Direct Cost of Gas**		$ 728,382	$ 728,669	$ 728,883	$ 728,788	$ 728,759	$ 728,730	$ 3,170,988	$ 4,235,168	$ 4,975,271	$ 3,984,803	$ 4,573,630	$ 2,486,777	$ 27,798,851
77	Working Capital														
78	Total Anticipated Direct Cost of Gas		$ 728,382	$ 728,669	$ 728,883	$ 728,788	$ 728,759	$ 728,730	$ 3,170,988	$ 4,235,168	$ 4,975,271	$ 3,984,803	$ 4,573,630	$ 2,486,777	$ 27,798,851
79	Working Capital Percentage		0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	
80	Working Capital Allowance		$ 1,384	$ 1,384	$ 1,385	$ 1,385	$ 1,385	$ 1,385	$ 6,025	$ 8,047	$ 9,453	$ 7,571	$ 8,690	$ 4,725	$ 52,818
81	Beginning Period Working Capital Balance		$ (83,069)	$ (81,846)	$ (80,621)	$ (79,392)	$ (78,162)	$ (76,929)	$ (75,693)	$ (69,811)	$ (61,893)	$ (52,552)	$ (45,076)	$ (36,466)	
82	End of Period Working Capital Allowance		$ (81,685)	$ (80,462)	$ (79,236)	$ (78,008)	$ (76,777)	$ (75,544)	$ (69,668)	$ (61,764)	$ (52,440)	$ (44,980)	$ (36,386)	$ (31,741)	
83	Interest		$ (161)	$ (159)	$ (156)	$ (154)	$ (152)	$ (149)	$ (142)	$ (129)	$ (112)	$ (95)	$ (80)	$ (67)	$ (1,556)
84	End of period with Interest	$ (83,069)	$ (81,846)	$ (80,621)	$ (79,392)	$ (78,162)	$ (76,929)	$ (75,693)	$ (69,811)	$ (61,893)	$ (52,552)	$ (45,076)	$ (36,466)	$ (31,808)	
85	Bad Debt														
86	Total Anticipated Direct Cost of Gas		$ 728,382	$ 728,669	$ 728,883	$ 728,788	$ 728,759	$ 728,730	$ 3,170,988	$ 4,235,168	$ 4,975,271	$ 3,984,803	$ 4,573,630	$ 2,486,777	$ 27,798,851
87	Prior Period Over/Under Collection (Incld AT	$ 2,527,403	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,527,403
88	Working Capital Allowance		$ (81,685)	$ (80,301)	$ (78,916)	$ (77,531)	$ (76,146)	$ (74,762)	$ (68,737)	$ (60,690)	$ (51,237)	$ (43,666)	$ (34,976)	$ (30,251)	$ (758,898)
89	Subtotal	$ 2,527,403	$ 646,697	$ 648,368	$ 649,968	$ 651,257	$ 652,613	$ 653,969	$ 3,102,251	$ 4,174,478	$ 4,924,034	$ 3,941,138	$ 4,538,654	$ 2,456,526	$ 29,567,356
90	Bad Debt Percentage	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	
91	Bad Debt Allowance	$ 11,373	$ 2,910	$ 2,918	$ 2,925	$ 2,931	$ 2,937	$ 2,943	$ 13,960	$ 18,785	$ 22,158	$ 17,735	$ 20,424	$ 11,054	$ 133,053
92	Beginning Period Bad Debt Balance		$ (2,655)	$ 253	$ 3,174	$ 6,108	$ 9,053	$ 12,011	$ 14,980	$ 28,983	$ 47,843	$ 70,117	$ 88,006	$ 108,623	
93	End of Period Bad Debt Balance		$ 255	$ 3,170	$ 6,099	$ 9,038	$ 11,990	$ 14,953	$ 28,940	$ 47,768	$ 70,001	$ 87,852	$ 108,430	$ 119,677	
94	Interest		$ (2)	$ 3	$ 9	$ 15	$ 21	$ 26	$ 43	$ 75	$ 115	$ 155	$ 192	$ 223	$ 876
95	End of Period Bad Debt Balance with Interest	$ (2,655)	$ 253	$ 3,174	$ 6,108	$ 9,053	$ 12,011	$ 14,980	$ 28,983	$ 47,843	$ 70,117	$ 88,006	$ 108,623	$ 119,900	
96	Local Production and Storage Capacity								$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 686,673
97	Miscellaneous Overhead								$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 16,389	$ 98,333
98	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
99	Beginning Balance Over/Under Collection		$2,527,403	$3,261,446	$3,997,212	$4,734,634	$5,473,404	$6,213,590	$ 6,955,197	$ 6,864,789	$ 5,964,979	$ 3,949,597	$ 2,001,967	$ 832,863	
100	Net Costs - Revenues		$ 728,382	$ 728,669	$ 728,883	$ 728,788	$ 728,759	$ 728,730	$ (103,921)	$ (912,355)	$ (2,025,077)	$ (1,953,449)	$ (1,171,875)	$ (949,635)	
101	Ending Balance before Interest		$3,255,786	$3,990,115	$4,726,096	$5,463,422	$6,202,163	$6,942,321	$ 6,851,275	$ 5,952,434	$ 3,939,902	$ 1,996,147	$ 830,091	$ (116,772)	
102	Average Balance		$2,891,594	$3,625,780	$4,361,654	$5,099,028	$5,837,783	$6,577,955	$ 6,903,236	$ 6,408,611	$ 4,952,441	$ 2,972,872	$ 1,416,029	$ 358,046	
103	Interest Rate		2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	
104	Interest Expense		$ 5,660	$ 7,097	$ 8,538	$ 9,981	$ 11,427	$ 12,876	$ 13,513	$ 12,545	$ 9,694	$ 5,819	$ 2,772	$ 701	$ 100,625
105	Ending Balance Incl Interest Expense	$ 2,527,403	$3,261,446	$3,997,212	$4,734,634	$5,473,404	$6,213,590	$6,955,197	$ 6,864,789	$ 5,964,979	$ 3,949,597	$ 2,001,967	$ 832,863	$ (116,071)	
106	**Total Over/Under Collection Ending Balance**		$3,179,852	$3,919,765	$4,661,349	$5,404,295	$6,148,672	$6,894,483	$ 6,823,961	$ 5,950,929	$ 3,967,162	$ 2,044,897	$ 905,020	$ (27,978)	
107	ATV Reconciliation														$ -
108															
109	**Total Indirect Cost of Gas**	$ 2,453,053	$ 9,791	$ 11,244	$ 12,700	$ 14,157	$ 15,618	$ 17,081	$ 164,233	$ 170,158	$ 172,143	$ 162,019	$ 162,833	$ 147,471	$ 3,512,501
110															
111	**Total Cost of Gas**	$ 2,453,053	$ 738,173	$ 739,913	$ 741,584	$ 742,946	$ 744,377	$ 745,811	$ 3,335,221	$ 4,405,326	$ 5,147,415	$ 4,146,823	$ 4,736,463	$ 2,634,248	$ 31,311,352
112															
113	**Total Interest**	$ -	$ 5,497	$ 6,942	$ 8,391	$ 9,842	$ 11,296	$ 12,754	$ 13,414	$ 12,491	$ 9,698	$ 5,879	$ 2,884	$ 858	$ 99,945
114															

Reserved for Future Use

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2010 through October 31, 2011

Pipeline	Contract ID	Rate	Negotiated Rate	MDQ	Dth / GJ	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Currency	Months Per Year	Support for Demand Rate	Note	Monthly Demand	Annual Demand
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	286	Dth	Centerville, NJ	Taunton, MA	$ 5.9771	USD	12	FXW-5A, Page 1		$ 1,709	$ 20,513
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes	965	Dth	Lambertville, NJ	Taunton, MA	$ 5.9771	USD	12	FXW-5A, Page 1		$ 5,768	$ 69,215
Algonquin	93002F	AFT-1 (AFT-2)	No	4,211	Dth	Mendon, MA	Brockton, MA	$ 6.1138	USD	12	FXW-5A, Page 2		$ 25,745	$ 308,943
Granite	10-010-FT-NN	FT-NN	No	100,000	Dth	NA	NA	$ 1.6666	USD	2	FXW-5A, Page 3	1	$ 166,660	$ 333,320
Granite	10-010-FT-NN	FT-NN	No	100,000	Dth	NA	NA	$ 3.5518	USD	10	FXW-5A, Page 4	1	$ 355,180	$ 3,551,800
Iroquois	R181001	RTS-1	No	6,569	Dth	Zone 1	Zone 1	$ 6.5971	USD	12	FXW-5A, Page 5		$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Dth	Pittsburgh	GSGT	$ 27.4017	USD	1	FXW-5A, Page 6	2	$ 30,142	$ 30,142
PNGTS	1997-003	FT	No	1,100	Dth	Pittsburgh	GSGT	$ 40.2456	USD	11	FXW-5A, Page 7	2	$ 44,270	$ 486,972
PNGTS	1997-004	FT	Yes	33,000	Dth	Pittsburgh	GSGT	$ 52.0632	USD	1	FXW-5A, Page 6	3	$ 1,718,086	$ 1,718,086
PNGTS	1997-004	FT	Yes	33,000	Dth	Pittsburgh	GSGT	$ 76.4666	USD	4	FXW-5A, Page 7	3	$ 2,523,398	$ 10,093,591
Tennessee	5083	FT-A	No	4,605	Dth	Zone 0	Zone 6	$ 16.5900	USD	12	FXW-5A, Page 8		$ 76,397	$ 916,763
Tennessee	5083	FT-A	No	8,550	Dth	Zone L	Zone 6	$ 15.1500	USD	12	FXW-5A, Page 8	4	$ 129,533	$ 1,554,390
Tennessee	5265	FT-A	No	2,653	Dth	Zone 4	Zone 6	$ 5.8900	USD	12	FXW-5A, Page 8		$ 15,626	$ 187,514
Tennessee	5292	FT-A	No	1,406	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 6,932	$ 83,179
Tennessee	39735	FT-A	No	929	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 4,580	$ 54,960
Tennessee	41099	FT-A	No	4,267	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 21,036	$ 252,436
Tennessee	46314	FT-A	No	950	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	FXW-5A, Page 8		$ 4,684	$ 56,202
Tennessee	31861	NET-284	No	1,382	Dth	3	3	$ 5.0700	USD	12	FXW-5A, Page 9	5	$ 7,007	$ 84,081
Tennessee	31861	NET-284	No	844	Dth	3	4	$ 10.6100	USD	12	FXW-5A, Page 9	5	$ 8,955	$ 107,458
Texas Eastern	800384	FT-1	No	965	Dth	M3	M3	$ 5.8080	USD	12	FXW-5A, Page 10 & 20	6	$ 5,605	$ 67,257
Texas Eastern	800436	CDS	No	64	Dth	M3	M3	$ 5.3710	USD	12	FXW-5A, Page 10		$ 344	$ 4,125
Texas Eastern	800464	CDS	No	33	Dth	ELA	M1	$ 2.3750	USD	12	FXW-5A, Page 10	7	$ 78	$ 941
Texas Eastern	800464	CDS	No	9	Dth	ETX	M1	$ 2.1890	USD	12	FXW-5A, Page 10	7	$ 20	$ 236
Texas Eastern	800464	CDS	No	16	Dth	STX	M1	$ 6.8120	USD	12	FXW-5A, Page 10	7	$ 109	$ 1,308
Texas Eastern	800464	CDS	No	18	Dth	WLA	M1	$ 2.8280	USD	12	FXW-5A, Page 10	7	$ 51	$ 611
Texas Eastern	800464	CDS	No	59	Dth	M1	M3	$ 11.2800	USD	12	FXW-5A, Page 10	7	$ 666	$ 7,986
TransCanada	29594	FT	No	6,264	GJ	Dawn	Iroquois	$ 11.6124	CAD	12	FXW-5A, Page 11 & 12	8	$ 69,103	$ 829,238
TransCanada	33322	FT	No	35,872	GJ	Dawn	E. Hereford	$ 18.7330	CAD	12	FXW-5A, Page 11 & 12	9	$ 638,391	$ 7,660,696
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Dth	Alliance	Dawn	$ 7.6042	USD	12	FXW-5A, Page 13		$ 130,579	$ 1,566,952
Vector	CRL-NUI-0727	FT-1	Yes	17,086	Dth	W-10	Dawn	$ 4.5625	USD	5	FXW-5A, Page 14		$ 77,955	$ 389,774
Vector	FT-1-NUI-0122	FT-1	Yes	6,070	Dth	Alliance	St. Clair	$ 7.7745	USD	12	FXW-5A, Page 15 & 16	10	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,404	GJ	St. Clair	Dawn	$ 0.4623	CAD	12	FXW-5A, Page 17		$ 2,813	$ 33,750

Total Annual Demand Costs $ 31,558,769

Exchange Rate (CAD/USD) =	0.95	FXW-5A, Page 18

Note 1: Granite filed new rates under FERC docket RP10-896. New Granite rates projected to take effect on 1/1/2011.
Note 2: PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.
Note 3: Seasonal Recourse Rate. PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.
Note 4: The demand rate applied for Zone L to Zone 6 transportation capacity Zone 1 to Zone 6 demand rate.
Note 5: The rate is the Segment 3 demand rate of $5.07 per Dth plus the Segment 4 demand rate of $5.54 per Dth.
Note 6: For Contract ID 800384, Northern pays both the FT-1 Reservation Charge of $5.148 (Page 10 of FXW-5A) and the FT-1/FTS Other Transportation Services charge of $0.66 (Page 20 of FXW-5A).
Note 7: Rate is expressed in the tariff sheet as as a Delivery Zone of AAB ("Access Area Boundary"). The AAB is the border between the Access Areas (ETX, ELA, WLA, and STX) and the M1 Zone.
Note 8: Rate is the Delivery Pressure Toll for deliveries into Iroquois of $CAD 0.78572 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to Iroquois of $CAD 10.82669 (Page 12 of FXW-5A).
Note 9: Rate is the Delivery Pressure Toll for deliveries into E. Hereford of $CAD 1.96558 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to E. Hereford of $CAD 16.76744 (Page 12 of FXW-5A).
Note 10: Maximum tariff rate of $7.7745 (Page 15 of FXW-5A) exceeds negotiated rate of $8.0908 (Page 16 of FXW-5A). Therefore, Maximum tariff rate applies.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2009 through October 31, 2010

Pipeline	Contract ID	MDQ	Dth / GJ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Monthly Demand	Monthly Pipeline Allocated Cost	Monthly Storage Allocated Cost	Monthly Peaking Allocated Cost	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Algonquin	93201A1C	286	Dth	201	85		70%	30%	0%	$ 1,709	$ 1,201	$ 508	$ -	$ 20,513	$ 14,417	$ 6,097	$ -
Algonquin	93201A1C	965	Dth	965			100%	0%	0%	$ 5,768	$ 5,768	$ -	$ -	$ 69,215	$ 69,215	$ -	$ -
Algonquin	93002F	4,211	Dth	4,211			100%	0%	0%	$ 25,745	$ 25,745	$ -	$ -	$ 308,943	$ 308,943	$ -	$ -
Granite	10-010-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 166,660	$ 39,825	$ 59,123	$ 67,712	$ 333,320	$ 79,650	$ 118,245	$ 135,425
Granite	10-010-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 355,180	$ 84,874	$ 126,000	$ 144,306	$ 3,551,800	$ 848,738	$ 1,260,001	$ 1,443,061
Iroquois	R181001	6,569	Dth	6,569			100%	0%	0%	$ 43,336	$ 43,336	$ -	$ -	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 30,142	$ 30,142	$ -	$ -	$ 30,142	$ 30,142	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 44,270	$ 44,270	$ -	$ -	$ 486,972	$ 486,972	$ -	$ -
PNGTS	1997-004	33,000	Dth		33,000		0%	100%	0%	$ 1,718,086	$ -	$ 1,718,086	$ -	$ 1,718,086	$ -	$ 1,718,086	$ -
PNGTS	1997-004	33,000	Dth		33,000		0%	100%	0%	$ 2,523,398	$ -	$ 2,523,398	$ -	$ 10,093,591	$ -	$ 10,093,591	$ -
Tennessee	5083	4,605	Dth	4,605			100%	0%	0%	$ 76,397	$ 76,397	$ -	$ -	$ 916,763	$ 916,763	$ -	$ -
Tennessee	5083	8,550	Dth	8,550			100%	0%	0%	$ 129,533	$ 129,533	$ -	$ -	$ 1,554,390	$ 1,554,390	$ -	$ -
Tennessee	5265	2,653	Dth		2,653		0%	100%	0%	$ 15,626	$ -	$ 15,626	$ -	$ 187,514	$ -	$ 187,514	$ -
Tennessee	5292	1,406	Dth	1,406	-		100%	0%	0%	$ 6,932	$ 6,932	$ -	$ -	$ 83,179	$ 83,179	$ -	$ -
Tennessee	39735	929	Dth	929	-		100%	0%	0%	$ 4,580	$ 4,580	$ -	$ -	$ 54,960	$ 54,960	$ -	$ -
Tennessee	41099	4,267	Dth	4,267	-		100%	0%	0%	$ 21,036	$ 21,036	$ -	$ -	$ 252,436	$ 252,436	$ -	$ -
Tennessee	46314	950	Dth	950	-		100%	0%	0%	$ 4,684	$ 4,684	$ -	$ -	$ 56,202	$ 56,202	$ -	$ -
Tennessee	31861	1,382	Dth	1,382			100%	0%	0%	$ 7,007	$ 7,007	$ -	$ -	$ 84,081	$ 84,081	$ -	$ -
Tennessee	31861	844	Dth	844			100%	0%	0%	$ 8,955	$ 8,955	$ -	$ -	$ 107,458	$ 107,458	$ -	$ -
Texas Eastern	800384	965	Dth	965	-		100%	0%	0%	$ 5,605	$ 5,605	$ -	$ -	$ 67,257	$ 67,257	$ -	$ -
Texas Eastern	800436	64	Dth	64	-		100%	0%	0%	$ 344	$ 344	$ -	$ -	$ 4,125	$ 4,125	$ -	$ -
Texas Eastern	800464	33	Dth	33			100%	0%	0%	$ 78	$ 78	$ -	$ -	$ 941	$ 941	$ -	$ -
Texas Eastern	800464	9	Dth	9			100%	0%	0%	$ 20	$ 20	$ -	$ -	$ 236	$ 236	$ -	$ -
Texas Eastern	800464	16	Dth	16			100%	0%	0%	$ 109	$ 109	$ -	$ -	$ 1,308	$ 1,308	$ -	$ -
Texas Eastern	800464	18	Dth	18			100%	0%	0%	$ 51	$ 51	$ -	$ -	$ 611	$ 611	$ -	$ -
Texas Eastern	800464	59	Dth	59			100%	0%	0%	$ 666	$ 666	$ -	$ -	$ 7,986	$ 7,986	$ -	$ -
TransCanada	29594	6,264	GJ	6,264	-		100%	0%	0%	$ 69,103	$ 69,103	$ -	$ -	$ 829,238	$ 829,238	$ -	$ -
TransCanada	33322	35,872	GJ		35,872		0%	100%	0%	$ 638,391	$ -	$ 638,391	$ -	$ 7,660,696	$ -	$ 7,660,696	$ -
Vector	CRL-NUI-0725	17,172	Dth		17,172		0%	100%	0%	$ 130,579	$ -	$ 130,579	$ -	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086	Dth		17,086		0%	100%	0%	$ 77,955	$ -	$ 77,955	$ -	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	Dth	6,070	-		100%	0%	0%	$ 47,191	$ 47,191	$ -	$ -	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,404	GJ	6,404	-		100%	0%	0%	$ 2,813	$ 2,813	$ -	$ -	$ 33,750	$ 33,750	$ -	$ -
Annual Total Demand Costs										$ 6,161,947	$ 660,263	$ 5,289,666	$ 212,018	$ 31,558,769	$ 6,979,327	$ 23,000,956	$ 1,578,485

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2010 through October 31, 2011

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0185	$ 1.1500	12	FXW-5A, Page 19	$ 9,677	$ 57,573	$ 58,553	$ 116,126
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.6020	12	FXW-5A, Page 20	$ 133	$ 189	$ 1,412	$ 1,601
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	FXW-5A, Page 20	$ 99	$ 497	$ 687	$ 1,184
W-10	01052	Storage	Yes	3,400,000		34,000			12	FXW-5A, Page 21	$ 240,833	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges			$ 3,008,911
MSQ = Maximum Space Quantity	13.1103545	8.01319821	
MDWQ = Maximum Daily Withdrawal Quantity			24.88671576

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2010 through October 31, 2011

Resource	Contract Quantity	Maximum Daily Quantity	Contract Quantity Demand Rate	MDQ Demand Rate	Months Per Year	Support for Demand Rates	Annual CQ Demand Cost	Annual MDQ Demand Cost	Monthly Fixed Charges	Annual Fixed Charges
Peaking Supply 1	755,000	5,000	$ -	$ 44.09	12	FXW-5A, Page 22	$ -	$ 2,645,238	$ 220,437	$ 2,645,238
Peaking Supply 2	1,435,000	57,400	$ 1.3500	$ -	5	FXW-5A, Page 23	$ 1,937,250	$ -	$ 387,450	$ 1,937,250
Total Peaking Supply Contract Demand Costs										$ 4,582,488

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2010 through October 31, 2011

Asset Management Agreeement Revenue		
Resources		Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	$	(442,000)
Wash 10 via Vector, TCPL, PNGTS	$	(1,100,000)
PNGTS Contract 1997-003	$	(30,000)
Tennessee Niagara	$	(100,000)
Tennessee Long-Haul	$	(835,000)
Total Asset Management	$	(2,507,000)

Capacity Release Revenue		
Resources		Projected Revenue
Texas Eastern Contract 800384	$	(66,701)
AGT Contract 93201A1C	$	(98,779)
Tennessee 5265	$	(259,050)
Total Capacity Release	$	(424,530)

Total Asset Management and Capacity Release Revenue	$	(2,931,530)

ALGONQUIN GAS TRANSMISSION, LLC
DISCOUNTED RATE LETTER - SCHEDULE

Customer Name	Contract No.	Contract Term	Rate Schedule	Discounted Rate	Recourse Reservation Rate	Recourse Usage Rate
NORTHERN UTILITIES, INC.	93201A1C	12/1/1997 - 10/31/2012	AFT-12	5.97710	6.58540	0.01120

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2009

•RATE SCHEDULE AFT-1

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-2/F-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-4)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(STB/SS-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(FTP)	$11.8368	$0.0019	$0.0019	$0.3911	$0.0019	$0.3892
(PSS-T)	$ 9.7854	$0.0019	$0.0019	$0.3236	$0.0019	$0.3217
(AFT-2)	$ 6.1138	$0.0019	$0.0019	$0.2029	$0.0019	$0.2010
(AFT-3)	$10.7554	$0.0019	$0.0019	$0.3555	$0.0019	$0.3536
(AFT-5)	$12.6265	$0.0019	$0.0019	$0.4170	$0.0019	$0.4151
(ITP)	$13.0110	$0.0019	$0.0019	$0.4297	$0.0019	$0.4278
(X-35)	$10.2027	$0.0019	$0.0019	$0.3373	$0.0019	$0.3354
X-39	$13.2089	$0.0019	$0.0019	$0.4362	$0.0019	$0.4343
Incremental Surcharges						
Hubline	$ 1.8607	$0.0000	$0.0000	$0.0000	$0.0000	$0.0612
Secondary 1/		$0.0612	$0.0000			
Tiverton	$ 1.6424	$0.0000	$0.0000	$0.0000	$0.0000	$0.0540
Ramapo	$ 7.5608	$0.0000	$0.0000	$0.2486	$0.0000	$0.2486

•RATE SCHEDULE AFT-1S

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-2/F-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-4)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0031	$0.0864
(STB/SS-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			

•OTHER FIRM RATE SCHEDULES

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
AFT-E	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0058		$0.0600		
AFT-4	$ 3.5211	$0.0032		$0.1190		
AFT-CL:						
Canal	$ 2.0858	$0.0019	$0.0019	$0.0705	$0.0019	$0.0686
Middletown	$ 3.2764	$0.0019	$0.0019	$0.1096	$0.0019	$0.1077
Cleary	$ 1.4529	$0.0019	$0.0019	$0.0497	$0.0019	$0.0478
Lake Road	$ 0.6476	$0.0019	$0.0019	$0.0232	$0.0019	$0.0213
Brayton Pt.	$ 1.2700	$0.0019	$0.0019	$0.0437	$0.0019	$0.0418
Manchester	$ 2.4500	$0.0019	$0.0019	$0.0824	$0.0019	$0.0805
Bellingham	$ 0.9714	$0.0019	$0.0019	$0.0338	$0.0019	$0.0319
Phelps Dodge	$ 0.0000	$0.0185	$0.0019	$0.0185	$0.0019	$0.0000
Cape Cod	$ 9.0501	$0.0019	$0.0019	$0.2994	$0.0019	$0.2975
Northeast Gateway	$ 4.3449	$0.0019	$0.0019	$0.1447	$0.0019	$0.1428
J-2 Facility	$ 4.9077	$0.0019	$0.0019	$0.1632	$0.0019	$0.1613
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun	
	Max	Min	Max	Min
AIT-1	$0.2440	$0.0095	$0.2440	$0.0095
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0437	$0.0019	$0.0437	$0.0019
Manchester	$0.0824	$0.0019	$0.0824	$0.0019
Canal	$0.0705	$0.0019	$0.0705	$0.0019
Cape Cod	$0.2994	$0.0019	$0.2994	$0.0019
Northeast Gateway	$0.1447	$0.0019	$0.1447	$0.0019
J-2 Facility	$0.1632	$0.0019	$0.1632	$0.0019
PAL	$0.2440	$0.0000	$0.0000	$0.0000

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charge of $0.0019.

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP

Rate Schedule FT-NN
Firm Transportation Service

	$/Dth		
	Base Tariff Rate 1/	ACA Adj.	Total Current Rate
Reservation Charge:			
Maximum	$1.6666		$\boxed{\$1.6666}$
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0019	$0.0019
Minimum	$0.0000	$0.0019	$0.0019
Authorized Overrun Commodity Charge:			
Maximum	$0.0548	$0.0019	$0.0567
Minimum	$0.0000	$0.0019	$0.0019
Fuel and Losses Percentage			0.5%
Volumetric Reservation Charge			
Maximum	$0.0548		$0.0548
Minimum	$0.0000		$0.0000

1/ The Base Tariff Rate is the effective rate on file with the Commission, excluding adjustment approved by the Commission.

Rate Schedule FT-NN
Firm Transportation Service

	$/Dth Base Tariff Rate	ACA Adj.	Total Current Rate
Reservation Charge:			
Maximum	$3.5518		$\boxed{\$3.5518}$
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0019	$0.0019
Minimum	$0.0000	$0.0019	$0.0019
Authorized Overrun Commodity Charge:			
Maximum	$0.1168	$0.0019	$0.1187
Minimum	$0.0000	$0.0019	$0.0019
Fuel and Losses Percentage			0.5%
Volumetric Reservation Charge			
Maximum	$0.1168	$0.0019	$0.1187
Minimum	$0.0000	$0.0019	$0.0019

Previous Next

Iroquois Gas Transmission System, L.P. Thirty First Revised Sheet No. 4

C Gas Tariff Superseding

T REVISED VOLUME NO. 1 Thirtieth Revised Sheet No. 4

--------------- RATES (All in $ Per Dth) ----------------

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/ Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Jan 26, 2009 Effective: Jan 27, 2009

Portland Natural Gas Transmission System
FERC Gas Tariff
Second Revised Volume No. 1

Seventh Revised Sheet No. 100 : Effective
Supercedes Sixth Revised Sheet No. 100

Statement of Transportation Rates

(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$27.4017	---------	$27.4017
	-- Minimum	$00.0000	---------	$00.0000
Seasonal	Recourse Reservation Rate			
	-- Maximum	$52.0632	---------	$52.0632
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0019	$00.0019
	-- Minimum	$00.0000	$00.0019	$00.0019
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$18.3920	-------	$18.3920
	--Minimum	$00.0000	-------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.2962	$00.0019	$00.2981
	--Minimum	$00.0000	$00.0019	$00.0019

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$40.2456	----------	$\boxed{\$40.2456}$
	-- Minimum	$00.0000	----------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$76.4666	----------	$\boxed{\$76.4666}$
	-- Minimum	$00.0000	----------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0019	$00.0019
	-- Minimum	$00.0000	$00.0019	$00.0019
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$27.0128	--------	$27.0128
	--Minimum	$00.0000	--------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.4350	$00.0019	$00.4369
	--Minimum	$00.0000	$00.0019	$00.0019

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

Minimum	down to -1.00%
Maximum	up to +1.00%

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 17 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

Tennessee Gas Pipeline Company
FERC Gas Tariff
Sixth Revised Volume No. 1

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
L		$0.00						
1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-A Reservation Rate is $0.00 per Dth

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

Tennessee Gas Pipeline Company
FERC Gas Tariff
Sixth Revised Volume No. 1

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/					
Segment U	$9.65		$0.00	$9.65	
Segment 1	$1.33		$0.00	$1.33	
Segment 2	$8.08		$0.00	$8.08	
Segment 3	$5.07		$0.00	$5.07	
Segment 4	$5.54		$0.00	$5.54	
Commodity Rate 2/, 3/					
Segments U, 1, 2, 3 & 4		$0.0019		$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/					
Segment U	$0.3173			$0.3173	5.52%
Segment 1	$0.0437			$0.0437	0.69%
Segment 2	$0.2656			$0.2656	0.59%
Segment 3	$0.1667			$0.1667	0.73%
Segment 4	$0.1821			$0.1821	0.36%

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

6/ The applicable fuel retention percentages are listed on Sheet No. 105.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

CURRENTLY EFFECTIVE RATES 2/01/2010

•RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.8120	6.5890	2.7250
WLA-AAB	2.8280	2.6050	1.1310
ELA-AAB	2.3750	2.1520	0.9500
ETX-AAB	2.1890	1.9660	0.8760
STX-STX	5.7400	5.5170	2.2950
STX-WLA	5.8990	5.6760	2.3580
STX-ELA	6.8160	6.5930	2.7240
STX-ETX	6.8170	6.5940	2.7250
WLA-WLA	2.0570	1.8340	0.8220
WLA-ELA	2.8310	2.6080	1.1310
WLA-ETX	2.8300	2.6070	1.1300
ELA-ELA	2.3790	2.1560	0.9500
ETX-ETX	2.1930	1.9700	0.8760
ETX-ELA	2.3780	2.1550	0.9500
M1-M1	4.5870	4.3640	1.8320
M1-M2	8.5650	8.3420	3.4230
M1-M3	11.2800	11.0570	4.5080
M2-M2	6.6330	6.4100	2.6510
M2-M3	9.4860	9.2630	3.7910
M3-M3	5.3710	5.1480	2.1460

7(C) RATE SCHEDULES	
FTS	5.3500
FTS-2	7.9590
FTS-4	7.7210
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0100

SCT DEMAND CHARGES	
Access Area	0.0020
M1-M1	0.0030
M1-M2	0.0030
M1-M3	0.0040

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0090	0.0098	0.0143	0.0143	0.0363	0.0726	0.0976
from WLA		0.0060	0.0105	0.0105	0.0325	0.0688	0.0938
from ELA			0.0089	0.0089	0.0309	0.0672	0.0922
from ETX				0.0089	0.0309	0.0672	0.0922
from M1					0.0220	0.0583	0.0833
from M2						0.0408	0.0655
from M3							0.0292

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0088						
from WLA	0.0096	0.0059					
from ELA	0.0140	0.0103	0.0087				
from ETX	0.0140	0.0103	0.0087	0.0087			
from M1	0.0358	0.0321	0.0305	0.0305	0.0218		
from M2	0.0720	0.0683	0.0667	0.0667	0.0580	0.0405	
from M3	0.0968	0.0931	0.0915	0.0915	0.0828	0.0651	0.0290

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1903	0.1963	0.2309	0.2309	0.3962	0.5632	0.6774
from WLA		0.0662	0.0961	0.0961	0.2614	0.4284	0.5427
from ELA			0.0797	0.0797	0.2449	0.4119	0.5262
from ETX				0.0736	0.2388	0.4058	0.5201
from M1					0.1653	0.3323	0.4465
from M2						0.2513	0.3698
from M3							0.1983

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1901						
from WLA	0.1961	0.0661					
from ELA	0.2306	0.0959	0.0795				
from ETX	0.2306	0.0959	0.0795	0.0734			
from M1	0.3957	0.2610	0.2445	0.2384	0.1651		
from M2	0.5626	0.4279	0.4114	0.4053	0.3320	0.2510	
from M3	0.6766	0.5420	0.5255	0.5194	0.4460	0.3694	0.1981

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1904	0.1964	0.2311	0.2311	0.3966	0.5636	0.6779
from WLA		0.0663	0.0962	0.0962	0.2618	0.4288	0.5431
from ELA			0.0798	0.0798	0.2453	0.4123	0.5266
from ETX				0.0736	0.2391	0.4061	0.5204
from M1					0.1655	0.3325	0.4468
from M2						0.2516	0.3701
from M3							0.1985

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1902						
from WLA	0.1962	0.0662					
from ELA	0.2308	0.0960	0.0796				
from ETX	0.2308	0.0960	0.0796	0.0734			
from M1	0.3961	0.2614	0.2449	0.2387	0.1653		
from M2	0.5630	0.4283	0.4118	0.4056	0.3322	0.2513	
from M3	0.6771	0.5424	0.5259	0.5197	0.4463	0.3697	0.1983

TransCanada
In business to deliver

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	0.78572	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	1.96558	0.03798	0.10260

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Dawn	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn	Iroquois	$\boxed{10.82669}$	0.01413	0.3700	0.4070
8	Union Dawn	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn	East Hereford	$\boxed{16.76744}$	0.02275	0.5741	0.6315
12	Union Dawn	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

1. Replacement Shipper's Name: Northern Utilities, Inc.

2. a. Master Service Agreement for Capacity Release Agreement No.: CRT-NUI-0079
   b. Underlying Rate Schedule No.: FT-1

3. Replacement Shipper's Firm Transportation Agreement No.: **CRL-NUI-0725**
   Temporary Assignment of Canadian portion Agreement No.: **CRL-NUI-C0725**

4. Releasing Shipper's Firm Transportation Agreement No.: FT1-DTE-0425

5. Commencement Date: **04/01/2008**
   Termination Date: **10/31/2017**

6. Reservation Quantity: **17,172 Dth/d**

7. Primary Receipt Point(s): — Maximum Daily Reservation Quantity Dth

   Alliance Interconnect — **17,172**

8. Primary Delivery Point(s): — Maximum Daily Reservation Quantity Dth

   St. Clair (US) Interconnect — **17,172**

9. Reservation Rate: $\boxed{\text{\$7.6042/Dth}}$ ($0.2500 per Dth on a 100% load factor basis), exclusive of ACA and fuel reimbursement.

10. Usage Rate: $0.00/Dth

11. Special Terms and Conditions of Release (if any):

    Replacement shipper will receive corresponding Vector-Canada capacity from St. Clair (International Border) to Dawn at no additional cost.

    The Term of the FT1-DTE-0425 contract underlying this release is subject to the June 30, 2005 Precedent Agreement between DTE Energy Trading, Inc. and Vector Pipeline L.P.

Authorized Signature of Replacement Shipper: DTe

Name: DON TUCHFNSKY

Title: ANALYST

Telephone: (508) 836-7259

Fax: ( ) 508-870-2294

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

1. Replacement Shipper's Name: Northern Utilities, Inc.

2. a. Master Service Agreement for Capacity Release Agreement No.: CRT-NUI-0079
   b. Underlying Rate Schedule No.: FT-1

3. Replacement Shipper's Firm Transportation Agreement No.: **CRL-NUI-0727**
   Temporary Assignment of Canadian portion Agreement No.: **CRL-NUI-C0727**

4. Releasing Shipper's Firm Transportation Agreement No.: FT1-DTE-0426

5. Commencement Date: **11/01/2008** Winter Only (November 1 thru March 31 on an annual basis)
   Termination Date: **03/31/2017**

6. Reservation Quantity: **17,086 Dth/d**

7. Primary Receipt Point(s): Maximum Daily Reservation Quantity Dth

   Washington 10 Interconnect **17,086**

8. Primary Delivery Point(s): Maximum Daily Reservation Quantity Dth

   St. Clair (US) Interconnect **17,086**

9. Reservation Rate: $\boxed{\$4.5625/\text{Dth}}$ ($0.1500 per Dth on a 100% load factor basis), exclusive of ACA and fuel reimbursement.

10. Usage Rate: **$0.00/Dth**

11. Special Terms and Conditions of Release (if any):

    Replacement shipper will receive corresponding Vector-Canada capacity from St. Clair (International Border) to Dawn at no additional cost.

    The Term of the FT1-DTE-0425 contract underlying this release is subject to the June 30, 2005 Precedent Agreement between DTE Energy Trading, Inc. and Vector Pipeline L.P.

Authorized Signature of Replacement Shipper: DTL

Name: DON TULCHINSKY

Title: ANALYST

Telephone: ( ) 508-836 7257

Fax: ( ) 508-870-2294

INFORMATIONAL POSTINGS

Capacity
Gas Quality
Index of Customers
Notices
Posted Imbalances
Standards of Conduct
Tariff
- Title Sheet
- Table of Contents
- Preliminary Statement
- Map
- Currently Effective Rates
- Rate Schedules
- General Terms and Conditions
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Vector - Canada Tariff
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Vector Pipeline L.P.
FERC Gas Tariff
Original Volume No. 1

Eleventh Revised Sheet No. 20
Superseding
Tenth Revised Sheet No. 20

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.2501	0.0000	$\boxed{\$7.7745}$	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0019	0.0019	0.0019	0.0019
Usage and ACA Charge	0.0019	0.0019	0.0019	0.0019

Negotiated Rates:

The effective maximum negotiated charge for any negotiated rate transportation agreement is the charge agreed to by the parties, as set forth in the attached Tariff sheets.

Rate Schedule FT-L 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum

Exhibit A
To
Firm Transportation Agreement No. FT1-NUI-0122
Under Rate Schedule FT-1
Between
Vector Pipeline L.P. and Northern Utilities, Inc.

Primary Term	05/01/2006 - 03/31/2016
Contracted Capacity:	6,070 Dth/day
Primary Receipt Points:	Alliance Interconnect
Primary Delivery Points:	St. Clair (US) Interconnect
Rate Election Recourse:	

The Reservation Charge applicable to this service is $\boxed{\text{\$8.0908/Dth/month}}$ ($0.2660 per Dth on a 100% load factor basis), exclusive of fuel reimbursement, Annual Charge Adjustment ("ACA") and any other future surcharges. Secondary points within the primary path and out of path secondary backhauls are subject to the same rate as the primary path.

Exhibit A
To
FT-1 Firm Transportation Agreement No. FT1-NUI-C0122
Under Toll Schedule FT-1
Between
Vector Pipeline Limited Partnership and Northern Utilities, Inc.

Primary Term:	05/01/2006 – 03/31/2016
Contracted Capacity:	6,404 GJ/d
Primary Receipt Points:	St. Clair (Canada) Interconnect
Primary Delivery Points:	Dawn Interconnect

Toll Election Negotiated:
The Reservation Charge applicable to this service is $\boxed{\text{\$0.4623/GJ/month}}$ ($0.0152 per GJ on a 100% load factor basis). Secondary points within the primary path and out of secondary from Dawn Interconnect to St. Clair (Canada) Interconnect are subject to the same rate as the primary path.

Bank of Canada

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:

10-Year Currency Converter

Using rates for: 20 Jul 2010

Convert to and from Canadian dollars, using the latest noon rates.

Currency:	U.S. dollar
Amount:	1.00
Convert:	◉ **from $Can** ○ **to $Can**
Use the:	◉ Nominal rate HELP ○ Cash rate (4%) HELP
Answer:	0.95 CONVERT
Exchange rate:	0.9500

Summary:

On 20 Jul 2010, 1.00 Canadian dollar(s) = 0.95 U.S. dollar(s), at an exchange rate of 0.9500 (using nominal rate.)

Effective 1 January 2009, the euro replaces the Slovak koruna.

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

Why is the currency I'm looking for not listed here?

The Bank currently collects data for over 50 foreign currencies. These data are intended primarily for individuals with a research interest in foreign exchange markets and represent only a sampling of currencies.

More comprehensive currency converters include **CanadianForex** and **OANDA.com**.

Are the exchange rates shown here accepted by the Canada Revenue Agency?

Yes. The Agency accepts Bank of Canada exchange rates as the basis for calculations involving income and expenses that are denominated in foreign currencies.

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Tennessee Gas Pipeline Company
FERC Gas Tariff
Sixth Revised Volume No. 1

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA					
Deliverability Rate	$2.02		$0.00	$2.02	
Space Rate	$0.0248		$0.0000	$0.0248	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	
Overrun Rate	$0.2427			$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA					
Deliverability Rate	$1.15		$0.00	$1.15	
Space Rate	$0.0185		$0.0000	$0.0185	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
Overrun Rate	$0.1380			$0.1380	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

•OTHER TRANSPORTATION SERVICES

	Reservation	Usage-1	Shrinkage In Path	Shrinkage Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3400 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	$\boxed{0.6600}$		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	5.4934		0.36%	
FT-1/NC	6.5590		0.00%	
FT-1/RIV	10.4380		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	1.2690 2/		0.00%	
FT-1/TME	12.3400		4.01%	4.25%
FT-1/TME2	24.4038		3.69%	4.63%
MLS-1/FH	0.6315		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270		0.01%	

1/ Pursuant to Section 26 of the General Terms and Conditions
2/ Effective May 1 through September 30
3/ Per Section 3.3 of MLS-1 Rate Schedule

•STORAGE SERVICES

	RES.	SPACE	INJ.	WITH.
SS	5.5050	0.1293	0.0339	0.0592
SS-1	$\boxed{5.6020}$	$\boxed{0.1293}$	0.0339	0.0591
X-28	4.9060	0.1293	0.0339	0.0549
FSS-1	$\boxed{0.8950}$	$\boxed{0.1293}$	0.0339	0.0339
ISS-1		0.0323	0.1896	0.0339

•SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.12%	2.32%	3.38%	3.38%	5.35%	7.30%	8.59%
from WLA	1.40%	1.40%	2.48%	2.48%	4.45%	6.40%	7.69%
from ELA	2.08%	2.08%	2.08%	2.08%	4.05%	6.00%	7.29%
from ETX	2.12%	2.08%	2.08%	2.08%	4.05%	6.00%	7.29%
from M1					1.97%	3.92%	5.21%
from M2						2.99%	4.30%
from M3							2.36%

April 1 through November 30

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.06%	2.22%	3.02%	3.02%	4.97%	6.46%	7.46%
from WLA	1.52%	1.52%	2.34%	2.34%	4.29%	5.78%	6.78%
from ELA	2.03%	2.03%	2.03%	2.03%	3.98%	5.47%	6.47%
from ETX	2.06%	2.03%	2.03%	2.03%	3.98%	5.47%	6.47%
from M1					1.95%	3.44%	4.44%
from M2						2.72%	3.73%
from M3							2.25%

NON-ASA RATE SCHEDULES

FTS-4 LEIDY		FTS	1.29%
(Apr 1-Nov 14)	1.00%	FTS-2	0.00%
(Nov 15-Mar 31)	4.89%	X-127	0.00%
FTS-4 CHMSBG	0.00%	X-129	0.00%
FTS-5	0.00%	X-130	0.00%
FTS-7 M3	2.00%	X-135	0.00%
FTS-7 M1 & M2	0.00%	X-137	1.30%
FTS-8 M3	1.50%		
FTS-8 M1 & M2	0.00%		

ASA STORAGE RATE SCHEDULES

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	3.11%	3.04%
FSS-1,ISS-1	0.96%	0.96%
INJECTIONS	0.96%	0.96%
INVENTORY LEVEL	0.08%	0.08%

•SURCHARGES

ACA Surcharge
Commodity 0.0019

•The Summary of Rates serves as a handy reference and does not replace Texas Eastern's Tariff.

