Unitil
Unitil Service Corp.

ORIGINAL
N.H.P.U.C. Case No. DG 10-250
Exhibit No. #2
Witness Panel 1
DO NOT REMOVE FROM FILE

VIA ELECTRONIC FILING AND OVERNIGHT MAIL

October 14, 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 10-250, Revised Winter 2010 / 2011 Cost of Gas and Associated Charges Filing

Dear Director Howland:

Enclosed please find an original and seven copies of Northern Utilities, Inc.'s ("Northern" or the "Company") Revised Cost of Gas and Associated Charges Filing. This filing revises Northern's September 15, 2010, Winter 2010/2011 Cost of Gas and Associated Charges Filing. The revisions included herein are consistent with the discussions that the Company had with the Commission Staff and the Office of Consumer Advocate at the October 6, 2010 Technical Session held at the Commission.

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 October 14, 2015 by Mark H. Collin, Treasurer, to be effective November 1, 2010.

The revised filing reflects a recalculated cost-of-gas rate that uses NYMEX futures gas prices as of October 6, 2010. This filing reflects other revisions, updates and corrections that are summarized in the supplemental testimonies of Joseph F. Conneely and Francis X. Wells. In addition, James D. Simpson will provide and discuss a redline testimony at the October 20, 2010 hearing.

The Revised Winter cost-of-gas rate for the residential heating class is $1.0987 per therm which is a decrease of $0.0191 per therm as compared to the cost-of-gas rate that was initially filed on September 15, 2010. The Winter bill for the typical residential heating customer will be $1,436 which is $94 or 7 percent higher than the Winter 2009 / 2010 bill.

Frederick J. Stewart
Manager Regulatory Services

6 Liberty Lane West
Hampton, NH 03842-1720

Phone: 603-773-6534
Fax: 603-773-6734

Email: stewart@unitil.com

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

Very Truly Yours,

Frederick J. Stewart

Enclosures

CC: Alexander Speidel, Staff Attorney
Meredith Hatfield, OCA
Kenneth Traum, OCA
Susan Geiger, Orr & Reno
James D. Simpson, CEA

Northern Utilities, Inc.

New Hampshire Division

UPDATED 2010 / 2011 WINTER PERIOD PROPOSED COST OF GAS ADJUSTMENT

TO BE EFFECTIVE NOVEMBER 1, 2010

FILED OCTOBER 14, 2010

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc. – New Hampshire Division

UPDATED 2010/2011 WINTER PERIOD PROPOSED COST OF GAS ADJUSTMENT

TO BE EFFECTIVE NOVEMBER 1, 2010

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    Fifty-first Revised Page 39 (CGA);
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    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);
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4. Supplemental Testimony of Frances X Wells
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Unitil
Northern Utilities, Inc.

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New Hampshire Division
Winter 2010-2011 Cost of Gas - Compliance Filing

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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	
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7	Original	
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19	Third Revised	
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20.1	Original	
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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	
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43	Second Revised	
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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	
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55-a	First Revised	
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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.

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85	Original	
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89	Original	
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93	Original	
94	Forty-fifth Revised	Forty-sixth Revised
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107	Original	
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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	

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.

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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	
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165	Original	
166	Original	
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170	Original	
170-a	Original	
170-b	Second Revised	Third Revised
171	First Revised	

Tariff Pages

Unitil
Northern Utilities, Inc.

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:	$1,916,476	
Supply Costs:	$5,588,474	
Storage & Peaking Gas:		
Demand, Capacity:	$13,349,125	
Commodity Costs:	$7,057,012	
Hedging (Gain)/Loss	$1,120,010	
Interruptible Included Above	$0	
Inventory Finance Charge	$12,234	
Capacity Release, Asset Management, PNGTS Cost	($1,761,855)	
PNGTS Refund		
Total Anticipated Direct Cost of Gas		$27,281,475
ANTICIPATED INDIRECT COST OF GAS		
Adjustments:		
Prior Period Under/(Over) Collection	$2,527,403	
Prior Period Adjustment (ATV Reconciliation)	$0	
Interest	$99,469	
Refunds	$0	
Interruptible Margins	$0	
Total Adjustments		$2,626,872
Working Capital:		
Total Anticipated Direct Cost of Gas	$27,281,475	
Working Capital Percentage	0.19%	
Working Capital Allowance	$51,835	
Plus: Working Capital Reconciliation (Acct 182.11)	($83,069)	
Total Working Capital Allowance		($31,234)
Bad Debt:		
Total Anticipated Direct Cost of Gas	$27,281,475	
Plus: Prior Period Under/(Over) Collection	$2,527,403	
Plus: Interest	$0	
Plus: Total Working Capital	($31,234)	
Subtotal	$29,777,645	
Bad Debt Percentage	0.45%	
Bad Debt Allowance	$133,999	
Plus: Bad Debt Reconciliation (Acct 182.16)	($2,655)	
Total Bad Debt Allowance		$131,344
Local Production and Storage Capacity		$686,673
Miscellaneous Overhead-25.15% Allocated to Winter Season		$98,333
Total Anticipated Indirect Cost of Gas		$3,511,989
Total Cost of Gas		$30,793,465