Attention: Vice-President, Washington 10 Storage Corporation
Telephone: (313) 235-6445
Fax: (313) 235-6450

SHIPPER:

NORTHERN UTILITIES, INC.
300 Friberg Parkway
Westborough, MA 01581-5039

INVOICES, STATEMENTS AND NOMINATIONS

Stacy Djucik
1500 – 165th Street
Hammond, IN 46324
Telephone: (219) 853-4320

ALL OTHER MATTERS

F. Chico DaFonte
Telephone: (508) 836-7253
Facsimile: (508) 870-2294
Email: fdafonte@nisource.com

ARTICLE VIII: FURTHER AGREEMENT

Article II is amended to add the following sentence at the end of the first paragraph:

The Monthly Deliverability Rate and Monthly Capacity Rate shall be paid in the form of a monthly demand charge of $240,833.34 (assuming a typical 12 month, April through March storage cycle). The parties agree that Transporter may, from time to time, modify the Monthly Deliverability Rate and the Monthly Capacity Rate set forth in Exhibit I, so long as the amounts set forth on the revised Exhibit I do not exceed Shipper's monthly demand charge of $240,833.34. Unless otherwise specified, the revised Exhibit I will be effective the first day of the month immediately following the date that Transporter provides a copy of the revised Exhibit I to Shipper.

Northern Utilities, Inc. Projected Peaking Supply 1 Demand Rate (Unit Call Payment) Effective November 2010 through October 2011		
PPI_Base	127.17	Average PPI - Nov 95 through Oct 96
Projected PPI	181.85	Average PPI - Nov 09 through Oct 10
Base Unit Call Payment	$ 30.83	NUI Agreement with Distrigas
Projected Unit Call Payment	$ 44.09	Base UCP times (PPI / PPI_BASE)

harge and the corresponding Base or Augmented Service SCQ and shall be payable in 5 equal monthly installments during the Winter Season of each Contract Year in accordance with the terms of Article 10.

Contract Year	Base Service Demand Charge ($/MMBtu)	Augmented Service Demand Charge ($/MMBtu)
2001-02	1.90	1.60
2002-03	1.90	1.45
2003-04	1.65	1.45
2004-05	1.65	1.35
2005-06	1.45	1.35
2006-07	1.40	1.35
2007-08	1.40	1.35
2008-09	1.40	1.35
2009-10	1.35	1.35
2010-11	1.35	1.35

7.2 <u>Commodity Charge</u>: Buyer shall pay Seller a Commodity Charge for each MMBtu requested and delivered during any Month under either the Base or Augmented Service, as appropriate, equal to the average of the prices posted in *Gas Daily's "Daily Price Survey"* for deliveries to the Tenn Zone 6 (delivered) and Algonquin City-gates on the actual delivery date plus $0.60 per MMBtu. If one or both City-gate prices from *"Daily Price Survey"* is unavailable for such date, then the average of the prices for deliveries to the Tenn Zone 6 (delivered) and Algonquin City-gates from the *"Daily Price Survey"* for the next Business Day shall apply. If *Gas Daily* is no longer published or if it no longer publishes in the *"Daily Price Survey,"* either or both prices for deliveries to the Tenn Zone 6 (delivered) and Algonquin City-gates, a comparable replacement publication and/or index mutually and reasonably agreeable to the Parties shall be used. In the event the Parties are unable to reach agreement regarding a comparable publication or index to be utilized, either Party may elect to resolve the dispute by arbitration under Article XIV by giving written notice to the other Party In the event either Party elects to resolve the dispute by arbitration, the dispute shall be resolved by arbitration regardless of the amount in controversy The

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2010 through October 2011		
Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (2,094,795)	Page 2
NH Division Storage Contract Capacity Assignment	$ (216,339)	Page 3
NH Division Peaking Demand	$ (392,804)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 71,945	Page 5
NH Division Net PNGTS Litigation Costs & Projected 2008 Rate Case Refund Assigned to Retail Suppliers	$ 31,856	Page 6
NH Division Capacity Assignment Demand Revenue	$ (2,600,137)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2010 through October 31, 2011

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	NH Annual Cap Assign Credit
Algonquin	93201A1C	$ 14,417	$ 6,097	$ -	N	NA	NA	-	-	$ -
Algonquin	93201A1C	$ 69,215	$ -	$ -	N	NA	NA	-	-	$ -
Algonquin	93002F	$ 308,943	$ -	$ -	Y	4,211	-	(267)	-	$ (19,589)
Granite	10-010-FT-NN	$ 79,650	$ 118,245	$ 135,425	Y	23,896	35,475	(1,516)	(2,553)	$ (21,982)
Granite	10-010-FT-NN	$ 848,738	$ 1,260,001	$ 1,443,061	Y	23,896	35,475	(1,516)	(2,553)	$ (234,241)
Iroquois	R181001	$ 520,036	$ -	$ -	Y	6,569	-	(417)	-	$ (33,012)
PNGTS	1997-003	$ 30,142	$ -	$ -	Y	1,100	-	(70)	-	$ (1,918)
PNGTS	1997-003	$ 486,972	$ -	$ -	Y	1,100	-	(70)	-	$ (30,989)
PNGTS	1997-004	$ -	$ 1,718,086	$ -	Y	-	33,000	-	(2,375)	$ (123,650)
PNGTS	1997-004	$ -	$ 10,093,591	$ -	Y	-	33,000	-	(2,375)	$ (726,433)
Tennessee	5083	$ 916,763	$ -	$ -	Y	4,605	-	(292)	-	$ (58,131)
Tennessee	5083	$ 1,554,390	$ -	$ -	Y	8,550	-	(542)	-	$ (98,536)
Tennessee	5265	$ -	$ 187,514	$ -	Y	-	2,653	-	(191)	$ (13,500)
Tennessee	5292	$ 83,179	$ -	$ -	Y	1,406	-	(89)	-	$ (5,265)
Tennessee	39735	$ 54,960	$ -	$ -	Y	929	-	(59)	-	$ (3,490)
Tennessee	41099	$ 252,436	$ -	$ -	Y	4,267	-	(271)	-	$ (16,032)
Tennessee	46314	$ 56,202	$ -	$ -	Y	950	-	(60)	-	$ (3,550)
Tennessee	31861	$ 84,081	$ -	$ -	Y	1,382	-	(88)	-	$ (5,354)
Tennessee	31861	$ 107,458	$ -	$ -	Y	844	-	(54)	-	$ (6,875)
Texas Eastern	800384	$ 67,257	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800436	$ 4,125	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 941	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 236	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 1,308	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 611	$ -	$ -	N	NA	NA	-	-	$ -
Texas Eastern	800464	$ 7,986	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	29594	$ 829,238	$ -	$ -	N	NA	NA	-	-	$ -
TransCanada	33322	$ -	$ 7,660,696	$ -	Y	-	35,872	-	(2,582)	$ (551,403)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	$ -	Y	-	17,172	-	(1,236)	$ (112,785)
Vector	CRL-NUI-0727	$ -	$ 389,774	$ -	Y	-	17,086	-	(1,230)	$ (28,059)
Vector	FT-1-NUI-0122	$ 566,295	$ -	$ -	N	NA	NA	-	-	$ -
Vector	FT-1-NUI-C0122	$ 33,750	$ -	$ -	N	NA	NA	-	-	$ -

Total NH Capacity Assignment Credits $ (2,094,795)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 1, 2010 through October 31, 2011

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Storage Assigned NH	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 116,126	Y	N	7.20%	(18,663)	(305)	$ (8,357)
W-10	01052	$ 2,890,000	Y	Y	7.20%	(244,685)	(2,447)	$ (207,982)

Total NH Division Storage Capacity Assignment $ (216,339)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2009 through October 2010

Asset Management Agreeement Revenue					
Resources	Projected Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	$ (442,000)	No	Pipeline	6.34%	$ -
Wash 10 via Vector, TCPL, PNGTS	$ (1,100,000)	Yes	Pipeline	6.34%	$ 69,786
PNGTS Contract 1997-003	$ (30,000)	Yes	Storage	7.20%	$ 2,159
Tennessee Niagara	$ (100,000)	No	Pipeline	6.34%	$ -
Tennessee Long-Haul	$ (835,000)	No	Pipeline	6.34%	$ -
Total Asset Management	$ (2,507,000)				$ 71,945

Capacity Release Revenue					
Resources	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Texas Eastern Contract 800384	$ (66,701)	No	Pipeline	6.34%	$ -
AGT Contract 93201A1C	$ (98,779)	No	Pipeline	6.34%	$ -
Tennessee 5265	$ (259,050)	No	Pipeline	7.20%	$ -
Total Capacity Release	$ (424,530)				$ -

Total Asset Management and Capacity Release Revenue	$ (2,931,530)				$ 71,945

Northern Utilities, Inc.
New Hampshire Division
Peaking Demand Capacity Assignment Revenues
November 2010 through April 2011

Month	Retail Supplier 1	Retail Supplier 2	Retail Supplier 3	Retail Supplier 4	Retail Supplier 5	Retail Supplier 6	Total Peaking Demand TCQ	Rate	Demand Revenue
Nov-10	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Dec-10	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Jan-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Feb-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Mar-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)
Apr-11	681	683	228	2,791	80	268	4,731	$ 13.84	$ (65,467)

Total Division Peaking Demand Revenue $ (392,804)

Northern Utilities, Inc.
New Hampshire Division
PNGTS Litigation Costs & Projected 2008 Rate Case Refund - Assigned to Retail Suppliers
November 2010 through October 2011

PNGTS Litigation Costs	$ 183,943
PNGTS Projected 2008 Rate Case Refund	$ (628,298)
Net PNGTS Litigation Items	$ (444,355)

PNGTS Contract	MDQ	Percentage MDQ	Allocated PNGTS Litigation Items	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ (14,334)	Pipeline	6.34%	$ 909
PNGTS Contract 1997-004	33,000	97%	$ (430,021)	Storage	7.20%	$ 30,947
PNGTS Total	34,100	100%	$ (444,355)			$ 31,856

Estimate of PNGTS Transportation Costs Subject to Refund

	Prior Rates		Filed Rates		Subject to Refund	
	Annual Rate	Winter Rate	Annual Rate	Winter Rate	Annual Rate	Winter Rate
Prior Rate	$ 25.245	$ 48.515	$ 27.4017	$ 52.063	$ 2.157	$ 3.549
Volume	1,100	33,000	1,100	33,000	1,100	33,000

Month	FT-1997-003	FT-1997-004	Total Cost	FT-1997-003	FT-1997-004	Total Cost	FT-1997-003	FT-1997-004	Total Cost
Sep-08	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Oct-08	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Nov-08	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Dec-08	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Jan-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Feb-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Mar-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Apr-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
May-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jun-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jul-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Aug-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Sep-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Oct-09	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Nov-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Dec-09	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Jan-10	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Feb-10	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Mar-10	$ 27,770	$ 1,600,985	$ 1,628,755	$ 30,142	$ 1,718,086	$ 1,748,227	$ 2,372	$ 117,101	$ 119,473
Apr-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
May-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jun-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Jul-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Aug-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Sep-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Oct-10	$ 27,770		$ 27,770	$ 30,142		$ 30,142	$ 2,372		$ 2,372
Period Total	$ 722,007	$ 16,009,851	$ 16,731,858	$ 783,689	$ 17,180,856	$ 17,964,545	$ 61,682	$ 1,171,005	$ 1,232,687

Month	ME Allocator	NH Allocator	ME Refund	NH Refund	Begin Month Balance	End Month Balance	Average Balance	Interest Rate	Interest
Sep-08	49.93%	50.07%	$ 1,185	$ 1,188	$ -	$ 2,372	$ 1,186	5.30%	$ 5
Oct-08	49.93%	50.07%	$ 1,185	$ 1,188	$ 2,378	$ 4,750	$ 3,564	5.00%	$ 15
Nov-08	49.91%	50.09%	$ 59,629	$ 59,844	$ 4,765	$ 124,238	$ 64,502	5.00%	$ 269
Dec-08	49.91%	50.09%	$ 59,629	$ 59,844	$ 124,507	$ 243,980	$ 184,243	5.00%	$ 793
Jan-09	49.91%	50.09%	$ 59,629	$ 59,844	$ 244,773	$ 364,246	$ 304,510	4.52%	$ 1,185
Feb-09	49.91%	50.09%	$ 59,629	$ 59,844	$ 365,431	$ 484,904	$ 425,168	4.52%	$ 1,495
Mar-09	49.91%	50.09%	$ 59,629	$ 59,844	$ 486,399	$ 605,872	$ 546,135	4.52%	$ 2,126
Apr-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 607,997	$ 610,370	$ 609,183	3.37%	$ 1,711
May-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 612,080	$ 614,453	$ 613,267	3.37%	$ 1,780
Jun-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 616,233	$ 618,605	$ 617,419	3.37%	$ 1,734
Jul-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 620,339	$ 622,711	$ 621,525	3.25%	$ 1,739
Aug-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 624,451	$ 626,823	$ 625,637	3.25%	$ 1,751
Sep-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 628,574	$ 630,946	$ 629,760	3.25%	$ 1,706
Oct-09	49.91%	50.09%	$ 1,184	$ 1,188	$ 632,652	$ 635,024	$ 633,838	3.25%	$ 1,774
Nov-09	52.54%	47.46%	$ 62,771	$ 56,702	$ 636,798	$ 756,271	$ 696,534	3.25%	$ 1,886
Dec-09	52.54%	47.46%	$ 62,771	$ 56,702	$ 758,157	$ 877,630	$ 817,894	3.25%	$ 2,289
Jan-10	52.54%	47.46%	$ 62,771	$ 56,702	$ 879,919	$ 999,392	$ 939,656	3.25%	$ 2,630
Feb-10	52.54%	47.46%	$ 62,771	$ 56,702	$ 1,002,022	$ 1,121,495	$ 1,061,758	3.25%	$ 2,684
Mar-10	52.54%	47.46%	$ 62,771	$ 56,702	$ 1,124,179	$ 1,243,651	$ 1,183,915	3.25%	$ 3,313
Apr-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,246,965	$ 1,249,337	$ 1,248,151	3.25%	$ 3,380
May-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,252,718	$ 1,255,090	$ 1,253,904	3.25%	$ 3,509
Jun-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,258,599	$ 1,260,971	$ 1,259,785	3.25%	$ 3,412
Jul-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,264,383	$ 1,266,756	$ 1,265,570	3.25%	$ 3,542
Aug-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,270,298	$ 1,272,670	$ 1,271,484	3.25%	$ 3,558
Sep-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,276,228	$ 1,278,601	$ 1,277,415	3.25%	$ 3,460
Oct-10	52.54%	47.46%	$ 1,246	$ 1,126	$ 1,282,060	$ 1,284,433	$ 1,283,247	3.25%	$ 3,591
Period Total	51.22%	48.78%	$ 631,382	$ 601,304	$ 1,288,024				$ 55,337
Period Total Including Interest			$ 659,726	**$ 628,298**				51.22% ME	$ 28,344
								48.78% NH	$ 26,994

Northern Utilities, Inc.
Expenses Incurred to Oppose Proposed PNGTS Rate Increases, 9/1/2009 - 8/13/2010

Service Provider	Service Period	Description of Services	Date Paid	Expense	Rate Case
Bates White, LLC - Total RP08-306				$ 39,237.49	RP08-306
Benjamin Schlesinger and Associates, Inc. - Total RP08-306				$ 11,836.80	RP08-306
Benjamin Schlesinger and Associates, Inc. - Total RP10-729				$ 746.70	RP10-729
Continental Economics, Inc. - Total RP10-729				$ 4,560.00	RP10-729
Hall Estill Attorneys at Law - Total RP08-306				$ 273,630.42	RP08-306
Hall Estill Attorneys at Law - Total RP10-729				$ 42,549.91	RP10-729
Jeffry L. Fink - Total RP08-306				$ 1,862.00	RP08-306
Jeffry L. Fink - Total RP10-729				$ 2,416.80	RP10-729
Snake Hill Energy Resources, Inc. - Total				$ -	
Subtotal - Rate Case = RP08-306				$ 326,566.71	RP08-306
Subtotal - Rate Case = RP10-729				$ 50,273.41	RP10-729
Total Expenses Paid Since September 1, 2009				$ 331,126.71	

	Fixed PR Allocators	RP08-306	RP10-729	Since 9/1/09
Maine	51.1880%	$ 167,163.10	$ 25,733.97	$ 192,897.08
New Hampshire	48.8120%	$ 159,403.61	$ 24,539.44	**$ 183,943.04**
Total Expenses Paid Since September 1, 2009		$ 326,566.71	$ 50,273.41	$ 376,840.12

	RP08-306	RP10-729	ME Total
ME Division - Presented to MPUC in Aug 2009	$ 228,066.64		$ 228,066.64
ME Division - Expenses since September 1, 2009	$ 167,163.10	$ 25,733.97	$ 192,897.08
Total ME Division Expenses	$ 395,229.75	$ 25,733.97	$ 420,963.72

Northern Utilities, Inc.
Commodity Cost by Supply Source
November 2010 through April 2011

Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	$ 411,430	$ -	$ 10,566	$ 75,236	$ 231,901	$ 938,668	$ 1,667,801
Pittsburgh, NH	$ 201,993	$ 217,831	$ 223,457	$ 200,878	$ 219,127	$ 176,781	$ 1,240,066
Niagara	$ 382,660	$ -	$ -	$ 53,935	$ 139,599	$ 459,192	$ 1,035,386
Tennessee Production	$1,763,674	$1,272,854	$ 953,501	$ 648,859	$1,582,445	$1,547,079	$ 7,768,412
Storage							
Tennessee Storage	$ -	$ -	$ 307,731	$ 158,390	$ 228,551	$ 12,830	$ 707,503
Washington 10 Storage	$ -	$2,582,738	$3,763,469	$3,230,332	$2,001,207	$ -	$ 11,577,747
Peaking							
Peaking Supply 1	$ 366,320	$ 504,034	$ 508,144	$ 451,147	$ 467,407	$ 107,416	$ 2,404,468
Peaking Supply 2	$ -	$ -	$ -	$ -	$ 21,557	$ -	$ 21,557
LNG	$ 9,402	$ 9,375	$ 9,290	$ 7,955	$ 65,264	$ 9,937	$ 111,223
Total Commodity Cost	$3,135,479	$4,586,832	$5,776,158	$4,826,734	$4,957,057	$3,251,903	$ 26,534,162

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) November 2010 through April 2011							
Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	73,841	0	1,773	12,562	39,178	174,508	301,862
Pittsburgh, NH	33,000	34,100	34,100	30,800	34,100	33,000	199,100
Niagara	68,184	0	0	8,953	23,563	83,993	184,693
Tennessee Production	324,343	222,595	161,528	110,471	274,333	281,822	1,375,093
Storage							
Tennessee Storage	0	0	64,297	33,094	47,753	2,536	147,681
Washington 10 Storage	0	571,056	832,121	714,242	442,476	0	2,559,895
Peaking							
Peaking Supply 1	91,721	126,202	127,231	112,960	117,031	26,895	602,041
Peaking Supply 2	0	0	0	0	2,670	0	2,670
LNG	1,350	1,395	1,395	1,260	11,646	1,826	18,872
Total Delivered (Dth)	592,439	955,348	1,222,446	1,024,342	992,752	604,580	5,391,907

Northern Utilities, Inc.
Delivered Cost per Dth by Supply Source
November 2010 through April 2011

Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	$ 5.5718		$ 5.9576	$ 5.9892	$ 5.9192	$ 5.3789	$ 5.5251
Pittsburgh, NH	$ 6.1210	$ 6.3880	$ 6.5530	$ 6.5220	$ 6.4260	$ 5.3570	$ 6.2284
Niagara	$ 5.6122			$ 6.0241	$ 5.9244	$ 5.4670	$ 5.6060
Tennessee Production	$ 5.4377	$ 5.7183	$ 5.9030	$ 5.8736	$ 5.7683	$ 5.4896	$ 5.6494
Storage							
Tennessee Storage			$ 4.7861	$ 4.7861	$ 4.7861	$ 5.0595	$ 4.7908
Washington 10 Storage		$ 4.5227	$ 4.5227	$ 4.5227	$ 4.5227		$ 4.5227
Peaking							
Peaking Supply 1	$ 3.9939	$ 3.9939	$ 3.9939	$ 3.9939	$ 3.9939	$ 3.9939	$ 3.9939
Peaking Supply 2					$ 8.0723		$ 8.0723
LNG	$ 6.9643	$ 6.7203	$ 6.6594	$ 6.3138	$ 5.6039	$ 5.4412	$ 5.8934
Total System	$ 5.2925	$ 4.8012	$ 4.7251	$ 4.7120	$ 4.9932	$ 5.3788	$ 4.9211

Source of Supply: Chicago (Interconnect of Alliance and Vector Pipelines)
Delivered to Northern via Vector, TransCanada, Iroquois, Tennessee and Granite Pipelines
Delivered to Northern via Vector, TransCanada, Iroquois, Tennessee, Algonquin Pipelines and Bay State Exchange Agreement

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 9	77,054	-	1,837	13,113	41,026	182,644	315,674
2	City Gate Delivered Volume	Sum Lines 54, 74 and 94	73,841	-	1,773	12,562	39,178	174,508	301,862
3	Total Purchase Cost	Line 14	$ 408,155	$ -	$ 10,524	$ 74,717	$ 229,828	$ 925,641	$ 1,648,866
4	Variable Transportation Costs	Sum Lines 26, 36, 46, 56, 66, 76, 86 and 96	$ 3,274	$ -	$ 41	$ 519	$ 2,074	$ 13,027	$ 18,935
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 411,430	$ -	$ 10,566	$ 75,236	$ 231,901	$ 938,668	$ 1,667,801
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.572	#DIV/0!	$ 5.958	$ 5.989	$ 5.919	$ 5.379	$ 5.525
7									
8	Chicago Supply Costs								
9	Purchased Volumes	Sendout Optimization	77,054	-	1,837	13,113	41,026	182,644	315,674
10	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.905	#DIV/0!	$ 5.337	$ 5.306	$ 5.210	$ 5.018	$ 5.029
11	NYMEX Cost	Line 9 times Line 10	$ 377,950	$ -	$ 9,804	$ 69,577	$ 213,745	$ 916,509	$ 1,587,586
12	NYMEX Basis Price	FXW-7A, Line 6 of Page 1	$ 0.392	#DIV/0!	$ 0.392	$ 0.392	$ 0.392	$ 0.050	$ 0.194
13	NYMEX Basis Costs	Line 9 times Line 12	$ 30,205	$ -	$ 720	$ 5,140	$ 16,082	$ 9,132	$ 61,280
14	Total Purchase Price	Line 10 plus Line 12	$ 5.297	#DIV/0!	$ 5.729	$ 5.698	$ 5.602	$ 5.068	$ 5.223
15	Total Purchase Cost	Line 11 plus Line 13	$ 408,155	$ -	$ 10,524	$ 74,717	$ 229,828	$ 925,641	$ 1,648,866
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with TransCanada)								
22	Received Volume	Line 9	77,054	-	1,837	13,113	41,026	182,644	315,674
23	Fuel Loss Rate	FXW 7A, Line 17 of Page 2	0.99%	#DIV/0!	0.99%	0.99%	0.99%	0.99%	0.99%
24	Delivered Volume	Line 22 times (1 - Line 23)	76,291	-	1,819	12,983	40,620	180,836	312,549
25	Variable Transportation Rate	FXW 7A, Line 17 of Page 2	$ 0.0019	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	$ 145	$ -	$ 3	$ 25	$ 77	$ 344	$ 594
27									
28	Transportation Segment 3								
29	TransCanada Pipeline (Contract 29594)								
30	Receipt Point: Dawn								
31	Delivery Point: Parkway (Interconnects with Iroquois)								
32	Received Volume	Line 24	76,291	-	1,819	12,983	40,620	180,836	312,549
33	Fuel Loss Rate	FXW 7A, Line 14 of Page 2	1.45%	#DIV/0!	1.45%	1.45%	1.45%	1.25%	1.33%
34	Delivered Volume	Line 32 times (1 - Line 33)	75,185	-	1,792	12,795	40,031	178,576	308,379
35	Variable Transportation Rate	FXW 7A, Line 14 of Page 2	$ 0.0141	#DIV/0!	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141
36	Variable Transportation Costs	Line 34 times Line 35	$ 1,060	$ -	$ 25	$ 180	$ 564	$ 2,518	$ 4,348
37									
38	Transportation Segment 4								
39	Iroquois Pipeline (Contract R181001)								
40	Receipt Point: Parkway								
41	Delivery Point: Wright (Interconnection with Tennessee)								
42	Received Volume	Line 34	75,185	-	1,792	12,795	40,031	178,576	308,379
43	Fuel Loss Rate	FXW 7A, Line 4 of Page 2	0.10%	#DIV/0!	0.10%	0.10%	0.10%	0.10%	0.10%
44	Delivered Volume	Line 42 times (1 - Line 43)	75,110	-	1,791	12,782	39,991	178,397	308,070
45	Variable Transportation Rate	FXW 7A, Line 4 of Page 2	$ 0.0052	#DIV/0!	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052
46	Variable Transportation Costs	Line 44 times Line 45	$ 391	$ -	$ 9	$ 66	$ 208	$ 928	$ 1,602
47									
48	Transporation Segment 5A								
49	Tennessee Gas Pipeline (Contract 31861)								
50	Receipt Point: Mendon								
51	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
52	Received Volume	Line 44	34,578	-	1,791	6,426	16,747	39,208	98,750
53	Fuel Loss Rate	FXW 7A, Line 12 of Page 2	0.96%	#DIV/0!	0.96%	0.96%	0.96%	0.96%	0.96%
54	City Gate Delivered Volume	Line 52 times (1 - Line 53)	34,246	-	1,773	6,365	16,587	38,831	97,802
55	Variable Transportation Rate	FXW 7A, Line 12 of Page 2	$ 0.0019	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
56	Variable Transportation Costs	Line 54 times Line 55	$ 65	$ -	$ 3	$ 12	$ 32	$ 74	$ 186
57									
58	Transportation Segment 5B								
59	Tennessee Gas Pipeline (Contract 31861)								
60	Receipt Point: Mendon								
61	Delivery Point: Pleasant St. (Interconnection with Granite)								
62	Received Volume	Line 44	21,006	-	-	3,530	8,474	24,017	57,027
63	Fuel Loss Rate	FXW 7A, Line 13 of Page 2	1.26%	#DIV/0!	#DIV/0!	1.26%	1.26%	1.26%	1.26%
64	Delivered Volume	Line 62 times (1 - Line 63)	20,742	-	-	3,486	8,367	23,715	56,309
65	Variable Transportation Rate	. FXW 7A, Line 13 of Page 2	$ 0.0019	#DIV/0!	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
66	Variable Transportation Costs	Line 64 times Line 65	$ 39	$ -	$ -	$ 7	$ 16	$ 45	$ 107
67									
68	Transportation Segment 6B								
69	Granite State Gas Transmission (Contract 10-010-FT-NN)								
70	Receipt Point: Pleasant St.								
71	Delivery Point: Northern City Gates								
72	Received Volume	Line 64	20,742	-	-	3,486	8,367	23,715	56,309
73	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
74	City Gate Delivered Volume	Line 72 times (1 - Line 73)	20,638	-	-	3,468	8,325	23,596	56,027
75	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
76	Variable Transportation Costs	Line 74 times Line 75	$ 39	$ -	$ -	$ 7	$ 16	$ 45	$ 106
77									
78	Transportation Segment 5C								
79	Tennessee Gas Pipeline (Contract 41099)								
80	Receipt Point: Wright								
81	Delivery Point: Mendon (Interconnection with Algonquin)								
82	Received Volume	Line 44	19,526	-	-	2,826	14,770	115,172	152,293
83	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	1.92%
84	Delivered Volume	Line 82 times (1 - Line 83)	19,118	-	-	2,767	14,461	113,030	149,375
85	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
86	Variable Transportation Costs	Line 84 times Line 85	$ 1,499	$ -	$ -	$ 217	$ 1,134	$ 8,862	$ 11,711
87									
88	Transportation Segment 6C								
89	Algonquin Gas Transmission (Contract 93200F)								
90	Receipt Point: Mendon								
91	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
92	Received Volume	Line 84	19,118	-	-	2,767	14,461	113,030	149,375
93	Fuel Loss Rate	FXW 7A, Line 1 of Page 2	0.84%	#DIV/0!	#DIV/0!	1.35%	1.35%	0.84%	0.90%
94	City Gate Delivered Volume	Line 92 times (1 - Line 93)	18,957	-	-	2,729	14,266	112,080	148,032
95	Variable Transportation Rate	FXW 7A, Line 1 of Page 2	$ 0.0019	#DIV/0!	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
96	Variable Transportation Costs	Line 94 times Line 95	$ 36	$ -	$ -	$ 5	$ 27	$ 213	$ 281

Source of Supply: Pittsburgh, NH
Delivered to Northern via PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 9	33,000	34,100	34,100	30,800	34,100	33,000	199,100
2	City Gate Delivered Volume	Line 34	33,000	34,100	34,100	30,800	34,100	33,000	199,100
3	Total Purchase Cost	Line 14	$ 201,993	$ 217,831	$ 223,457	$ 200,878	$ 219,127	$ 176,781	$ 1,240,066
4	Variable Transportation Costs	Sum Lines 26 and 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 201,993	$ 217,831	$ 223,457	$ 200,878	$ 219,127	$ 176,781	$ 1,240,066
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.121	$ 6.388	$ 6.553	$ 6.522	$ 6.426	$ 5.357	$ 6.228
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	33,000	34,100	34,100	30,800	34,100	33,000	199,100
10	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.905	$ 5.172	$ 5.337	$ 5.306	$ 5.210	$ 5.018	$ 5.158
11	NYMEX Cost	Line 9 times Line 10	$ 161,865	$ 176,365	$ 181,992	$ 163,425	$ 177,661	$ 165,594	$ 1,026,902
12	NYMEX Basis Price	FXW-7A, Line 8 of Page 1	$ 1.216	$ 1.216	$ 1.216	$ 1.216	$ 1.216	$ 0.339	$ 1.071
13	NYMEX Basis Costs	Line 9 times Line 12	$ 40,128	$ 41,466	$ 41,466	$ 37,453	$ 41,466	$ 11,187	$ 213,165
14	Total Purchase Price	Line 10 plus Line 12	$ 6.121	$ 6.388	$ 6.553	$ 6.522	$ 6.426	$ 5.357	$ 6.228
15	Total Purchase Cost	Line 11 plus Line 13	$ 201,993	$ 217,831	$ 223,457	$ 200,878	$ 219,127	$ 176,781	$ 1,240,066

Source of Supply: Niagara (Interconnect of TransCanada and Tennessee Pipelines)
Delivered to Northern via Tennessee and Granite Pipelines
Delivered to Northern via Tennessee and Bay State Exhange Agreement

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 9	69,700	-	-	9,155	24,089	85,695	188,640
2	City Gate Delivered Volume	Sum Lines 24, 54 and 44	68,184	-	-	8,953	23,563	83,993	184,693
3	Total Purchase Cost	Line 14	$ 377,288	$ -	$ -	$ 53,228	$ 137,741	$ 452,557	$ 1,020,815
4	Variable Transportation Costs	Sum Lines 26, 56, 36 and 46	$ 5,373	$ -	$ -	$ 707	$ 1,858	$ 6,635	$ 14,572
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 382,660	$ -	$ -	$ 53,935	$ 139,599	$ 459,192	$ 1,035,386
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.612	#DIV/0!	#DIV/0!	$ 6.024	$ 5.924	$ 5.467	$ 5.606
7									
8	<u>Niagara Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	69,700	-	-	9,155	24,089	85,695	188,640
10	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.905	#DIV/0!	#DIV/0!	$ 5.306	$ 5.210	$ 5.018	$ 5.015
11	NYMEX Cost	Line 9 times Line 10	$ 341,880	$ -	$ -	$ 48,578	$ 125,504	$ 430,019	$ 945,981
12	NYMEX Basis Price	FXW-7A, Line 7 of Page 1	$ 0.508	#DIV/0!	#DIV/0!	$ 0.508	$ 0.508	$ 0.263	$ 0.397
13	NYMEX Basis Costs	Line 9 times Line 12	$ 35,408	$ -	$ -	$ 4,651	$ 12,237	$ 22,538	$ 74,834
14	Total Purchase Price	Line 10 plus Line 12	$ 5.413	#DIV/0!	#DIV/0!	$ 5.814	$ 5.718	$ 5.281	$ 5.411
15	Total Purchase Cost	Line 11 plus Line 13	$ 377,288	$ -	$ -	$ 53,228	$ 137,741	$ 452,557	$ 1,020,815
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1A								
19	Tennessee Gas Pipeline (Contract 5292)								
20	Receipt Point: Niagara								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 9	34,398	-	-	3,558	11,864	37,571	87,391
23	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	1.99%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	33,679	-	-	3,484	11,616	36,872	85,651
25	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
26	Variable Transportation Costs	Line 24 times Line 25	$ 2,640	$ -	$ -	$ 273	$ 911	$ 2,891	$ 6,715
27									
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 39375)								
30	Receipt Point: Niagara								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 9	12,166	-	-	2,173	4,571	22,165	41,075
33	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	1.97%
34	Delivered Volume	Line 32 times (1 - Line 33)	11,912	-	-	2,127	4,476	21,753	40,268
35	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
36	Variable Transportation Costs	Line 34 times Line 35	$ 934	$ -	$ -	$ 167	$ 351	$ 1,705	$ 3,157
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	11,912	-	-	2,127	4,476	21,753	40,268
43	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	11,853	-	-	2,117	4,454	21,644	40,067
45	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 23	$ -	$ -	$ 4	$ 8	$ 41	$ 76
47									
48	Transportation Segment 1C								
49	Tennessee Gas Pipeline (Contract 46314)								
50	Receipt Point: Niagara								
51	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
52	Received Volume	Line 9	23,136	-	-	3,424	7,654	25,960	60,173
53	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	1.99%
54	City Gate Delivered Volume	Line 52 times (1 - Line 53)	22,652	-	-	3,352	7,494	25,477	58,975
55	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
56	Variable Transportation Costs	Line 54 times Line 55	$ 1,776	$ -	$ -	$ 263	$ 588	$ 1,997	$ 4,624

Source of Supply: Tennessee Production
Delivered to Northern via Tennessee and Granite Pipelines

Line	**City Gate Delivered Costs**	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	City Gate Volumes - Z0	Line 2 of Page 5	113,541	4,766	24,620	30,248	72,689	74,272	320,137
2	City Gate Volumes - Z1	Line 2 of Page 6	210,802	217,829	136,908	80,223	201,644	207,550	1,054,956
3	Total City Gate Volumes	Line 1 plus Line 2	324,343	222,595	161,528	110,471	274,333	281,822	1,375,093
4	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ 619,779	$ 27,417	$ 146,100	$ 178,466	$ 421,189	$ 409,056	$ 1,802,007
5	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 1,143,896	$ 1,245,437	$ 807,401	$ 470,393	$ 1,161,256	$ 1,138,022	$ 5,966,405
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 1,763,674	$ 1,272,854	$ 953,501	$ 648,859	$ 1,582,445	$ 1,547,079	$ 7,768,412
7	Average Delivered Price	Line 6 divided by Line 3	$ 5.438	$ 5.718	$ 5.903	$ 5.874	$ 5.768	$ 5.490	$ 5.649

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B

Source of Supply: Tennessee Zone 0
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 32	124,999	5,247	27,104	33,301	80,025	80,628	351,304
2	City Gate Delivered Volume	Line 44	113,541	4,766	24,620	30,248	72,689	74,272	320,137
3	Total Purchase Price	Line 24	$ 4.808	$ 5.075	$ 5.240	$ 5.209	$ 5.113	$ 4.921	$ 4.976
4	Total Purchase Cost	Line 2 times Line 3	$ 600,997	$ 26,628	$ 142,027	$ 173,462	$ 409,165	$ 396,770	$ 1,749,050
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 18,782	$ 788	$ 4,073	$ 5,004	$ 12,024	$ 12,286	$ 52,956
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 619,779	$ 27,417	$ 146,100	$ 178,466	$ 421,189	$ 409,056	$ 1,802,007
7	Average Delivered Price	Line 6 divided by Line 2	$ 5.459	$ 5.753	$ 5.934	$ 5.900	$ 5.794	$ 5.508	$ 5.629
8									
9	**Tennessee Northern Storage Injection Meter Deliveries**								
10	Purchased Volumes	Line 52	-	-	-	-	-	17,827	17,827
11	Storage Delivered Volume	Line 54	-	-	-	-	-	16,793	16,793
12	Total Purchase Price	Line 24	$ 4.808	$ 5.075	$ 5.240	$ 5.209	$ 5.113	$ 4.921	$ 4.976
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 87,725	$ 87,725
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ 1,909	$ 1,909
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ 89,635	$ 89,635
16	Average Delivered Price	Line 15 divided by Line 11	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.338	$ 5.338
17									
18	Tennessee Zone 0 Supply Costs								
19	Purchased Volumes	Sendout Optimization	124,999	5,247	27,104	33,301	80,025	98,455	369,130
20	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.905	$ 5.172	$ 5.337	$ 5.306	$ 5.210	$ 5.018	$ 5.073
21	NYMEX Cost	Line 25 times Line 26	$ 613,122	$ 27,137	$ 144,656	$ 176,693	$ 416,928	$ 494,046	$ 1,872,581
22	NYMEX Basis Price	FXW-7A, Line 4 of Page 1	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)
23	NYMEX Basis Costs	Line 25 times Line 28	$ (12,125)	$ (509)	$ (2,629)	$ (3,230)	$ (7,762)	$ (9,550)	$ (35,806)
24	Total Purchase Price	Line 26 plus Line 28	$ 4.808	$ 5.075	$ 5.240	$ 5.209	$ 5.113	$ 4.921	$ 4.976
25	Total Purchase Cost	Line 27 plus Line 29	$ 600,997	$ 26,628	$ 142,027	$ 173,462	$ 409,165	$ 484,496	$ 1,836,776
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1A								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone 0								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	124,999	5,247	27,104	33,301	80,025	80,628	351,304
33	Fuel Loss Rate	FXW 7A, Line 7 of Page 2	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	8.41%
34	Delivered Volume	Line 32 times (1 - Line 33)	114,112	4,790	24,744	30,400	73,054	74,645	321,745
35	Variable Transportation Rate	FXW 7A, Line 7 of Page 2	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627
36	Variable Transportation Costs	Line 34 times Line 35	$ 18,566	$ 779	$ 4,026	$ 4,946	$ 11,886	$ 12,145	$ 52,348
37									
38	Transportation Segment 2A								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	114,112	4,790	24,744	30,400	73,054	74,645	321,745
43	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	113,541	4,766	24,620	30,248	72,689	74,272	320,137
45	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 216	$ 9	$ 47	$ 57	$ 138	$ 141	$ 608
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	17,827	17,827
53	Fuel Loss Rate	FXW 7A, Line 6 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	5.80%	5.80%
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	16,793	16,793
55	Variable Transportation Rate	FXW 7A, Line 6 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1137	$ 0.1137
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ 1,909	$ 1,909

Source of Supply: Tennessee Zone L
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
2	Purchased Volumes	Line 33	229,835	237,496	149,269	87,466	219,850	223,500	1,147,415
3	City Gate Delivered Volume	Line 45	210,802	217,829	136,908	80,223	201,644	207,550	1,054,956
4	Total Purchase Price	Line 25	$ 4.835	$ 5.102	$ 5.267	$ 5.236	$ 5.140	$ 4.948	$ 5.056
5	Total Purchase Cost	Line 2 times Line 3	$ 1,111,250	$ 1,211,703	$ 786,199	$ 457,970	$ 1,130,028	$ 1,105,880	$ 5,803,030
6	Variable Transportation Costs	Sum Lines 37 and 47	$ 32,646	$ 33,734	$ 21,202	$ 12,424	$ 31,228	$ 32,142	$ 163,376
7	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 1,143,896	$ 1,245,437	$ 807,401	$ 470,393	$ 1,161,256	$ 1,138,022	$ 5,966,405
8	Average Delivered Price	Line 6 divided by Line 2	$ 5.426	$ 5.718	$ 5.897	$ 5.864	$ 5.759	$ 5.483	$ 5.656
9									
10	**Tennessee Northern Storage Injection Meter Deliveries**								
11	Purchased Volumes	Line 53	-	-	-	-	-	14,805	14,805
12	Storage Delivered Volume	Line 55	-	-	-	-	-	14,055	14,055
13	Total Purchase Price	Line 25	$ 4.835	$ 5.102	$ 5.267	$ 5.236	$ 5.140	$ 4.948	$ 5.056
14	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 73,253	$ 73,253
15	Variable Transportation Costs	Line 57	$ -	$ -	$ -	$ -	$ -	$ 1,452	$ 1,452
16	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ 74,705	$ 74,705
17	Average Delivered Price	Line 15 divided by Line 11	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.315	$ 5.315
18									
19	Tennessee Zone L Supply Costs								
20	Purchased Volumes	Sendout Optimization	229,835	237,496	149,269	87,466	219,850	238,305	1,162,219
21	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 4.905	$ 5.172	$ 5.337	$ 5.306	$ 5.210	$ 5.018	$ 5.126
22	NYMEX Cost	Line 25 times Line 26	$ 1,127,338	$ 1,228,328	$ 796,648	$ 464,092	$ 1,145,418	$ 1,195,814	$ 5,957,638
23	NYMEX Basis Price	FXW-7A, Line 5 of Page 1	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)	$ (0.070)
24	NYMEX Basis Costs	Line 25 times Line 28	$ (16,088)	$ (16,625)	$ (10,449)	$ (6,123)	$ (15,389)	$ (16,681)	$ (81,355)
25	Total Purchase Price	Line 26 plus Line 28	$ 4.835	$ 5.102	$ 5.267	$ 5.236	$ 5.140	$ 4.948	$ 5.056
26	Total Purchase Cost	Line 27 plus Line 29	$ 1,111,250	$ 1,211,703	$ 786,199	$ 457,970	$ 1,130,028	$ 1,179,133	$ 5,876,282
27									
28	Transportation Fuel Losses and Variable Charges								
29	Transportation Segment 1B								
30	Tennessee Gas Pipeline (Contract 5083)								
31	Receipt Point: Tennessee Zone L								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 20	229,835	237,496	149,269	87,466	219,850	223,500	1,147,415
34	Fuel Loss Rate	FXW 7A, Line 9 of Page 2	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	7.60%
35	Delivered Volume	Line 33 times (1 - Line 34)	211,861	218,923	137,596	80,626	202,658	208,593	1,060,257
36	Variable Transportation Rate	FXW 7A, Line 9 of Page 2	$ 0.1522	$ 0.1522	$ 0.1522	$ 0.1522	$ 0.1522	$ 0.1522	$ 0.1522
37	Variable Transportation Costs	Line 35 times Line 36	$ 32,245	$ 33,320	$ 20,942	$ 12,271	$ 30,844	$ 31,748	$ 161,371
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 10-010-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	211,861	218,923	137,596	80,626	202,658	208,593	1,060,257
44	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	210,802	217,829	136,908	80,223	201,644	207,550	1,054,956
46	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
47	Variable Transportation Costs	Line 45 times Line 46	$ 401	$ 414	$ 260	$ 152	$ 383	$ 394	$ 2,004
48									
49	Transportation Segment 3								
50	Tennessee Gas Pipeline (Contract 5083)								
51	Receipt Point: Tennessee Zone L								
52	Delivery Point: Tennessee Market Area Storage								
53	Received Volume	Line 25 minus Line 38	-	-	-	-	-	14,805	14,805
54	Fuel Loss Rate	FXW 7A, Line 8 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	5.06%	5.06%
55	Storage Delivered Volume	Line 53 times (1 - Line 54)	-	-	-	-	-	14,055	14,055
56	Variable Transportation Rate	FXW 7A, Line 8 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1033	$ 0.1033
57	Variable Transportation Costs	Line 55 times Line 56	$ -	$ -	$ -	$ -	$ -	$ 1,452	$ 1,452

Source of Supply: Tennessee FS-MA Inventory
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	2010-2011 Peak
	Gross Withdrawn Volume	Line 9	-	-	66,054	33,998	49,058	2,599	-	-	-	-	-	-	-	23,679	68,725	51,746	57,257	-	151,708
	City Gate Delivered Volume	Line 36	-	-	64,297	33,094	47,753	2,536	-	-	-	-	-	-	-	23,049	66,897	50,370	55,735	-	147,681
3	Total Withdrawal Costs	Line 17	$ -	$ -	$ 302,097	$ 155,491	$ 224,366	$ 12,608	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,747	$ 356,255	$ 268,242	$ 296,808	$ -	$ 694,562
4	Variable Transportation Costs	Sum Lines 28 and 38	$ -	$ -	$ 5,634	$ 2,900	$ 4,185	$ 222	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,020	$ 5,862	$ 4,414	$ 4,884	$ -	$ 12,941
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ 307,731	$ 158,390	$ 228,551	$ 12,830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124,767	$ 362,118	$ 272,656	$ 301,692	$ -	$ 707,503
6	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	$ 4.786	$ 4.786	$ 4.786	$ 5.059	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.413	$ 5.413	$ 5.413	$ 5.413	#DIV/0!	$ 4.791
7																					
8	Tennessee FS-MA Withdrawn Inventory (Segment 1)																				
9	Gross Withdrawn Volume	Sendout Optimization	-	-	66,054	33,998	49,058	2,599	-	-	-	-	-	-	-	23,679	68,725	51,746	57,257	-	151,708
10	Withdrawal Rate	FXW-7A, Line 1 of Page 3	#DIV/0!	#DIV/0!	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0102	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0102	#DIV/0!	$ 0.0102
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ 674	$ 347	$ 500	$ 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 242	$ 701	$ 528	$ 584	$ -	$ 1,547
12	Inventory Rate	JDS-8, Page 1	#DIV/0!	#DIV/0!	$ 4.5633	$ 4.5633	$ 4.5633	$ 4.8418	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.1736	$ 5.1736	$ 5.1736	$ 5.1736	#DIV/0!	$ 4.5681
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ 301,423	$ 155,144	$ 223,866	$ 12,582	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,506	$ 355,554	$ 267,715	$ 296,224	$ -	$ 693,014
14	Withdrawal Fuel Loss Rate	FXW-7A, Line 1 of Page 3	#DIV/0!	#DIV/0!	0.00%	0.00%	0.00%	0.00%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	0.00%	0.00%	0.00%	0.00%	#DIV/0!	0.00%
15	Withdrawal Fuel Losses		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Net Withdrawn Volume	Line 9 minus Line 14	-	-	66,054	33,998	49,058	2,599	-	-	-	-	-	-	-	23,679	68,725	51,746	57,257	-	151,708
17	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ 302,097	$ 155,491	$ 224,366	$ 12,608	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,747	$ 356,255	$ 268,242	$ 296,808	$ -	$ 694,562
18																					
19	Transportation Fuel Losses and Variable Charges																				
20	Transportation Segment 2																				
21	Tennessee Gas Pipeline (Contract 5265)																				
22	Receipt Point: Tennessee FS-MA Withdrawal Meter																				
23	Delivery Point: Pleasant St. (Interconnection with Granite)																				
24	Received Volume	Line 16	-	-	66,054	33,998	49,058	2,599	-	-	-	-	-	-	-	23,679	68,725	51,746	57,257	-	151,708
25	Fuel Loss Rate	FXW 7A, Line 10 of Page 2	#DIV/0!	#DIV/0!	2.17%	2.17%	2.17%	1.92%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	2.17%	2.17%	2.17%	2.17%	#DIV/0!	2.17%
26	Delivered Volume	Line 24 times (1 - Line 25)	-	-	64,620	33,260	47,993	2,549	-	-	-	-	-	-	-	23,165	67,234	50,624	56,015	-	148,423
27	Variable Transportation Rate	FXW 7A, Line 10 of Page 2	#DIV/0!	#DIV/0!	$ 0.0853	$ 0.0853	$ 0.0853	$ 0.0853	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.0853	$ 0.0853	$ 0.0853	$ 0.0853	#DIV/0!	$ 0.0853
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ -	$ 5,512	$ 2,837	$ 4,094	$ 217	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,976	$ 5,735	$ 4,318	$ 4,778	$ -	$ 12,660
29																					
30	Transportation Segment 3																				
31	Granite State Gas Transmission (Contract 10-010-FT-NN)																				
32	Receipt Point: Pleasant St.																				
33	Delivery Point: Northern City Gates																				
34	Received Volume	Line 26	-	-	64,620	33,260	47,993	2,549	-	-	-	-	-	-	-	23,165	67,234	50,624	56,015	-	148,423
35	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
36	City Gate Delivered Volume	Line 34 times (1 - Line 35)	-	-	64,297	33,094	47,753	2,536	-	-	-	-	-	-	-	23,049	66,897	50,370	55,735	-	147,681
37	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
38	Variable Transportation Costs	Line 36 times Line 37	$ -	$ -	$ 122	$ 63	$ 91	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44	$ 127	$ 96	$ 106	$ -	$ 281

Source of Supply: Washington 10 Inventory
Delivered to Northern via TransCanada, PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Gross Withdrawn Volume	Line 9	-	584,864	852,241	731,512	453,175	-	2,621,792
2	City Gate Delivered Volume	Line 66	-	571,056	832,121	714,242	442,476	-	2,559,895
3	Total Withdrawal Costs	Line 17	$ -	$ 2,544,508	$ 3,707,761	$ 3,182,515	$ 1,971,584	$ -	$ 11,406,369
4	Variable Transportation Costs	Sum Lines 28, 38, 48, 58 and 68	$ -	$ 38,231	$ 55,708	$ 47,816	$ 29,623	$ -	$ 171,378
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ 2,582,738	$ 3,763,469	$ 3,230,332	$ 2,001,207	$ -	$ 11,577,747
6	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	$ 4.523	$ 4.523	$ 4.523	$ 4.523	#DIV/0!	$ 4.523
7									
8	Washington 10 Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	-	584,864	852,241	731,512	453,175	-	2,621,792
10	Withdrawal Rate	FXW-7A, Line 2 of Page 3	#DIV/0!	$ -	$ -	$ -	$ -	#DIV/0!	$ -
11	Withdrawal Charges	Line 9 times Line 10	-	-	-	-	-	-	$ -
12	Inventory Rate	JDS-8, Page 1	#DIV/0!	$ 4.3506	$ 4.3506	$ 4.3506	$ 4.3506	#DIV/0!	$ 4.3506
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ 2,544,508	$ 3,707,761	$ 3,182,515	$ 1,971,584	$ -	$ 11,406,369
14	Withdrawal Fuel Loss Rate	FXW-7A, Line 2 of Page 3	#DIV/0!	0.40%	0.40%	0.40%	0.40%	#DIV/0!	0.40%
15	Withdrawal Fuel Losses		-	2,339	3,409	2,926	1,813	-	10,487
16	Net Withdrawn Volume	Line 9 minus Line 14	-	582,524	848,832	728,586	451,363	-	2,611,305
17	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ 2,544,508	$ 3,707,761	$ 3,182,515	$ 1,971,584	$ -	$ 11,406,369
18									
19	Transportation Fuel Losses and Variable Charges								
20	Transportation Segment 2A								
21	Vector Pipeline (Contract CRL-NUI-0725)								
22	Receipt Point: Washington 10 Withdrawal Meter								
23	Delivery Point: Dawn (Interconnects with TransCanada)								
24	Received Volume	Line 16	-	420,691	424,402	354,754	207,516	-	1,407,363
25	Fuel Loss Rate	FXW 7A, Line 17 of Page 2	#DIV/0!	0.34%	0.34%	0.34%	0.34%	#DIV/0!	0.34%
26	Delivered Volume	Line 24 times (1 - Line 25)	-	419,260	422,959	353,548	206,810	-	1,402,578
27	Variable Transportation Rate	FXW 7A, Line 17 of Page 2	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!	$ 0.0019
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ 797	$ 804	$ 672	$ 393	$ -	$ 2,665
29									
30	Transportation Segment 2B								
31	Vector Pipeline (Contract CRL-NUI-0727)								
32	Receipt Point: Washington 10 Withdrawal Meter								
33	Delivery Point: Union Dawn (Interconnects with TransCanada)								
34	Received Volume	Line 26	-	161,833	424,430	373,832	243,847	-	1,203,942
35	Fuel Loss Rate	FXW 7A, Line 17 of Page 2	#DIV/0!	0.34%	0.34%	0.34%	0.34%	#DIV/0!	0.34%
36	Delivered Volume	Line 34 times (1 - Line 35)	-	161,283	422,987	372,561	243,018	-	1,199,849
37	Variable Transportation Rate	FXW 7A, Line 17 of Page 2	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!	$ 0.0019
38	Variable Transportation Costs	Line 36 times Line 37	$ -	$ 306	$ 804	$ 708	$ 462	$ -	$ 2,280
39									
40	Transportation Segment 3								
41	TransCanada Pipeline (Contract 33322)								
42	Receipt Point: Union Dawn								
43	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)								
44	Received Volume	Line 36	-	580,544	845,946	726,109	449,828	-	2,602,426
45	Fuel Loss Rate	FXW 7A, Line 15 of Page 2	#DIV/0!	1.14%	1.14%	1.14%	1.14%	#DIV/0!	1.14%
46	Delivered Volume	Line 44 times (1 - Line 45)	-	573,925	836,302	717,831	444,700	-	2,572,759
47	Variable Transportation Rate	FXW 7A, Line 15 of Page 2	#DIV/0!	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	#DIV/0!	$ 0.0609
48	Variable Transportation Costs	Line 46 times Line 47	$ -	$ 34,952	$ 50,931	$ 43,716	$ 27,082	$ -	$ 156,681
49									
50	Transportation Segment 4								
51	PNGTS (Contract 1997-004)								
52	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
53	Delivery Point: Granite (Westbrook, Newington, Eliot)								
54	Received Volume	Line 46	-	573,925	836,302	717,831	444,700	-	2,572,759
55	Fuel Loss Rate	FXW 7A, Line 5 of Page 2	#DIV/0!	0.00%	0.00%	0.00%	0.00%	#DIV/0!	0.00%
56	Delivered Volume	Line 54 times (1 - Line 55)	-	573,925	836,302	717,831	444,700	-	2,572,759
57	Variable Transportation Rate	FXW 7A, Line 5 of Page 2	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!	$ 0.0019
58	Variable Transportation Costs	Line 56 times Line 57	$ -	$ 1,090	$ 1,589	$ 1,364	$ 845	$ -	$ 4,888
59									
60	Transportation Segment 5								
61	Granite State Gas Transmission (Contract 10-010-FT-NN)								
62	Receipt Point: Westbrook, Newington, Eliot								
63	Delivery Point: Northern City Gates								
64	Received Volume	Line 56	-	573,925	836,302	717,831	444,700	-	2,572,759
65	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
66	City Gate Delivered Volume	Line 64 times (1 - Line 65)	-	571,056	832,121	714,242	442,476	-	2,559,895
67	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
68	Variable Transportation Costs	Line 66 times Line 67	$ -	$ 1,085	$ 1,581	$ 1,357	$ 841	$ -	$ 4,864

Source of Supply: Peaking Supply 1
Delivered to Northern via Tennessee and Granite Pipelines
Delivered to Northern in liquid form via trucks

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 10	92,182	126,837	127,871	113,528	117,619	27,030	605,066
2	City Gate Delivered Volume	Line 33	91,721	126,202	127,231	112,960	117,031	26,895	602,041
3	Total Purchase Price	Line 24	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972
4	Total Purchase Cost	Line 1 times Line 3	$ 366,145	$ 503,795	$ 507,902	$ 450,933	$ 467,184	$ 107,365	$ 2,403,324
5	Variable Transportation Costs	Line 35	$ 174	$ 240	$ 242	$ 215	$ 222	$ 51	$ 1,144
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 366,320	$ 504,034	$ 508,144	$ 451,147	$ 467,407	$ 107,416	$ 2,404,468
7	Average Delivered Price	Line 6 divided by Line 2	$ 3.994	$ 3.994	$ 3.994	$ 3.994	$ 3.994	$ 3.994	$ 3.994
8									
9	**LNG Storage Deliveries**								
10	Purchased Volumes	Line 41	2,023	1,395	361	2,294	10,612	2,860	19,545
11	Storage Delivered Volume	Line 43	2,023	1,395	361	2,294	10,612	2,860	19,545
12	Total Purchase Price	Line 24	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972
13	Total Purchase Cost	Line 10 times Line 12	$ 8,034	$ 5,541	$ 1,433	$ 9,112	$ 42,151	$ 11,361	$ 77,633
14	Variable Transportation Costs	Line 45	$ 1,901	$ 1,311	$ 339	$ 2,156	$ 9,975	$ 2,689	$ 18,372
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ 9,935	$ 6,852	$ 1,773	$ 11,269	$ 52,127	$ 14,050	$ 96,005
16	Average Delivered Price	Line 15 divided by Line 11	$ 4.912	$ 4.912	$ 4.912	$ 4.912	$ 4.912	$ 4.912	$ 4.912
17									
18	Peaking Supply 1 Costs (Segment 1)								
19	Purchased Volumes	Sendout Optimization	94,204	128,232	128,232	115,822	128,232	29,891	624,612
20	Peaking Supply 1 Prices	FXW 7A, Line 2 of Page 1	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972
21	Peaking Supply 1 Costs	Line 19 times Line 20	$ 374,179	$ 509,336	$ 509,336	$ 460,045	$ 509,336	$ 118,726	$ 2,480,957
22	NYMEX Basis Price	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	NYMEX Basis Costs	Line 19 times Line 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Total Purchase Price	Line 20 plus Line 22	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972	$ 3.972
25	Total Purchase Cost	Line 23 times (1 - Line 24)	$ 374,179	$ 509,336	$ 509,336	$ 460,045	$ 509,336	$ 118,726	$ 2,480,957
26									
27	Transportation Segment 2								
28	Granite State Gas Transmission (Contract 10-010-FT-NN)								
29	Receipt Point: Pleasant St.								
30	Delivery Point: Northern City Gates								
[illegible]	Received Volume	Sendout Optimization	92,182	126,837	127,871	113,528	117,619	27,030	605,066
[illegible]	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
33	City Gate Delivered Volume	Line 31 times (1 - Line 32)	91,721	126,202	127,231	112,960	117,031	26,895	602,041
34	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
35	Variable Transportation Costs	Line 33 times Line 34	$ 174	$ 240	$ 242	$ 215	$ 222	$ 51	$ 1,144
36									
37	Transportation Segment 3								
38	Trucking Contract (TransGas)								
39	Receipt Point: Distrigas Terminal								
40	Delivery Point: Northern LNG Facility (Lewiston, ME)								
41	Received Volume	Line 19 minus Line 31	2,023	1,395	361	2,294	10,612	2,860	19,545
42	Fuel Loss Rate	Company Forecast	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Storage Delivered Volume	Line 41 times (1 - Line 42)	2,023	1,395	361	2,294	10,612	2,860	19,545
44	Variable Transportation Rate	Company Forecast	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400
45	Variable Transportation Costs	Line 43 times Line 44	$ 1,901	$ 1,311	$ 339	$ 2,156	$ 9,975	$ 2,689	$ 18,372

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
2	Gross Withdrawn Volume	Line 10	1,350	1,395	1,395	1,260	11,646	1,826	18,872
3	City Gate Delivered Volume	Line 16	1,350	1,395	1,395	1,260	11,646	1,826	18,872
4	Total Withdrawal Costs	Line 17	$ 9,402	$ 9,375	$ 9,290	$ 7,955	$ 65,264	$ 9,937	$ 111,223
5	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 9,402	$ 9,375	$ 9,290	$ 7,955	$ 65,264	$ 9,937	$ 111,223
7	Average Delivered Price	Line 5 divided by Line 2	$ 6.964	$ 6.720	$ 6.659	$ 6.314	$ 5.604	$ 5.441	$ 5.893
8									
9	Northern LNG Withdrawn Inventory								
10	Gross Withdrawn Volume	Sendout Optimization	1,350	1,395	1,395	1,260	11,646	1,826	18,872
11	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Withdrawal Charges	Line 9 times Line 10	-	-	-	-	-	-	$ -
13	Inventory Rate	JDS-8, Page 1	$ 6.9643	$ 6.7203	$ 6.6594	$ 6.3138	$ 5.6039	$ 5.4412	$ 5.8934
14	Withdrawn Inventory Value	Line 9 times Line 12	$ 9,402	$ 9,375	$ 9,290	$ 7,955	$ 65,264	$ 9,937	$ 111,223
15	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
16	Net Withdrawn Volume	Line 9 minus Line 14	1,350	1,395	1,395	1,260	11,646	1,826	18,872
17	Total Withdrawal Costs	Line 11 plus Line 13	$ 9,402	$ 9,375	$ 9,290	$ 7,955	$ 65,264	$ 9,937	$ 111,223

Source of Supply: Peaking Supply 2
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 9	-	-	-	-	2,684	-	2,684
2	City Gate Delivered Volume	Line 24	-	-	-	-	2,670	-	2,670
3	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ 21,552	$ -	$ 21,552
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ 5	$ -	$ 5
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ 21,557	$ -	$ 21,557
6	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 8.072	#DIV/0!	$ 8.072
7									
8	Peaking Supply 2 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	2,684	-	2,684
10	Monthly NYMEX Price	FXW 7A, Line 1 of Page 1	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.210	#DIV/0!	$ 5.210
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ 13,983	$ -	$ 13,983
12	NYMEX Basis Price	FXW 7A, Line 9 of Page 1	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 2.820	#DIV/0!	$ 2.820
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ 7,569	$ -	$ 7,569
14	Total Purchase Price	Line 10 plus Line 12	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 8.030	#DIV/0!	$ 8.030
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ 21,552	$ -	$ 21,552
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	2,684	-	2,684
23	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	2,670	-	2,670
25	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ 5	$ -	$ 5

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for July 22, 2010

Line	Item	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
1	NYMEX	$4.905	$5.172	$5.337	$5.306	$5.210	$5.018
2	Peaking Supply 1	$3.972	$3.972	$3.972	$3.972	$3.972	$3.972
3	Adders to NYMEX by Supply Source						
4	TGP Z0	($0.097)	($0.097)	($0.097)	($0.097)	($0.097)	($0.097)
5	TGP Z1	($0.070)	($0.070)	($0.070)	($0.070)	($0.070)	($0.070)
6	Chicago	$0.392	$0.392	$0.392	$0.392	$0.392	$0.050
7	Niagara	$0.508	$0.508	$0.508	$0.508	$0.508	$0.263
8	TGP Z6	$1.216	$1.216	$1.216	$1.216	$1.216	$0.339
9	Peaking Supply 2	$2.820	$2.820	$2.820	$2.820	$2.820	

Northern Utilities, Inc.
Pipeline Variable Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Variable Commodity Rate	Nov-10 Fuel Rates	Dec-10 Fuel Rates	Jan-11 Fuel Rates	Feb-11 Fuel Rates	Mar-11 Fuel Rates	Apr-11 Fuel Rates	Notes	Commodity Rate Support	Fuel Rate Support
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A	$ 0.0019	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%		Pg 4	Pg 5
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A	$ 0.0131	0.84%	1.35%	1.35%	1.35%	1.35%	0.84%		Pg 4	Pg 5
3	Granite	FT-NN	N/A	N/A	$ 0.0019	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%		Pg 6	Pg 6
4	Iroquois	RTS-1	Zone 1	Zone 1	$ 0.0052	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	1	Pgs 7 & 8	Estimated
5	PNGTS	FT	N/A	N/A	$ 0.0019	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		Pg 9	Estimated
6	Tennessee	FT-A	Zone 0	Zone 4	$ 0.1137	6.79%	6.79%	6.79%	6.79%	6.79%	5.80%		Pg 10	Pg 11
7	Tennessee	FT-A	Zone 0	Zone 6	$ 0.1627	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%		Pg 10	Pg 11
8	Tennessee	FT-A	Zone L	Zone 4	$ 0.1033	5.90%	5.90%	5.90%	5.90%	5.90%	5.06%	2	Pg 10	Pg 11
9	Tennessee	FT-A	Zone L	Zone 6	$ 0.1522	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	2	Pg 10	Pg 11
10	Tennessee	FT-A	Zone 4	Zone 6	$ 0.0853	2.17%	2.17%	2.17%	2.17%	2.17%	1.92%		Pg 10	Pg 11
11	Tennessee	FT-A	Zone 5	Zone 6	$ 0.0784	2.09%	2.09%	2.09%	2.09%	2.09%	1.86%		Pg 10	Pg 11
12	Tennessee	NET	Segment 3	Segment 3	$ 0.0019	0.96%	0.96%	0.96%	0.96%	0.96%	0.96%		Pg 12	Pg 13
13	Tennessee	NET	Segment 3	Segment 4	$ 0.0019	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%		Pg 12	Pg 13
14	TransCanada	FT	Dawn	Iroquois	$ 0.0141	1.45%	1.45%	1.45%	1.45%	1.45%	1.25%		Pg 14	Pg 18
15	TransCanada	FT	Dawn	E. Hereford	$ 0.0609	1.14%	1.14%	1.14%	1.14%	1.14%	0.84%		Pg 14	Pg 18
16	Vector	FT-1	Alliance	W-10 Storage	$ 0.0019	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%		Pg 19	Pg 20
17	Vector	FT-1	W-10 Storage	Dawn	$ 0.0019	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%		Pg 19	Pg 20
18	Vector	FT-1	Alliance	Dawn	$ 0.0019	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%		Pg 19	Pg 20

Note 1: Iroquois Commodity Rates are equal to the RTS Commodity rate on Page 7 plus the ACA Adjustment and Deferred Asset Surcharge on Page 8.
Note 2: For Receipts from Zone L, the rates for Receipts from Zone 1 apply.

Northern Utilities, Inc. Underground Storage Variable Rates							
Line	Storage	Rate Schedule	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss	Reference
1	Tennessee	FS-MA	$ 0.0102	0.00%	$ 0.0102	1.49%	Page 21
2	Washington 10	AFT-1 (F-2/F-3)	$ -	0.40%	$ -	1.00%	Pages 22 & 23

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2009

•RATE SCHEDULE AFT-1

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-2/F-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(F-4)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(STB/SS-3)	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(FTP)	$11.8368	$0.0019	$0.0019	$0.3911	$0.0019	$0.3892
(PSS-T)	$ 9.7854	$0.0019	$0.0019	$0.3236	$0.0019	$0.3217
(AFT-2)	$ 6.1138	$0.0019	$0.0019	$0.2029	$0.0019	$0.2010
(AFT-3)	$10.7554	$0.0019	$0.0019	$0.3555	$0.0019	$0.3536
(AFT-5)	$12.6265	$0.0019	$0.0019	$0.4170	$0.0019	$0.4151
(ITP)	$13.0110	$0.0019	$0.0019	$0.4297	$0.0019	$0.4278
(X-35)	$10.2027	$0.0019	$0.0019	$0.3373	$0.0019	$0.3354
X-39	$13.2089	$0.0019	$0.0019	$0.4362	$0.0019	$0.4343
Incremental Surcharges						
Hubline	$ 1.8607	$0.0000	$0.0000	$0.0000	$0.0000	$0.0612
Secondary 1/		$0.0612	$0.0000			
Tiverton	$ 1.6424	$0.0000	$0.0000	$0.0000	$0.0000	$0.0540
Ramapo	$ 7.5608	$0.0000	$0.0000	$0.2486	$0.0000	$0.2486

•RATE SCHEDULE AFT-1S

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-2/F-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(F-4)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0031	$0.0864
(STB/SS-3)	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			

•OTHER FIRM RATE SCHEDULES

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
AFT-E	$ 6.5734	$0.0131	$0.0131	$0.2292	$0.0131	$0.2161
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6294	$0.2292	$0.0131	$0.2292	$0.0131	$0.0864
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0058		$0.0600		
AFT-4	$ 3.5211	$0.0032		$0.1190		
AFT-CL:						
Canal	$ 2.0858	$0.0019	$0.0019	$0.0705	$0.0019	$0.0686
Middletown	$ 3.2764	$0.0019	$0.0019	$0.1096	$0.0019	$0.1077
Cleary	$ 1.4529	$0.0019	$0.0019	$0.0497	$0.0019	$0.0478
Lake Road	$ 0.6476	$0.0019	$0.0019	$0.0232	$0.0019	$0.0213
Brayton Pt.	$ 1.2700	$0.0019	$0.0019	$0.0437	$0.0019	$0.0418
Manchester	$ 2.4500	$0.0019	$0.0019	$0.0824	$0.0019	$0.0805
Bellingham	$ 0.9714	$0.0019	$0.0019	$0.0338	$0.0019	$0.0319
Phelps Dodge	$ 0.0000	$0.0185	$0.0019	$0.0185	$0.0019	$0.0000
Cape Cod	$ 9.0501	$0.0019	$0.0019	$0.2994	$0.0019	$0.2975
Northeast Gateway	$ 4.3449	$0.0019	$0.0019	$0.1447	$0.0019	$0.1428
J-2 Facility	$ 4.9077	$0.0019	$0.0019	$0.1632	$0.0019	$0.1613
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun	
	Max	Min	Max	Min
AIT-1	$0.2440	$0.0095	$0.2440	$0.0095
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0437	$0.0019	$0.0437	$0.0019
Manchester	$0.0824	$0.0019	$0.0824	$0.0019
Canal	$0.0705	$0.0019	$0.0705	$0.0019
Cape Cod	$0.2994	$0.0019	$0.2994	$0.0019
Northeast Gateway	$0.1447	$0.0019	$0.1447	$0.0019
J-2 Facility	$0.1632	$0.0019	$0.1632	$0.0019
PAL	$0.2440	$0.0000	$0.0000	$0.0000

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charge of $0.0019.

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP

System Services

Winter	Dec 1 - Mar 31	1.35%
Spring, Summer and Fall	Apr 1 - Nov 30	0.84%

Incremental Ramapo Services

er	Dec 1 - Mar 31	2.36%
ng, Summer and Fall	Apr 1 - Nov 30	1.18%

1/ Hubline Surcharge applicable to all customers utilizing secondary receipt points between and including Beverly and Weymouth and/or utilizing secondary delivery points between Beverly and Weymouth,including Beverly and excluding Weymouth,and in addition to other applicable charges.

•The Summary of Rates serves as a handy reference and does not replace Algonquin's Tariff. The rates are subject to commission approval.

Rate Schedule FT-NN
Firm Transportation Service

	Base Tariff Rate 1/ ($/Dth)	ACA Adj. ($/Dth)	Total Current Rate ($/Dth)
Reservation Charge:			
Maximum	$1.6666		$1.6666
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0019	$0.0019
Minimum	$0.0000	$0.0019	$0.0019
Authorized Overrun Commodity Charge:			
Maximum	$0.0548	$0.0019	$0.0567
Minimum	$0.0000	$0.0019	$0.0019
Fuel and Losses Percentage			0.5%
Volumetric Reservation Charge			
Maximum	$0.0548		$0.0548
Minimum	$0.0000		$0.0000

1/ The Base Tariff Rate is the effective rate on file with the Commission, excluding adjustment approved by the Commission.

Previous Next

Iroquois Gas Transmission System, L.P. Thirty First Revised Sheet No. 4

FERC Gas Tariff Superseding

1ST REVISED VOLUME NO. 1 Thirtieth Revised Sheet No. 4

--------------- RATES (All in $ Per Dth) ----------------

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/ Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$\boxed{\$0.0030}$
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).
2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.
3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

(Footnotes continued on Sheet 4.01)

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Jan 26, 2009 Effective: Jan 27, 2009

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Iroquois Gas Transmission System, L.P. Twenty-Fourth Revised Sheet No. 4a
FERC Gas Tariff Superseding
FIRST REVISED VOLUME NO. 1 Twenty-Third Sheet No. 4a

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:		
Commodity	$\boxed{0.0019}$	
DEFERRED ASSET SURCHARGE:		
Commodity		
Zone 1	$\boxed{0.0003}$	
Zone 2	0.0002	
Inter-Zone	0.0005	
MEASUREMENT VARIANCE/FUEL USE FACTOR:		
Minimum		0.00%
Maximum (Non-Eastchester Shipper)		1.00%
Maximum (Eastchester Shipper)		4.50%
Maximum (Brookfield Shipper)		1.20%

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary
Issued on: Sep 30, 2009 Effective: Nov 01, 2009

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Portland Natural Gas Transmission System
FERC Gas Tariff
Second Revised Volume No. 1

Seventh Revised Sheet No. 100 : Effective
Supercedes Sixth Revised Sheet No. 100

Statement of Transportation Rates

(Rates per DTH)

Rate Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ Rate

FT Recourse Reservation Rate

-- Maximum $27.4017 --------- $27.4017

-- Minimum $00.0000 --------- $00.0000

Seasonal Recourse Reservation Rate

-- Maximum $52.0632 --------- $52.0632

-- Minimum $00.0000 --------- $00.0000

Recourse Usage Rate

-- Maximum $00.0000 $00.0019 $00.0019

-- Minimum $00.0000 $00.0019 $00.0019

FT-FLEX Recourse Reservation Rate

--Maximum $18.3920 ------- $18.3920

--Minimum $00.0000 ------- $00.0000

Recourse Usage Rate

--Maximum $00.2962 $00.0019 $00.2981

--Minimum $00.0000 $00.0019 $00.0019

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0458		$0.0688	$0.0899	$0.0997	$0.1137	$0.1250	$0.1627
L		$0.0305						
1	$0.0688		$0.0591	$0.0795	$0.0893	$0.1033	$0.1145	$0.1522
2	$0.0899		$0.0795	$0.0452	$0.0549	$0.0700	$0.0802	$0.1178
3	$0.0997		$0.0893	$0.0549	$0.0385	$0.0682	$0.0784	$0.1161
4	$0.1148		$0.1044	$0.0700	$0.0682	$0.0420	$0.0478	$0.0853
5	$0.1250		$0.1145	$0.0802	$0.0784	$0.0478	$0.0446	$0.0784
6	$0.1627		$0.1522	$0.1178	$0.1161	$0.0853	$0.0784	$0.0661

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

2/ The applicable fuel retention percentages are listed on Sheet No. 32, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\,3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G.

Tennessee Gas Pipeline Company
FERC Gas Tariff
Sixth Revised Volume No. 1

RATES PER DEKATHERM

RATE SCHEDULE NET 284

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (PCB) 5/	Rate After Current Adjustments	Fuel and Use
Demand Rate 1/, 5/					
Segment U	$9.65		$0.00	$9.65	
Segment 1	$1.33		$0.00	$1.33	
Segment 2	$8.08		$0.00	$8.08	
Segment 3	$5.07		$0.00	$5.07	
Segment 4	$5.54		$0.00	$5.54	
Commodity Rate 2/, 3/					
Segments U, 1, 2, 3 & 4		$0.0019		$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/					
Segment U	$0.3173			$0.3173	5.52%
Segment 1	$0.0437			$0.0437	0.69%
Segment 2	$0.2656			$0.2656	0.59%
Segment 3	$0.1667			$0.1667	0.73%
Segment 4	$0.1821			$0.1821	0.36%

Notes:
1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.
2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.
3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.
4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.
5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
6/ The applicable fuel retention percentages are listed on Sheet No. 105.
7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

NET-284 RATE SCHEDULE (continued)

5. FUEL AND USE (continued)

Shipper	Transportation Quantity (Dth)	Segments U	1	2	3	4	Fuel and Use
Bay State (from Granite) - Pleasant St.	3,706				*	*	1.26%
Bay State (from Granite) - Agawam	6,068				*		0.96%
Boston Gas d/b/a National Grid	35,000				*	*	1.31%
Boston Gas d/b/a National Grid	8,600				*	*	1.31%
Barclays Bank PLC	14,010				*	*	1.23%
EnergyNorth Natural Gas, Inc. d/b/a National Grid	4,000				*	*	1.54%
Essex Gas Company d/b/a National Grid	2,000				*	*	1.44%
Iroquois Gas Transmission (Connecticut Natural, Yankee Gas)	37,000				*		0.68%
Lockport Energy Associates	13,184	*	*				6.21%
New York State Electric & Gas Corp	14,816	*	*				6.21%
Northern Utilities (from Granite) Pleasant St.	844				*	*	1.26%
Northern Utilities (from Granite) Agawam	1,382				*		0.96%
The Narragansett Electric Company d/b/a National Grid	1,000				*	*	1.25%
Yankee Gas Services Company (Wright)	9,000				*		1.07%
Total	150,610						

TransCanada Variable Transportation Rates

Line	Item	Units	Value	Reference
1	Union Dawn to Iroquois			
2	Commodity Rate	$CAD / GJ	$ 0.01413	Page 15
3	Delivery Pressure Commodity Rate	$CAD / GJ	$ -	
4	Variable Transportation Rate	$CAD / GJ	$ 0.01413	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.95	Page 17
6	Variable Transportation Rate	$US / GJ	$ 0.0134	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ 0.0141	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford			
11	Commodity Rate	$CAD / GJ	$ 0.02275	Page 15
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ 0.03798	Page 16
13	Variable Transportation Rate	$CAD / GJ	$ 0.06073	Line 11 plus Line 12
14	$CAD to $US	Ratio	0.95	Page 17
15	Variable Transportation Rate	$US / GJ	$ 0.0577	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ 0.0609	Line 15 divided by Line 16

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Dawn	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn	Iroquois	10.82669	0.01413	0.3700	0.4070
8	Union Dawn	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn	East Hereford	16.76744	0.02275	0.5741	0.6315
12	Union Dawn	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

TransCanada
In business to deliver

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	0.78572	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	1.96558	$\boxed{0.03798}$	0.10260

*(1) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

Bank of Canada

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:
10-Year Currency Converter

Using rates for: 20 Jul 2010

Convert to and from Canadian dollars, using the latest noon rates.

Currency:	U.S. dollar
Amount:	1.00
Convert:	◉ **from $Can** ○ **to $Can**
Use the:	◉ Nominal rate HELP ○ Cash rate (4%) HELP
Answer:	0.95 CONVERT
Exchange rate:	0.9500

Summary:

On 20 Jul 2010, 1.00 Canadian dollar(s) = 0.95 U.S. dollar(s), at an exchange rate of 0.9500 (using nominal rate.)

Effective 1 January 2009, the euro replaces the Slovak koruna.

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

Why is the currency I'm looking for not listed here?

The Bank currently collects data for over 50 foreign currencies. These data are intended primarily for individuals with a research interest in foreign exchange markets and represent only a sampling of currencies.

More comprehensive currency converters include **CanadianForex** and **OANDA.com**.

Are the exchange rates shown here accepted by the Canada Revenue Agency?

Yes. The Agency accepts Bank of Canada exchange rates as the basis for calculations involving income and expenses that are denominated in foreign currencies.

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Historic TransCanada Fuel Loss Percentages

	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Last 12 Months	Last Nov - Mar	Last Apr - Oct
Union Dawn - Iroquois	0.69%	0.94%	1.00%	1.63%	1.41%	1.62%	1.60%	1.47%	1.36%	1.39%	1.35%	1.56%	1.34%	1.45%	1.25%
Union Dawn - East Hereford	0.00%	0.50%	0.49%	1.36%	1.14%	1.42%	1.31%	1.05%	1.01%	1.08%	1.03%	1.20%	0.97%	1.14%	0.84%
Empress - East Hereford	0.00%	2.01%	1.55%	3.84%	3.71%	4.43%	3.80%	2.78%	3.09%	3.43%	3.32%	3.23%	2.93%	3.47%	2.55%

INFORMATIONAL POSTINGS

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Vector Pipeline L.P.
FERC Gas Tariff — Eleventh Revised Sheet No. 20
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Tenth Revised Sheet No. 20

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.2501	0.0000	$7.7745	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0019	0.0019	0.0019	0.0019
Usage and ACA Charge	0.0019	0.0019	0.0019	0.0019

Negotiated Rates:

The effective maximum negotiated charge for any negotiated rate transportation agreement is the charge agreed to by the parties, as set forth in the attached Tariff sheets.

Rate Schedule FT-L 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum

Historic Vector Fuel Loss Rates

Receipt	Delivery	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Last 12 Months
W-10 Storage	Dawn	0.32%	0.30%	0.33%	0.30%	0.30%	0.48%	0.31%	0.30%	0.30%	0.32%	0.33%	0.47%	0.34%
Alliance	W-10 Storage	0.95%	0.91%	0.99%	0.91%	0.91%	1.11%	0.91%	0.90%	0.89%	0.95%	0.99%	1.40%	0.99%
Alliance	Dawn	0.95%	0.91%	0.99%	0.91%	0.91%	1.11%	0.91%	0.90%	0.89%	0.95%	0.99%	1.40%	0.99%

Tennessee Gas Pipeline Company
FERC Gas Tariff
Sixth Revised Volume No. 1

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	(PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA					
Deliverability Rate	$2.02		$0.00	$2.02	
Space Rate	$0.0248		$0.0000	$0.0248	
Injection Rate	$0.0053			$0.0053	1.49%
Withdrawal Rate	$0.0053			$0.0053	
Overrun Rate	$0.2427			$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA					
Deliverability Rate	$1.15		$0.00	$1.15	
Space Rate	$0.0185		$0.0000	$0.0185	
Injection Rate	$0.0102			$0.0102	1.49%
Withdrawal Rate	$0.0102			$0.0102	
Overrun Rate	$0.1380			$0.1380	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

EXHIBIT I

Rates:

Monthly Deliverability Rate:	$ 2.4754 per Dth
Monthly Capacity Rate:	$ 0.0238 per Dth
Injection Rate:	$ 0.00 per Dth
Withdrawal Rate:	$ 0.00 per Dth
Authorized Overrun Rate:	$ 0.05 per Dth
Interruptible Rate:	$ 0.05 per Dth

Service Parameters:

Maximum Storage Quantity (MSQ): 3,400,000 Dth

Maximum Daily Injection Quantity (MDIQ):

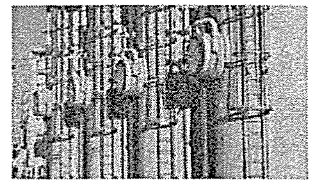
Inventory	MDIQ
April 1 through October 31	17,000 Dth/d Firm
November 1 through March 31	17,000 Dth/d Interruptible

Maximum Daily Withdrawal Quantity (MDWQ):

Inventory	MDWQ
November 1 through November 30	64,600 Dth/d Firm
December 1 through March 31	
Inventory ≥ 680,000 Dth	34,000 Dth/d Firm
Inventory ≥ 340,000 Dth and < 680,000 Dth	22,780 Dth/d Firm
Inventory ≥ 0 Dth and < 340,000 Dth	13,600 Dth/d Firm
April 1 through October 31	34,000Dth/d Interruptible

Primary Receipt Point(s):	W-10 / Vector Interconnect
Secondary Receipt Point(s):	W-10 / MichCon Interconnect
Primary Delivery Point(s):	W-10 / Vector Interconnect
Secondary Delivery Point(s):	W-10 / MichCon Interconnect

DTE Energy



DTE Gas Storage - Washington 10 Historic Fuel Rates

Effective Date	Injection	Withdrawal	Wheel From Hub to Interconnect
Apr 1, 2010	1.00%	0.40%	0.30%
Mar 10, 2010	1.00%	0.40%	0.45%
Mar 3, 2010	1.00%	0.40%	0.00%
Mar 1, 2010	1.00%	0.40%	0.45%
Nov 1, 2009	0.00%	0.40%	n/a
Apr 1, 2009	0.95%	0.00%	n/a
Nov 1, 2008	0.00%	0.55%	n/a
Apr 1, 2008	0.70%	0.50%	n/a
Nov 1, 2007	0.00%	0.70%	n/a
Apr 1, 2007	0.70%	0.00%	n/a
Dec 1, 2006	0.00%	0.30%	n/a
Apr 1, 2006	0.50%	0.00%	n/a
Nov 1, 2005	0.00%	0.50%	n/a
Apr 1, 2005	0.72%	0.00%	n/a
Nov 1, 2004	0.00%	0.50%	n/a
Apr 1, 2004	0.58%	0.00%	n/a

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Northern Utilities, Inc. Hedging Gains and Losses November 2010 through April 2011 As of 7/22/2010							
Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Time Triggered NYMEX Contracts	7	8	4	5	5	9	38
Average Purchase Price	$ 6.385	$ 6.636	$ 6.991	$ 6.902	$ 6.713	$ 6.178	$ 6.564
Current NYMEX Price	$ 4.905	$ 5.172	$ 5.337	$ 5.306	$ 5.210	$ 5.018	$ 5.126
Hedging (Gains) or Losses - Allocate	$ 103,600	$ 117,140	$ 66,170	$ 79,800	$ 75,150	$ 104,380	$ 546,240
Price Triggered NYMEX Contracts (NH Only)	6	5	3	4	4	6	28
Average Purchase Price	$ 6.260	$ 6.647	$ 6.983	$ 6.825	$ 6.730	$ 6.200	$ 6.542
Current NYMEX Price	$ 4.905	$ 5.172	$ 5.337	$ 5.306	$ 5.210	$ 5.018	$ 6.957
Hedging (Gains) or Losses - NH ONLY	$ 81,300	$ 73,750	$ 49,390	$ 60,760	$ 60,800	$ 70,920	$ 396,920

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Winter 2010-2011 vs. Winter 2009-2010

Typical Usage: therms			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2010- 2011																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.1177	$121.83						$121.83								
	CGA 2	$1.1177		$167.66					$167.66								
	CGA 3	$1.1177			$209.01				$209.01								
	CGA 4	$1.1177				$210.13			$210.13								
	CGA 5	$1.1177					$185.54		$185.54								
	CGA 6	$1.1177						$147.54	$147.54								
	LDAC	$0.0454	$4.95	$6.81	$8.49	$8.54	$7.54	$5.99	$42.31								
Summer 2010																	
Customer Charge	units @	$ 9.50								$ 9.50	$9.50	$9.50	$9.50	$ 9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.6545								$58.91						$58.91	
	CGA 2	$0.5969									$32.83					$32.83	
	CGA 3	$0.7280										$21.84				$21.84	
	CGA 4	$0.7280											$21.84			$21.84	
	CGA 5	$0.7280												$30.58		$30.58	
	CGA 6	$0.7280													$51.69	$51.69	
	LDAC	$ 0.0297								$2.67	$1.63	$0.89	$0.89	$1.25	$2.11	$9.44	
	TOTAL		$174.43	$234.38	$288.47	$289.93	$257.77	$208.06	$1,453.04	$103.55	$65.97	$44.54	$44.54	$58.55	$90.09	$407.23	$1,860.26

Typical Usage: therms			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2009 - 2010																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.0980	$119.68						$119.68								
	CGA 2	$1.0980		$164.70					$164.70								
	CGA 3	$1.0218			$191.08				$191.08								
	CGA 4	$1.0758				$202.25			$202.25								
	CGA 5	$1.0758					$178.58		$178.58								
	CGA 6	$0.6693						$88.35	$88.35								
	LDAC	$ 0.0297	$3.24	$4.46	$5.55	$5.58	$4.93	$3.92	$27.68								
Summer 2009																	
Customer Charge	units @	$ 9.50								$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.7385								$66.47						$66.47	
	CGA 2	$0.7385									$40.62					$40.62	
	CGA 3	$0.7385										$22.16				$22.16	
	CGA 4	$0.7385											$22.16			$22.16	
	CGA 5	$0.7385												$31.02		$31.02	
	CGA 6	$0.9231													$65.54	$65.54	
	LDAC	$ 0.0255								$2.30	$1.40	$0.77	$0.77	$1.07	$1.81	$8.11	
	TOTAL		$170.57	$229.07	$267.60	$279.11	$248.21	$146.80	$1,341.35	$110.73	$73.53	$44.73	$44.73	$58.82	$103.64	$436.16	$1,777.51
	Change		$3.86	$5.31	$20.87	$10.83	$9.56	$61.26	$111.69	($7.18)	($7.56)	($0.19)	($0.19)	($0.26)	($13.55)	**($28.94)**	$82.75
	% Chg		2.26%	2.32%	7.80%	3.88%	3.85%	41.73%	8.33%	-6.49%	-10.28%	-0.42%	-0.42%	-0.45%	-13.08%	**-6.63%**	4.66%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 2,000 therms/year

Comparison of Winter 2010-2010 vs. Winter 2009-2010

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2010 - 2011																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3077	$23.08	$23.08	$23.08	$23.08	$23.08	$23.08	$138.47								
Over	75 units @	$0.2007	$23.68	$38.94	$44.76	$37.53	$31.91	$19.27	$196.08								
	CGA 1	$1.1398	$219.98						$219.98								
	CGA 2	$1.1398		$306.61					$306.61								
	CGA 3	$1.1398			$339.66				$339.66								
	CGA 4	$1.1398				$298.63			$298.63								
	CGA 5	$1.1398					$266.71		$266.71								
	CGA 6	$1.1398						$194.91	$194.91								
	LDAC	$0.0259	$5.00	$6.97	$7.72	$6.79	$6.06	$4.43	$36.96								
Summer 2010																	
Customer Charge	units @	$ 18.70								$ 18.70	$18.70	$18.70	$18.70	$ 18.70	$18.70	$112.20	
First	75 units @	$0.3077								$23.08	$23.08	$22.15	$22.15	$23.08	$23.08	$136.62	
Over	75 units @	$0.2007								$8.43	$1.20	$0.00	$0.00	$2.81	$13.45	$25.89	
	CGA 1	$0.6905								$80.79						$80.79	
	CGA 2	$0.6329									$51.26					$51.26	
	CGA 3	$0.7640										$55.01				$55.01	
	CGA 4	$0.7640											$55.01			$55.01	
	CGA 5	$0.7640												$68.00		$68.00	
	CGA 6	$0.7640													$108.49	$108.49	
	LDAC	$ 0.0166								$1.94	$1.34	$1.20	$1.20	$1.48	$2.36	$9.51	
		TOTAL	$290.44	$394.29	$433.91	$384.72	$346.46	$260.38	$2,110.20	$132.94	$95.59	$97.06	$97.06	$114.06	$166.07	$702.77	$2,812.98

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2009 - 2010																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3077	$23.08	$23.08	$23.08	$23.08	$23.08	$23.08	$138.47								
Over	75 units @	$0.2007	$23.68	$38.94	$44.76	$37.53	$31.91	$19.27	$196.08								
	CGA 1	$1.1058	$213.42						$213.42								
	CGA 2	$1.1058		$297.46					$297.46								
	CGA 3	$1.0296			$306.82				$306.82								
	CGA 4	$1.0836				$283.90			$283.90								
	CGA 5	$1.0836					$253.56		$253.56								
	CGA 6	$0.6771						$115.78	$115.78								
	LDAC	$ 0.0166	$3.20	$4.47	$4.95	$4.35	$3.88	$2.84	$23.69								
Summer 2009																	
Customer Charge	units @	$ 18.70								$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20	
First	75 units @	$0.3077								$23.08	$23.08	$22.15	$22.15	$23.08	$23.08	$136.62	
Over	75 units @	$0.2007								$8.43	$1.20	$0.00	$0.00	$2.81	$13.45	$25.89	
	CGA 1	$0.8355								$97.75						$97.75	
	CGA 2	$0.8355									$67.68					$67.68	
	CGA 3	$0.8355										$60.16				$60.16	
	CGA 4	$0.8355											$60.16			$60.16	
	CGA 5	$0.8355												$74.36		$74.36	
	CGA 6	$1.0444													$148.30	$148.30	
	LDAC	$ 0.0211								$2.47	$1.71	$1.52	$1.52	$1.88	$3.00	$12.09	
		TOTAL	$282.08	$382.64	$398.30	$367.56	$331.14	$179.67	$1,941.39	$150.43	$112.37	$102.53	$102.53	$120.82	$206.53	$795.20	$2,736.59
		Change	$8.36	$11.65	$35.61	$17.16	$15.33	$80.71	$168.82	($17.49)	($16.78)	($5.47)	($5.47)	($6.76)	($40.46)	($92.43)	$76.39
		% Chg	2.96%	3.04%	8.94%	4.67%	4.63%	44.92%	8.70%	-11.63%	-14.93%	-5.34%	-5.34%	-5.60%	-19.59%	-11.62%	2.79%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 21,023 therms/year

Comparison of Winter 2010-2011 vs. Winter 2009-2010

	Typical Usage: therms		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2010 - 2011																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.1942	$301.59	$500.65	$634.06	$796.80	$660.67	$480.26	$3,374.03								
	CGA 1	$1.1398	$1,770.11						$1,770.11								
	CGA 2	$1.1398		$2,938.40					$2,938.40								
	CGA 3	$1.1398			$3,721.45				$3,721.45								
	CGA 4	$1.1398				$4,676.60			$4,676.60								
	CGA 5	$1.1398					$3,877.60		$3,877.60								
	CGA 6	$1.1398						$2,818.73	$2,818.73								
	LDAC	$0.0259	$40.22	$66.77	$84.56	$106.27	$88.11	$64.05	$449.99								
Summer 2010																	
Customer Charge	units @	$ 60.30								$ 60.30	$60.30	$60.30	$60.30	$ 60.30	$60.30	$361.80	
All	units @	$0.1124								$141.40	$78.79	$46.53	$23.94	$40.91	$78.57	$410.15	
	CGA 1	$0.6905								$868.65						$868.65	
	CGA 2	$0.6329									$443.66					$443.66	
	CGA 3	$0.7640										$316.30				$316.30	
	CGA 4	$0.7640											$162.73			$162.73	
	CGA 5	$0.7640												$278.10		$278.10	
	CGA 6	$0.7640													$534.04	$534.04	
	LDAC	$ 0.0166								$20.88	$11.64	$6.87	$3.54	$6.04	$11.60	$60.57	
	TOTAL		$2,172.22	$3,566.12	$4,500.37	$5,639.97	$4,686.68	$3,423.33	$23,988.70	$1,091.23	$594.39	$430.00	$250.51	$385.35	$684.51	$3,435.99	$27,424.70

	Typical Usage: therms		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2009 - 2010																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.1942	$301.59	$500.65	$634.06	$796.80	$660.67	$480.26	$3,374.03								
	CGA 1	$1.1058	$1,717.31						$1,717.31								
	CGA 2	$1.1058		$2,850.75					$2,850.75								
	CGA 3	$1.0296			$3,361.64				$3,361.64								
	CGA 4	$1.0836				$4,446.01			$4,446.01								
	CGA 5	$1.0836					$3,686.41		$3,686.41								
	CGA 6	$0.6771						$1,674.47	$1,674.47								
	LDAC	$ 0.0166	$25.78	$42.79	$54.20	$68.11	$56.47	$41.05	$288.41								
Summer 2009																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
All	units @	$0.1124								$141.40	$78.79	$46.53	$23.94	$40.91	$78.57	$410.15	
	CGA 1	$0.8355								$1,051.06						$1,051.06	
	CGA 2	$0.8355									$585.69					$585.69	
	CGA 3	$0.8355										$345.90				$345.90	
	CGA 4	$0.8355											$177.96			$177.96	
	CGA 5	$0.8355												$304.12		$304.12	
	CGA 6	$1.0444													$730.04	$730.04	
	LDAC	$ 0.0211								$26.54	$14.79	$8.74	$4.49	$7.68	$14.75	$76.99	
	TOTAL		$2,104.98	$3,454.49	$4,110.21	$5,371.22	$4,463.85	$2,256.08	$21,760.83	$1,279.30	$739.57	$461.47	$266.70	$413.02	$883.65	$4,043.70	$25,804.53
	Change		$67.24	$111.63	$390.17	$268.75	$222.83	$1,167.26	$2,227.87	($188.07)	($145.18)	($31.46)	($16.19)	($27.66)	($199.15)	($607.71)	$1,620.16
	% Chg		3.19%	3.23%	9.49%	5.00%	4.99%	51.74%	10.24%	-14.70%	-19.63%	-6.82%	-6.07%	-6.70%	-22.54%	-15.03%	6.28%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 20,489 therms/year
Comparison of Winter 2010-2011 vs. Winter 2009-2010

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2010 - 2011																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.1862	$242.06	$242.06	$242.06	$242.06	$242.06	$242.06	$1,452.36								
Over	1,300 units @	$0.1467	$61.91	$115.31	$151.10	$151.54	$145.38	$83.91	$709.15								
CGA 1		$1.0019	$1,725.27						$1,725.27								
CGA 2		$1.0019		$2,089.96					$2,089.96								
CGA 3		$1.0019			$2,334.43				$2,334.43								
CGA 4		$1.0019				$2,337.43			$2,337.43								
CGA 5		$1.0019					$2,295.35		$2,295.35								
CGA 6		$1.0019						$1,875.56	$1,875.56								
LDAC		$0.0259	$44.60	$54.03	$60.35	$60.42	$59.34	$48.48	$327.22								
Summer 2010																	
Customer Charge	units @	$ 60.30								$ 60.30	$60.30	$60.30	$60.30	$ 60.30	$60.30	$361.80	
First	1,000 units @	$0.1112								$111.20	$111.20	$111.20	$111.20	$111.20	$111.20	$667.20	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27	$14.82	$16.38	$25.27	$144.69	
CGA 1		$0.6075								$917.33						$917.33	
CGA 2		$0.5499									$755.56					$755.56	
CGA 3		$0.6810										$849.21				$849.21	
CGA 4		$0.6810											$810.39			$810.39	
CGA 5		$0.6810												$824.01		$824.01	
CGA 6		$0.6810													$901.64	$901.64	
LDAC		$ 0.0166								$25.07	$22.81	$20.70	$19.75	$20.09	$21.98	$130.39	
		TOTAL	$2,134.14	$2,561.66	$2,848.24	$2,851.76	$2,802.43	$2,310.31	$15,508.53	$1,153.67	$979.04	$1,060.67	$1,016.46	$1,031.98	$1,120.39	$6,362.22	$21,870.75

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2009 - 2010																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.1862	$242.06	$242.06	$242.06	$242.06	$242.06	$242.06	$1,452.36								
Over	1,300 units @	$0.1467	$61.91	$115.31	$151.10	$151.54	$145.38	$83.91	$709.15								
CGA 1		$1.0630	$1,830.49						$1,830.49								
CGA 2		$1.0630		$2,217.42					$2,217.42								
CGA 3		$0.9868			$2,299.24				$2,299.24								
CGA 4		$1.0408				$2,428.19			$2,428.19								
CGA 5		$1.0408					$2,384.47		$2,384.47								
CGA 6		$0.6343						$1,187.41	$1,187.41								
LDAC		$ 0.0166	$28.59	$34.63	$38.68	$38.73	$38.03	$31.08	$209.72								
Summer 2009																	
Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
First	1,000 units @	$0.1112								$111.20	$111.20	$111.20	$111.20	$111.20	$111.20	$667.20	
Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27	$14.82	$16.38	$25.27	$144.69	
CGA 1		$0.6785								$1,024.54						$1,024.54	
CGA 2		$0.6785									$932.26					$932.26	
CGA 3		$0.6785										$846.09				$846.09	
CGA 4		$0.6785											$807.42			$807.42	
CGA 5		$0.6785												$820.99		$820.99	
CGA 6		$0.8481													$1,122.88	$1,122.88	
LDAC		$ 0.0211								$31.86	$28.99	$26.31	$25.11	$25.53	$27.94	$165.74	
		TOTAL	$2,223.34	$2,669.71	$2,791.38	$2,920.82	$2,870.24	$1,604.76	$15,080.25	$1,267.68	$1,161.92	$1,063.17	$1,018.84	$1,034.40	$1,347.59	$6,893.60	$21,973.85
		Change	($89.20)	($108.05)	$56.85	($69.06)	($67.81)	$705.56	$428.28	($114.01)	($182.88)	($2.49)	($2.38)	($2.42)	($227.20)	($531.38)	($103.09)
		% Chg	-4.01%	-4.05%	2.04%	-2.36%	-2.36%	43.97%	2.84%	-8.99%	-15.74%	-0.23%	-0.23%	-0.23%	-16.86%	-7.71%	-0.47%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Winter 2010-2011 vs. Actual Winter 2009-2010

Residential Heating	Winter 2009-2010	Winter 2010- 2011
Customer Charge	$9.50	$9.50
First 50 Therms	$0.4102	$0.4102
Over 50 therms	$0.2990	$0.2990
LDAC	$0.0297	$0.0454
CGA	$1.0136	$1.1177

	Usage (Therms)	Winter 2009-2010 Bill Amount	Winter 2010-2011 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$16.77	$17.37	$0.60	3.6%	$0.00	0.0%	$0.52	3.1%	$0.08	0.5%
	10	$24.04	$25.23	$1.20	5.0%	$0.00	0.0%	$1.04	4.3%	$0.16	0.7%
	20	$38.57	$40.97	$2.40	6.2%	$0.00	0.0%	$2.08	5.4%	$0.31	0.8%
	25	$45.84	$48.83	$3.00	6.5%	$0.00	0.0%	$2.60	5.7%	$0.39	0.9%
	30	$53.11	$56.70	$3.59	6.8%	$0.00	0.0%	$3.12	5.9%	$0.47	0.9%
	45	$74.91	$80.30	$5.39	7.2%	$0.00	0.0%	$4.68	6.2%	$0.71	0.9%
Average Monthly	50	$82.18	$88.17	$5.99	7.3%	$0.00	0.0%	$5.20	6.3%	$0.79	1.0%
	75	$115.73	$124.72	$8.98	7.8%	$0.00	0.0%	$7.81	6.7%	$1.18	1.0%
	125	$182.85	$197.82	$14.98	8.2%	$0.00	0.0%	$13.01	7.1%	$1.96	1.1%
	150	$216.41	$234.38	$17.97	8.3%	$0.00	0.0%	$15.62	7.2%	$2.36	1.1%
	200	$283.52	$307.48	$23.96	8.5%	$0.00	0.0%	$20.82	7.3%	$3.14	1.1%

Northern Utilities New Hampshire Division
Period Covered: November 1, 2010 - April 30, 2011
Variance Analysis

		2009 / 2010 Winter (6 months actual)			2010 / 2011 Winter (6 months proposed)		
1	Therm Sales	27,711,610			28,028,950		
2							
3				EFFECT			EFFECT
4		THERM SENDOUT	COSTS	ON COST OF GAS	THERM SENDOUT	COSTS	ON COST OF GAS
5							
6	Demand Charges (Pipeline & Storage)		$ 11,198,728	$ 0.4041		$ 15,483,102	$ 0.5524
7							
8	Purchased Gas (Pipeline Commodity)		10,694,244	0.3859		5,408,538	0.1930
9							
10	Storage & Peaking Gas (Commodity)		2,920,424	0.1054		7,629,178	0.2722
11							
12	Hedging (Gain)/Loss		2,884,703	0.1041		1,054,446	0.0376
13							
14							
15	Total Volumes and Cost	$ -	$ 27,698,099	$ 0.9995	$ -	$ 29,575,264	$ 1.0552
16							
17	Prior Period Balance		$2,464,908	$ 0.0889		$ 2,527,403	$ 0.0902
18	ATV Reconciliation		-	$ -		-	$ -
19	Interest		$ 105,685	$ 0.0038		99,945	$ 0.0036
20	Refunds from Suppliers		-	$ -		-	$ -
21							
22	Prior Period Adjustment						
23	Interruptible Sales Margin		7,649	$ 0.0003		-	$ -
24	Capacity Release, Asset Mgmt, PNGTS		(1,665,775)	$ (0.0601)		(1,771,080)	$ (0.0632)
25	Working Capital Allowance		(83,069)	$ (0.0030)		(30,222)	$ (0.0011)
26	Bad Debt Allowance		(2,655)	$ (0.0001)		133,747	$ 0.0048
27	Fuel Inventory Financing		7,801	$ 0.0003		10,094	$ 0.0004
28	Local Production and Storage		686,673	$ 0.0248		686,673	$ 0.0245
29	Misc Overhead		95,845	$ 0.0035		98,333	$ 0.0035
30							
31	Total Anticipated Indirect Cost of Gas		$1,617,062	$ 0.0584		1,754,892	$ 0.0626
32	Total Adjusted Cost	-	29,315,161	$ 1.0579		31,330,157	$ 1.1178

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

Base Capacity Costs

LN	BASE SENDOUT BY CLASS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
2	**Total Therms**								
3	Res Heat	390,983	404,016	404,016	364,917	404,016	390,983	2,358,930	Schedule 10B, LN 52
4	Res General	15,639	16,160	16,160	14,597	16,160	15,639	94,356	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	111,303	115,013	115,013	103,882	115,013	111,303	671,525	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	65,573	67,759	67,759	61,201	67,759	65,573	395,622	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	143,292	148,068	148,068	133,739	148,068	143,292	864,526	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	119,756	123,747	123,747	111,772	123,747	119,756	722,525	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	8,488	11,047	11,968	10,859	10,482	9,159	62,003	Schedule 10B, LN 58
10	G42 High Annual-High Winter	11,459	11,841	11,841	10,695	11,841	11,459	69,136	Schedule 10B, LN 59
11	Total Firm Sales	866,491	897,651	898,572	811,662	897,086	867,162	5,238,625	Sum LN 3 : LN 10
12									
13	**% of Total**								
14	Res Heat	45.12%	45.01%	44.96%	44.96%	45.04%	45.09%		LN 3 / LN 11
15	Res General	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%		LN 4 / LN 11
16	G50 Low Annual-Low Winter	12.85%	12.81%	12.80%	12.80%	12.82%	12.84%		LN 5 / LN 11
17	G40 Low Annual-High Winter	7.57%	7.55%	7.54%	7.54%	7.55%	7.56%		LN 6 / LN 11
18	G51 Med Annual-Low Winter	16.54%	16.50%	16.48%	16.48%	16.51%	16.52%		LN 7 / LN 11
19	G41 Med Annual-High Winter	13.82%	13.79%	13.77%	13.77%	13.79%	13.81%		LN 8 / LN 11
20	G52 High Annual-Low Winter	0.98%	1.23%	1.33%	1.34%	1.17%	1.06%		LN 9 / LN 11
21	G42 High Annual-High Winter	1.32%	1.32%	1.32%	1.32%	1.32%	1.32%		LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		LN 11 / LN 11
23									

LN	PIPELINE BASE DEMAND COSTS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
25	TOTAL PIPELINE BASE DEMAND COST	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 57,910	$ 347,460	Schedule 1A, LN 69
26	Res Heat	$ 26,130	$ 26,064	$ 26,037	$ 26,036	$ 26,081	$ 26,110	$ 156,459	LN 25 * LN 14
27	Res General	$ 1,045	$ 1,043	$ 1,041	$ 1,041	$ 1,043	$ 1,044	$ 6,258	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 7,439	$ 7,420	$ 7,412	$ 7,412	$ 7,424	$ 7,433	$ 44,540	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 4,382	$ 4,371	$ 4,367	$ 4,367	$ 4,374	$ 4,379	$ 26,240	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 9,577	$ 9,552	$ 9,542	$ 9,542	$ 9,558	$ 9,569	$ 57,341	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 8,004	$ 7,983	$ 7,975	$ 7,975	$ 7,988	$ 7,997	$ 47,922	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 567	$ 713	$ 771	$ 775	$ 677	$ 612	$ 4,114	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 766	$ 764	$ 763	$ 763	$ 764	$ 765	$ 4,586	LN 25 * LN 21
34									
35	Residential	$ 27,176	$ 27,107	$ 27,079	$ 27,077	$ 27,124	$ 27,155	$ 162,717	LN 26 + LN 27
36	SALES HLF CLASSES	$ 17,582	$ 17,685	$ 17,726	$ 17,728	$ 17,659	$ 17,614	$ 105,995	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 13,152	$ 13,118	$ 13,105	$ 13,104	$ 13,127	$ 13,142	$ 78,748	LN 29 + LN 31 + LN 33
38									

Remaining Capacity Costs

LN		Column A	Column B	Column C	Column D	
39		Design Day Demand (MMBtu)	Avg Daily Base Use Load (MMBtu)	Remaining Design Day Demand (MMBtu)	% of Total Remaining Design Day Demand	
40	Res Heat	16,366	1,404	14,962	46.95%	Company Analysis
41	Res General	214	56	158	0.50%	Company Analysis
42	G50 Low Annual-Low Winter	880	346	534	1.67%	Company Analysis
43	G40 Low Annual-High Winter	7,688	263	7,425	23.30%	Company Analysis
44	G51 Med Annual-Low Winter	1,388	492	896	2.81%	Company Analysis
45	G41 Med Annual-High Winter	7,566	443	7,123	22.35%	Company Analysis
46	G52 High Annual-Low Winter	42	24	17	0.05%	Company Analysis
47	G42 High Annual-High Winter	846	94	753	2.36%	Company Analysis
48	TOTAL	34,989	3,122	31,868	100.00%	Sum LN 40 : LN 47
49						

LN	REMAINING PIPELINE DEMAND	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
51		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 98,866	$ 222,178	$ 577,963	$ 314,622	$ 275,764	$ 107,443	$ 1,596,836	Schedule 1A, LN 70
53									
54	Res Heat	$ 46,418	$ 104,314	$ 271,357	$ 147,717	$ 129,473	$ 50,445	$ 749,724	LN 40 Col D * LN 52
55	Res General	$ 491	$ 1,103	$ 2,868	$ 1,561	$ 1,369	$ 533	$ 7,925	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 1,656	$ 3,721	$ 9,679	$ 5,269	$ 4,618	$ 1,799	$ 26,741	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 23,036	$ 51,768	$ 134,666	$ 73,307	$ 64,253	$ 25,034	$ 372,064	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 2,779	$ 6,244	$ 16,244	$ 8,843	$ 7,751	$ 3,020	$ 44,880	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 22,098	$ 49,661	$ 129,185	$ 70,324	$ 61,638	$ 24,015	$ 356,921	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 54	$ 122	$ 317	$ 172	$ 151	$ 59	$ 875	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 2,335	$ 5,246	$ 13,648	$ 7,429	$ 6,512	$ 2,537	$ 37,707	LN 47 Col D * LN 52
62	TOTAL	$ 98,866	$ 222,178	$ 577,963	$ 314,622	$ 275,764	$ 107,443	$ 1,596,836	Sum LN 54 : LN 61
63									
64	Residential	$ 46,909	$ 105,416	$ 274,225	$ 149,278	$ 130,842	$ 50,978	$ 757,649	LN 54 + LN 55
65	SALES HLF CLASSES	$ 4,488	$ 10,087	$ 26,239	$ 14,284	$ 12,520	$ 4,878	$ 72,496	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 47,469	$ 106,675	$ 277,498	$ 151,060	$ 132,403	$ 51,587	$ 766,692	LN 57 + LN 59 + LN 61
67									

LN	PEAKING AND STORAGE DEMAND	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
69		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 838,236	$ 1,883,740	$ 4,900,270	$ 2,667,531	$ 2,338,074	$ 910,955	$ 13,538,806	Schedule 1A, LN 73
71									
72	Res Heat	$ 393,556	$ 884,426	$ 2,300,705	$ 1,252,421	$ 1,097,739	$ 427,699	$ 6,356,546	LN 40 Col D * LN 70
73	Res General	$ 4,160	$ 9,349	$ 24,320	$ 13,239	$ 11,604	$ 4,521	$ 67,192	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 14,037	$ 31,546	$ 82,062	$ 44,671	$ 39,154	$ 15,255	$ 226,725	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 195,310	$ 438,913	$ 1,141,767	$ 621,537	$ 544,773	$ 212,253	$ 3,154,553	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 23,559	$ 52,944	$ 137,725	$ 74,973	$ 65,713	$ 25,603	$ 380,517	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 187,360	$ 421,049	$ 1,095,296	$ 596,240	$ 522,600	$ 203,614	$ 3,026,160	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 459	$ 1,032	$ 2,684	$ 1,461	$ 1,281	$ 499	$ 7,417	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 19,794	$ 44,481	$ 115,712	$ 62,989	$ 55,210	$ 21,511	$ 319,697	LN 47 Col D * LN 70
80	TOTAL	$ 838,236	$ 1,883,740	$ 4,900,270	$ 2,667,531	$ 2,338,074	$ 910,955	$ 13,538,806	Sum LN 72 : LN 79
81									
82	Residential	$ 397,716	$ 893,775	$ 2,325,024	$ 1,265,660	$ 1,109,342	$ 432,220	$ 6,423,737	LN 72 + LN 73
83	SALES HLF CLASSES	$ 38,056	$ 85,521	$ 222,471	$ 121,105	$ 106,148	$ 41,357	$ 614,659	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 402,464	$ 904,443	$ 2,352,775	$ 1,280,766	$ 1,122,583	$ 437,379	$ 6,500,410	LN 75 + LN 77 + LN 79
85									

Ln	Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
86	**CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**								
87		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ (118,194)	$ (248,666)	$ (625,108)	$ (346,478)	$ (305,364)	$ (127,269)	$ (1,771,080)	Schedule 1A, LN 76
89									
90	Res Heat	$ (55,493)	$ (116,750)	$ (293,492)	$ (162,673)	$ (143,370)	$ (59,754)	$ (831,532)	LN 40 Col D * LN 88
91	Res General	$ (587)	$ (1,234)	$ (3,102)	$ (1,720)	$ (1,515)	$ (632)	$ (8,790)	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ (1,979)	$ (4,164)	$ (10,468)	$ (5,802)	$ (5,114)	$ (2,131)	$ (29,659)	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ (27,539)	$ (57,939)	$ (145,651)	$ (80,730)	$ (71,150)	$ (29,654)	$ (412,663)	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ (3,322)	$ (6,989)	$ (17,569)	$ (9,738)	$ (8,582)	$ (3,577)	$ (49,777)	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ (26,419)	$ (55,581)	$ (139,723)	$ (77,444)	$ (68,254)	$ (28,447)	$ (395,867)	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ (65)	$ (136)	$ (342)	$ (190)	$ (167)	$ (70)	$ (970)	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ (2,791)	$ (5,872)	$ (14,761)	$ (8,182)	$ (7,211)	$ (3,005)	$ (41,821)	LN 47 Col D * LN 88
98	TOTAL	$ (118,194)	$ (248,666)	$ (625,108)	$ (346,478)	$ (305,364)	$ (127,269)	$ (1,771,080)	Sum LN 90 : LN 97
99									
100	Residential	$ (56,080)	$ (117,984)	$ (296,594)	$ (164,393)	$ (144,886)	$ (60,385)	$ (840,322)	LN 90 + LN 91
101	SALES HLF CLASSES	$ (5,366)	$ (11,289)	$ (28,380)	$ (15,730)	$ (13,863)	$ (5,778)	$ (80,407)	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ (56,749)	$ (119,393)	$ (300,134)	$ (166,355)	$ (146,615)	$ (61,106)	$ (850,352)	LN 93 + LN 95 + LN 97
103									
104	**INTERRUPTIBLE MARGINS BY CLASS**								
105		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 77
107									
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117									
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115
121									

LN		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
122	**REMAINING RE-ENTRY FEE CREDIT**								
123		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
124	NH DIVISION - RE-ENTRY FEE CREDITS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 78
125									
126	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 124
127	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 124
128	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 124
129	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 124
130	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 124
131	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 124
132	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 124
133	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 124
134	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 126 : LN 133
135									
136	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 126 + LN 127
137	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 128 + LN 130 + LN 132
138	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 129 + LN 131 + LN 133
139									
140	**TOTAL NON-BASE CAPACITY COSTS**								
141		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
142	Res Heat	$ 384,481	$ 871,990	$ 2,278,569	$ 1,237,465	$ 1,083,842	$ 418,390	$ 6,274,737	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 4,064	$ 9,217	$ 24,086	$ 13,081	$ 11,457	$ 4,423	$ 66,327	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 13,714	$ 31,102	$ 81,272	$ 44,138	$ 38,658	$ 14,923	$ 223,808	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 190,806	$ 432,741	$ 1,130,782	$ 614,115	$ 537,876	$ 207,634	$ 3,113,954	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 23,016	$ 52,199	$ 136,400	$ 74,077	$ 64,881	$ 25,046	$ 375,620	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 183,040	$ 415,128	$ 1,084,758	$ 589,120	$ 515,984	$ 199,183	$ 2,987,213	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 449	$ 1,017	$ 2,659	$ 1,444	$ 1,265	$ 488	$ 7,321	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 19,337	$ 43,856	$ 114,599	$ 62,237	$ 54,511	$ 21,043	$ 315,582	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 818,907	$ 1,857,251	$ 4,853,125	$ 2,635,676	$ 2,308,474	$ 891,129	$ 13,364,562	Sum LN 142 : LN 149
151									
152	Residential	$ 388,546	$ 881,207	$ 2,302,655	$ 1,250,545	$ 1,095,298	$ 422,813	$ 6,341,064	LN 142 + LN 143
153	SALES HLF CLASSES	$ 37,178	$ 84,319	$ 220,331	$ 119,659	$ 104,804	$ 40,457	$ 606,748	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 393,183	$ 891,725	$ 2,330,139	$ 1,265,471	$ 1,108,372	$ 427,859	$ 6,416,750	LN 145 + LN 147 + LN 149
155									
156	**TOTAL CAPACITY COSTS**								
157		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
158	Res Heat	$ 410,612	$ 898,054	$ 2,304,607	$ 1,263,501	$ 1,109,922	$ 444,500	$ 6,431,196	LN 142 + LN 26
159	Res General	$ 5,109	$ 10,260	$ 25,127	$ 14,122	$ 12,500	$ 5,467	$ 72,585	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 21,152	$ 38,522	$ 88,684	$ 51,550	$ 46,083	$ 22,356	$ 268,347	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 195,188	$ 437,112	$ 1,135,149	$ 618,481	$ 542,250	$ 212,013	$ 3,140,194	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 32,592	$ 61,752	$ 145,943	$ 83,619	$ 74,439	$ 34,615	$ 432,961	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 191,044	$ 423,111	$ 1,092,733	$ 597,094	$ 523,973	$ 207,180	$ 3,035,136	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,016	$ 1,730	$ 3,430	$ 2,219	$ 1,941	$ 1,100	$ 11,435	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 20,103	$ 44,620	$ 115,362	$ 63,000	$ 55,275	$ 21,808	$ 320,168	LN 149 + LN 33
166	TOTAL	$ 876,817	$ 1,915,161	$ 4,911,035	$ 2,693,586	$ 2,366,384	$ 949,039	$ 13,712,022	Sum LN 158 : LN 165
167									
168	Residential	$ 415,721	$ 908,314	$ 2,329,734	$ 1,277,623	$ 1,122,422	$ 449,967	$ 6,503,781	LN 158 + LN 159
169	SALES HLF CLASSES	$ 54,761	$ 102,004	$ 238,057	$ 137,388	$ 122,464	$ 58,071	$ 712,743	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 406,335	$ 904,844	$ 2,343,244	$ 1,278,576	$ 1,121,498	$ 441,001	$ 6,495,498	LN 161 + LN 163 + LN 165
171									
172	% ALLOCATION BETWEEN SALES HLF AND LLF								
173	SALES HLF CLASSES							9.89%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES							90.11%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2010 - 2011 Period

Line No.		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	Winter
	Forecasted Normal Sales By Class- Therms								
	Calendar Month Firm Sales Volumes								
	Normal Winter	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**TOTAL**	Winter
1	Res Heat	1,386,117	2,028,539	2,940,793	2,483,851	2,462,475	1,513,652	15,976,924	12,815,427
2	Res General	28,367	33,694	45,558	40,897	40,603	30,695	333,007	219,813
3	**Total Residential**	**1,414,484**	**2,062,233**	**2,986,351**	**2,524,748**	**2,503,078**	**1,544,347**	**16,309,931**	**13,035,240**
4	G50 Low Annual-Low Winter	126,011	160,228	185,341	168,024	169,955	129,888	1,665,440	939,446
5	G40 Low Annual-High Winter	549,636	954,242	1,555,171	1,338,420	1,186,947	670,021	7,128,120	6,254,438
6	G51 Med Annual-Low Winter	216,377	253,938	268,531	229,592	249,273	184,512	2,368,685	1,402,223
7	G41 Med Annual-High Winter	629,249	1,127,812	1,221,751	1,030,698	1,035,822	594,798	6,950,395	5,640,131
8	G52 High Annual-Low Winter	8,288	10,781	11,698	10,614	10,245	8,952	202,215	60,577
9	G42 High Annual-High Winter	103,055	153,283	151,387	127,883	102,208	59,078	804,805	696,894
10	**Total C&I**	**1,632,616**	**2,660,284**	**3,393,879**	**2,905,231**	**2,754,451**	**1,647,249**	**19,119,661**	**14,993,709**
11	**Total Sales**	**3,047,100**	**4,722,517**	**6,380,229**	**5,429,979**	**5,257,529**	**3,191,596**	**35,429,591**	**28,028,950**
12									
13	Residential Heat & Non Heat	1,414,484	2,062,233	2,986,351	2,524,748	2,503,078	1,544,347	16,309,931	13,035,240
14	SALES HLF CLASSES	350,675	424,947	465,570	408,229	429,473	323,352	4,236,340	2,402,246
15	SALES LLF CLASSES	1,281,941	2,235,337	2,928,309	2,497,002	2,324,978	1,323,897	14,883,320	12,591,463
16	**Total Firm Sales**	**3,047,100**	**4,722,517**	**6,380,229**	**5,429,979**	**5,257,529**	**3,191,596**	**35,429,591**	**28,028,950**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)								
20	Normal Winter	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**TOTAL**	**Winter**
21	Res Heat	1,419,511	2,078,694	3,008,803	2,541,163	2,519,528	1,548,654	16,354,570	13,116,353
22	Res General	29,050	34,527	46,611	41,841	41,543	31,405	340,931	224,978
23	G50 Low Annual-Low Winter	129,046	164,189	189,628	171,901	173,892	132,892	1,705,286	961,548
24	G40 Low Annual-High Winter	562,878	977,836	1,591,136	1,369,303	1,214,448	685,515	7,295,923	6,401,115
25	G51 Med Annual-Low Winter	221,590	260,217	274,741	234,890	255,049	188,779	2,425,336	1,435,264
26	G41 Med Annual-High Winter	644,409	1,155,697	1,250,006	1,054,481	1,059,821	608,553	7,115,143	5,772,966
27	G52 High Annual-Low Winter	8,488	11,047	11,968	10,859	10,482	9,159	207,099	62,003
28	G42 High Annual-High Winter	105,538	157,072	154,888	130,834	104,576	60,444	823,902	713,353
29	**Subtotal**								
30	Residential	1,448,561	2,113,221	3,055,414	2,583,004	2,561,072	1,580,059	16,695,501	13,341,331
31	SALES HLF CLASSES	359,124	435,454	476,336	417,649	439,423	330,829	4,337,721	2,458,815
32	SALES LLF CLASSES	1,312,825	2,290,605	2,996,030	2,554,617	2,378,845	1,354,512	15,234,968	12,887,434
33	**Total Firm Sales**	3,120,510	4,839,280	6,527,780	5,555,270	5,379,340	3,265,400	36,268,190	28,687,580

Northern Utilities - NEW HAMPSHIRE DIVISION
2010 - 2011 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes	
	Firm Sales	
1	Res Heat	Company Analysis
2	Res General	Company Analysis
3	**Total Residential**	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	Company Analysis
5	G40 Low Annual-High Winter	Company Analysis
6	G51 Med Annual-Low Winter	Company Analysis
7	G41 Med Annual-High Winter	Company Analysis
8	G52 High Annual-Low Winter	Company Analysis
9	G42 High Annual-High Winter	Company Analysis
10	**Total C&I**	Sum LN 4 : LN 9
11	**Total Sales**	LN 3 + LN 10
12		
13	Residential Heat & Non Heat	LN 3
14	SALES HLF CLASSES	LN 4 + LN 6 + LN 8
15	SALES LLF CLASSES	LN 5 + LN 7 + LN 9
16	**Total Firm Sales**	Sum LN 13 : LN 15
17		
18	**ESTIMATED SENDOUT BY CLASS - Therms**	
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)	
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Company Use, LAUF, BTU) x 10
22	Res General	LN 2 x Adj factor (Company Use, LAUF, BTU) x 10
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Company Use, LAUF, BTU) x 10
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Company Use, LAUF, BTU) x 10
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Company Use, LAUF, BTU) x 10
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Company Use, LAUF, BTU) x 10
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Company Use, LAUF, BTU) x 10
28	G42 High Annual-High Winter	LN 9 x Adj factor (Company Use, LAUF, BTU) x 10
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	13,033
37	Res General	521
38	G50 Low Annual-Low Winter	3,710
39	G40 Low Annual-High Winter	2,186
40	G51 Med Annual-Low Winter	4,776
41	G41 Med Annual-High Winter	3,992
42	G52 High Annual-Low Winter	721
43	G42 High Annual-High Winter	382
44	**Subtotal**	
45	Residential	13,554
46	SALES HLF CLASSES	9,208
47	SALES LLF CLASSES	6,560
48	**Total Firm Sales**	**29,321**

49	**BASE SENDOUT BY CLASS - Therms**									
50	Days per Month		30	31	31	28	31	30		
51			**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**TOTAL**	**WINTER**
52	Res Heat		390,983	404,016	404,016	364,917	404,016	390,983	4,728,740	2,358,930
53	Res General		15,639	16,160	16,160	14,597	16,160	15,639	187,959	94,356
54	G50 Low Annual-Low Winter		111,303	115,013	115,013	103,882	115,013	111,303	1,335,873	671,525
55	G40 Low Annual-High Winter		65,573	67,759	67,759	61,201	67,759	65,573	776,363	395,622
56	G51 Med Annual-Low Winter		143,292	148,068	148,068	133,739	148,068	143,292	1,726,857	864,526
57	G41 Med Annual-High Winter		119,756	123,747	123,747	111,772	123,747	119,756	1,423,799	722,525
58	G52 High Annual-Low Winter		8,488	11,047	11,968	10,859	10,482	9,159	194,639	62,003
59	G42 High Annual-High Winter		11,459	11,841	11,841	10,695	11,841	11,459	139,220	69,136
60	**Subtotal**									
61	Residential		406,622	420,176	420,176	379,514	420,176	406,622	4,916,699	2,453,287
62	SALES HLF CLASSES		263,082	274,128	275,049	248,480	273,563	263,753	3,257,369	1,598,055
63	SALES LLF CLASSES		196,787	203,347	203,347	183,668	203,347	196,787	2,339,383	1,187,283
64	**Total Firm Sales**		866,491	897,651	898,572	811,662	897,086	867,162	10,513,451	5,238,625
65										
66	**REMAINING SENDOUT BY CLASS - Therms**									
67			**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**TOTAL**	**WINTER**
68	Res Heat		1,028,528	1,674,678	2,604,787	2,176,245	2,115,513	1,157,671	11,625,830	10,757,423
69	Res General		13,411	18,367	30,451	27,245	25,383	15,766	152,971	130,621
70	G50 Low Annual-Low Winter		17,744	49,177	74,615	68,018	58,880	21,589	369,413	290,022
71	G40 Low Annual-High Winter		497,305	910,077	1,523,378	1,308,102	1,146,689	619,942	6,519,560	6,005,493
72	G51 Med Annual-Low Winter		78,298	112,149	126,673	101,151	106,981	45,487	698,478	570,738
73	G41 Med Annual-High Winter		524,653	1,031,950	1,126,258	942,709	936,073	488,797	5,691,344	5,050,441
74	G52 High Annual-Low Winter		-	-	-	-	-	-	12,460	-
75	G42 High Annual-High Winter		94,079	145,231	143,047	120,139	92,735	48,985	684,682	644,217
76	**Subtotal**									
77	Residential		1,041,939	1,693,045	2,635,238	2,203,490	2,140,896	1,173,437	11,778,801	10,888,044
78	SALES HLF CLASSES		96,042	161,326	201,287	169,169	165,860	67,076	1,080,352	860,760
79	SALES LLF CLASSES		1,116,038	2,087,258	2,792,683	2,370,949	2,175,498	1,157,724	12,895,586	11,700,151
80	**Total Firm Sales**		2,254,019	3,941,629	5,629,208	4,743,608	4,482,254	2,398,238	25,754,739	23,448,955

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	DAILY BASE GAS ENTITLEMENT - Therms/day	
36	Res Heat	Avg (LN 21 Jul : LN 21 Aug) / 31 days
37	Res General	Avg (LN 22 Jul : LN 22 Aug) / 31 days
38	G50 Low Annual-Low Winter	Avg (LN 23 Jul : LN 23 Aug) / 31 days
39	G40 Low Annual-High Winter	Avg (LN 24 Jul : LN 24 Aug) / 31 days
40	G51 Med Annual-Low Winter	Avg (LN 25 Jul : LN 25 Aug) / 31 days
41	G41 Med Annual-High Winter	Avg (LN 26 Jul : LN 26 Aug) / 31 days
42	G52 High Annual-Low Winter	Avg (LN 27 Jul : LN 27 Aug) / 31 days
43	G42 High Annual-High Winter	Avg (LN 28 Jul : LN 28 Aug) / 31 days
44	**Subtotal**	
45	Residential	LN 36 + LN 37
46	SALES HLF CLASSES	LN 38 + LN 40 + LN 42
47	SALES LLF CLASSES	LN 39 + LN 41 + LN 43
48	**Total Firm Sales**	Sum LN 45 : LN 47
49	**BASE SENDOUT BY CLASS - Therms**	
50	Days per Month	
51		
52	Res Heat	MIN(LN 36 * LN 50, LN 21)
53	Res General	MIN(LN 37 * LN 50, LN 22)
54	G50 Low Annual-Low Winter	MIN(LN 38 * LN 50, LN 23)
55	G40 Low Annual-High Winter	MIN(LN 39 * LN 50, LN 24)
56	G51 Med Annual-Low Winter	MIN(LN 40 * LN 50, LN 25)
57	G41 Med Annual-High Winter	MIN(LN 41 * LN 50, LN 26)
58	G52 High Annual-Low Winter	MIN(LN 42 * LN 50, LN 27)
59	G42 High Annual-High Winter	MIN(LN 43 * LN 50, LN 28)
60	**Subtotal**	
61	Residential	LN 52 + LN 53
62	SALES HLF CLASSES	LN 54 + LN 56 + LN 58
63	SALES LLF CLASSES	LN 55 + LN 57 + LN 59
64	**Total Firm Sales**	Sum LN 61 : LN 63
65		
66	REMAINING SENDOUT BY CLASS - Therms	
67		
68	Res Heat	LN 21 - LN 52
69	Res General	LN 22 - LN 53
70	G50 Low Annual-Low Winter	LN 23 - LN 54
71	G40 Low Annual-High Winter	LN 24 - LN 55
72	G51 Med Annual-Low Winter	LN 25 - LN 56
73	G41 Med Annual-High Winter	LN 26 - LN 57
74	G52 High Annual-Low Winter	LN 27 - LN 58
75	G42 High Annual-High Winter	LN 28 - LN 59
76	**Subtotal**	
77	Residential	LN 68 + LN 69
78	SALES HLF CLASSES	LN 70 + LN 72 + LN 74
79	SALES LLF CLASSES	LN 71 + LN 73 + LN 75
80	**Total Firm Sales**	Sum LN 77 : LN 79

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Total Division Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	542,536	525,777	16,759	3.2%	6,843	9,916	549,450	-6,913	-1.3%	26,429	-33,342
Dec	770,259	785,751	-15,492	-2.0%	10,178	-25,670	792,007	-21,748	-2.7%	18,404	-40,152
Jan	1,015,419	1,050,941	-35,522	-3.4%	13,506	-49,029	990,236	25,183	2.5%	23,574	1,608
Feb	1,015,501	974,983	40,518	4.2%	12,588	27,930	991,088	24,413	2.5%	23,136	1,277
Mar	878,056	868,777	9,279	1.1%	11,220	-1,941	894,108	-16,052	-1.8%	22,156	-38,208
Apr	677,756	697,010	-19,254	-2.8%	8,954	-28,208	678,954	-1,198	-0.2%	19,779	-20,977
May	429,234	419,968	9,267	2.2%	5,386	3,880	437,655	-8,420	-1.9%	13,375	-21,795
Jun	349,143	332,756	16,388	4.9%	4,237	12,151	317,236	31,907	10.1%	10,730	21,177
Jul	284,277	274,405	9,872	3.6%	3,595	6,278	279,336	4,941	1.8%	7,374	-2,433
Aug	281,167	270,407	10,760	4.0%	3,548	7,211	268,980	12,187	4.5%	7,084	5,103
Sep	300,274	290,974	9,301	3.2%	3,821	5,480	284,834	15,440	5.4%	7,528	7,912
Oct	376,496	367,722	8,774	2.4%	4,762	4,012	362,059	14,438	4.0%	9,435	5,003
Peak	4,899,527	4,903,238	-3,712	-0.1%	63,326	-67,038	4,895,842	3,685	0.1%	140,200	-136,515
Off-Peak	2,020,593	1,956,231	64,361	3.3%	25,385	38,976	1,950,100	70,492	3.6%	55,112	15,380
Annual	6,920,119	6,859,469	60,650	0.9%	88,802	-28,152	6,845,942	74,177	1.1%	194,757	-120,580

Note 1 Company Forecast
Note 2 Pages 2 - 4; Sum of Column 2 of Billed Deliveries table. Actual Data is weather normalized.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Pages 2 - 4; Sum of Column 7 of Billed Deliveries Table. Actual Data provided is weather normalized.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	28,386	28,021	365	1.3%	27,083	1,303	4.8%
Dec	28,522	28,157	365	1.3%	27,874	648	2.3%
Jan	28,586	28,223	363	1.3%	27,921	665	2.4%
Feb	28,613	28,248	365	1.3%	27,960	653	2.3%
Mar	28,606	28,241	365	1.3%	27,914	692	2.5%
Apr	28,675	28,311	364	1.3%	27,863	812	2.9%
May	28,722	28,358	364	1.3%	27,870	852	3.1%
Jun	28,693	28,332	361	1.3%	27,754	939	3.4%
Jul	28,593	28,224	370	1.3%	27,858	735	2.6%
Aug	28,543	28,174	370	1.3%	27,811	732	2.6%
Sep	28,523	28,154	370	1.3%	27,789	734	2.6%
Oct	28,917	28,548	370	1.3%	28,183	734	2.6%
Peak	28,564	28,200	364	1.3%	27,769	795	2.9%
Off-Peak	28,665	28,298	367	1.3%	27,878	788	2.8%
Annual	28,615	28,249	366	1.3%	27,823	792	2.8%

Note 1 Company Forecast
Note 2 Actual Data. Page 2 - 4; Sum of Column 2 of Meter Counts table.
Note 3 Actual Data. Page 2 - 4; Sum of Column 5 of Meter Counts table.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	19.11	18.76	0.35	1.9%	20.29	-1.17	-5.8%
Dec	27.01	27.91	-0.90	-3.2%	28.41	-1.41	-5.0%
Jan	35.52	37.24	-1.72	-4.6%	35.47	0.06	0.2%
Feb	35.49	34.52	0.98	2.8%	35.45	0.04	0.1%
Mar	30.70	30.76	-0.07	-0.2%	32.03	-1.34	-4.2%
Apr	23.64	24.62	-0.98	-4.0%	24.37	-0.73	-3.0%
May	14.94	14.81	0.14	0.9%	15.70	-0.76	-4.8%
Jun	12.17	11.74	0.42	3.6%	11.43	0.74	6.5%
Jul	9.94	9.72	0.22	2.3%	10.03	-0.09	-0.8%
Aug	9.85	9.60	0.25	2.6%	9.67	0.18	1.8%
Sep	10.53	10.34	0.19	1.9%	10.25	0.28	2.7%
Oct	13.02	12.88	0.14	1.1%	12.85	0.17	1.3%
Peak	171.53	173.87	-2.35	-1.3%	176.30	-4.55	-2.6%
Off-Peak	70.49	69.13	1.36	2.0%	69.95	0.52	0.7%
Annual	241.84	242.82	-0.98	-0.4%	246.05	-4.03	-1.6%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Residential Non-Heat Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	2,705	2,628	77	2.9%	-61	138	2,542	163	6.4%	-47	210
Dec	3,059	3,144	-84	-2.7%	-73	-11	3,151	-92	-2.9%	-107	15
Jan	4,452	4,882	-430	-8.8%	-114	-317	4,430	21	0.5%	-135	156
Feb	4,551	4,423	128	2.9%	-103	231	3,922	629	16.0%	-110	739
Mar	3,918	3,888	30	0.8%	-91	120	3,543	375	10.6%	-91	466
Apr	3,379	3,566	-187	-5.2%	-81	-105	3,029	350	11.6%	-53	403
May	2,490	2,558	-68	-2.7%	-58	-11	2,562	-72	-2.8%	-40	-33
Jun	2,126	2,076	50	2.4%	-46	96	2,457	-332	-13.5%	-9	-323
Jul	1,352	1,384	-32	-2.3%	-32	0	1,507	-155	-10.3%	-68	-87
Aug	1,786	1,827	-42	-2.3%	-42	0	1,801	-16	-0.9%	-82	66
Sep	1,634	1,672	-38	-2.3%	-39	1	1,695	-61	-3.6%	-77	16
Oct	1,881	1,926	-44	-2.3%	-45	0	1,963	-82	-4.2%	-89	7
Peak	22,065	22,531	-466	-2.1%	-522	56	20,618	1,447	7.0%	-529	1,976
Off-Peak	11,269	11,443	-175	-1.5%	-262	88	11,986	-718	-6.0%	-401	-317
Annual	33,334	33,974	-641	-1.9%	-783	143	32,604	729	2.2%	-964	1,694

Note 1 Company Forecast
Note 2 Actual, weather normalized data.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1,601	1,639	-38	-2.3%	1,631	-30	-1.8%
Dec	1,597	1,635	-38	-2.3%	1,653	-56	-3.4%
Jan	1,593	1,631	-38	-2.3%	1,643	-50	-3.0%
Feb	1,594	1,632	-38	-2.3%	1,640	-46	-2.8%
Mar	1,591	1,629	-38	-2.3%	1,633	-42	-2.6%
Apr	1,624	1,662	-38	-2.3%	1,653	-29	-1.8%
May	1,648	1,686	-38	-2.3%	1,674	-26	-1.6%
Jun	1,661	1,699	-38	-2.2%	1,667	-6	-0.4%
Jul	1,605	1,643	-38	-2.3%	1,681	-76	-4.5%
Aug	1,601	1,639	-38	-2.3%	1,677	-76	-4.5%
Sep	1,587	1,625	-38	-2.3%	1,663	-76	-4.6%
Oct	1,600	1,638	-38	-2.3%	1,676	-76	-4.5%
Peak	1,600	1,638	-38	-2.3%	1,642	-42	-2.6%
Off-Peak	1,617	1,655	-38	-2.3%	1,673	-56	-3.3%
Annual	1,609	1,647	-38	-2.3%	1,658	-49	-3.0%

Note 1 Company Forecast
Note 2 Actual Data.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1.69	1.60	0.09	5.4%	1.56	0.13	8.4%
Dec	1.92	1.92	-0.01	-0.4%	1.91	0.01	0.5%
Jan	2.79	2.99	-0.20	-6.6%	2.70	0.10	3.6%
Feb	2.86	2.71	0.14	5.4%	2.39	0.46	19.4%
Mar	2.46	2.39	0.08	3.2%	2.17	0.29	13.5%
Apr	2.08	2.15	-0.06	-3.0%	1.83	0.25	13.5%
May	1.51	1.52	-0.01	-0.4%	1.53	-0.02	-1.3%
Jun	1.28	1.22	0.06	4.7%	1.47	-0.19	-13.2%
Jul	0.84	0.84	0.00	0.0%	0.90	-0.05	-6.0%
Aug	1.12	1.11	0.00	0.0%	1.07	0.04	3.8%
Sep	1.03	1.03	0.00	0.1%	1.02	0.01	1.0%
Oct	1.18	1.18	0.00	0.0%	1.17	0.00	0.4%
Peak	13.79	13.76	0.04	0.3%	12.56	1.24	9.9%
Off-Peak	6.97	6.91	0.05	0.8%	7.16	-0.21	-3.0%
Annual	20.72	20.63	0.09	0.4%	19.67	1.03	5.2%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Residential Heat Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	120,827	112,682	8,145	7.2%	2,008	6,137	106,140	14,687	13.8%	5,768	8,919
Dec	170,645	171,593	-948	-0.6%	3,043	-3,991	181,356	-10,711	-5.9%	5,846	-16,557
Jan	282,229	293,494	-11,265	-3.8%	5,190	-16,455	285,999	-3,770	-1.3%	9,487	-13,256
Feb	289,307	271,764	17,544	6.5%	4,800	12,743	284,338	4,969	1.7%	9,201	-4,231
Mar	240,535	233,252	7,283	3.1%	4,119	3,164	242,924	-2,389	-1.0%	7,858	-10,247
Apr	182,901	191,201	-8,300	-4.3%	3,367	-11,666	169,833	13,068	7.7%	6,647	6,421
May	94,928	94,707	222	0.2%	1,664	-1,443	106,345	-11,416	-10.7%	4,364	-15,780
Jun	59,856	57,139	2,718	4.8%	1,005	1,713	37,302	22,554	60.5%	1,661	20,893
Jul	44,063	43,285	778	1.8%	765	13	44,040	23	0.1%	1,584	-1,561
Aug	34,745	34,139	605	1.8%	604	2	32,461	2,284	7.0%	1,169	1,115
Sep	33,080	32,504	576	1.8%	574	2	31,489	1,591	5.1%	1,132	459
Oct	44,397	43,637	760	1.7%	761	0	41,685	2,712	6.5%	1,479	1,233
Peak	1,286,445	1,273,986	12,459	1.0%	22,543	-10,084	1,270,590	15,855	1.2%	47,245	-31,390
Off-Peak	311,069	305,411	5,659	1.9%	5,375	284	293,321	17,748	6.1%	11,191	6,557
Annual	1,597,515	1,579,397	18,118	1.1%	27,872	-9,754	1,563,912	33,603	2.1%	58,911	-25,309

Note 1 Company Forecast
Note 2 Actual, weather normalized data.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	20,481	20,122	359	1.8%	19,425	1,056	5.4%
Dec	20,581	20,222	359	1.8%	19,938	643	3.2%
Jan	20,640	20,281	359	1.8%	19,977	663	3.3%
Feb	20,663	20,304	359	1.8%	20,015	648	3.2%
Mar	20,670	20,311	359	1.8%	20,022	648	3.2%
Apr	20,728	20,369	359	1.8%	19,947	781	3.9%
May	20,768	20,409	359	1.8%	19,949	819	4.1%
Jun	20,749	20,390	359	1.8%	19,864	885	4.5%
Jul	20,661	20,303	359	1.8%	19,944	717	3.6%
Aug	20,641	20,283	359	1.8%	19,924	717	3.6%
Sep	20,670	20,312	359	1.8%	19,953	717	3.6%
Oct	20,930	20,572	359	1.7%	20,213	717	3.5%
Peak	20,627	20,268	359	1.8%	19,887	739	3.7%
Off-Peak	20,737	20,378	359	1.8%	19,975	762	3.8%
Annual	20,682	20,323	359	1.8%	19,931	751	3.8%

Note 1 Company Forecast
Note 2 Actual Data.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	5.90	5.60	0.30	5.4%	5.46	0.44	8.0%
Dec	8.29	8.49	-0.19	-2.3%	9.10	-0.80	-8.8%
Jan	13.67	14.47	-0.80	-5.5%	14.32	-0.64	-4.5%
Feb	14.00	13.38	0.62	4.6%	14.21	-0.20	-1.4%
Mar	11.64	11.48	0.15	1.3%	12.13	-0.50	-4.1%
Apr	8.82	9.39	-0.56	-6.0%	8.51	0.31	3.6%
May	4.57	4.64	-0.07	-1.5%	5.33	-0.76	-14.3%
Jun	2.88	2.80	0.08	2.9%	1.88	1.01	53.6%
Jul	2.13	2.13	0.00	0.0%	2.21	-0.08	-3.4%
Aug	1.68	1.68	0.00	0.0%	1.63	0.05	3.3%
Sep	1.60	1.60	0.00	0.0%	1.58	0.02	1.4%
Oct	2.12	2.12	0.00	0.0%	2.06	0.06	2.9%
Peak	62.37	62.86	-0.49	-0.8%	63.89	-1.40	-2.2%
Off-Peak	15.00	14.99	0.01	0.1%	14.68	0.31	2.1%
Annual	77.24	77.71	-0.47	-0.6%	78.47	-1.10	-1.4%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Metered Distribution Deliveries and Meter Counts

	Total Division C&I Metered Deliveries (Dth)										
	2010-2011	2010-2011 Compared to 2009-2010					2010-2011 Compared to 2008-2009				
	Forecast	2009-2010 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2008-2009 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	419,004	410,467	8,537	2.1%	2,887	5,650	440,768	-21,764	-4.9%	20,259	-42,024
Dec	596,555	611,015	-14,460	-2.4%	4,270	-18,730	607,499	-10,945	-1.8%	5,901	-16,845
Jan	728,738	752,564	-23,827	-3.2%	5,011	-28,838	699,807	28,931	4.1%	5,778	23,153
Feb	721,642	698,796	22,846	3.3%	4,874	17,972	702,827	18,815	2.7%	5,688	13,127
Mar	633,603	631,636	1,967	0.3%	4,413	-2,447	647,641	-14,038	-2.2%	8,901	-22,940
Apr	491,476	502,243	-10,767	-2.1%	3,441	-14,208	506,092	-14,616	-2.9%	4,850	-19,466
May	331,816	322,703	9,114	2.8%	2,217	6,897	328,748	3,068	0.9%	3,106	-38
Jun	287,161	273,541	13,620	5.0%	1,754	11,867	277,477	9,684	3.5%	2,676	7,008
Jul	238,862	229,736	9,126	4.0%	1,794	7,332	233,789	5,073	2.2%	3,528	1,546
Aug	244,636	234,440	10,196	4.3%	1,838	8,358	234,718	9,919	4.2%	3,441	6,477
Sep	265,561	256,798	8,763	3.4%	2,025	6,738	251,650	13,910	5.5%	3,793	10,117
Oct	330,218	322,160	8,058	2.5%	2,492	5,566	318,411	11,807	3.7%	4,707	7,100
Peak	3,591,017	3,606,721	-15,705	-0.4%	24,942	-40,647	3,604,634	-13,617	-0.4%	56,533	-70,150
Off-Peak	1,698,255	1,639,377	58,877	3.6%	12,174	46,703	1,644,792	53,462	3.3%	21,572	31,890
Annual	5,289,271	5,246,098	43,173	0.8%	37,615	5,557	5,249,426	39,845	0.8%	75,594	-35,749

Note 1 Company Forecast
Note 2 Actual, weather normalized data.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	6,304	6,260	44	0.7%	6,027	277	4.6%
Dec	6,344	6,300	44	0.7%	6,283	61	1.0%
Jan	6,353	6,311	42	0.7%	6,301	52	0.8%
Feb	6,356	6,312	44	0.7%	6,305	51	0.8%
Mar	6,345	6,301	44	0.7%	6,259	86	1.4%
Apr	6,323	6,280	43	0.7%	6,263	60	1.0%
May	6,306	6,263	43	0.7%	6,247	59	0.9%
Jun	6,283	6,243	40	0.6%	6,223	60	1.0%
Jul	6,327	6,278	49	0.8%	6,233	94	1.5%
Aug	6,301	6,252	49	0.8%	6,210	91	1.5%
Sep	6,266	6,217	49	0.8%	6,173	93	1.5%
Oct	6,387	6,338	49	0.8%	6,294	93	1.5%
Peak	6,338	6,294	44	0.7%	6,240	98	1.6%
Off-Peak	6,312	6,265	47	0.7%	6,230	82	1.3%
Annual	6,325	6,280	45	0.7%	6,235	90	1.4%

Note 1 Company Forecast
Note 2 Actual Data.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2010-2011	Compared to 2009-2010			Compared to 2008-2009		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	66.47	65.57	0.90	1.4%	73.13	-6.67	-9.1%
Dec	94.03	96.99	-2.95	-3.0%	96.69	-2.66	-2.7%
Jan	114.71	119.25	-4.54	-3.8%	111.06	3.64	3.3%
Feb	113.54	110.71	2.83	2.6%	111.47	2.07	1.9%
Mar	99.86	100.24	-0.39	-0.4%	103.47	-3.62	-3.5%
Apr	77.73	79.98	-2.25	-2.8%	80.81	-3.08	-3.8%
May	52.62	51.53	1.09	2.1%	52.62	-0.01	0.0%
Jun	45.70	43.82	1.89	4.3%	44.59	1.12	2.5%
Jul	37.75	36.59	1.16	3.2%	37.51	0.24	0.7%
Aug	38.82	37.50	1.33	3.5%	37.80	1.03	2.7%
Sep	42.38	41.31	1.08	2.6%	40.77	1.61	4.0%
Oct	51.70	50.83	0.87	1.7%	50.59	1.11	2.2%
Peak	566.63	573.04	-6.41	-1.1%	577.70	-10.31	-1.8%
Off-Peak	269.06	261.66	7.40	2.8%	264.01	5.11	1.9%
Annual	836.30	835.42	0.88	0.1%	841.95	-5.20	-0.6%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Calendar Month Sales Service Usage (Dth)
(Total Forecast Deliveries times Sales Service Percentage)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-10	2,837	138,612	54,964	12,601	62,925	21,638	10,306	829	0	304,710
Dec-10	3,369	202,854	95,424	16,023	112,781	25,394	15,328	1,078	0	472,252
Jan-11	4,556	294,079	155,517	18,534	122,175	26,853	15,139	1,170	0	638,023
Feb-11	4,090	248,385	133,842	16,802	103,070	22,959	12,788	1,061	0	542,998
Mar-11	4,060	246,248	118,695	16,995	103,582	24,927	10,221	1,024	0	525,753
Apr-11	3,070	151,365	67,002	12,989	59,480	18,451	5,908	895	0	319,160
May-11	2,348	76,297	26,657	13,117	25,507	16,654	1,449	2,491	0	164,519
Jun-11	1,950	43,422	12,120	11,436	17,546	14,630	1,275	2,289	0	104,668
Jul-11	1,352	42,206	4,523	9,443	8,839	12,845	1,175	2,189	0	82,572
Aug-11	1,802	36,657	8,701	13,005	15,312	16,055	1,136	2,175	0	94,844
Sep-11	1,716	45,020	11,800	12,499	22,054	16,041	2,256	2,301	0	113,688
Oct-11	2,151	72,546	23,568	13,100	41,768	20,421	3,500	2,719	0	179,773
Nov-11	2,770	141,044	55,567	12,364	64,850	21,570	9,750	924	0	308,838
Dec-11	3,295	206,394	96,463	15,720	116,207	25,315	14,376	1,180	0	478,951
Jan-12	4,581	302,685	166,543	18,761	125,096	26,853	15,875	1,417	0	661,812
Feb-12	4,259	264,966	148,732	17,614	109,478	23,779	12,917	1,331	0	583,076
Mar-12	4,084	254,019	128,606	17,223	106,493	24,927	10,010	1,267	0	546,629
Apr-12	3,093	157,228	75,115	13,214	62,291	18,451	6,285	1,093	0	336,770
Peak	21,981	1,281,543	625,444	93,945	564,013	140,222	69,689	6,058	0	2,802,895
Off-Peak	11,319	316,150	87,368	72,599	131,026	96,646	10,791	14,164	0	740,064
Annual	33,301	1,597,692	712,812	166,544	695,040	236,869	80,481	20,222	0	3,542,959

Forecast Calendar Month Distribution Service Usage (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-10	2,837	138,612	62,459	17,221	104,182	36,010	50,052	94,648	80,622	586,642
Dec-10	3,369	202,854	108,436	21,897	186,726	42,262	74,447	123,115	88,545	851,652
Jan-11	4,556	294,079	176,724	25,329	202,280	44,690	73,526	133,586	90,265	1,045,034
Feb-11	4,090	248,385	152,093	22,962	170,648	38,210	62,111	121,206	92,758	912,462
Mar-11	4,060	246,248	134,880	23,226	171,496	41,485	49,641	116,996	104,626	892,658
Apr-11	3,070	151,365	76,139	17,750	98,478	30,707	28,693	102,228	90,932	599,363
May-11	2,348	76,297	33,415	15,596	43,149	26,645	15,975	88,645	81,151	383,221
Jun-11	1,950	43,422	15,192	13,597	29,683	23,406	14,061	81,464	85,379	308,155
Jul-11	1,352	42,206	5,670	11,228	14,953	20,550	12,963	77,893	92,725	279,541
Aug-11	1,802	36,657	10,907	15,463	25,904	25,687	12,526	77,402	79,567	285,914
Sep-11	1,716	45,020	14,791	14,862	37,309	25,665	24,884	81,873	83,308	329,429
Oct-11	2,151	72,546	29,543	15,576	70,659	32,671	38,595	96,774	88,790	447,305
Nov-11	2,770	141,044	63,144	16,896	107,369	35,898	47,352	105,507	80,622	600,602
Dec-11	3,295	206,394	109,617	21,483	192,398	42,131	69,824	134,798	88,545	868,484
Jan-12	4,581	302,685	189,253	25,638	207,115	44,690	77,104	161,856	90,265	1,103,189
Feb-12	4,259	264,966	169,013	24,071	181,258	39,574	62,734	152,002	92,758	990,635
Mar-12	4,084	254,019	146,143	23,537	176,315	41,485	48,618	144,652	104,626	943,479
Apr-12	3,093	157,228	85,358	18,059	103,133	30,707	30,523	124,799	90,932	643,831
Peak	21,981	1,281,543	710,730	128,384	933,810	233,365	338,471	691,779	547,748	4,887,810
Off-Peak	11,319	316,150	109,518	86,321	221,657	154,624	119,005	504,051	510,920	2,033,565
Annual	33,301	1,597,693	820,248	214,705	1,155,466	387,989	457,476	1,195,830	1,058,667	6,921,375

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-10	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	51.9%
Dec-10	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	55.5%
Jan-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	61.1%
Feb-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	59.5%
Mar-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	58.9%
Apr-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	53.2%
May-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	42.9%
Jun-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	34.0%
Jul-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	29.5%
Aug-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	33.2%
Sep-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	34.5%
Oct-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	40.2%

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Billed Sales Service Usage (Dth)
(Forecast Billed Distribution Usage times Sales Service Percentage)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-10	2,705	120,827	48,573	12,053	53,061	20,528	10,306	829	0	268,881
Dec-10	3,059	170,645	83,329	14,680	95,211	22,868	15,328	1,078	0	406,199
Jan-11	4,452	282,229	151,198	18,093	115,709	25,985	15,139	1,170	0	613,974
Feb-11	4,551	289,307	151,073	18,728	123,618	26,218	12,788	1,061	0	627,345
Mar-11	3,918	240,535	115,202	16,405	101,938	24,177	10,221	1,024	0	513,420
Apr-11	3,379	182,901	78,520	14,312	76,152	20,883	5,908	895	0	382,950
May-11	2,490	94,928	32,612	13,797	35,544	17,895	1,449	2,491	0	201,206
Jun-11	2,126	59,856	17,365	12,329	26,096	16,054	1,275	2,289	0	137,389
Jul-11	1,352	44,063	5,274	9,406	10,026	12,828	1,175	2,189	0	86,314
Aug-11	1,786	34,745	8,082	12,918	14,302	15,911	1,136	2,175	0	91,055
Sep-11	1,634	33,080	7,909	12,148	15,703	15,359	2,256	2,301	0	90,390
Oct-11	1,881	44,397	14,423	11,701	26,684	18,080	3,500	2,719	0	123,386
Nov-11	2,641	122,948	49,106	11,826	54,684	20,464	9,750	924	0	272,343
Dec-11	2,992	173,624	84,236	14,403	98,103	22,798	14,376	1,180	0	411,711
Jan-12	4,477	290,579	162,094	18,319	118,630	25,985	15,875	1,417	0	637,377
Feb-12	4,653	302,793	164,399	19,264	128,534	26,662	12,690	1,317	0	660,313
Mar-12	4,008	252,268	126,814	16,904	106,482	24,586	10,172	1,278	0	542,513
Apr-12	3,403	189,485	87,084	14,542	79,010	20,883	6,287	1,096	0	401,791
Peak	22,065	1,286,445	627,894	94,271	565,688	140,659	69,689	6,058	0	2,812,769
Off-Peak	11,269	311,069	85,665	72,299	128,354	96,128	10,791	14,164	0	729,739
Annual	33,334	1,597,514	713,559	166,570	694,042	236,787	80,481	20,222	0	3,542,509

Forecast Billed Distribution Service Usage (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-10	2,705	120,827	55,197	16,471	87,850	34,164	50,052	94,648	80,622	542,536
Dec-10	3,059	170,645	94,691	20,061	157,636	38,059	74,447	123,115	88,545	770,259
Jan-11	4,452	282,229	171,816	24,725	191,574	43,246	73,526	133,586	90,265	1,015,419
Feb-11	4,551	289,307	171,674	25,593	204,668	43,633	62,111	121,206	92,758	1,015,501
Mar-11	3,918	240,535	130,911	22,419	168,774	40,236	49,641	116,996	104,626	878,056
Apr-11	3,379	182,901	89,227	19,559	126,081	34,755	28,693	102,228	90,932	677,756
May-11	2,490	94,928	40,880	16,405	60,129	28,631	15,975	88,645	81,151	429,234
Jun-11	2,126	59,856	21,767	14,659	44,146	25,685	14,061	81,464	85,379	349,143
Jul-11	1,352	44,063	6,611	11,184	16,961	20,524	12,963	77,893	92,725	284,277
Aug-11	1,786	34,745	10,131	15,360	24,194	25,456	12,526	77,402	79,567	281,167
Sep-11	1,634	33,080	9,914	14,444	26,564	24,573	24,884	81,873	83,308	300,274
Oct-11	1,881	44,397	18,080	13,912	45,141	28,926	38,595	96,774	88,790	376,496
Nov-11	2,641	122,948	55,802	16,161	90,538	34,058	47,352	105,507	80,622	555,629
Dec-11	2,992	173,624	95,722	19,683	162,424	37,941	69,824	134,798	88,545	785,553
Jan-12	4,477	290,579	184,198	25,035	196,409	43,246	77,104	161,856	90,265	1,073,170
Feb-12	4,653	302,793	186,817	26,326	212,808	44,372	61,634	150,395	92,758	1,082,557
Mar-12	4,008	252,268	144,107	23,101	176,297	40,918	49,406	145,956	104,626	940,687
Apr-12	3,403	189,485	98,959	19,873	130,814	34,755	30,535	125,175	90,932	723,931
Peak	22,065	1,286,445	713,515	128,830	936,582	234,092	338,471	691,779	547,748	4,899,527
Off-Peak	11,269	311,069	107,383	85,965	217,136	153,795	119,005	504,051	510,920	2,020,593
Annual	33,334	1,597,515	820,898	214,795	1,153,719	387,887	457,476	1,195,830	1,058,667	6,920,119

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-10	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	49.6%
Dec-10	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	52.7%
Jan-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	60.5%
Feb-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	61.8%
Mar-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	58.5%
Apr-11	100.0%	100.0%	88.0%	73.2%	60.4%	60.1%	20.6%	0.9%	0.0%	56.5%
May-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	46.9%
Jun-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	39.4%
Jul-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	30.4%
Aug-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	32.4%
Sep-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	30.1%
Oct-11	100.0%	100.0%	79.8%	84.1%	59.1%	62.5%	9.1%	2.8%	0.0%	32.8%

Northern Utilities, Inc.
New Hampshire Division
Estimation of Northern City-Gate Receipts Required to Meet Sales Service Deliveries Forecast

Month	Calendar Month Distribution Service Usage (Dth)	Estimated Company Use Factor	Estimated Company Use (Dth)	Billed Sales Service Deliveries (Dth)	Unbilled Sales Service Deliveries (Dth)	Calendar Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Lost and Unaccounted For (Percent)	Lost and Unaccounted For (Dth)	Estimated Division City-Gate Receipts (Dth)
Nov-10	586,642	0.07%	413	268,881	35,829	304,710	305,123	2.22%	6,928	312,051
Dec-10	851,652	0.11%	933	406,199	66,053	472,252	473,184	2.22%	10,744	483,928
Jan-11	1,045,034	0.03%	263	613,974	24,049	638,023	638,286	2.22%	14,492	652,778
Feb-11	912,462	0.02%	197	627,345	-84,347	542,998	543,194	2.22%	12,333	555,527
Mar-11	892,658	0.03%	239	513,420	12,333	525,753	525,992	2.22%	11,942	537,934
Apr-11	599,363	0.02%	131	382,950	-63,791	319,160	319,291	2.22%	7,249	326,540
May-11	383,221	0.02%	59	201,206	-36,687	164,519	164,577	2.22%	3,737	168,314
Jun-11	308,155	0.07%	208	137,389	-32,722	104,668	104,876	2.22%	2,382	107,258
Jul-11	279,541	0.04%	112	86,314	-3,742	82,572	82,684	2.22%	1,878	84,562
Aug-11	285,914	0.08%	227	91,055	3,789	94,844	95,071	2.22%	2,159	97,230
Sep-11	329,429	0.09%	296	90,390	23,299	113,688	113,985	2.22%	2,587	116,572
Oct-11	447,305	0.06%	264	123,386	56,388	179,773	180,038	2.22%	4,087	184,125
Peak	4,887,810	0.04%	2,175	2,812,769	-9,874	2,802,895	2,805,070	2.22%	63,688	2,868,758
Off-Peak	2,033,565	0.06%	1,167	729,739	10,325	740,064	741,231	2.22%	16,830	758,061
Annual	6,921,375	0.05%	3,343	3,542,509	450	3,542,959	3,546,302	2.22%	80,517	3,626,819

M **Northern Utilities - MAINE DIVISION**

M **Allocation of Commodity Costs to Customer Classes**

M

N **Northern Utilities - NEW HAMPSHIRE DIVISION**

N **Allocation of Commodity Costs to Customer Classes**

N

N **Base Commodity Costs**

N	1	**BASE SENDOUT BY CLASS**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**TOTAL**	**WINTER**
N	2	**Total Therms**								
N	3	Res Heat	390,983	404,016	404,016	364,917	404,016	390,983	4,728,740	2,358,930
N	4	Res General	15,639	16,160	16,160	14,597	16,160	15,639	187,959	94,356
N	5	G50 Low Annual-Low Winter	111,303	115,013	115,013	103,882	115,013	111,303	1,335,873	671,525
N	6	G40 Low Annual-High Winter	65,573	67,759	67,759	61,201	67,759	65,573	776,363	395,622
N	7	G51 Med Annual-Low Winter	143,292	148,068	148,068	133,739	148,068	143,292	1,726,857	864,526
N	8	G41 Med Annual-High Winter	119,756	123,747	123,747	111,772	123,747	119,756	1,423,799	722,525
N	9	G52 High Annual-Low Winter	8,488	11,047	11,968	10,859	10,482	9,159	194,639	62,003
N	10	G42 High Annual-High Winter	11,459	11,841	11,841	10,695	11,841	11,459	139,220	69,136
N	11	Total Firm Sales	866,491	897,651	898,572	811,662	897,086	867,162	10,513,451	5,238,625
N	12	**% of Total**								
N	13	Res Heat	45.12%	45.01%	44.96%	44.96%	45.04%	45.09%		
N	14	Res General	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%		
N	15	G50 Low Annual-Low Winter	12.85%	12.81%	12.80%	12.80%	12.82%	12.84%		
N	16	G40 Low Annual-High Winter	7.57%	7.55%	7.54%	7.54%	7.55%	7.56%		
N	17	G51 Med Annual-Low Winter	16.54%	16.50%	16.48%	16.48%	16.51%	16.52%		
N	18	G41 Med Annual-High Winter	13.82%	13.79%	13.77%	13.77%	13.79%	13.81%		
N	19	G52 High Annual-Low Winter	0.98%	1.23%	1.33%	1.34%	1.17%	1.06%		
N	20	G42 High Annual-High Winter	1.32%	1.32%	1.32%	1.32%	1.32%	1.32%		
N	21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		
N										
N	22	**BASE COMMODITY COSTS Excld Hedging**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**TOTAL**	**WINTER**
N	23	TOTAL BASE COMMODITY Excld Hedging	$ 402,615	$ 448,307	$ 469,215	$ 425,755	$ 459,002	$ 418,489	$ 5,226,141	$ 2,623,383
N	24	Res Heat	$ 181,670	$ 201,774	$ 210,968	$ 191,416	$ 206,718	$ 188,687	$ 2,350,316	$ 1,181,234
N	25	Res General	$ 7,267	$ 8,071	$ 8,439	$ 7,657	$ 8,269	$ 7,547	$ 93,440	$ 47,249
N	26	G50 Low Annual-Low Winter	$ 51,717	$ 57,440	$ 60,057	$ 54,491	$ 58,847	$ 53,714	$ 664,119	$ 336,266
N	27	G40 Low Annual-High Winter	$ 30,468	$ 33,840	$ 35,382	$ 32,103	$ 34,669	$ 31,645	$ 386,060	$ 198,108
N	28	G51 Med Annual-Low Winter	$ 66,580	$ 73,948	$ 77,318	$ 70,152	$ 75,760	$ 69,152	$ 858,430	$ 432,911
N	29	G41 Med Annual-High Winter	$ 55,644	$ 61,802	$ 64,618	$ 58,630	$ 63,316	$ 57,794	$ 707,954	$ 361,804
N	30	G52 High Annual-Low Winter	$ 3,944	$ 5,517	$ 6,250	$ 5,696	$ 5,363	$ 4,420	$ 96,626	$ 31,190
N	31	G42 High Annual-High Winter	$ 5,324	$ 5,914	$ 6,183	$ 5,610	$ 6,059	$ 5,530	$ 69,196	$ 34,620
N	32									
N	33	Residential	$ 188,937	$ 209,845	$ 219,407	$ 199,073	$ 214,987	$ 196,234	$ 2,443,757	$ 1,228,483
N	34	SALES HLF CLASSES	$ 122,241	$ 136,906	$ 143,625	$ 130,339	$ 139,971	$ 127,286	$ 1,619,175	$ 800,368
N	35	SALES LLF CLASSES	$ 91,437	$ 101,556	$ 106,183	$ 96,343	$ 104,044	$ 94,969	$ 1,163,209	$ 594,532
N										
N	36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**								
N	37	TOTAL BASE HEDGING COMMODITY	$ 72,841	$ 142,684	$ 106,985	$ 143,041	$ 67,367	$ 54,475	$ 605,987	$ 587,394
N	38	Res Heat	$ 32,868	$ 64,219	$ 48,103	$ 64,310	$ 30,340	$ 24,561	$ 272,666	$ 264,401
N	39	Res General	$ 1,315	$ 2,569	$ 1,924	$ 2,572	$ 1,214	$ 982	$ 10,907	$ 10,576
N	40	G50 Low Annual-Low Winter	$ 9,357	$ 18,282	$ 13,694	$ 18,307	$ 8,637	$ 6,992	$ 77,621	$ 75,268
N	41	G40 Low Annual-High Winter	$ 5,512	$ 10,770	$ 8,067	$ 10,786	$ 5,088	$ 4,119	$ 45,729	$ 44,343
N	42	G51 Med Annual-Low Winter	$ 12,046	$ 23,536	$ 17,629	$ 23,569	$ 11,119	$ 9,002	$ 99,929	$ 96,901
N	43	G41 Med Annual-High Winter	$ 10,067	$ 19,670	$ 14,734	$ 19,698	$ 9,293	$ 7,523	$ 83,516	$ 80,984
N	44	G52 High Annual-Low Winter	$ 714	$ 1,756	$ 1,425	$ 1,914	$ 787	$ 575	$ 7,628	$ 7,171
N	45	G42 High Annual-High Winter	$ 963	$ 1,882	$ 1,410	$ 1,885	$ 889	$ 720	$ 7,991	$ 7,749
N	46									
N	47	Residential	$ 34,183	$ 66,788	$ 50,027	$ 66,882	$ 31,553	$ 25,544	$ 283,572	$ 274,977
N	48	SALES HLF CLASSES	$ 22,116	$ 43,573	$ 32,748	$ 43,790	$ 20,543	$ 16,569	$ 185,178	$ 179,339
N	49	SALES LLF CLASSES	$ 16,543	$ 32,323	$ 24,211	$ 32,368	$ 15,270	$ 12,362	$ 137,237	$ 133,077

Northern Utilities - MAINE DIVISION
Allocation of Commodity Costs to Customer Classes

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	
2	**Total Therms**	
3	Res Heat	Schedule 10B, LN 52
4	Res General	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	Schedule 10B, LN 58
10	G42 High Annual-High Winter	Schedule 10B, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12	**% of Total**	
13	Res Heat	LN 3 / LN 11
14	Res General	LN 4 / LN 11
15	G50 Low Annual-Low Winter	LN 5 / LN 11
16	G40 Low Annual-High Winter	LN 6 / LN 11
17	G51 Med Annual-Low Winter	LN 7 / LN 11
18	G41 Med Annual-High Winter	LN 8 / LN 11
19	G52 High Annual-Low Winter	LN 9 / LN 11
20	G42 High Annual-High Winter	LN 10 / LN 11
21	Total Firm Sales	LN 11 / LN 11

22	**BASE COMMODITY COSTS Excld Hedging**	
23	TOTAL BASE COMMODITY Excld Hedging	Schedule 1B, LN 37
24	Res Heat	LN 23 * LN 13
25	Res General	LN 23 * LN 14
26	G50 Low Annual-Low Winter	LN 23 * LN 15
27	G40 Low Annual-High Winter	LN 23 * LN 16
28	G51 Med Annual-Low Winter	LN 23 * LN 17
29	G41 Med Annual-High Winter	LN 23 * LN 18
30	G52 High Annual-Low Winter	LN 23 * LN 19
31	G42 High Annual-High Winter	LN 23 * LN 20
32		
33	Residential	LN 24 + LN 25
34	SALES HLF CLASSES	LN 26 + LN 28 + LN 30
35	SALES LLF CLASSES	LN 27 + LN 29 + LN 31

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	
37	TOTAL BASE HEDGING COMMODITY	Schedule 1B, LN 38
38	Res Heat	LN 13 * LN 37
39	Res General	LN 14 * LN 37
40	G50 Low Annual-Low Winter	LN 15 * LN 37
41	G40 Low Annual-High Winter	LN 16 * LN 37
42	G51 Med Annual-Low Winter	LN 17 * LN 37
43	G41 Med Annual-High Winter	LN 18 * LN 37
44	G52 High Annual-Low Winter	LN 19 * LN 37
45	G42 High Annual-High Winter	LN 20 * LN 37
46		
47	Residential	LN 38 + LN 39
48	SALES HLF CLASSES	LN 40 + LN 42 + LN 44
49	SALES LLF CLASSES	LN 41 + LN 43 + LN 45

M **Northern Utilities - MAINE DIVISION**

M **Allocation of Commodity Costs to Customer Classes**

M

N

N **Remaining Commodity Costs**

N	50	REMAINING SENDOUT BY CLASS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
N	51	Total Therms								
N	52	Res Heat	1,028,528	1,674,678	2,604,787	2,176,245	2,115,513	1,157,671	11,625,830	10,757,423
N	53	Res General	13,411	18,367	30,451	27,245	25,383	15,766	152,971	130,621
N	54	G50 Low Annual-Low Winter	17,744	49,177	74,615	68,018	58,880	21,589	369,413	290,022
N	55	G40 Low Annual-High Winter	497,305	910,077	1,523,378	1,308,102	1,146,689	619,942	6,519,560	6,005,493
N	56	G51 Med Annual-Low Winter	78,298	112,149	126,673	101,151	106,981	45,487	698,478	570,738
N	57	G41 Med Annual-High Winter	524,653	1,031,950	1,126,258	942,709	936,073	488,797	5,691,344	5,050,441
N	58	G52 High Annual-Low Winter	-	-	-	-	-	-	12,460	-
N	59	G42 High Annual-High Winter	94,079	145,231	143,047	120,139	92,735	48,985	684,682	644,217
N	60	Total Firm Sales	2,254,019	3,941,629	5,629,208	4,743,608	4,482,254	2,398,238	25,754,739	23,448,955
N	61	% of Total								
N	62	Res Heat	45.63%	42.49%	46.27%	45.88%	47.20%	48.27%		
N	63	Res General	0.59%	0.47%	0.54%	0.57%	0.57%	0.66%		
N	64	G50 Low Annual-Low Winter	0.79%	1.25%	1.33%	1.43%	1.31%	0.90%		
N	65	G40 Low Annual-High Winter	22.06%	23.09%	27.06%	27.58%	25.58%	25.85%		
N	66	G51 Med Annual-Low Winter	3.47%	2.85%	2.25%	2.13%	2.39%	1.90%		
N	67	G41 Med Annual-High Winter	23.28%	26.18%	20.01%	19.87%	20.88%	20.38%		
N	68	G52 High Annual-Low Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
N	69	G42 High Annual-High Winter	4.17%	3.68%	2.54%	2.53%	2.07%	2.04%		
N	70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		
N										
N	71	REMAINING COMMODITY COSTS EXCLD HEDGING	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
N	72	REMAINING COMMODITY Excld Hedging	$ 1,018,400	$ 1,721,760	$ 2,449,559	$ 2,055,564	$ 2,032,520	$ 1,146,625	$ 11,571,544	$ 10,424,427
N	73	Res Heat	$ 464,705	$ 731,523	$ 1,133,477	$ 943,040	$ 959,299	$ 553,496	$ 5,216,126	$ 4,785,540
N	74	Res General	$ 6,059	$ 8,023	$ 13,251	$ 11,806	$ 11,510	$ 7,538	$ 69,224	$ 58,187
N	75	G50 Low Annual-Low Winter	$ 8,017	$ 21,481	$ 32,469	$ 29,475	$ 26,700	$ 10,322	$ 167,947	$ 128,463
N	76	G40 Low Annual-High Winter	$ 224,690	$ 397,535	$ 662,900	$ 566,844	$ 519,977	$ 296,401	$ 2,922,863	$ 2,668,347
N	77	G51 Med Annual-Low Winter	$ 35,376	$ 48,988	$ 55,122	$ 43,832	$ 48,511	$ 21,748	$ 317,673	$ 253,577
N	78	G41 Med Annual-High Winter	$ 237,046	$ 450,770	$ 490,093	$ 408,507	$ 424,471	$ 233,700	$ 2,565,325	$ 2,244,588
N	79	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,213	$ -
N	80	G42 High Annual-High Winter	$ 42,506	$ 63,439	$ 62,247	$ 52,060	$ 42,052	$ 23,420	$ 306,173	$ 285,725
N	81									
N	82	Residential	$ 470,764	$ 739,546	$ 1,146,728	$ 954,846	$ 970,809	$ 561,034	$ 5,285,350	$ 4,843,727
N	83	SALES HLF CLASSES	$ 43,393	$ 70,469	$ 87,591	$ 73,307	$ 75,211	$ 32,070	$ 491,833	$ 382,040
N	84	SALES LLF CLASSES	$ 504,243	$ 911,744	$ 1,215,241	$ 1,027,412	$ 986,500	$ 553,521	$ 5,794,361	$ 5,198,660
N										
N	85	REMAINING COMMODITY HEDGING COSTS								
N	86	TOTAL REMAINING COMMODITY HEDGING	$ 148,273	$ 63,999	$ 18,519	$ 12,542	$ 83,669	$ 140,051	$ 483,848	$ 467,052
N	87	Res Heat	$ 67,658	$ 27,191	$ 8,569	$ 5,754	$ 39,489	$ 67,605	$ 223,637	$ 216,267
N	88	Res General	$ 882	$ 298	$ 100	$ 72	$ 474	$ 921	$ 2,893	$ 2,747
N	89	G50 Low Annual-Low Winter	$ 1,167	$ 798	$ 245	$ 180	$ 1,099	$ 1,261	$ 5,139	$ 4,751
N	90	G40 Low Annual-High Winter	$ 32,714	$ 14,777	$ 5,012	$ 3,459	$ 21,405	$ 36,203	$ 117,504	$ 113,568
N	91	G51 Med Annual-Low Winter	$ 5,151	$ 1,821	$ 417	$ 267	$ 1,997	$ 2,656	$ 13,032	$ 12,309
N	92	G41 Med Annual-High Winter	$ 34,513	$ 16,755	$ 3,705	$ 2,493	$ 17,473	$ 28,545	$ 107,430	$ 103,483
N	93	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 80	$ -
N	94	G42 High Annual-High Winter	$ 6,189	$ 2,358	$ 471	$ 318	$ 1,731	$ 2,861	$ 14,134	$ 13,927
N	95								$ -	$ -
N	96	Residential	$ 68,540	$ 27,489	$ 8,669	$ 5,826	$ 39,963	$ 68,526	$ 226,530	$ 219,014
N	97	SALES HLF CLASSES	$ 6,318	$ 2,619	$ 662	$ 447	$ 3,096	$ 3,917	$ 18,251	$ 17,060
N	98	SALES LLF CLASSES	$ 73,415	$ 33,890	$ 9,187	$ 6,269	$ 40,609	$ 67,608	$ 239,067	$ 230,978

Northern Utilities - MAINE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	
51	**Total Therms**	
52	Res Heat	Schedule 10B, LN 68
53	Res General	Schedule 10B, LN 69
54	G50 Low Annual-Low Winter	Schedule 10B, LN 70
55	G40 Low Annual-High Winter	Schedule 10B, LN 71
56	G51 Med Annual-Low Winter	Schedule 10B, LN 72
57	G41 Med Annual-High Winter	Schedule 10B, LN 73
58	G52 High Annual-Low Winter	Schedule 10B, LN 74
59	G42 High Annual-High Winter	Schedule 10B, LN 75
60	Total Firm Sales	Sum LN 52 : LN 59
61	**% of Total**	
62	Res Heat	LN 52 / LN 60
63	Res General	LN 53 / LN 60
64	G50 Low Annual-Low Winter	LN 54 / LN 60
65	G40 Low Annual-High Winter	LN 55 / LN 60
66	G51 Med Annual-Low Winter	LN 56 / LN 60
67	G41 Med Annual-High Winter	LN 57 / LN 60
68	G52 High Annual-Low Winter	LN 58 / LN 60
69	G42 High Annual-High Winter	LN 59 / LN 60
70	Total Firm Sales	LN 60 / LN 60

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	
72	REMAINING COMMODITY Excld Hedging	Schedule 1B, LN 39
73	Res Heat	LN 72 * LN 62
74	Res General	LN 72 * LN 63
75	G50 Low Annual-Low Winter	LN 72 * LN 64
76	G40 Low Annual-High Winter	LN 72 * LN 65
77	G51 Med Annual-Low Winter	LN 72 * LN 66
78	G41 Med Annual-High Winter	LN 72 * LN 67
79	G52 High Annual-Low Winter	LN 72 * LN 68
80	G42 High Annual-High Winter	LN 72 * LN 69
81		
82	Residential	LN 73 + LN 74
83	SALES HLF CLASSES	LN 75 + LN 77 + LN 79
84	SALES LLF CLASSES	LN 76 + LN 78 + LN 80

85	**REMAINING COMMODITY HEDGING COSTS**	
86	TOTAL REMAINING COMMODITY HEDGING	Schedule 1B, LN 40
87	Res Heat	LN 62 * LN 86
88	Res General	LN 63 * LN 86
89	G50 Low Annual-Low Winter	LN 64 * LN 86
90	G40 Low Annual-High Winter	LN 65 * LN 86
91	G51 Med Annual-Low Winter	LN 66 * LN 86
92	G41 Med Annual-High Winter	LN 67 * LN 86
93	G52 High Annual-Low Winter	LN 68 * LN 86
94	G42 High Annual-High Winter	LN 69 * LN 86
95		
96	Residential	LN 87 + LN 88
97	SALES HLF CLASSES	LN 89 + LN 91 + LN 93
98	SALES LLF CLASSES	LN 90 + LN 92 + LN 94

M **Northern Utilities - MAINE DIVISION**

M **Allocation of Commodity Costs to Customer Classes**

M

N

N **Total Commodity Costs**

N 99	**TOTAL COMMODITY COSTS Excluding Hedging**								
N 100	TOTAL COMMODITY Excld Hedging	$ 1,421,015	$ 2,170,067	$ 2,918,774	$ 2,481,319	$ 2,491,522	$ 1,565,114	$ 16,797,685	$ 13,047,810
N 101	Res Heat	$ 646,375	$ 933,298	$ 1,344,446	$ 1,134,456	$ 1,166,017	$ 742,183	$ 7,566,442	$ 5,966,774
N 102	Res General	$ 13,326	$ 16,094	$ 21,689	$ 19,463	$ 19,779	$ 15,085	$ 162,664	$ 105,435
N 103	G50 Low Annual-Low Winter	$ 59,734	$ 78,921	$ 92,526	$ 83,966	$ 85,547	$ 64,036	$ 832,067	$ 464,729
N 104	G40 Low Annual-High Winter	$ 255,158	$ 431,375	$ 698,282	$ 598,947	$ 554,646	$ 328,046	$ 3,308,923	$ 2,866,455
N 105	G51 Med Annual-Low Winter	$ 101,957	$ 122,937	$ 132,440	$ 113,984	$ 124,272	$ 90,900	$ 1,176,103	$ 686,489
N 106	G41 Med Annual-High Winter	$ 292,691	$ 512,572	$ 554,711	$ 467,137	$ 487,788	$ 291,493	$ 3,273,279	$ 2,606,392
N 107	G52 High Annual-Low Winter	$ 3,944	$ 5,517	$ 6,250	$ 5,696	$ 5,363	$ 4,420	$ 102,839	$ 31,190
N 108	G42 High Annual-High Winter	$ 47,831	$ 69,353	$ 68,430	$ 57,670	$ 48,110	$ 28,951	$ 375,369	$ 320,345
N 109									
N 110	Residential	$ 659,701	$ 949,391	$ 1,366,135	$ 1,153,919	$ 1,185,796	$ 757,268	$ 7,729,106	$ 6,072,210
N 111	SALES HLF CLASSES	$ 165,634	$ 207,375	$ 231,215	$ 203,646	$ 215,182	$ 159,356	$ 2,111,009	$ 1,182,408
N 112	SALES LLF CLASSES	$ 595,680	$ 1,013,300	$ 1,321,424	$ 1,123,754	$ 1,090,544	$ 648,490	$ 6,957,570	$ 5,793,192
N									
N 113	**TOTAL HEDGING COMMODITY COSTS**								
N 114	TOTAL HEDGING COMMODITY	$ 221,115	$ 206,683	$ 125,504	$ 155,583	$ 151,036	$ 194,526	$ 1,089,835	$ 1,054,446
N 115	Res Heat	$ 100,526	$ 91,410	$ 56,672	$ 70,064	$ 69,829	$ 92,167	$ 496,303	$ 480,668
N 116	Res General	$ 2,197	$ 2,867	$ 2,024	$ 2,644	$ 1,687	$ 1,903	$ 13,799	$ 13,323
N 117	G50 Low Annual-Low Winter	$ 10,524	$ 19,080	$ 13,939	$ 18,487	$ 9,736	$ 8,253	$ 82,760	$ 80,019
N 118	G40 Low Annual-High Winter	$ 38,226	$ 25,547	$ 13,079	$ 14,244	$ 26,493	$ 40,322	$ 163,233	$ 157,912
N 119	G51 Med Annual-Low Winter	$ 17,196	$ 25,357	$ 18,046	$ 23,837	$ 13,116	$ 11,658	$ 112,961	$ 109,210
N 120	G41 Med Annual-High Winter	$ 44,580	$ 36,425	$ 18,439	$ 22,190	$ 26,766	$ 36,068	$ 190,945	$ 184,468
N 121	G52 High Annual-Low Winter	$ 714	$ 1,756	$ 1,425	$ 1,914	$ 787	$ 575	$ 7,708	$ 7,171
N 122	G42 High Annual-High Winter	$ 7,152	$ 4,240	$ 1,880	$ 2,202	$ 2,620	$ 3,580	$ 22,125	$ 21,676
N 123									
N 124	Residential	$ 102,723	$ 94,277	$ 58,696	$ 72,709	$ 71,517	$ 94,070	$ 510,102	$ 493,991
N 125	SALES HLF CLASSES	$ 28,434	$ 46,193	$ 33,410	$ 44,237	$ 23,639	$ 20,486	$ 203,429	$ 196,399
N 126	SALES LLF CLASSES	$ 89,958	$ 66,212	$ 33,398	$ 38,637	$ 55,880	$ 79,970	$ 376,304	$ 364,055
N									
N 127	TOTAL COMMODITY	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	TOTAL	WINTER
N 128	Res Heat	$ 746,901	$ 1,024,708	$ 1,401,117	$ 1,204,520	$ 1,235,846	$ 834,350	$ 8,062,745	$ 6,447,443
N 129	Res General	$ 15,523	$ 18,961	$ 23,714	$ 22,107	$ 21,466	$ 16,988	$ 176,463	$ 118,759
N 130	G50 Low Annual-Low Winter	$ 70,257	$ 98,001	$ 106,465	$ 102,453	$ 95,283	$ 72,289	$ 914,827	$ 544,748
N 131	G40 Low Annual-High Winter	$ 293,384	$ 456,922	$ 711,361	$ 613,191	$ 581,139	$ 368,369	$ 3,472,156	$ 3,024,367
N 132	G51 Med Annual-Low Winter	$ 119,153	$ 148,293	$ 150,486	$ 137,821	$ 137,388	$ 102,558	$ 1,289,065	$ 795,698
N 133	G41 Med Annual-High Winter	$ 337,271	$ 548,998	$ 573,150	$ 489,327	$ 514,554	$ 327,561	$ 3,464,224	$ 2,790,860
N 134	G52 High Annual-Low Winter	$ 4,657	$ 7,273	$ 7,675	$ 7,609	$ 6,151	$ 4,995	$ 110,546	$ 38,361
N 135	G42 High Annual-High Winter	$ 54,983	$ 73,593	$ 70,311	$ 59,873	$ 50,731	$ 32,531	$ 397,494	$ 342,021
N 136	Total Firm Sales	$ 1,642,129	$ 2,376,749	$ 3,044,278	$ 2,636,902	$ 2,642,557	$ 1,759,640	$ 17,887,520	$ 14,102,256
N 137									
N 138	Residential	$ 762,424	$ 1,043,669	$ 1,424,831	$ 1,226,627	$ 1,257,312	$ 851,338	$ 8,239,208	$ 6,566,201
N 139	SALES HLF CLASSES	$ 194,068	$ 253,568	$ 264,625	$ 247,883	$ 238,821	$ 179,842	$ 2,314,438	$ 1,378,807
N 140	SALES LLF CLASSES	$ 685,638	$ 1,079,513	$ 1,354,822	$ 1,162,391	$ 1,146,424	$ 728,461	$ 7,333,874	$ 6,157,247
N 141									
N 142	% ALLOCATION BETWEEN SALES HLF AND LLF								
N 143	SALES HLF CLASSES								18.30%
N 144	SALES LLF CLASSES								81.70%

Northern Utilities - MAINE DIVISION
Allocation of Commodity Costs to Customer Classes

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	
100	TOTAL COMMODITY Excld Hedging	Schedule 1B, LN 41
101	Res Heat	LN 24 + LN 73
102	Res General	LN 25 + LN 74
103	G50 Low Annual-Low Winter	LN 26 + LN 75
104	G40 Low Annual-High Winter	LN 27 + LN 76
105	G51 Med Annual-Low Winter	LN 28 + LN 77
106	G41 Med Annual-High Winter	LN 29 + LN 78
107	G52 High Annual-Low Winter	LN 30 + LN 79
108	G42 High Annual-High Winter	LN 31 + LN 80
109		
110	Residential	LN 101 + LN 102
111	SALES HLF CLASSES	LN 103 + LN 105 + LN 107
112	SALES LLF CLASSES	LN 104 + LN 106 + LN 108
113	**TOTAL HEDGING COMMODITY COSTS**	
114	TOTAL HEDGING COMMODITY	Schedule 1B, LN 42
115	Res Heat	LN 38 + LN 87
116	Res General	LN 39 + LN 88
117	G50 Low Annual-Low Winter	LN 40 + LN 89
118	G40 Low Annual-High Winter	LN 41 + LN 90
119	G51 Med Annual-Low Winter	LN 42 + LN 91
120	G41 Med Annual-High Winter	LN 43 + LN 92
121	G52 High Annual-Low Winter	LN 44 + LN 93
122	G42 High Annual-High Winter	LN 45 + LN 94
123		
124	Residential	LN 115 + LN 116
125	SALES HLF CLASSES	LN 117 + LN 119 + LN 121
126	SALES LLF CLASSES	LN 118 + LN 120 + LN 122
127	**TOTAL COMMODITY**	
128	Res Heat	LN 101 + LN 115
129	Res General	LN 102 + LN 116
130	G50 Low Annual-Low Winter	LN 103 + LN 117
131	G40 Low Annual-High Winter	LN 104 + LN 118
132	G51 Med Annual-Low Winter	LN 105 + LN 119
133	G41 Med Annual-High Winter	LN 106 + LN 120
134	G52 High Annual-Low Winter	LN 107 + LN 121
135	G42 High Annual-High Winter	LN 108 + LN 122
136	Total Firm Sales	Sum LN 128 : LN 135
137		
138	Residential	LN 128 + LN 129
139	SALES HLF CLASSES	LN 130 + LN 132 + LN 134
140	SALES LLF CLASSES	LN 131 + LN 133 + LN 135
141		
142	% ALLOCATION BETWEEN SALES HLF AND LLF	
143	SALES HLF CLASSES	LN 139 / (LN 139 + LN 140)
144	SALES LLF CLASSES	LN 140 / (LN 139 + LN 140)

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2010 through April 2011

Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	73,841	0	1,773	12,562	39,178	174,508	301,862
Pittsburgh, NH	33,000	34,100	34,100	30,800	34,100	33,000	199,100
Niagara	68,184	0	0	8,953	23,563	83,993	184,693
Tennessee Production	324,343	222,595	161,528	110,471	274,333	281,822	1,375,093
Subtotal Pipeline Volumes	499,368	256,695	197,401	162,786	371,174	573,323	2,060,747
Storage							
Tennessee Storage	0	0	64,297	33,094	47,753	2,536	147,681
Washington 10 Storage	0	571,056	832,121	714,242	442,476	0	2,559,895
Subtotal Storage Volumes	0	571,056	896,418	747,336	490,230	2,536	2,707,576
Peaking							
Peaking Supply 1	91,721	126,202	127,231	112,960	117,031	26,895	602,041
Peaking Supply 2	0	0	0	0	2,670	0	2,670
LNG	1,350	1,395	1,395	1,260	11,646	1,826	18,872
Subtotal Peaking Volumes	93,071	127,597	128,626	114,220	131,348	28,722	623,584
Total Delivered (Dth)	592,439	955,348	1,222,446	1,024,342	992,752	604,580	5,391,907

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2010 through April 2011

Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	175,173	180,435	180,435	162,974	174,615	175,782	1,049,415
PNGTS - Delivered	33,000	34,100	34,100	30,800	34,100	33,000	199,100
Niagara	98,411	101,691	101,691	91,850	98,411	96,562	588,615
Tennessee Production	392,668	405,757	405,757	366,490	404,093	374,722	2,349,486
Subtotal Pipeline Volumes	699,251	721,983	721,983	652,114	711,219	680,066	4,186,616
Storage							
Tennessee Storage	1,147	23,758	56,487	34,317	57,300	67,929	240,938
Washington 10 Storage	134,434	663,155	960,392	694,251	576,676	122,937	3,151,846
Subtotal Storage Volumes	135,581	686,913	1,016,879	728,568	633,976	190,867	3,392,784
Peaking							
Peaking Supply 1	132,990	124,141	141,421	113,574	78,712	119,882	710,722
Peaking Supply 2	0	2,706	56,522	48,071	31,774	0	139,073
LNG	1,350	1,395	1,395	1,260	1,395	20,029	26,824
Subtotal Peaking Volumes	134,340	128,242	199,339	162,905	111,881	139,911	876,619
Total Delivered (Dth)	969,173	1,537,138	1,938,201	1,543,587	1,457,076	1,010,844	8,456,019

Northern Utilities, Inc.
Capacity Utilization
Normal Winter Scenario (Includes Only Sales Service Customers)

Description	Peak Period Normal Year Use (Dth)	Capacity Path MDQ	Nov-Mar MDQ (Less Capacity Assignment)	Apr MDQ (Less Capacity Assignment)	Seasonal Quantity (Dth)	Utilization Rate
Pipeline						
Chicago	301,862	6,433	5,314	6,025	983,164	31%
Pittsburgh, NH	199,100	1,100	1,100	1,100	199,100	100%
Niagara	184,693	3,280	2,709	3,072	501,219	37%
Tennessee Production	1,375,093	13,089	10,812	12,259	2,000,382	69%
Subtotal Pipeline Volumes	2,060,747	23,902	19,935	22,456	3,683,865	56%
Storage						
Tennessee Storage	147,681	2,640	2,158	2,450	206,360	72%
Washington 10 Storage	2,559,895	32,835	26,843	30,471	2,684,300	95%
Subtotal Storage Volumes	2,707,576	35,475	29,001	32,921	2,890,660	94%
Peaking						
Peaking Supply 1	602,041	4,975	4,116	3,860	614,126	98%
Peaking Supply 2	2,670	57,113	47,250	44,311	1,339,014	0%
LNG	18,872	10,000	8,273	7,758	9,669	195%
Subtotal Peaking Volumes	623,584	72,088	59,639	55,929	1,962,809	32%
Total Delivered (Dth)	5,391,907	131,465	108,575	111,306	8,537,335	63%

Northern Utilities, Inc.
Capacity Utilization
Design Cold Winter Scenario (Includes All Customers Eligible for Sales Service)

Description	Peak Period Design Year Use (Dth)	Capacity Path MDQ	Seasonal Quantity (Dth)	Utilization Rate
Pipeline				
Chicago	1,049,415	6,433	1,164,373	90%
Pittsburgh, NH	199,100	1,100	199,100	100%
Niagara	588,615	3,280	593,680	99%
Tennessee Production	2,349,486	13,089	2,369,109	99%
Subtotal Pipeline Volumes	4,186,616	23,902	4,326,262	97%
Storage				
Tennessee Storage	240,938	2,640	252,452	95%
Washington 10 Storage	3,151,846	32,835	3,283,500	96%
Subtotal Storage Volumes	3,392,784	35,475	3,535,952	96%
Peaking				
Peaking Supply 1	710,722	4,975	751,225	95%
Peaking Supply 2	139,073	57,113	1,427,825	10%
LNG	26,824	10,000	9,669	277%
Subtotal Peaking Volumes	876,619	72,088	2,188,719	40%
Total Delivered (Dth)	8,456,019	131,465	10,050,933	84%

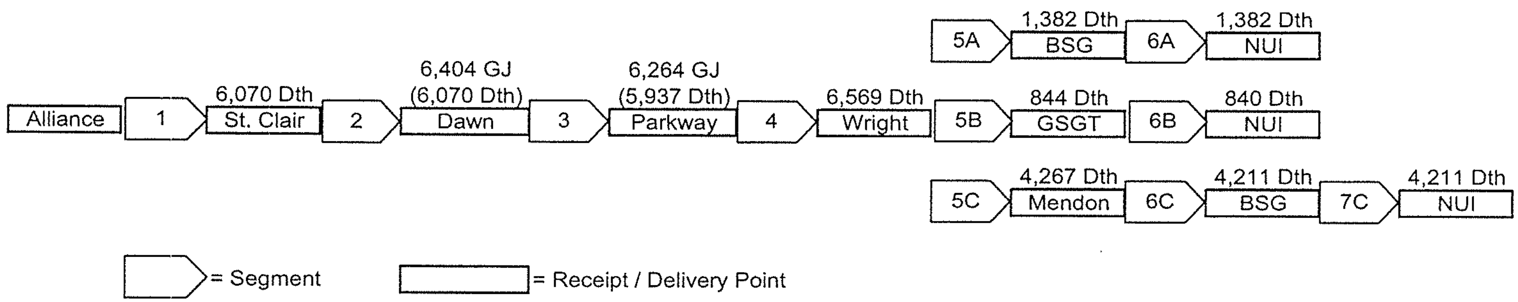
Northern Utilities Inc.
Forecast of Upcomming Winter Period Design Day Report
2010-2011 Winter
(Therms)

Demand	
Firm Sales	645,003
Interruptible Sales	0
Capacity Exempt Transportation	260,631
Non-Capacity Exempt Transportation	248,920
Interruptible Transportation	0
Total	1,154,554
Supplies	
Capacity Exempt Transportation	260,631
Pipeline	238,970
Storage	354,750
On-System LNG	100,000
Off-System Peaking	620,880
On-System Propane	0
Total	1,575,231
Effective Degree Day	
New Hampshire	80
Maine	81
Probability	1 in 30

Report Prepared By: Francis X. Wells
Title: Sr. Energy Trader

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Chicago (Interconnection of Alliance and Vector Pipelines)

Capacity Path Diagram

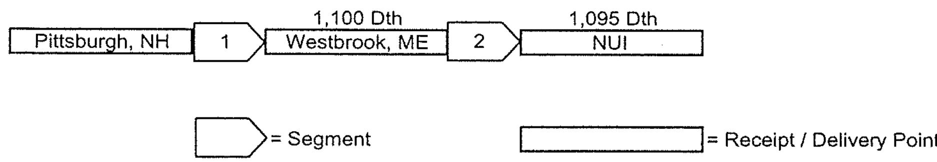


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	TransCanada
3	Transportation	TransCanada	29594	FT	10/31/2016	6,264	GJ	Year-Round	Dawn	Parkway	Iroquois
4	Transportation	Iroquois	R181001	RTS-1	10/31/2013	6,569	Dth	Year-Round	Parkway	Wright	Tennessee
5A	Transportation	Tennessee	31861	NET-284	10/31/2012	1,382	Dth	Year-Round	Wright	Bay State City Gate	
6A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
5B	Transportation	Tennessee	31861	NET-284	10/31/2012	844	Dth	Year-Round	Wright	Pleasant St.	Granite
6B	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	840	Dth	Year-Round	Pleasant St.	Northern City Gates	
5C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
6C	Transportation	Algonquin	93200F	AFT-1	10/31/2012	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
7C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,433	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)

Capacity Path Diagram

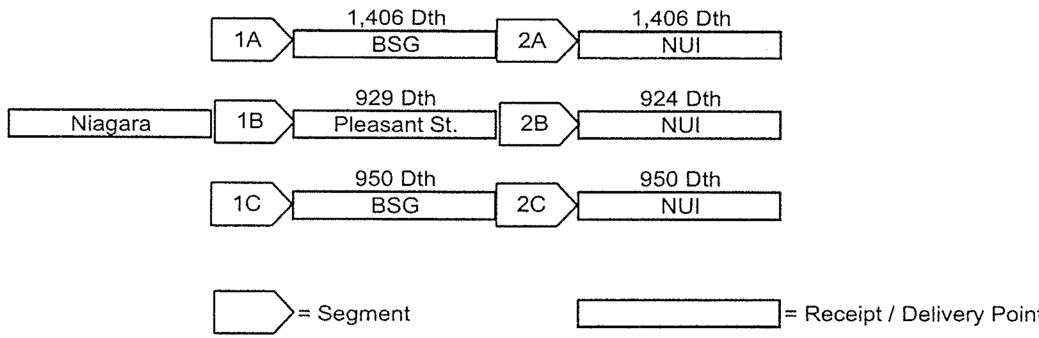


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	1,095	Dth	Year-Round	Westbrook, ME	Northern City Gates	
Total Path Deliverable						1,095	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Niagara (Interconnection of TransCanada and Tennessee Pipelines)

Capacity Path Diagram

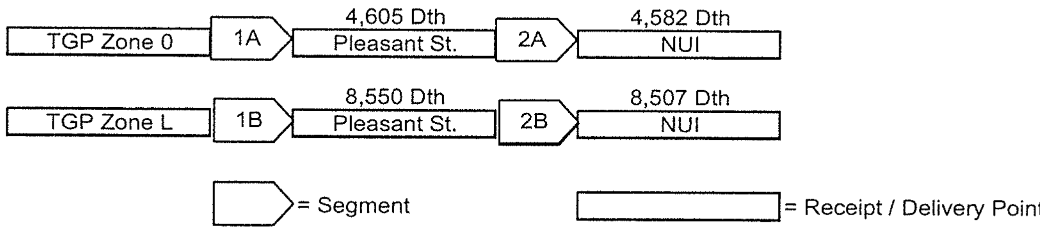


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2015	1,406	Dth	Year-Round	Niagara	Bay State City Gate	
2A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,406	Dth	Year-Round	Bay State City Gate	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2015	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	924	Dth	Year-Round	Pleasant St.	Northern City Gates	
1C	Transportation	Tennessee	46314	FT-A	3/31/2012	950	Dth	Year-Round	Niagara	Bay State City Gate	
2C	Exchange	Bay State Gas	NA	NA	Renewal Clause	950	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						3,280	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Production Area

Capacity Path Diagram



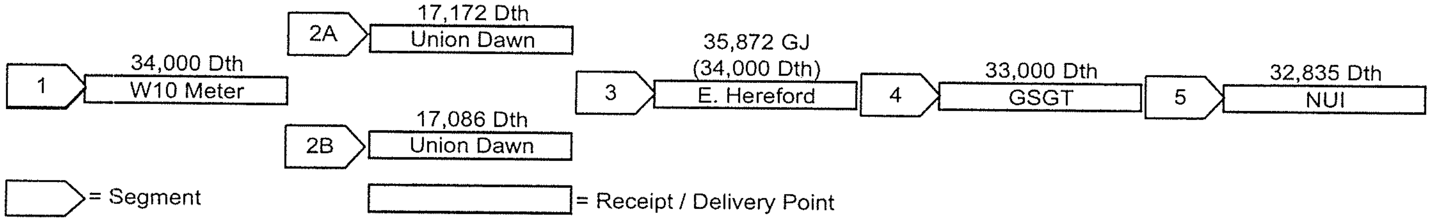
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	4,582	Dth	Year-Round	Pleasant St.	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	8,507	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						13,089	Dth				

Note 1: Tennessee Contract No. 5083 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Washington 10 Storage

Capacity Path Diagram



Capacity Path Detail

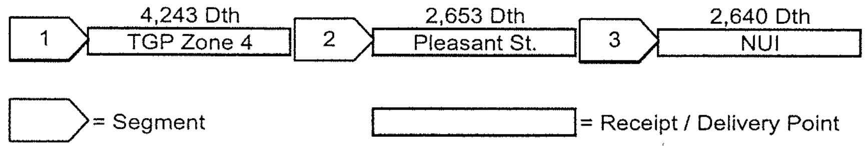
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-0725	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-0727	FT	3/31/2017	17,086	Dth	Winter Only (Nov - Mar)	W10 Withdrawal Meter	Union Dawn	TransCanada
3	Transportation	TransCanada	33322	FT	3/31/2018	35,872	GJ	Year-Round	Union Dawn	East Hereford	PNGTS
4	Transportation	PNGTS	1997-004	FT	3/9/2019	33,000	Dth	Winter Only (Nov - Mar)	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	32,835	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,835	Dth				

Note 1: Washington 10 Contract 01052 has a maximum storage quantity of 3,400,000 Dth.

Note 2: Vector Contract No. CRL-NUI-0725 allows for receipt from the Alliance Interconnect (Chicago). Gas is received on this contract at the W10 Withdrawal meter on a secondary, firm basis. This capacity is used for summer refill of the Washington 10 storage contract.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Firm Storage - Market Area

Capacity Path Diagram



Capacity Path Detail

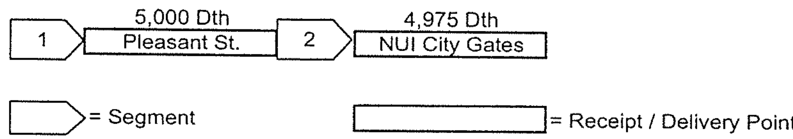
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	10/31/2013	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	10/31/2013	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	2,640	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,640	Dth				

Note 1: Tennessee Contract No. 5195 has a maximum storage quantity of 259,337 Dth.

Note 2: Tennessee Contract No. 5265 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Supply 1

Capacity Path Diagram



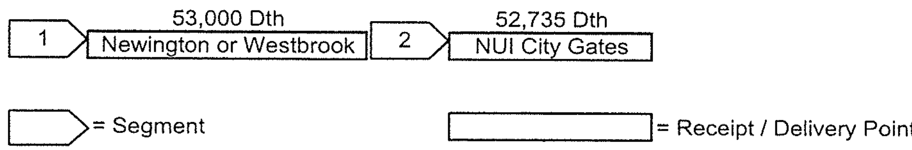
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Distrigas	NA	NA	10/31/2011	5,000	Dth	Year-Round	NA	Pleasant St.	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	4,975	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						4,975	Dth				

Note 1: Peaking Supply 1 Contract allows Northern to nominate an additional 5,000 Dth per Day of liquified LNG, which Northern delivers to its Lewiston LNG facility via truck. Annual maximum take is 755,000 Dth.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Supply 2

Capacity Path Diagram



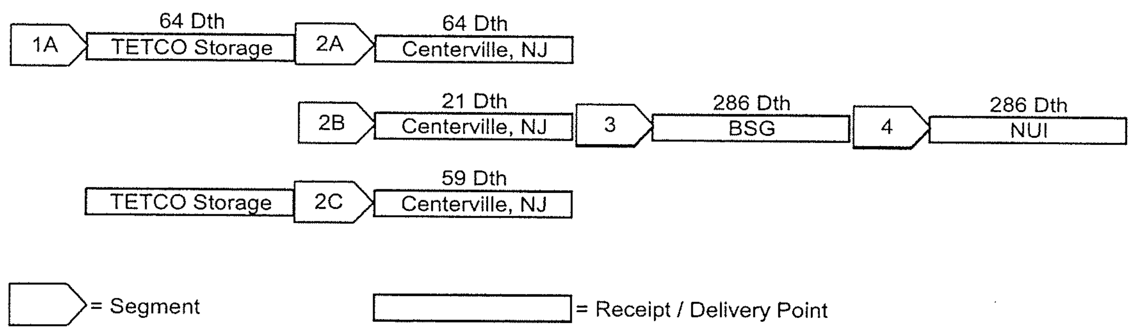
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	FPL Energy	NA	NA	3/31/2011	57,400	Dth	Winter Only (Nov-Mar)	NA	Newington, NH or Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	57,113	Dth	Year-Round	Newington, NH or Westbrook, ME	Northern City Gates	
Total Path Deliverable						57,113	Dth				

Note 1. Effective November 1, 2010, the Peaking Supply 2 Contract MDQ increases from 53,000 Dth to 57,400 Dth. The annual maximum take is 1,272,000 Dth, which increases to 1,435,000 Dth effective November 1, 2010.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Texas Eastern Production and Storage & Algonquin (Centerville, NJ)

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Storage	Texas Eastern	400513	FSS-1	4/30/2012	64	Dth	Year-Round		Texas Eastern M3 Storage	
2A	Transportation	Texas Eastern	800436	CDS	10/31/2012	64	Dth	Year-Round	Texas Eastern M3 Storage	Centerville, NJ	Algonquin
2B[2]	Storage	Texas Eastern	400215	SS-1	4/30/2013	21	Dth	Year-Round	Texas Eastern M3 Storage	Centerville, NJ	Algonquin
2C	Transportation	Texas Eastern	800464	CDS	10/31/2012	59	Dth	Year-Round	Texas Eastern Production Area	Centerville, NJ	Algonquin
3[3]	Transportation	Algonquin	93201A1C	AFT-1	10/31/2012	286	Dth	Year-Round	Centerville, NJ	Bay State City Gate	
4	Exchange	Bay State Gas	NA	NA	Renewal Clause	286	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						286	Dth				

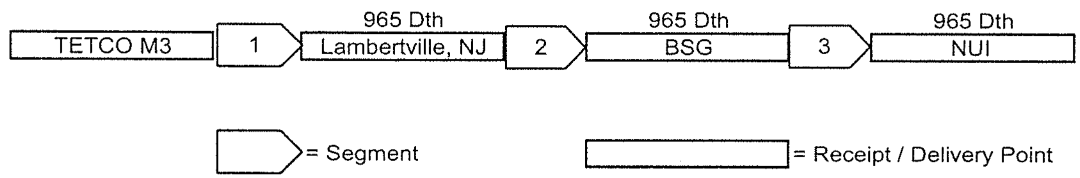
Note 1: Texas Eastern Contract No. 400513 has a maximum storage quantity of 3,840 Dth.

Note 2: Texas Eastern Contract No. 400215 has a maximum storage quantity of 1,470 Dth.

Note 3: Northern has entered into a permanent release of Algonquin Contract No. 93201A1C. As such, these supplies are not deliverable to Northern City Gates. Northern plans to continue to seek permanent release of the other Texas Eastern contracts in this capacity path.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Texas Eastern Zone M3

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Transportation	Texas Eastern	800384	FT-1	10/31/2017	965	Dth	Year-Round	Texas Eastern M3 Storage	Lambertville, NJ	Algonquin
2[1]	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2012	965	Dth	Year-Round	Lambertville, NJ	Bay State City Gate	
3	Exchange	Bay State Gas	NA	NA	Renewal Clause	965	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						965	Dth				

Note 1: Northern has entered into a permanent release of both Texas Eastern Contract No. 800384 and Algonquin Contract No. 93201A1C. As such, these supplies are not deliverable to Northern City Gates.

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2010 through October 2011

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	712,812	37%	87%
G50	166,544	9%	78%
G41	695,040	36%	60%
G51	236,869	12%	61%
G42	80,481	4%	18%
G52	20,222	1%	2%
Special Contracts	-	0%	0%
Total C&I	1,911,966	100%	36%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
T40	107,436	3%	13%
T50	48,161	1%	22%
T41	460,427	14%	40%
T51	151,120	4%	39%
T42	376,995	11%	82%
T52	1,175,609	35%	98%
Special Contracts	1,058,667	31%	100%
Total C&I	3,378,416	100%	64%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G/T40	820,248	16%
G/T50	214,705	4%
G/T41	1,155,466	22%
G/T51	387,989	7%
G/T42	457,476	9%
G/T52	1,195,830	23%
Special Contracts	1,058,667	20%
Total C&I	5,290,382	100%

Northern Utilities, Inc.
Storage Analysis

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-10	212,008	-	-	212,008	$ 915,940	$ 4.32	NA	$ -	$ 4.32	$ -	$ 915,940	2.35%	$ 1,793	$ 915,940	$ -
Dec-10	212,008	-	-	212,008	$ 915,940	$ 4.32	NA	$ -	$ 4.32	$ -	$ 915,940	2.35%	$ 1,793	$ 915,940	$ -
Jan-11	212,008	-	66,054	145,954	$ 915,940	$ 4.32	NA	$ -	$ 4.32	$ 285,373	$ 630,567	2.35%	$ 1,514	$ 630,567	$ 285,373
Feb-11	145,954	-	33,998	111,956	$ 630,567	$ 4.32	NA	$ -	$ 4.32	$ 146,883	$ 483,685	2.35%	$ 1,091	$ 483,685	$ 146,883
Mar-11	111,956	-	49,058	62,898	$ 483,685	$ 4.32	NA	$ -	$ 4.32	$ 211,945	$ 271,740	2.35%	$ 739	$ 271,740	$ 211,945
Apr-11	62,898	30,389	2,599	90,688	$ 271,740	$ 4.32	$ 4.80	$ 145,843	$ 4.48	$ 11,632	$ 405,951	2.35%	$ 663	$ 405,951	$ 11,632
May-11	90,688	53,599	-	144,287	$ 405,951	$ 4.48	$ 4.81	$ 258,011	$ 4.60	$ -	$ 663,962	2.35%	$ 1,047	$ 663,962	$ -
Jun-11	144,287	51,870	-	196,157	$ 663,962	$ 4.60	$ 4.87	$ 252,685	$ 4.67	$ -	$ 916,647	2.35%	$ 1,547	$ 916,647	$ -
Jul-11	196,157	5,250	-	201,408	$ 916,647	$ 4.67	$ 4.95	$ 25,968	$ 4.68	$ -	$ 942,615	2.35%	$ 1,820	$ 942,615	$ -
Aug-11	201,408	-	-	201,408	$ 942,615	$ 4.68	NA	$ -	$ 4.68	$ -	$ 942,615	2.35%	$ 1,845	$ 942,615	$ -
Sep-11	201,408	-	-	201,408	$ 942,615	$ 4.68	NA	$ -	$ 4.68	$ -	$ 942,615	2.35%	$ 1,845	$ 942,615	$ -
Oct-11	201,408	-	-	201,408	$ 942,615	$ 4.68	NA	$ -	$ 4.68	$ -	$ 942,615	2.35%	$ 1,845	$ 942,615	$ -

Washington 10 Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-10	2,779,500	-	-	2,779,500	$ 11,629,662	$ 4.18	NA	$ -	$ 4.18	$ -	$ 11,629,662	2.35%		$ 11,629,662	$ -
Dec-10	2,779,500	-	584,864	2,194,636	$ 11,629,662	$ 4.18	NA	$ -	$ 4.18	$2,447,119	$ 9,182,544	2.35%		$ 9,182,544	$2,447,119
Jan-11	2,194,636	-	852,241	1,342,395	$ 9,182,544	$ 4.18	NA	$ -	$ 4.18	$3,565,850	$ 5,616,694	2.35%		$ 5,616,694	$3,565,850
Feb-11	1,342,395	-	731,512	610,883	$ 5,616,694	$ 4.18	NA	$ -	$ 4.18	$3,060,707	$ 2,555,987	2.35%		$ 2,555,987	$3,060,707
Mar-11	610,883	-	453,175	157,708	$ 2,555,987	$ 4.18	NA	$ -	$ 4.18	$1,896,124	$ 659,863	2.35%		$ 659,863	$1,896,124
Apr-11	157,708	-	-	157,708	$ 659,863	$ 4.18	NA	$ -	$ 4.18	$ -	$ 659,863	2.35%		$ 659,863	$ -
May-11	157,708	484,222	-	641,930	$ 659,863	$ 4.18	$ 4.58	$2,217,535	$ 4.48	$ -	$ 2,877,399	2.35%		$ 2,877,399	$ -
Jun-11	641,930	468,602	-	1,110,533	$ 2,877,399	$ 4.48	$ 4.64	$2,172,154	$ 4.55	$ -	$ 5,049,552	2.35%		$ 5,049,552	$ -
Jul-11	1,110,533	484,222	-	1,594,755	$ 5,049,552	$ 4.55	$ 4.71	$2,279,428	$ 4.60	$ -	$ 7,328,980	2.35%		$ 7,328,980	$ -
Aug-11	1,594,755	484,222	-	2,078,977	$ 7,328,980	$ 4.60	$ 4.76	$2,305,008	$ 4.63	$ -	$ 9,633,988	2.35%		$ 9,633,988	$ -
Sep-11	2,078,977	468,602	-	2,547,580	$ 9,633,988	$ 4.63	$ 4.79	$2,242,595	$ 4.66	$ -	$ 11,876,583	2.35%		$ 11,876,583	$ -
Oct-11	2,547,579	231,921	-	2,779,500	$ 11,876,583	$ 4.66	$ 4.87	$1,129,761	$ 4.68	$ -	$ 13,006,344	2.35%		$ 13,006,344	$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-10	9,669	2,023	1,350	10,341	$ 71,486	$ 7.39	$ 4.77	$ 9,638	$ 6.94	$ 9,368	$ 71,757	2.35%	$ 140	$ 71,757	$ 9,368
Dec-10	10,341	1,395	1,395	10,341	$ 71,757	$ 6.94	$ 4.77	$ 6,648	$ 6.68	$ 9,319	$ 69,085	2.35%	$ 138	$ 69,085	$ 9,319
Jan-11	10,341	361	1,395	9,307	$ 69,085	$ 6.68	$ 4.77	$ 1,720	$ 6.62	$ 9,229	$ 61,576	2.35%	$ 128	$ 61,576	$ 9,229
Feb-11	9,307	2,294	1,260	10,341	$ 61,576	$ 6.62	$ 4.77	$ 10,932	$ 6.25	$ 7,875	$ 64,633	2.35%	$ 124	$ 64,633	$ 7,875
Mar-11	10,341	10,612	11,646	9,307	$ 64,633	$ 6.25	$ 4.77	$ 50,570	$ 5.50	$ 64,032	$ 51,171	2.35%	$ 113	$ 51,171	$ 64,032
Apr-11	9,307	2,860	1,826	10,341	$ 51,171	$ 5.50	$ 4.77	$ 13,631	$ 5.33	$ 9,726	$ 55,075	2.35%	$ 104	$ 55,075	$ 9,726
May-11	10,341	-	1,395	8,946	$ 55,075	$ 5.33	NA	$ -	$ 5.33	$ 7,429	$ 47,646	2.35%	$ 101	$ 47,646	$ 7,429
Jun-11	8,946	-	1,350	7,596	$ 47,646	$ 5.33	NA	$ -	$ 5.33	$ 7,190	$ 40,456	2.35%	$ 86	$ 40,456	$ 7,190
Jul-11	7,596	-	1,395	6,201	$ 40,456	$ 5.33	NA	$ -	$ 5.33	$ 7,429	$ 33,027	2.35%	$ 72	$ 33,027	$ 7,429
Aug-11	6,201	-	1,395	4,806	$ 33,027	$ 5.33	NA	$ -	$ 5.33	$ 7,429	$ 25,597	2.35%	$ 57	$ 25,597	$ 7,429
Sep-11	4,806	-	1,350	3,456	$ 25,597	$ 5.33	NA	$ -	$ 5.33	$ 7,190	$ 18,407	2.35%	$ 43	$ 18,407	$ 7,190
Oct-11	3,456	-	1,395	2,061	$ 18,407	$ 5.33	NA	$ -	$ 5.33	$ 7,429	$ 10,978	2.35%	$ 29	$ 10,978	$ 7,429

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-2010 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
November 2009 - April 2010

	AMOUNT	
Winter Period Beg. Balance	$2,464,908	SCHEDULE 2
Less: Reported Collections	($26,875,520)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$26,833,523	SCHEDULE 4
Add: Interest	$104,492	SCHEDULE 2
Winter Period Ending Balance	$2,527,403	

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
May 2009 - April 2010
Acct 191.10

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
WINTER PERIOD													
Winter Period Account Beginning Balance(1)	$ 2,066,133	$ 2,464,908	$ 2,959,005	$ 3,165,364	$ 3,634,792	$ 4,213,161	$ 4,557,492	$ 5,394,762	$ 5,457,786	$ 3,076,567	$ 1,876,432	$ 1,802,213	$ 2,464,908
Plus: Cost of Firm Gas (Schedule 4)	$ 324,218	$ 499,289	$ 202,141	$ 463,098	$ 583,812	$ 340,706	$ 3,461,034	$ 5,515,279	$ 5,103,627	$ 4,387,573	$ 3,966,842	$ 2,310,122	$ 26,833,523
Less: Reported Collections (Schedule 3)	$ 68,430	$ (12,527)	$ (4,064)	$ (2,866)	$ (16,056)	$ (8,236)	$ (2,637,223)	$ (5,466,931)	$ (7,496,388)	$ (5,594,406)	$ (4,046,036)	$ (1,590,786)	$ (26,875,520)
Less: Billing Adjustment													
Winter Period Account Ending Balance	$ 2,458,781	$ 2,951,670	$ 3,157,082	$ 3,625,596	$ 4,202,548	$ 4,545,631	$ 5,381,303	$ 5,443,110	$ 3,065,025	$ 1,869,733	$ 1,797,238	$ 2,521,548	$ 2,422,912
Month's Average Balance	$ 2,262,457	$ 2,708,289	$ 3,058,044	$ 3,395,480	$ 3,918,670	$ 4,379,396	$ 4,969,398	$ 5,418,936	$ 4,261,406	$ 2,473,150	$ 1,836,835	$ 2,161,880	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 6,127	$ 7,335	$ 8,282	$ 9,196	$ 10,613	$ 11,861	$ 13,459	$ 14,676	$ 11,541	$ 6,698	$ 4,975	$ 5,855	$ 104,492
Winter Period Account Ending Balance w/int	$ 2,464,908	$ 2,959,005	$ 3,165,364	$ 3,634,792	$ 4,213,161	$ 4,557,492	$ 5,394,762	$ 5,457,786	$ 3,076,567	$ 1,876,432	$ 1,802,213	$ 2,527,403	$ 2,527,403

(1) Beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
May 2009 - April 2010

FORM III
Schedule 3

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Accrued Revenue	$ (1,311,072)						$ 1,671,036	$ 1,496,137	$ 140,433	$ (343,134)	$ (716,828)	$ (1,425,408)	$ 822,237
Billed Revenue	$ 1,242,642	$ 12,527	$ 4,064	$ 2,866	$ 16,056	$ 8,236	$ 966,188	$ 3,970,794	$ 7,355,955	$ 5,937,540	$ 4,762,863	$ 3,016,194	$ 26,053,283
Calendarized Revenue	**$ (68,430)**	**$ 12,527**	**$ 4,064**	**$ 2,866**	**$ 16,056**	**$ 8,236**	**$ 2,637,223**	**$ 5,466,931**	**$ 7,496,388**	**$ 5,594,406**	**$ 4,046,036**	**$ 1,590,786**	**$ 26,875,520**

(1) Revenue figures reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2009 - April 2010

Commodity Costs:	May-09 (Actual)	Jun-09 (Actual)	Jul-09 (Actual)	Aug-09 (Actual)	Sep-09 (Actual)	Oct-09 (Actual)	Nov-09 (Actual)	Dec-09 (Actual)	Jan-10 (Actual)	Feb-10 (Actual)	Mar-10 (Actual)	Apr-10 (Actual)	Total Winter
BG Energy	$ 34,182	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,662	$ -	$ -	$ 31,403	$ 40,065
Boss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,928	$ -	$ -	$ -	$ 12,928
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,755	$ 615,705	$ 1,520,629	$ 823,812	$ -	$ 3,012,900
Classic	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	$ -	$ -	$ 92
Distrigas of Mass	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,357	$ 251,243	$ 327,297	$ 299,197	$ 333,212	$ 1,311,307
DTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 398,780	$ -	$ -	$ -	$ -	$ 398,780
Emera Energy	$ 67,194	$ -	$ -	$ -	$ -	$ -	$ -	$ 120,652	$ 149,959	$ 114,759	$ 117,063	$ 101,123	$ 603,556
FPL/NextEra	$ 62,478	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,130	$ -	$ -	$ -	$ 10,130
Iberdrola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 760,290	$ 726,122	$ 628,066	$ -	$ 2,114,478
Integrys	$ 5,032	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. P. Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,705	$ -	$ -	$ -	$ -	$ 12,705
Louis Dreyfus Electric Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,243	$ -	$ 7,243
Macquarie Cook Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,042,914	$ 9,657	$ -	$ -	$ 1,052,571
National Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Northeast Gas Marketing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180,861	$ 205,686	$ 269,427	$ 222,108	$ -	$ 878,081
Sequent Energy Management, LP	$ 394,997	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,970	$ -	$ -	$ -	$ -	$ 3,970
South Jersey	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,587	$ -	$ -	$ -	$ -	$ 214,587
Spark	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,004	$ -	$ -	$ -	$ 13,004
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,977	$ -	$ 38,977
Tennessee	$ 885	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,333	$ 7,809	$ 7,964	$ 25,260	$ 12,304	$ 60,669
Subtotal	$ 564,769	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,092,000	$ 3,078,330	$ 2,975,947	$ 2,161,725	$ 478,042	$ 9,786,044
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,080,518	$ 2,970,078	$ 2,999,574	$ 2,210,204	$ 472,450	$ 908,200	$ 10,641,024
Commodity Cost Reversals	$ (517,082)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,080,518)	$ (2,970,078)	$ (2,999,574)	$ (2,210,204)	$ (472,450)	$ (9,732,824)
Subtotal	$ 47,686	$ -	$ -	$ -	$ -	$ -	$ 1,080,518	$ 2,981,560	$ 3,107,825	$ 2,186,577	$ 423,971	$ 913,792	$ 10,694,244
Withdrawal Charges	$ 108	$ 2,801	$ 2,273	$ 3,064	$ -	$ 4,088	$ 5,007	$ 100,799	$ 1,171,362	$ 1,644,641	$ 1,125,338	$ 10,539	$ 4,069,912
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,649	$ -	$ -	$ -	$ 7,649
Non Traditional Sales	$ (58,807)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (71,930)	$ (958,751)	$ (1,694,948)	$ -	$ (2,725,629)
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,022	$ 13,478	$ 7,907	$ (4,850)	$ (3,845)	$ (81)	$ 21,632
Company Managed	$ -	$ -	$ (8,779)	$ -	$ -	$ -	$ -	$ (13,437)	$ (283,247)	$ (273,692)	$ (235,583)	$ (243,681)	$ (1,058,418)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,706	$ -	$ -	$ -	$ -	$ -	$ 3,706
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 101,847	$ 593,753	$ 834,653	$ 703,532	$ 500,280	$ 278,881	$ 3,012,946
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,680	$ 497,797	$ 359,604	$ 415,832	$ 551,773	$ 668,016	$ 2,884,703
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Inventory Finance Charges	$ 512	$ 431	$ 514	$ 815	$ 898	$ 938	$ 1,088	$ 1,130	$ 920	$ 556	$ 302	$ 209	$ 7,801
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal	$ (58,187)	$ 3,231	$ (5,991)	$ 3,879	$ 898	$ 5,027	$ 512,351	$ 1,193,520	$ 2,026,918	$ 1,527,268	$ 243,317	$ 713,885	$ 6,224,302
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,243,562)	$ (1,932,442)	$ (243,681)	$ (400,495)	$ (3,820,180)
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,243,562	$ 1,932,442	$ 243,681	$ 3,419,685
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,243,562)	$ (688,880)	$ 1,688,761	$ (156,814)	$ (400,495)
Total Commodity Costs	$ (10,501)	$ 3,231	$ (5,991)	$ 3,879	$ 898	$ 5,027	$ 1,592,869	$ 4,175,080	$ 3,891,181	$ 3,024,966	$ 2,356,050	$ 1,470,863	$ 16,518,052

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009-10 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2009 - April 2010

Demand Costs

	May-09 (Actual)	Jun-09 (Actual)	Jul-09 (Actual)	Aug-09 (Actual)	Sep-09 (Actual)	Oct-09 (Actual)	Nov-09 (Actual)	Dec-09 (Actual)	Jan-10 (Actual)	Feb-10 (Actual)	Mar-10 (Actual)	Apr-10 (Actual)	Total Winter
Pipeline Reservation													
Algonquin	$ 16,627	$ 16,583	$ 16,641	$ 16,673	$ -	$ 33,316	$ 16,671	$ 15,722	$ 15,767	$ 15,767	$ 15,767	$ 15,767	$ 178,675
BG Energy	$ 204,893	$ 211,309	$ 213,511	$ 217,940	$ 221,483	$ 233,893	$ 228,130	$ 213,086	$ 221,372	$ 305,309	$ 312,580	$ 319,133	$ 2,697,747
Granite	$ 82,533	$ 82,533	$ 82,533	$ 82,533	$ 82,533	$ 82,628	$ 78,289	$ 78,375	$ 78,375	$ 78,375	$ 78,400	$ 78,400	$ 882,971
Emera	$ 20,421	$ 19,920	$ 21,221	$ 21,340	$ 21,170	$ 21,484	$ 21,734	$ 20,850	$ 20,664	$ 29,988	$ 36,680	$ 31,506	$ 266,557
Iberdrola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,939	$ 30,801	$ 33,994	$ 34,571	$ 148,305
Iroquois	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 21,707	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 20,567	$ 233,080
J.P. Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ 128,153	$ -	$ -	$ -	$ -	$ -	$ 128,153
PNGTS (DEM)	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 15,098	$ 829,709	$ 829,709	$ 829,709	$ 829,709	$ 829,709	$ 4,239,132
Sequent	$ 22,226	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spectra	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,014	$ -	$ -	$ -	$ -	$ -	$ 17,014
Tennessee Gas (El Paso)	$ 140,197	$ 140,197	$ 137,622	$ 137,622	$ 135,736	$ 137,622	$ 137,622	$ 46,404	$ 130,396	$ 130,396	$ 130,396	$ 102,900	$ 1,366,911
Texas Eastern	$ 3,395	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,707	$ 6,497	$ -	$ 16,204
Vector LP	$ 91,274	$ 91,322	$ 91,340	$ 91,357	$ 91,204	$ 91,654	$ 91,421	$ 123,617	$ 123,656	$ 122,705	$ 122,755	$ 122,777	$ 1,163,809
Co-Managed (includes Off System Sales)	$ (5,524)	$ (5,631)	$ (5,587)	$ -	$ (11,527)	$ -	$ (10,551)	$ -	$ -	$ (229,041)	$ -	$ -	$ (262,337)
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pipeline Reservation	$ 612,846	$ 593,037	$ 594,086	$ 604,269	$ 577,405	$ 637,401	$ 745,288	$ 1,348,331	$ 1,489,445	$ 1,344,283	$ 1,587,346	$ 1,555,330	$ 11,076,222
Product Demand													
Alberta Northeast Gas Ltd.	$ 1,147	$ 1,155	$ 1,223	$ 1,672	$ 1,189	$ 1,146	$ 1,283	$ 1,235	$ 1,067	$ 1,044	$ 1,089	$ 1,066	$ 13,169
Distrigas of Massachusetts	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 116,012	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 99,140	$ 1,191,773
FPL/NextEra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,997	$ 162,997	$ 162,997	$ 162,997	$ 162,997	$ 814,983
NEGM	$ 358	$ 370	$ 358	$ 370	$ 370	$ 358	$ 370	$ 340	$ 351	$ 351	$ 317	$ 351	$ 3,907
LNG used to vaporize	$ (39,958)	$ (43,633)	$ -	$ -	$ -	$ (44,082)	$ (45,029)	$ -	$ -	$ -	$ -	$ -	$ (132,744)
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Product Demand	$ 77,560	$ 73,905	$ 117,594	$ 118,055	$ 117,572	$ 73,435	$ 72,636	$ 263,711	$ 263,554	$ 263,531	$ 263,542	$ 263,553	$ 1,891,088
Storage Pipeline Transportation and Demand Reservation													
Spectra	$ -	$ -	$ -	$ -	$ -	$ -	$ 435	$ -	$ -	$ -	$ -	$ -	$ 435
Tennessee Gas Pipeline	$ 4,632	$ 4,632	$ 4,632	$ 4,847	$ 4,847	$ 4,847	$ 4,847	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 4,593	$ 51,616
Washington 10 (BG Energy)	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ 120,633	$ -	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 114,300	$ 1,174,665
Texas Eastern	$ 88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 248	$ 165	$ -	$ 414
Company Managed	$ -	$ -	$ (44,167)	$ (91,004)	$ -	$ -	$ -	$ (246,597)	$ (273,254)	$ (273,452)	$ (268,438)	$ (265,617)	$ (1,462,528)
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage and Demand Reservation	$ 125,353	$ 125,265	$ 81,098	$ 34,477	$ 125,481	$ 125,481	$ 5,283	$ (127,705)	$ (154,362)	$ (154,311)	$ (149,380)	$ (146,725)	$ (235,398)
Demand Cost Estimates	$ 1,093,496	$ 1,093,496	$ 800,208	$ 800,208	$ 937,830	$ 800,208	$ 1,834,817	$ 1,755,720	$ 1,482,990	$ 1,488,004	$ 1,487,979	$ 663,217	$ 13,144,679
Demand Cost Reversals	$ (1,093,496)	$ (1,093,496)	$ (1,093,496)	$ (800,208)	$ (800,208)	$ (937,830)	$ (800,208)	$ (1,834,817)	$ (1,755,720)	$ (1,482,990)	$ (1,488,004)	$ (1,487,979)	$ (13,574,957)
Total Fixed Demand	$ 815,759	$ 792,208	$ 499,490	$ 756,801	$ 958,079	$ 698,695	$ 1,857,816	$ 1,405,241	$ 1,325,908	$ 1,458,518	$ 1,701,483	$ 847,396	$ 12,301,633
Interruptible Profits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,206	$ 41,206	$ 41,206	$ 41,206	$ 41,206	$ -	$ 206,029
Capacity Release	$ (235,351)	$ (45,131)	$ (44,064)	$ (46,590)	$ (113,612)	$ (112,384)	$ (39,815)	$ (229,706)	$ (270,306)	$ (260,100)	$ (254,880)	$ (249,185)	$ (1,665,775)
Capacity Mitigation	$ (6,218)	$ (11,531)	$ -	$ (11,521)	$ (22,081)	$ (11,161)	$ (10,773)	$ (6,961)	$ (7,419)	$ (7,362)	$ (7,436)	$ (7,436)	$ (103,680)
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 114,446	$ 686,673
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,974	$ 15,974	$ 15,974	$ 15,974	$ 15,974	$ 15,974	$ 95,845
Transp. Demand Revenues	$ -	$ (18)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (18)
Prior Period Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Cost Estimates - Capacity Release	$ (119,782)	$ (119,782)	$ (127,604)	$ (127,604)	$ (127,604)	$ (127,604)	$ (238,292)	$ (238,292)	$ (245,654)	$ (245,728)	$ (245,728)	$ (127,663)	$ (1,971,556)
Demand Cost Reversals - Capacity Release	$ 119,782	$ 119,782	$ 119,782	$ 127,604	$ 127,604	$ 127,604	$ 127,604	$ 238,292	$ 238,292	$ 245,654	$ 245,728	$ 245,728	$ 1,963,675
Total Demand Costs	$ 574,190	$ 735,528	$ 447,603	$ 698,690	$ 822,385	$ 575,150	$ 1,868,165	$ 1,340,199	$ 1,212,446	$ 1,362,607	$ 1,610,792	$ 839,259	$ 11,512,825
Demand Costs Transferred to Summer Period	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ (239,471)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,197,354)
Net Demand Costs For Winter Period	$ 334,719	$ 496,058	$ 208,133	$ 459,219	$ 582,915	$ 335,679	$ 1,868,165	$ 1,340,199	$ 1,212,446	$ 1,362,607	$ 1,610,792	$ 839,259	$ 10,315,471
Total Gas Costs	$ 324,218	$ 499,289	$ 202,141	$ 463,098	$ 583,812	$ 340,706	$ 3,461,034	$ 5,515,279	$ 5,103,627	$ 4,387,573	$ 3,966,842	$ 2,310,122	$ 26,833,523

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 - 2010 WINTER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2009 - April 2010

New Hampshire	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Throughput IN													
BTU Factor	1.058	1.043	1.046	1.029	1.05	1.042	1.037	1.04053	1.042	1.044	1.039	1.03975	
GST Meter Throughput (MCF)	318,202	259,715	275,694	259,076	278,578	460,252	528,094	880,611	977,063	812,599	665,946	416,782	6,132,612
Salem Meter (MCF)	13,740	10,711	11,098	10,145	11,353	21,545	27,009	56,707	61,967	49,058	34,966	18,950	327,249
GST Meter Throughpurt (DTH)	336,658	270,883	288,376	266,589	292,507	479,583	547,633	916,302	1,018,100	848,353	691,918	433,349	6,390,251
Salem Meter (DTH)	14,537	11,172	11,609	10,439	11,921	22,450	28,008	59,005	64,570	51,217	36,330	19,703	340,960
LNG/Propane													0
Total Throughput	351,195	282,054	299,984	277,028	304,428	502,032	575,642	975,307	1,082,669	899,570	728,248	453,052	6,731,210
Throughput OUT													
Residential Gas													
Charged	91,409	45,514	54,713	33,949	34,637	53,953	114,181	153,165	320,901	266,164	208,617	154,085	1,531,288
Uncharged Current	40,334	10,780	19,977	21,823	32,708	47,772	71,699	132,901	139,568	126,626	96,640	71,183	812,011
Uncharged Prior	-57,682	-40,334	-10,780	-19,977	-21,823	-32,708	-47,772	-71,699	-132,901	-139,568	-126,626	-96,640	-798,510
Total Residential Gas	**74,060**	**15,960**	**63,910**	**35,795**	**45,522**	**69,016**	**138,108**	**214,367**	**327,568**	**253,222**	**178,631**	**128,628**	1,544,788
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	95,223	92,202	53,650	54,112	54,903	82,024	134,296	213,173	371,131	308,200	236,761	162,214	1,857,888
Uncharged Current	41,496	33,674	21,433	33,488	37,652	56,218	81,951	157,742	163,939	151,115	114,042	75,149	967,898
Uncharged Prior	-65,679	-41,496	-33,674	-21,433	-33,488	-37,652	-56,218	-81,951	-157,742	-163,939	-151,115	-114,042	-958,429
Total C/I Gas	**71,040**	**84,379**	**41,409**	**66,168**	**59,067**	**100,589**	**160,029**	**288,963**	**377,329**	**295,376**	**199,688**	**123,321**	1,867,358
Transportation													
Charged	205,707	194,417	194,706	180,110	199,077	252,958	274,355	362,827	418,102	374,369	348,655	274,469	3,279,751
Uncharged Current	16,613	42,700	40,205	12,581	70,882	101,472	110,691	186,138	147,132	139,598	124,303	85,504	1,077,819
Uncharged Prior	-21,875	-16,613	-42,700	-40,205	-12,581	-70,882	-101,472	-110,691	-186,138	-147,132	-139,598	-124,303	-1,014,190
Total Transportation	**200,445**	**220,504**	**192,210**	**152,485**	**257,379**	**283,547**	**283,574**	**438,274**	**379,095**	**366,836**	**333,359**	**235,670**	**3,343,380**
Company Use	**88**	**47**	**5**	**1**	**7**	**21**	**38**	**81**	**137**	**118**	**76**	**49**	**666**
Total Throughput OUT	**345,633**	**320,891**	**297,533**	**254,449**	**361,975**	**453,174**	**581,750**	**941,685**	**1,084,129**	**915,550**	**711,754**	**487,669**	**6,756,192**
Total Throughput IN	**351,195**	**282,054**	**299,984**	**277,028**	**304,428**	**502,032**	**575,642**	**975,307**	**1,082,669**	**899,570**	**728,248**	**453,052**	**6,731,210**
Difference IN/OUT	5,562	-38,836	2,451	22,579	-57,547	48,859	-6,108	33,622	-1,460	-15,980	16,494	-34,616	-24,982
%													-0.37%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2010

OFF-PEAK PERIOD - Acct 182.21

		BEGINNING BALANCE(1)	WORKING CAP ALLOWANCE(2)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2009	$	(28,876)	183	0.0564%	147	330	(28,546)	(28,711)	3.25%	(78)	(28,623)
June	$	(28,623)	282	0.0564%	-	282	(28,342)	(28,482)	3.25%	(77)	(28,419)
July	$	(28,419)	114	0.0564%	(0)	114	(28,305)	(28,362)	3.25%	(77)	(28,382)
August	$	(28,382)	261	0.0564%	(0)	261	(28,121)	(28,251)	3.25%	(77)	(28,197)
September	$	(28,197)	329	0.0564%	(6)	323	(27,874)	(28,036)	3.25%	(76)	(27,950)
October	$	(27,950)	192	0.0564%	(5)	187	(27,763)	(27,857)	3.25%	(75)	(27,839)
November	$	(27,839)	1,952	0.0564%	(6,275)	(4,323)	(32,162)	(30,000)	3.25%	(81)	(32,243)
December	$	(32,243)	3,111	0.0564%	(13,017)	(9,907)	(42,149)	(37,196)	3.25%	(101)	(42,250)
January 2010	$	(42,250)	2,878	0.0564%	(18,330)	(15,451)	(57,701)	(49,976)	3.25%	(135)	(57,837)
February	$	(57,837)	2,475	0.0564%	(14,266)	(11,792)	(69,628)	(63,732)	3.25%	(173)	(69,801)
March	$	(69,801)	2,237	0.0564%	(9,837)	(7,600)	(77,401)	(73,601)	3.25%	(199)	(77,600)
April	$	(77,600)	1,303	0.0564%	(6,553)	(5,250)	(82,850)	(80,225)	3.25%	(217)	(83,068)

(1) The beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009, has been reduced by $538.08 for an adjustment made by NiSource prior to Unitil ownership. In addition, the amount of $2,762.35 has been added back to reverse an adjustment made in the prior winter period reconciliation as this amount pertains to the summer period (See Attachment A, Footnote 3). These two changes combined with a small change in interest as a result yields a starting balance of ($28,876).
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2010

OFF-PEAK PERIOD - Acct 182.22

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE(2)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
May 2009	46,749	1,460	0.45%	348	1,808	48,557	47,653	3.25%	129	48,686
June	48,686	2,248	0.45%	0	2,248	50,934	49,810	3.25%	135	51,069
July	51,069	910	0.45%	(0)	910	51,979	51,524	3.25%	140	52,119
August	52,119	2,085	0.45%	(0)	2,085	54,203	53,161	3.25%	144	54,347
September	54,347	2,629	0.45%	(15)	2,614	56,961	55,654	3.25%	151	57,112
October	57,112	1,534	0.45%	(13)	1,521	58,633	57,872	3.25%	157	58,790
November	58,790	15,583	0.45%	(15,940)	(357)	58,433	58,611	3.25%	159	58,592
December	58,592	24,833	0.45%	(33,042)	(8,209)	50,383	54,487	3.25%	148	50,530
January 2010	50,530	22,979	0.45%	(46,531)	(23,552)	26,979	38,754	3.25%	105	27,083
February	27,083	19,755	0.45%	(36,217)	(16,462)	10,622	18,853	3.25%	51	10,673
March	10,673	17,861	0.45%	(24,968)	(7,107)	3,566	7,119	3.25%	19	3,585
April	3,585	10,401	0.45%	(16,634)	(6,232)	(2,647)	469	3.25%	1	(2,646)

(1) The beginning balance for May-09 from Revised 2008-09 Winter Period Cost of Gas Adjustment Reconciliation in docket DG 08-115, dated March 4, 2009, has been reduced by $1,276.81 for an adjustment made by NiSource prior to Unitil ownership. In addition, the amount of $6,387.92 has been added back to reverse an adjustment made in the prior winter period reconciliation as this amount pertains to the summer period (See Attachment A, Footnote 3). These two changes combined with a small change in interest as a result yields a starting balance of $46,749.
(2) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2009 - 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL
Forecast Calendar Month Sales	259,755	451,329	631,824	625,692	525,469	390,952	2,885,021
Actual Sales	254,579	363,628	691,982	574,357	445,323	441,292	2,771,161
Difference	(5,176)	(87,701)	60,158	(51,335)	(80,146)	50,340	(113,860)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	298,137	503,331	704,897	548,597	378,318	251,950	2,685,229
Actual Sales	254,579	363,628	691,982	574,357	445,323	441,292	2,771,161
Weather Variance	43,558	139,703	12,915	(25,760)	(67,005)	(189,342)	(85,932)
Total Variance Excluding Weather (excl weather effect)	38,382	52,002	73,073	(77,095)	(147,151)	(139,002)	(199,792)
Variance-difference due to meter count							(141,263)
-difference in load pattern							27,403
SALES							(113,860)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2009 - 2010

	NORMAL MMBtu			METERS		
	2009-10 Forecast	2009-10 Actual	Difference	2009-10 Forecast	2009-10 Actual	Difference
Res Heat	1,272,586	1,341,110	68,524	121,032	121,602	570
Res General	19,689	24,362	4,673	9,510	9,828	318
Total Res	1,292,275	1,365,472	73,197	130,542	131,430	888
G-40	687,262	588,608	(98,654)	28,135	25,518	(2,617)
G-50	94,010	92,977	(1,033)	6,064	5,500	(564)
G-41	567,659	502,726	(64,933)	2,569	2,330	(239)
G-51	172,943	134,779	(38,164)	1,119	1,015	(104)
G-42	50,540	80,819	30,279	112	102	(10)
G-52	20,331	5,779	(14,552)	22	20	(2)
Total C & I	1,592,745	1,405,688	(187,057)	38,021	34,485	(3,536)
Total Company	2,885,021	2,771,160	(113,860)	168,563	165,915	(2,648)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2009-10 Forecast	2009-10 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.51	11.03	0.51	5,993	62,531	68,524	5.38%
Res General	2.07	2.48	0.41	658	4,015	4,673	23.73%
Total Res	12.58	13.51	0.92	6,652	66,545	73,197	5.66%
G-40	24.43	23.07	(1.36)	(63,926)	(34,728)	(98,654)	-14.35%
G-50	15.50	16.90	1.40	(8,744)	7,711	(1,033)	-1.10%
G-41	220.96	215.76	(5.20)	(52,811)	(12,122)	(64,933)	-11.44%
G-51	154.55	132.79	(21.76)	(16,073)	(22,091)	(38,164)	-22.07%
G-42	451.25	792.34	341.09	(4,513)	34,792	30,279	59.91%
G-52	924.14	288.95	(635.19)	(1,848)	(12,704)	(14,552)	-71.58%
Total C & I	41.89	40.76	(1.13)	(147,915)	(39,142)	(187,057)	-11.74%
Total Company	17.12	16.70	(0.41)	(141,263)	27,403	(113,860)	-3.95%

Northern Utilities--New Hampshire Division
Residential Low Income Assistance Program (RLIAP)
Estimated Balance: November 2009 through October 2010

	Estimate Nov-10	Estimate Dec-10	Estimate Jan-11	Estimate Feb-11	Estimate Mar-11	Estimate Apr-11	Estimate May-11	Estimate Jun-11	Estimate Jul-11	Estimate Aug-11	Estimate Sep-11	Estimate Oct-11
Beginning Balance	$ (28,892)	$ (31,488)	$ (36,833)	$ (44,067)	$ (44,832)	$ (38,120)	$ (16,829)	$ (4,040)	$ 5,504	$ 6,785	$ 7,590	$ 5,134
Plus: Program Costs	$ 17,349	$ 26,687	$ 36,219	$ 39,356	$ 36,669	$ 35,916	$ 21,376	$ 16,113	$ 8,869	$ 9,061	$ 8,093	$ 9,403
Less: Revenues	$ (19,862)	$ (29,314)	$ (39,782)	$ (39,678)	$ (33,257)	$ (25,233)	$ (14,968)	$ (11,342)	$ (8,237)	$ (8,669)	$ (9,330)	$ (12,371)
Month Activity	$ (2,514)	$ (2,627)	$ (3,562)	$ (322)	$ 3,412	$ 10,683	$ 6,409	$ 4,771	$ 632	$ 393	$ (1,237)	$ (2,969)
Ending Bal w/o interest	$ (31,406)	$ (36,741)	$ (43,958)	$ (44,711)	$ (38,008)	$ (16,755)	$ (4,012)	$ 5,502	$ 6,768	$ 7,570	$ 5,116	$ (804)
Average Balance	$ (30,149)	$ (34,114)	$ (40,396)	$ (44,389)	$ (41,420)	$ (27,437)	$ (10,421)	$ 731	$ 6,136	$ 7,178	$ 6,353	$ 2,165
Monthly Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Monthly Interest	$ (81.65)	$ (92.39)	$ (109.41)	$ (120.22)	$ (112.18)	$ (74.31)	$ (28.22)	$ 1.98	$ 16.62	$ 19.44	$ 17.21	$ 5.86

Northern Utilities--New Hampshire Division
Residential Low Income Assistance Program (RLIAP)
Estimated Program Costs and Recoveries: November 2010 through October 2011

	Estimate Nov-10	Estimate Dec-10	Estimate Jan-11	Estimate Feb-11	Estimate Mar-11	Estimate Apr-11	Estimate May-11	Estimate Jun-11	Estimate Jul-11	Estimate Aug-11	Estimate Sep-11	Estimate Oct-11	
Customer Count (1)													
Actual / Projected No. of Customers:													
LIHEAP	872	868	863	856	852	848	835	830	973	938	914	891	
Non-LIHEAP	23	24	24	24	23	23	23	26	25	24	26	26	
Total	896	893	888	881	876	872	859	857	998	962	940	917	
RLIAP Recoveries (1)													
Actual / Projected													
Therm Sales-Total Firm Throughput	4,619,147	6,817,145	9,251,536	9,227,431	7,734,292	5,868,240	3,480,836	2,637,644	1,915,520	2,015,995	2,169,667	2,877,067	
RLIAP Rate Per Therm	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	$ 0.0043	
Total	$ 19,862	$ 29,314	$ 39,782	$ 39,678	$ 33,257	$ 25,233	$ 14,968	$ 11,342	$ 8,237	$ 8,669	$ 9,330	$ 12,371	
Program Costs (1)													
Projected Costs													
IT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Admin.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Education	$ 1,230	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Interest	$ 194	$ 156	$ 120	$ 114	$ 147	$ 141	$ 172	$ 180	$ 193	$ 202	$ 102	$ 110	
Discounts-LIHEAP	$ 15,774	$ 26,597	$ 36,128	$ 39,269	$ 36,585	$ 35,828	$ 21,288	$ 16,025	$ 8,805	$ 8,981	$ 7,923	$ 9,184	
Discounts -Non-LIHEAP	$ 345	$ 90	$ 91	$ 87	$ 85	$ 88	$ 88	$ 88	$ 63	$ 81	$ 170	$ 219	
Total Costs	$ 17,543	$ 26,843	$ 36,339	$ 39,470	$ 36,816	$ 36,057	$ 21,548	$ 16,293	$ 9,062	$ 9,263	$ 8,195	$ 9,513	
Avg Monthly Residential Customer Bill	$ 98	$ 152	$ 241	$ 227	$ 176	$ 143	$ 68	$ 43	$ 34	$ 29	$ 35	$ 37	
Avg Monthly Residential Low Income Customer Bill	$ 80	$ 128	$ 206	$ 194	$ 146	$ 117	$ 50	$ 30	$ 23	$ 19	$ 24	$ 26	
Avg Monthly RLIAP Customer Discount	$ 18	$ 25	$ 35	$ 33	$ 30	$ 26	$ 18	$ 13	$ 11	$ 10	$ 11	$ 11	
Avg. Monthly RLIAP Customer Discount as a % to Avg. Monthly Residential Customer Bill	19%	16%	14%	15%	17%	18%	26%	30%	32%	34%	32%	31%	
Gross Monthly Revenues	$ 3,981,839	$ 6,010,649	$ 10,409,204	$ 8,582,090	$ 6,994,539	$ 4,768,398	$ 2,430,301	$ 1,540,386	$ 1,351,861	$ 1,352,128	$ 1,472,706	$ 2,140,779	$ 51,034,881
Total Costs as a percent of Gross Monthly Revenues	0.44%	0.45%	0.35%	0.46%	0.53%	0.76%	0.89%	1.06%	0.67%	0.69%	0.56%	0.44%	

(1) Forecast based on actual results for the 12-month period ended August 2010.

Northern Utilities, Inc. -- New Hampshire Division

Energy Efficiency Budget

	Residential	Low-Income	Gen Service	Total
August-10	$11,443	$8,939	$82,030	$102,412
September-10	$5,722	$4,469	$82,030	$92,221
October-10	$5,722	$4,469	$41,015	$51,206
November-10	$5,722	$4,469	$54,686	$64,877
December-10	$27,464	$21,453	$54,686	$103,603
January-11	$22,231	$5,500	$25,834	$53,565
February-11	$26,677	$6,600	$34,446	$67,723
March-11	$31,123	$7,700	$25,834	$64,657
April-11	$31,123	$7,700	$43,057	$81,880
May-11	$22,231	$5,500	$25,834	$53,565
June-11	$75,585	$18,700	$60,280	$154,565
July-11	$17,785	$4,400	$17,223	$39,408
August-11	$44,462	$11,000	$51,668	$107,130
September-11	$22,231	$5,500	$51,668	$79,399
October-11	$22,231	$5,500	$25,834	$53,565
15-Month Budget	$371,750	$121,900	$676,127	$1,169,776

Budget with Low-Income Costs Allocated to Residential and General Service Classes

	Residential	Low-Income	Gen Service	Total
August-10	$13,323	0	$89,089	$102,412
September-10	$6,581	0	$85,639	$92,221
October-10	$6,562	0	$44,643	$51,206
November-10	$6,885	0	$57,993	$64,877
December-10	$33,290	0	$70,313	$103,603
January-11	$23,964	0	$29,601	$53,565
February-11	$28,911	0	$38,812	$67,723
March-11	$33,642	0	$31,016	$64,657
April-11	$33,614	0	$48,267	$81,880
May-11	$24,025	0	$29,540	$53,565
June-11	$80,552	0	$74,013	$154,565
July-11	$18,768	0	$20,640	$39,408
August-11	$46,789	0	$60,342	$107,130
September-11	$23,290	0	$56,109	$79,399
October-11	$23,265	0	$30,300	$53,565
15-Month Budget	$403,460	$0	$766,316	$1,169,776

Northern Utilities, Inc.

New Hampshire Division

Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge

To Be Effective November 1, 2010 through October 31, 2011

Residential Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Costs	DSM SHI	Allocated Low Income Costs	Allocated Low Income SHI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
July-10	Actual	152,267	$0.0185	6,949	10,388	1,724	5,607	128	163,165	157,716	3.25%	435	163,600	375,418	31
August-10	Forecast	163,600	$0.0185	6,722	11,443	1,724	1,879	137	172,061	167,831	3.25%	463	172,524	363,367	31
September-10	Forecast	172,524	$0.0185	7,814	5,722	1,724	860	126	173,141	172,833	3.25%	462	173,603	422,359	30
October-10	Forecast	173,603	$0.0185	9,175	5,722	1,724	841	123	172,837	173,220	3.25%	478	173,315	495,952	31
November-10	Forecast	173,315	$0.0355	40,000	5,722	1,724	1,163	170	142,094	157,704	3.25%	421	142,515	1,126,635	30
December-10	Forecast	142,515	$0.0355	67,464	27,464	1,724	5,827	177	110,242	126,378	3.25%	349	110,591	1,900,203	31
January-11	Forecast	110,591	$0.0355	99,555	22,231	2,964	1,733	231	38,195	74,393	3.25%	205	38,400	2,804,066	31
February-11	Forecast	38,400	$0.0355	103,950	26,677	2,964	2,234	248	(33,427)	2,486	3.25%	6	(33,421)	2,927,871	28
March-11	Forecast	(33,421)	$0.0355	86,768	31,123	2,964	2,519	240	(83,344)	(58,382)	3.25%	(161)	(83,505)	2,443,900	31
April-11	Forecast	(83,505)	$0.0355	64,703	31,123	2,964	2,490	237	(111,393)	(97,449)	3.25%	(260)	(111,653)	1,822,428	30
May-11	Forecast	(111,653)	$0.0355	39,264	22,231	2,964	1,794	239	(123,688)	(117,671)	3.25%	(325)	(124,013)	1,105,900	31
June-11	Forecast	(124,013)	$0.0355	23,275	75,585	2,964	4,967	195	(63,578)	(93,796)	3.25%	(251)	(63,829)	655,568	30
July-11	Forecast	(63,829)	$0.0355	14,915	17,785	2,964	983	164	(56,848)	(60,339)	3.25%	(167)	(57,015)	420,094	31
August-11	Forecast	(57,015)	$0.0355	12,998	44,462	2,964	2,327	155	(20,106)	(38,560)	3.25%	(106)	(20,212)	366,114	31
September-11	Forecast	(20,212)	$0.0355	15,105	22,231	2,964	1,059	141	(8,921)	(14,566)	3.25%	(39)	(8,960)	425,454	30
October-11	Forecast	(8,960)	$0.0355	17,735	22,231	2,964	1,034	138	(329)	(4,644)	3.25%	(13)	(342)	499,521	31

Northern Utilities, Inc.

New Hampshire Division

Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge

To Be Effective November 1, 2010 through October 31, 2011

General Service Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Costs	DSM SHI	Allocated Low Income Costs	Allocated Low Income SHI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
July-10	Actual	(176,433)	$0.0054	8,343	9,439	2,659	23,075	525	(149,078)	(162,756)	3.25%	(449)	(149,529)	1,544,966	31
August-10	Forecast	(149,529)	$0.0054	7,370	82,030	2,659	7,059	516	(64,635)	(107,082)	3.25%	(296)	(64,931)	1,364,896	31
September-10	Forecast	(64,931)	$0.0054	9,574	82,030	2,659	3,609	527	14,320	(25,305)	3.25%	(68)	14,252	1,772,983	30
October-10	Forecast	14,252	$0.0054	11,559	41,015	2,659	3,629	530	50,526	32,389	3.25%	89	50,615	2,140,510	31
November-10	Forecast	50,615	$0.0160	51,301	54,686	2,659	3,306	483	60,448	55,531	3.25%	148	60,596	3,202,347	30
December-10	Forecast	60,596	$0.0160	81,636	54,686	2,659	15,626	475	52,407	56,502	3.25%	156	52,563	5,095,925	31
January-11	Forecast	52,563	$0.0160	97,663	25,834	2,871	3,767	502	(12,125)	20,219	3.25%	56	(12,069)	6,096,372	31
February-11	Forecast	(12,069)	$0.0160	91,674	34,446	2,871	4,366	485	(61,576)	(36,822)	3.25%	(92)	(61,668)	5,722,498	28
March-11	Forecast	(61,668)	$0.0160	80,541	25,834	2,871	5,181	493	(107,829)	(84,748)	3.25%	(234)	(108,063)	5,027,531	31
April-11	Forecast	(108,063)	$0.0160	61,068	43,057	2,871	5,210	496	(117,497)	(112,780)	3.25%	(301)	(117,798)	3,812,030	30
May-11	Forecast	(117,798)	$0.0160	36,584	25,834	2,871	3,706	494	(121,478)	(119,638)	3.25%	(330)	(121,808)	2,283,685	31
June-11	Forecast	(121,808)	$0.0160	29,035	60,280	2,871	13,733	538	(73,421)	(97,614)	3.25%	(261)	(73,682)	1,812,458	30
July-11	Forecast	(73,682)	$0.0160	23,392	17,223	2,871	3,417	569	(72,994)	(73,338)	3.25%	(202)	(73,196)	1,460,200	31
August-11	Forecast	(73,196)	$0.0160	21,862	51,668	2,871	8,673	578	(31,267)	(52,231)	3.25%	(144)	(31,411)	1,364,700	31
September-11	Forecast	(31,411)	$0.0160	28,570	51,668	2,871	4,441	592	(409)	(15,910)	3.25%	(42)	(451)	1,783,427	30
October-11	Forecast	(451)	$0.0160	34,559	25,834	2,871	4,466	595	(1,244)	(847)	3.25%	(2)	(1,246)	2,157,275	31

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE
November 1, 2010 through October 31, 2011

Total ERC Costs for the Period	$367,188
Less Current (Over) Collection (Estimated)	($36,705)
Total ERC Cost to be Recovered	$330,483
Forcasted Firm Sales & Firm Transportation Volumes	58,898,383
ERC Recovery Rate	**$0.0056**

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDIATION ADJUSTMENT CLAUSE COMPLIAN[illegible]G
2009-2010 ENVIORMENTAL RESPONSE COS[illegible]
SITE SPECIFIC EXPENSES

SCHEDULE 1
PAGE 1 OF 1

e	Description	Total	11/07 - 10/08	11/08 - 10/09	11/09 - 10/10	11/10 - 10/11	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14 10/15	11/15-10/16
	ENVIRONMENTAL RESPONSE COST (ERC)										
	July 03 - June 04 Expenses Amortization (1/7)	$ 291,630	$ 41,661	$ 41,661	$ 41,661	$ 41,661					
	July 04 - June 05 Expenses Amortization (1/7)	$ 909,099	$ 129,871	$ 129,871	$ 129,871	$ 129,871	$ 129,871				
	July 05 - June 06 Expenses Amortization (1/7)	$ 632,461	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352			
	July 06 - June 07 Expenses Amortization (1/7)	$ 186,804	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686		
	July 07 - June 08 Expenses Amortization (1/7)	$ 232,960		$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	
	July 08 - June 09 Expenses Amortization (1/7)	$ 127,728			$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247
	July 09 - June 10 Expenses Amortization (1/7)	$ 189,634				$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091
	Subtotal (Line 1 through Line 5)	$ 2,570,316	$ 468,432	$ 501,712	$ 372,043	$ 367,188	$ 325,527	$ 195,655	$ 105,304	$ 78,617	$ 45,337
	Add: Excess amortization from prior years (from schedule 5, Line 9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Less: Excess amortization to be deferred (from schedule 5, Line 8)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	Total Enviromental Response cost to be recovered (ERC)	$ 2,570,316	$ 468,433	$ 501,712	$ 372,043	$ 367,188	$ 325,527	$ 195,655	$ 105,304	$ 78,617	$ 45,337
	UNAMORTIZED ENVIRONMENTAL RESPONSE COST										
2	July 2003 - June 2004 Unamortized beginning balance		$ 166,646	$ 124,984	$ 83,323	$ 41,661	$ -				
3	July 2004 - June 2005 Unamortized beginning balance		$ 649,356	$ 519,485	$ 389,614	$ 259,743	$ 129,871	$ 0			
4	July 2005 - June 2006 Unamortized beginning balance		$ 542,109	$ 451,758	$ 361,406	$ 271,055	$ 180,703	$ 90,352	$ -		
5	July 2006 - June 2007 Unamortized beginning balance		$ 186,804	$ 160,118	$ 133,431	$ 106,745	$ 80,059	$ 53,373	$ 26,686	$ -	
6	July 2007 - June 2008 Unamortized beginning balance			$ 232,960	$ 199,680	$ 166,400	$ 133,120	$ 99,840	$ 66,560	$ 33,280	$ -
7	July 2008 - June 2009 Unamortized beginning balance				$ 127,728	$ 109,481	$ 91,234	$ 72,987	$ 54,741	$ 36,494	$ 18,247
8	July 2009 - June 2010 Unamortized beginning balance					$ 189,634	$ 162,544	$ 135,453	$ 108,362	$ 81,272	$ 54,181
9	Total Unamortized beginning balance		$ 2,690,645	$ 2,455,173	$ 1,327,128	$ 1,144,719	$ 777,531	$ 452,004	$ 256,349	$ 151,045	$ 72,428
0	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)										
1	INSURANCE/3RD PARTY RECOVERIES (IR)										
2	UNDER/OVER Recovery from previous year										
3	**Total of Lines 15, 16, 17, 18**		$ 2,690,645	$ 2,455,173	$ 1,327,128	$ 1,144,719	$ 777,531	$ 452,004	$ 256,349	$ 151,045	$ 72,428

Northern Utilities, Inc.-New Hampshire
Calculation of Balancing Charge

November 2010 through October 2011

	MDQ		Max Swing	% MDQ	
New Hampshire Underground	17,495		3,532	20.19%	
LNG	4,895		0	0.00%	
Propane	1,958		0	0.00%	

	% MDQ	Costs	Balancing Costs	% Allocated to Balancing	Allocated Costs
New Hampshire Underground					
Del., Res., and Transp.	20.19%	$10,762,980	$2,172,901	0.19%	$4,208
Capacity	20.19%	$1,443,260	$291,375	35.42%	$103,211
LNG	0.00%	$112,432	$0	140.86%	$0
Propane	0.00%	$122,856	$0	0.00%	$0
Total		$12,441,529	$2,464,276		$107,420
Annual Sum of Absolute Swings					142,624
Balancing Rate Per MMBtu Swing					**$0.75**

Note: LNG and LP MDQ allocated based on New Hampshire's current PR-Allocator percentage. 48.95% 0.02418093

Northern Utilities, Inc.
NH Division Peaking Capacity Assignment Demand Rate
November 2010 through April 2011

Line	Description	Northern	NH Division
1	Capacity Allocation Factor		48.95%
2	Peaking Contracts	62,088	30,392
3	Peaking Plants	10,000	4,895
4	Total	72,088	35,287
5	Peaking Contracts Costs	$ 4,582,488	$ 2,243,128
6	Peaking Plants		$ 686,673
7	Capacity Costs (Before Cap Assignment)		$ 2,929,801
8	NH Division Peaking Capacity Assignment Rate		$ 13.838

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2010-2011
Derivation of Class Assignments and Weightings

Basic assumptions:

1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
  a The base use portion of the class design day demand based on base use
  b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

			Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	214	2,141	252	0.4%		56	197
2	RATE B-Resi Htg	16,366	163,663	19,300	32.4%		1,404	17,896
3	RATE G-40 (R)	7,688	76,877	9,066	15.2%		263	8,803
4	RATE G-50 (Q)	880	8,798	1,037	1.7%		346	691
5	RATE G-41 (T)	7,566	75,659	8,922	15.0%		443	8,479
6	RATE G-51 (S)	1,388	13,880	1,637	2.7%		492	1,144
7	RATE G-42 (V)	846	8,460	998	1.7%		94	904
8	RATE G-52a (U)	42	417	49	0.1%		24	25
9	Special Contract	0	3,217	379	0.6%		3,070	-
10	RATE T-40	1,048	10,483	1,236	2.1%		36	1,200
11	RATE T-50	323	3,225	380	0.6%		127	253
12	RATE T-41	4,961	49,606	5,850	9.8%		290	5,559
13	RATE T-51	922	9,220	1,087	1.8%		327	760
14	RATE T-42	3,263	32,630	3,848	6.5%		361	3,487
15	RATE T-52	4,719	47,191	5,565	9.3%		2,743	2,822
16	Total		505,467	59,607	100.0%		10,076	52,222
17								-
18	Residential Total		165,804	19,552	**32.8%**		1,460	18,092
19	LLF Total		253,715	29,919	50.2%		1,486	28,433
20	HLF Total		85,947	10,135	17.0%		7,130	3,006
21	Total		505,467	59,607	100.0%		10,076	49,531
22								
23								
24			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
25	Pipeline		2,141,251	11,697	15.25			
26	Storage		12,731,830	17,365	61.10			
27	Peaking		3,702,470	30,545	10.10			
28	Total		18,575,551	59,607	**25.97**	**62.33**		
29								
30								
31								
32			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
33	Pipeline - Baseload		1,844,459	10,076	15.25			
34	Pipeline - Remaining		296,792	1,621	15.25			
35	Storage		12,731,830	17,365	61.10			
36	Peaking		3,702,470	30,545	10.10			
37	Total		18,575,551	59,607	25.97			
38								
39								
40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.			
41	Pipeline - Base	**32.8%**	605,023	3,305	15.25			
42	Pipeline - Remaining	**32.8%**	97,354	532	15.25			
43	Storage	**32.8%**	4,176,316	5,696	61.10			
44	Peaking	**32.8%**	1,214,490	10,019	10.10			
45	Total	**32.8%**	6,093,183	19,552	25.97			

C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		1,239,437	6,771	15.25
Pipeline - Remaining		199,438	1,089	15.25
Storage		8,555,514	11,669	61.10
Peaking		2,487,979	20,525	10.10
Total	**67.2%**	12,482,368	40,055	25.97

LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		213,759	1,168	15.25
Pipeline - Remaining		180,371	985	15.25
Storage		7,737,599	10,553	61.10
Peaking		2,250,126	18,563	10.10
Total	**55.9%**	10,381,856	31,270	**27.67**

HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		1,025,678	5,603	15.25
Pipeline - Remaining		19,066	104	15.25
Storage		817,915	1,116	61.10
Peaking		237,853	1,962	10.10
Total	**11.3%**	2,100,512	8,785	**19.93**

Unit Cost	Residential	LLF C&I	HLF C&I
Pipeline	$ 15.25	$ 15.25	$ 15.25
Storage	$ 61.10	$ 61.10	$ 61.10
Peaking	$ 10.10	$ 10.10	$ 10.10
Total	$ 25.97	$ 27.67	$ 19.93
Checktotal	$ 25.97	$ 27.67	$ 19.93

Load Makeup	Residential	**LLF C&I**	**HLF C&I**
Pipeline	19.62%	**6.89%**	**64.97%**
Storage	29.13%	**33.75%**	**12.70%**
Peaking	51.24%	**59.37%**	**22.34%**
Total	100.00%	**100.00%**	**100.00%**

Storage and Peaking

LLF C&I	**HLF C&I**
NA	**NA**
36.25%	**36.25%**
63.75%	**63.75%**

Supply Makeup	Residential	LLF C&I	HLF C&I	Total
Pipeline	32.80%	18.41%	48.79%	100.00%
Storage	32.80%	60.77%	6.42%	100.00%
Peaking	32.80%	60.77%	6.42%	100.00%

Provided in Summer 2011 Cost-of-Gas Filing

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 6,979,327
Storage Demand	$ 26,009,867
Peaking Demand	$ 6,160,974
Subtotal Demand	$ 39,150,168
Litigation Expense - PNGTS Invoices from 9/1/2009 - 8/13/2010	$ 376,840
Capacity Release (Credit)	$ (424,530)
Asset Management (Credit)	$ (2,507,000)
Total Net Demand Costs	$ 36,595,478

Proportional Responsibility (PR) Allocators

Allocation of Product and Pipeline Demand Costs (including Injections) to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
Rank	4	2	1	6	3	5	8	9	12	11	10	7	
% Max Month	96.85%	100.00%	100.00%	90.32%	98.51%	94.19%	86.61%	60.01%	51.03%	54.37%	58.89%	89.57%	
PR	0.66%	0.75%	0.00%	0.13%	0.55%	0.77%	3.32%	0.12%	4.25%	0.30%	0.45%	0.42%	11.74%
CumPR	10.44%	11.74%	11.74%	9.01%	11.00%	9.78%	8.46%	5.13%	4.25%	4.56%	5.01%	8.88%	100.00%
Product and Pipeline Demand Costs	$ 728,959	$ 819,550	$ 819,550	$ 628,551	$ 767,521	$ 682,593	$ 590,239	$ 358,201	$ 296,825	$ 318,012	$ 349,555	$ 619,771	$ 6,979,327

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	5,234	554,104	556,770	575,329	574,118	556,770	551,826	3,374,152
Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	47.0%	56.2%	61.0%	59.4%	56.7%	46.0%	32.3%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 5,214	$ 277,309	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 285,364	$ 1,337,337

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	135,581	686,913	1,016,879	728,568	633,976	190,867	24,831	-	-	-	-	17,189	3,434,803
Rank	6	3	1	2	4	5	7	9	9	9	9	8	
% Max Month	13.33%	67.55%	100.00%	71.65%	62.35%	18.77%	2.44%	0.00%	0.00%	0.00%	0.00%	1.69%	
PR	1.82%	1.74%	28.35%	2.05%	10.89%	1.09%	0.11%	0.00%	0.00%	0.00%	0.00%	0.21%	46.25%
CumPR	2.13%	15.85%	46.25%	17.90%	14.12%	3.22%	0.32%	0.00%	0.00%	0.00%	0.00%	0.21%	100.00%
Storage Demand Costs	$ 555,014	$ 4,122,650	$ 12,029,843	$ 4,655,382	$ 3,671,308	$ 837,833	$ 82,881	$ -	$ -	$ -	$ -	$ 54,956	$ 26,009,867
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 5,214	$ 277,309	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 285,364	$ 1,337,337
TOTAL	$ 555,014	$ 4,122,650	$ 12,029,843	$ 4,655,382	$ 3,671,308	$ 843,047	$ 360,190	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 340,320	$ 27,347,204

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	134,340	128,242	199,339	162,905	111,881	139,911	16,142	1,350	1,395	1,395	1,350	3,873	902,124
Rank	4	5	1	2	6	3	7	12	10	9	11	8	
% Max Month	67.39%	64.33%	100.00%	81.72%	56.13%	70.19%	8.10%	0.68%	0.70%	0.70%	0.68%	1.94%	
PR	0.76%	1.64%	18.28%	5.77%	8.00%	0.93%	0.88%	0.06%	0.00%	0.00%	0.00%	0.16%	36.48%
CumPR	11.50%	10.74%	36.48%	18.20%	9.10%	12.44%	1.09%	0.06%	0.06%	0.06%	0.06%	0.21%	100.00%
Peaking Demand Costs	$ 708,782	$ 661,665	$ 2,247,566	$ 1,121,516	$ 560,532	$ 766,178	$ 67,359	$ 3,477	$ 3,616	$ 3,616	$ 3,477	$ 13,189	$ 6,160,974

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

1		
2		
3	Pipeline Demand	Schedule 5
4	Storage Demand	Schedule 5
5	Peaking Demand	Schedule 5
6	Subtotal Demand	Sum LN 3 : LN 5
7	Litigation Expense - PNGTS Invoices from 9/1/2009 - 8/13/2010	ME Attachment NUI-FXW-9
8	Capacity Release (Credit)	Schedule 5
9	Asset Management (Credit)	Schedule 5
10	Total Net Demand Costs	Sum LN 6 : LN 9
11		
12		

13 **Proportional Responsibility (PR) Allocators**

14

15 **Allocation of Product and Pipeline Demand Costs (including Injections) to Months**

16		
17	Design Year Pipeline Sendout	Company Analysis
18	Rank	LN 17 Ranking
19	% Max Month	LN 17 / LN 17 MAX
20	PR	The difference between LN 19 for the month and LN 19 for next highest rank
21	CumPR	Cumulative Values, LN 20
22	Product and Pipeline Demand Costs	LN 21 * LN 3
23		

24 **Allocation of Storage Injection Fees to Months**

25		
26	Storage Injection Volume	Company Analysis
27	Design Year Pipeline Sendout	LN 17
28	% of Deliveries Injected	LN 26 / Sum (LN 26 : LN 27)
29	Injection Fees	LN 28 * LN 22
30		

31 **Allocation of Storage Demand Costs to Months**

32		
33	Design Year Storage	Company Analysis
34	Rank	LN 33 Ranking
35	% Max Month	LN 33 / LN 33 MAX
36	PR	The difference between LN 35 for the month and LN 35 for next highest rank
37	CumPR	Cumulative Values, LN 36
38	Storage Demand Costs	LN 37 * LN 4
39	Plus Injection Fees	LN 29
40	TOTAL	LN 38 + LN 39
41		

42 **Allocation of Peaking Demand Costs to Months**

43		
44	Design Year Peaking Volumes	Company Analysis
45	Rank	Rank LN 44
46	% Max Month	LN 44 / LN 44 MAX
47	PR	The difference between LN 46 for the month and LN 46 for next highest rank
48	CumPR	Cumulative Values, LN 47
49	Peaking Demand Costs	LN 48 * LN 5

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
Pipeline & Product Demand	$ 728,959	$ 819,550	$ 819,550	$ 628,551	$ 767,521	$ 682,593	$ 590,239	$ 358,201	$ 296,825	$ 318,012	$ 349,555	$ 619,771	$ 6,979,327
Storage Incld Inj Fees	$ 555,014	$ 4,122,650	$ 12,029,843	$ 4,655,382	$ 3,671,308	$ 843,047	$ 360,190	$ 201,445	$ 180,942	$ 188,867	$ 198,195	$ 340,320	$ 27,347,204
Peaking	$ 708,782	$ 661,665	$ 2,247,566	$ 1,121,516	$ 560,532	$ 766,178	$ 67,359	$ 3,477	$ 3,616	$ 3,616	$ 3,477	$ 13,189	$ 6,160,974
Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (5,214)	$ (277,309)	$ (201,445)	$ (180,942)	$ (188,867)	$ (198,195)	$ (285,364)	$ (1,337,337)
Less: Capacity Release	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (424,530)
Less: Asset Mgmt net of Current PNGTS	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,130,160)
Total Demand	$ 1,552,822	$ 5,163,932	$ 14,657,027	$ 5,965,517	$ 4,559,428	$1,931,577	$ 740,479	$ 361,678	$ 300,441	$ 321,628	$ 353,032	$ 687,917	$ 36,595,478

Capacity Cost Allocator based on Design Year Firm Sendout

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
Therms													
Maine	512,441	802,081	984,724	779,373	729,594	512,543	334,300	199,982	211,643	224,651	216,214	361,107	5,868,653
New Hampshire	456,732	735,057	953,477	764,214	727,482	498,301	331,952	234,620	158,216	169,317	210,339	306,619	5,546,326
Total	969,173	1,537,138	1,938,201	1,543,587	1,457,076	1,010,844	666,252	434,602	369,859	393,968	426,553	667,726	11,414,979

Percentage of Total	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL
Maine	52.87%	52.18%	50.81%	50.49%	50.07%	50.70%	50.18%	46.01%	57.22%	57.02%	50.69%	54.08%	51.05%
New Hampshire	47.13%	47.82%	49.19%	49.51%	49.93%	49.30%	49.82%	53.99%	42.78%	42.98%	49.31%	45.92%	48.95%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Allocation of Demand Costs by Division

Maine	$821,040	$2,694,548	$7,446,661	$3,012,051	$2,283,019	$979,396	$371,544	$166,426	$171,920	$183,401	$178,947	$372,026	$18,680,979
New Hampshire	$731,782	$2,469,384	$7,210,366	$2,953,466	$2,276,410	$952,182	$368,935	$195,252	$128,521	$138,227	$174,085	$315,891	$17,914,499
Total	$ 1,552,822	$ 5,163,932	$ 14,657,027	$ 5,965,517	$ 4,559,428	$ 1,931,577	$ 740,479	$ 361,678	$ 300,441	$ 321,628	$ 353,032	$ 687,917	$ 36,595,478

Detailed Allocation of Demand Costs by Division

Maine	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	
Pipeline & Product Demand	$ 385,430	$ 427,642	$ 416,381	$ 317,362	$ 384,317	$ 346,105	$ 296,160	$ 164,826	$ 169,851	$ 181,339	$ 177,185	$ 335,173	$ 3,601,771	51.61%
Storage Incld Injection Fees	$ 293,458	$ 2,151,205	$ 6,111,892	$ 2,350,551	$ 1,838,315	$ 427,462	$ 180,730	$ 92,695	$ 103,540	$ 107,697	$ 100,462	$ 184,046	$ 13,942,053	50.98%
Peaking	$ 374,762	$ 345,258	$ 1,141,900	$ 566,265	$ 280,672	$ 388,487	$ 33,798	$ 1,600	$ 2,069	$ 2,062	$ 1,762	$ 7,133	$ 3,145,768	51.06%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,644)	$ (139,143)	$ (92,695)	$ (103,540)	$ (107,697)	$ (100,462)	$ (154,325)	$ (700,506)	
Capacity Release (Credit)	$ (44,893)	$ (44,304)	$ (43,137)	$ (42,870)	$ (42,515)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (217,719)	51.28%
Asset Management - PNGTS (Credit)	$ (187,717)	$ (185,253)	$ (180,375)	$ (179,257)	$ (177,771)	$ (180,014)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,090,387)	51.19%
Total Allocated Demand	$ 821,040	$ 2,694,548	$ 7,446,661	$ 3,012,051	$ 2,283,019	$ 979,396	$ 371,544	$ 166,426	$ 171,920	$ 183,401	$ 178,947	$ 372,026	$ 18,680,979	51.05%

New Hampshire	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	
Pipeline & Product Demand	$ 343,529	$ 391,908	$ 403,169	$ 311,189	$ 383,204	$ 336,488	$ 294,080	$ 193,375	$ 126,974	$ 136,673	$ 172,370	$ 284,598	$ 3,377,556	48.39%
Storage Incld Injection Fees	$ 261,555	$ 1,971,445	$ 5,917,951	$ 2,304,832	$ 1,832,993	$ 415,584	$ 179,461	$ 108,750	$ 77,402	$ 81,170	$ 97,732	$ 156,275	$ 13,405,151	49.02%
Peaking	$ 334,020	$ 316,407	$ 1,105,666	$ 555,251	$ 279,860	$ 377,692	$ 33,561	$ 1,877	$ 1,547	$ 1,554	$ 1,715	$ 6,057	$ 3,015,206	48.94%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,570)	$ (138,166)	$ (108,750)	$ (77,402)	$ (81,170)	$ (97,732)	$ (131,039)	$ (636,830)	
Capacity Release	$ (40,013)	$ (40,602)	$ (41,769)	$ (42,036)	$ (42,391)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (206,811)	48.72%
Asset Management - PNGTS (Credit)	$ (167,310)	$ (169,773)	$ (174,652)	$ (175,770)	$ (177,256)	$ (175,012)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,039,773)	48.81%
Total Allocated Demand	$ 731,782	$ 2,469,384	$ 7,210,366	$ 2,953,466	$ 2,276,410	$ 952,182	$ 368,935	$ 195,252	$ 128,521	$ 138,227	$ 174,085	$ 315,891	$ 17,914,499	48.95%

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

50	Pipeline & Product Demand	LN 22
51	Storage	LN 40
52	Peaking	LN 49
53	Less: Injection Fees	-(LN 29)
54	Less: Capacity Release	LN 8 / 5
55	Less: Asset Management	(LN 9 + LN 7) / 6
56	Total Demand	Sum (LN 50 : LN 55)
57		
58	**Capacity Cost Allocator based on Design Year Firm Sendout**	
59		
60	**Therms**	
61	Maine	Company Analysis
62	New Hampshire	Company Analysis
63	Total	LN 61 + LN 62
64	**Percentage of Total**	
65	Maine	LN 61 / LN 63
66	New Hampshire	LN 62 / LN 63
67	Total	LN 65 + LN 66
68		
69	**Allocation of Demand Costs by Division**	
70	Maine	LN 56 * LN 65
71	New Hampshire	LN 56 * LN 66
72	Total	LN 70 + LN 71
73	**Detailed Allocation of Demand Costs by Division**	
74	**Maine**	
75	Pipeline & Product Demand	LN 50 * LN 65
76	Storage	LN 51 * LN 65
77	Peaking	LN 52 * LN 65
78	Injection Fees	LN 53 * LN 65
79	Capacity Release (Credit)	LN 54 * LN 65
80	Asset Management (Credit)	LN 55 * LN 65
81	**Total Allocated Demand**	Sum (LN 75 : LN 80)
82		
83	**New Hampshire**	
84	Pipeline & Product Demand	LN 50 * LN 66
85	Storage	LN 51 * LN 66
86	Peaking	LN 52 * LN 66
87	Injection Fees	LN 53 * LN 66
88	Capacity Release	LN 54 * LN 66
89	Asset Management (Credit)	LN 55 * LN 66
90	**Total Allocated Demand**	Sum (LN 84 : LN 89)

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	499,368	256,695	197,401	162,786	371,174	573,323	3,444,961	2,060,747
3	Total Storage	0	571,056	896,418	747,336	490,230	2,536	2,707,576	2,707,576
4	Total Peaking	93,071	127,597	128,626	114,220	131,348	28,722	631,864	623,584
5	Subtotal	592,439	955,348	1,222,446	1,024,342	992,752	604,580	6,784,401	5,391,907
6	Less Interruptible - Maine	0	0	0	0	0	0	0	0
7	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
8	Total Firm Supply	592,439	955,348	1,222,446	1,024,342	992,752	604,580	6,784,401	5,391,907
9	Total Firm Pipeline Sendout	499,368	256,695	197,401	162,786	371,174	573,323	3,444,961	2,060,747
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 2,759,757	$ 1,490,684	$ 1,187,524	$ 978,909	$ 2,173,072	$ 3,121,720	$ 19,355,513	$ 11,711,666
12	NYMEX Price Used for Forecast	$4.905	$5.172	$5.337	$5.306	$5.210	$5.018		
13	NYMEX Price Used for Update	$4.025	$4.359	$4.543	$4.538	$4.472	$4.399		
14	Increase/(Decrease) NYMEX Price	-$0.880	-$0.813	-$0.794	-$0.768	-$0.738	-$0.619		
15	Increase/(Decrease) in Pipeline Costs	$ (439,444)	$ (208,693)	$ (156,737)	$ (125,020)	$ (273,927)	$ (354,887)		
16	Total Updated Pipeline Costs	$ 2,320,313	$ 1,281,991	$ 1,030,787	$ 853,889	$ 1,899,146	$ 2,766,833	$ 17,001,598	$ 10,152,959
17									
18	Total Pipeline	$ 2,320,313	$ 1,281,991	$ 1,030,787	$ 853,889	$ 1,899,146	$ 2,766,833	$ 17,001,598	$ 10,152,959
19	Total Storage	$ -	$ 2,485,349	$ 3,913,239	$ 3,258,653	$ 2,142,377	$ 11,880	$ 11,811,500	$ 11,811,500
20	Total Peaking	$ 375,688	$ 513,353	$ 517,373	$ 459,022	$ 552,995	$ 117,142	$ 2,579,670	$ 2,535,574
21	Subtotal	$ 2,696,001	$ 4,280,694	$ 5,461,399	$ 4,571,564	$ 4,594,518	$ 2,895,855	$ 31,392,767	$ 24,500,032
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	7	8	4	5	5	9	46	38
26	Average Purchase Price	$ 6.385	$ 6.636	$ 6.991	$ 6.902	$ 6.713	$ 6.178		
27	NYMEX Price Used for Forecast	$ 4.905	$ 5.172	$ 5.337	$ 5.306	$ 5.210	$ 5.018		
28	NYMEX Price Used for Update	$ 4.025	$ 4.359	$ 4.543	$ 4.538	$ 4.472	$ 4.399		
29	Increase/(Decrease) NYMEX Price	$ (0.880)	$ (0.813)	$ (0.794)	$ (0.768)	$ (0.738)	$ (0.619)		
30	Futures Hedging (Gain)/Loss - Allocate	$ 165,200	$ 182,180	$ 97,930	$ 118,200	$ 112,050	$ 160,090	$ 901,540	$ 835,650
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	6	5	3	4	4	6	28	28
33	Average Purchase Price	$ 6.260	$ 6.647	$ 6.983	$ 6.825	$ 6.730	$ 6.200		
34	NYMEX Price Used for Forecast	$ 4.905	$ 5.172	$ 5.337	$ 5.306	$ 5.210	$ 5.018		
35	NYMEX Price Used for Update	$ 4.025	$ 4.359	$ 4.543	$ 4.538	$ 4.472	$ 4.399		
36	Increase/(Decrease) NYMEX Price	$ (0.880)	$ (0.813)	$ (0.794)	$ (0.768)	$ (0.738)	$ (0.619)		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ 134,100	$ 114,400	$ 73,210	$ 91,480	$ 90,320	$ 108,060	$ 611,570	$ 611,570
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 2,320,313	$ 1,281,991	$ 1,030,787	$ 853,889	$ 1,899,146	$ 2,766,833	$ 17,001,598	$ 10,152,959
41	Average Supply Cost ($/MMBtu)	$ 4.646	$ 4.994	$ 5.222	$ 5.245	$ 5.117	$ 4.826		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 2,320,313	$ 1,281,991	$ 1,030,787	$ 853,889	$ 1,899,146	$ 2,766,833	$ 17,001,598	$ 10,152,959
46	Total Storage	$ -	$ 2,485,349	$ 3,913,239	$ 3,258,653	$ 2,142,377	$ 11,880	$ 11,811,500	$ 11,811,500
47	Total Peaking	$ 375,688	$ 513,353	$ 517,373	$ 459,022	$ 552,995	$ 117,142	$ 2,579,670	$ 2,535,574
48	Firm Sales Variable Costs Excld Hedge	$ 2,696,001	$ 4,280,694	$ 5,461,399	$ 4,571,564	$ 4,594,518	$ 2,895,855	$ 31,392,767	$ 24,500,032
49	Plus Hedging (Gain)/Loss	$ 165,200	$ 182,180	$ 97,930	$ 118,200	$ 112,050	$ 160,090	$ 901,540	$ 835,650
50	Total Firm Sales Variable Costs	$ 2,861,201	$ 4,462,874	$ 5,559,329	$ 4,689,764	$ 4,706,568	$ 3,055,945	$ 32,294,307	$ 25,335,682

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Schedule 6A, page 2
3	Total Storage	Schedule 6A, page 2
4	Total Peaking	Schedule 6A, page 2
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Schedule 6A, page 2
7	Less Interruptible - New Hampshire	Schedule 6A, page 2
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Schedule 6A, Page 1
12	NYMEX Price Used for Forecast	Schedule 6A
13	NYMEX Price Used for Update	Schedule 6A
14	Increase/(Decrease) NYMEX Price	LN 13 - LN 12
15	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 14
16	Total Updated Pipeline Costs	LN 15 + LN 11
17		
18	Total Pipeline	LN 16
19	Total Storage	Schedule 6A, page 2
20	Total Peaking	Schedule 6A, page 2
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)	
25	NYMEX NG Futures Contracts	Schedule 6A, Page 2
26	Average Purchase Price	Schedule 6A, Page 2
27	NYMEX Price Used for Forecast	Schedule 6A
28	NYMEX Price Used for Update	Company Analysis
29	Increase/(Decrease) NYMEX Price	LN 28 - LN 27
30	Futures Hedging (Gain)/Loss - Allocate	(LN 26 - LN 27 - LN 29) * LN 25*10,000
31	Price Triggered NYMEX Contracts (NH Only)	
32	NYMEX NG Futures Contracts	Schedule 6A, Page 2
33	Average Purchase Price	Schedule 6A, Page 2
34	NYMEX Price Used for Forecast	Schedule 6A, Page 2
35	NYMEX Price Used for Update	Company Analysis
36	Increase/(Decrease) NYMEX Price	LN 35 - LN 34
37	Futures Hedging (Gain)/Loss (NH ONLY)	(LN 33 - LN 34 - LN 36) * LN 32*10,000
38		
39	Interruptible Cost Estimate	
40	Variable Pipeline Costs Excld Hedges	LN 16
41	Average Supply Cost ($/MMBtu)	LN 40 / LN 2
42	Interruptible Cost - Maine	LN 41 * LN 6
43	Interruptible Cost - New Hampshire	LN 41 * LN 7
44		
45	Firm Sales Pipeline Commodity Excld Hedge	LN 40 - LN 42 - LN 43
46	Total Storage	LN 19
47	Total Peaking	LN 20
48	Firm Sales Variable Costs Excld Hedge	Sum LN 45 : LN 47
49	Plus Hedging (Gain)/Loss	LN 30
50	Total Firm Sales Variable Costs	LN 48 + LN 49

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
Maine	280,388	471,420	569,668	468,815	454,818	278,040	3,157,582	2,523,149
New Hampshire	312,051	483,928	652,778	555,527	537,934	326,540	3,626,819	2,868,758
Total	592,439	955,348	1,222,446	1,024,342	992,752	604,580	6,784,401	5,391,907

Percentage of Total								
Maine	47.33%	49.35%	46.60%	45.77%	45.81%	45.99%	46.54%	46.80%
New Hampshire	52.67%	50.65%	53.40%	54.23%	54.19%	54.01%	53.46%	53.20%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Commodity Allocation by Jurisdiction

Maine

Firm Sales Pipeline Commodity Excld Hedge	$ 1,098,152	$ 632,603	$ 480,354	$ 390,803	$ 870,072	$ 1,272,437	$ 7,867,440	$ 4,744,421
Hedging (Gains) Losses	$ 78,185	$ 89,897	$ 45,636	$ 54,097	$ 51,334	$ 73,624	$ 423,275	$ 392,774
Storage	$ -	$ 1,226,405	$ 1,823,596	$ 1,491,402	$ 981,506	$ 5,464	$ 5,528,372	$ 5,528,372
Peaking	$ 177,804	$ 253,316	$ 241,099	$ 210,083	$ 253,349	$ 53,872	$ 1,209,364	$ 1,189,523
Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Maine Commodity Costs	$ 1,354,142	$ 2,202,222	$ 2,590,685	$ 2,146,385	$ 2,156,261	$ 1,405,397	$ 15,028,451	$ 11,855,090
Maine Inventory Finance Costs	$ 864	$ 1,629	$ 2,027	$ 1,646	$ 1,562	$ 855	$ 8,583	$ 8,583
Total Maine Variable Costs	$ 1,355,006	$ 2,203,851	$ 2,592,712	$ 2,148,031	$ 2,157,823	$ 1,406,252	$ 15,037,034	$ 11,863,674

New Hampshire

Firm Sales Pipeline Commodity Excld Hedge	$ 1,222,161	$ 649,388	$ 550,433	$ 463,086	$ 1,029,074	$ 1,494,396	$ 9,134,158	$ 5,408,538
Hedging (Gains) Losses	$ 221,115	$ 206,683	$ 125,504	$ 155,583	$ 151,036	$ 194,526	$ 1,089,835	$ 1,054,446
Storage	$ -	$ 1,258,945	$ 2,089,644	$ 1,767,251	$ 1,160,872	$ 6,417	$ 6,283,128	$ 6,283,128
Peaking	$ 197,883	$ 260,037	$ 276,274	$ 248,940	$ 299,647	$ 63,270	$ 1,370,306	$ 1,346,050
New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 1,641,159	$ 2,375,052	$ 3,041,855	$ 2,634,860	$ 2,640,628	$ 1,758,608	$ 17,877,426	$ 14,092,162
New Hampshire Inventory Finance Costs	$ 970	$ 1,697	$ 2,423	$ 2,042	$ 1,929	$ 1,032	$ 10,094	$ 10,094
Total New Hampshire Variable Costs	$ 1,642,129	$ 2,376,749	$ 3,044,278	$ 2,636,902	$ 2,642,557	$ 1,759,640	$ 17,887,520	$ 14,102,256

Northern Utilities

Firm Sales Pipeline Commodity Excld Hedge	$ 2,320,313	$ 1,281,991	$ 1,030,787	$ 853,889	$ 1,899,146	$ 2,766,833	$ 17,001,598	$ 10,152,959
Hedging (Gains) Losses	$ 299,300	$ 296,580	$ 171,140	$ 209,680	$ 202,370	$ 268,150	$ 1,513,110	$ 1,447,220
Storage	$ -	$ 2,485,349	$ 3,913,239	$ 3,258,653	$ 2,142,377	$ 11,880	$ 11,811,500	$ 11,811,500
Peaking	$ 375,688	$ 513,353	$ 517,373	$ 459,022	$ 552,995	$ 117,142	$ 2,579,670	$ 2,535,574
Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Northern Commodity Costs	$ 2,995,301	$ 4,577,274	$ 5,632,539	$ 4,781,244	$ 4,796,888	$ 3,164,005	$ 32,905,877	$ 25,947,252
Northern Inventory Finance Costs	$ 1,834	$ 3,326	$ 4,451	$ 3,688	$ 3,491	$ 1,887	$ 18,677	$ 18,677
Total Northern Variable Costs	$ 2,997,135	$ 4,580,600	$ 5,636,990	$ 4,784,932	$ 4,800,380	$ 3,165,892	$ 32,924,554	$ 25,965,929

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51	**Commodity Allocation Factors**	
52	Firm Sales Sendout for Normal Winter, MMBtu	
53		
54	Maine	ME Attachment NUI-JDS-4, LN 33 / 10
55	New Hampshire	Company Analysis
56	Total	LN 54 + LN 55
57		
58	**Percentage of Total**	
59	Maine	LN 54 / LN 56
60	New Hampshire	LN 55 / LN 56
61	Total	LN 59 + LN 60
62		
63	**Commodity Allocation by Jurisdiction**	
64	**Maine**	
65	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 59
66	Hedging (Gains) Losses	LN 30 * LN 59
67	Storage	LN 46 * LN 59
68	Peaking	LN 47 * LN 59
69	Maine Interruptible	LN 42
70	Total Maine Commodity Costs	Sum LN 65 : LN 69
71	Maine Inventory Finance Costs	LN 112
72	Total Maine Variable Costs	LN 70 + LN 71
73	**New Hampshire**	
74	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 60
75	Hedging (Gains) Losses	LN 30 * LN 60 + LN 37
76	Storage	LN 46 * LN 60
77	Peaking	LN 47 * LN 60
78	New Hampshire Interruptible	LN 43
79	Total New Hampshire Commodity Costs	Sum LN 74 : LN 78
80	New Hampshire Inventory Finance Costs	LN 117
81	Total New Hampshire Variable Costs	LN 79 + LN 80
82	**Northern Utilities**	
83	Firm Sales Pipeline Commodity Excld Hedge	LN 65 + LN 74
84	Hedging (Gains) Losses	LN 66 + LN 75
85	Storage	LN 67 + LN 76
86	Peaking	LN 68 + LN 77
87	Northern Interruptible	LN 69 + LN 78
88	Total Northern Commodity Costs	LN 70 + LN 79
89	Northern Inventory Finance Costs	LN 71 + LN 80
90	Total Northern Variable Costs	LN 88 + LN 89
91		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE

Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N
Inventory Finance Charge	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL
Storage	$ 1,793	$ 1,793	$ 1,514	$ 1,091	$ 739	$ 663	$ 17,542
Peaking	$ 140	$ 138	$ 128	$ 124	$ 113	$ 104	$ 1,135
Total	$ 1,933	$ 1,931	$ 1,642	$ 1,214	$ 853	$ 767	$ 18,677

Inventory Finance Charge Allocation by Jurisdiction							
Maine	$ 915	$ 953	$ 765	$ 556	$ 391	$ 353	$ 8,583
New Hampshire	$ 1,018	$ 978	$ 877	$ 658	$ 462	$ 414	$ 10,094
Total	$ 1,933	$ 1,931	$ 1,642	$ 1,214	$ 853	$ 767	$ 18,677

Inventory Finance Charge Allocation by Month

Maine

Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
Firm Sales Normal Remaining Sendout	213,227	402,021	500,269	406,132	385,419	210,879	2,117,945	2,117,945
Monthly % Sendout of Total Winter	10.07%	18.98%	23.62%	19.18%	18.20%	9.96%	100.00%	100.00%
ME Allocated Inventory Finance Charge	$ 864	$ 1,629	$ 2,027	$ 1,646	$ 1,562	$ 855	$ 8,583	$ 8,583

New Hampshire

Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
Firm Sales Normal Remaining Sendout	225,402	394,163	562,921	474,361	448,225	239,824	2,344,895	2,344,895
Monthly % Sendout of Total Winter	9.61%	16.81%	24.01%	20.23%	19.11%	10.23%	100.00%	100.00%
NH Allocated Inventory Finance Charge	$ 970	$ 1,697	$ 2,423	$ 2,042	$ 1,929	$ 1,032	$ 10,094	$ 10,094

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

92 **Northern Utilities**
93 **Simplified Market Based Allocator (MBA) Calculations**
94 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**
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LN		
98	**Inventory Finance Charge**	
99	Storage	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
100	Peaking	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
101	Total	Sum LN 99 : LN 100
102		
103	**Inventory Finance Charge Allocation by Jurisdiction**	
104	Maine	LN 101 * LN 59
105	New Hampshire	LN 101 * LN 60
106	Total	Sum LN 104 : LN 105
107		
108	**Inventory Finance Charge Allocation by Month**	
109	**Maine**	
110	Firm Sales Remaining Sendout	ME Attachment NUI-JDS-4, LN 80 / 10
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 Col N
112	ME Allocated Inventory Finance Charge	LN 104 Col N * LN 111
113		
114	**New Hampshire**	
115	Firm Sales Remaining Sendout	Company Analysis
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Northern Utilities - NEW HAMPSHIRE DIVISION
Supporting Detail to Proposed Tariff Sheets
Average Cost of Gas Calculation

LN		Winter	Summer	Total	
1	Demand	$ 13,712,022	$ 1,077,843	$ 14,789,865	Schedule 1A, LN 80
2	Commodity	$ 14,102,256	$ 3,785,265	$ 17,887,520	Schedule 1B, LN 0
3	Total	$ 27,814,277	$ 4,863,108	$ 32,677,385	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,028,950	7,400,642	35,429,591	Schedule 10B, LN 11 * 10
6	Forecasted Residential Sales (Therms)	13,035,240	3,274,690	16,309,931	Schedule 10B, LN 3 * 10
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.4892	$0.1456		LN 1 / LN 5
9	Average Commodity Rate	$0.5031	$0.5115		LN 2 / LN 5
10	Average Rate	$0.9923	$0.6571		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 6,503,781	$ 509,014	$ 7,012,796	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 6,376,960	$ 476,795	$ 6,853,755	LN 8 * LN 6
15	**Demand Reallocation:**	$ 126,821	$ 32,219	$ 159,040	LN 13 - LN 14
16	**HLF Allocation**	$ 12,540	$ 8,067	$ 20,607	LN 15 / LN 20
17	**LLF Allocation**	$ 114,281	$ 24,152	$ 138,433	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	9.89%	25.04%		Schedule 10A, LN 173
21	LLF	90.11%	74.96%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 6,566,201	$ 1,673,007	$ 8,239,208	Schedule 10A, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 6,558,444	$ 1,675,004	$ 8,233,448	LN 18 * LN 16
25	**Commodity Reallocation:**	$ 7,757	$ (1,997)	$ 5,760	LN 23 - LN 24
26	**HLF Allocation**	$ 1,419	$ (885)	$ 535	LN 25 / LN 30
27	**LLF Allocation**	$ 6,338	$ (1,112)	$ 5,226	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	18.30%	44.30%		Schedule 10C, LN 143
31	LLF	81.70%	55.70%		Schedule 10C, LN 144