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	$27,281,475		
Projected Prorated Sales (11/01/10-04/30/11)	28,028,950		
Direct Cost of Gas Rate		$0.9733	per therm
Demand Cost of Gas Rate	$13,503,746	$0.4818	per therm
Commodity Cost of Gas Rate	$13,777,730	$0.4916	per therm
Total Direct Cost of Gas Rate	$27,281,476	**$0.9734**	per therm
Total Anticipated Indirect Cost of Gas	$3,511,989		
Projected Prorated Sales (11/01/10-04/30/11)	28,028,950		
Indirect Cost of Gas		$0.1253	per therm
TOTAL PERIOD AVERAGE COST OF GAS		**$1.0987**	**per therm**

RESIDENTIAL COST OF GAS RATE - 11/01/10	**COGwr**	**$1.0987**	**per therm**
	Maximum (COG+25%)	**$1.3734**	
COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10	**COGwl**	**$0.9702**	**per therm**
	Maximum (COG+25%)	**$1.2128**	

C&I HLF DEMAND COSTS ALLOCATED PER SMBA	$702,159
PLUS: RESIDENTIAL DEMAND RELOCATION TO C7I HLF	$12,353
C&I HLF TOTAL ADJUSTED DEMAND COSTS	$714,512
C&I HLF PROJECTED PRORATED SALES (11/1/10-04/30/11)	2,402,246
DEMAND COST OF GAS RATE	**$0.2974**
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	$1,314,829
PLUS: RESIDENTIAL COMMODITY COSTS	$387
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	$1,315,216
C&I HLF PROJECTED PRORATED SALES (11/01/10-04/30/11)	2,402,246
COMMODITY COST OF GAS RATE	**$0.5475**
INDIRECT COST OF GAS	**$0.1253**
TOTAL C&I HLF COST OF GAS RATE	**$0.9702**

COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/10	**COGwh**	**$1.1231**	**per therm**
	Maximum (COG+25%)	**$1.4039**	

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$6,396,599
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	$112,536
C&I LLF TOTAL ADJUSTED DEMAND COSTS	$6,509,135
C&I LLF PROJECTED PRORATED SALES (11/01/10-04/30/11)	12,591,463
DEMAND COST OF GAS RATE	**$0.5169**
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$6,053,212
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	$1,783
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	$6,054,995
C&I LLF PROJECTED PRORATED SALES (11/1/10-04/30/11)	12,591,463
COMMODITY COST OF GAS RATE	**$0.4809**
INDIRECT COST OF GAS	**$0.1253**
TOTAL C&I LLF COST OF GAS RATE	**$1.1231**

Issued: October 14, 2010
Effective Date: November 1, 2010
Authorized by NHPUC Order No. ___, in Docket No. DG 10-___, dated ___, 2010.

Issued By: [signature]
Treasurer

Local Delivery Adjustment Clause

Rate Schedule	RLIAP	DSM	ERC	ITM	WLNG	CCE	RCE	LDAC
Residential Heating	$0.0043	$0.0359	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0458
Residential Non-Heating	$0.0043	$0.0359	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0458
Small C&I	$0.0043	$0.0152	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0251
Medium C&I	$0.0043	$0.0152	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0251
Large C&I	$0.0043	$0.0152	$0.0056	$0.0000	$0.0000	$0.0000	$0.0000	$0.0251
No Previous Sales Service								

Issued: October 14, 2010

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

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

Issued by: [signature]

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	$0.4558	$1.5545
	All usage over 50 therms		$0.2990	$0.3446	$1.4433
	LDAC		$0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		$1.0987		
Residential Heating Low Income	Tariff Rate R 10:				
	Monthly Customer Charge		$3.80	$3.80	$3.80
	First 50 therms		$0.1641	$0.2097	$1.3084
	All usage over 50 therms		$0.1196	$0.1652	$1.2639
	LDAC		$0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		$1.0987		
Residential Non-Heating	Tariff Rate R 6:				
	Bi-monthly Customer Charge		$19.00	$19.00	$19.00
	First 20 therms		$0.4067	$0.4523	$1.5510
	All usage over 20 therms		$0.3082	$0.3538	$1.4525
	Monthly Customer Charge		$9.50	$9.50	$9.50
	First 10 therms		$0.4067	$0.4523	$1.5510
	All usage over 10 therms		$0.3082	$0.3538	$1.4525
	LDAC		$0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		$1.0987		
Residential Non-Heating Low Income	Tariff Rate R 11:				
	Bi-monthly Customer Charge		$13.80	$13.80	$13.80
	First 20 therms		$0.3084	$0.3540	$1.4527
	All usage over 20 therms		$0.2335	$0.2791	$1.3778
	Monthly Customer Charge		$6.90	$6.90	$6.90
	First 10 therms		$0.3084	$0.3540	$1.4527
	All usage over 10 therms		$0.2335	$0.2791	$1.3778
	LDAC		$0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		$1.0987		

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	$0.3326	$1.4557
	All usage over 75 therms	$0.2007	$0.2256	$1.3487
	LDAC	$0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	$1.1231		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$18.70	$18.70	$18.70
	First 75 therms	$0.3018	$0.3267	$1.2969
	All usage over 75 therms	$0.1969	$0.2218	$1.1920
	LDAC	$0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	$0.9702		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$60.30	$60.30	$60.30
	All usage	$0.1942	$0.2191	$1.3422
	LDAC	$0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	$1.1231		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$60.30	$60.30	$60.30
	First 1300 therms	$0.1862	$0.2111	$1.1813
	All usage over 1300 therms	$0.1467	$0.1716	$1.1418
	LDAC	$0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	$0.9702		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$254.00	$254.00	$254.00
	All usage	$0.1725	$0.1974	$1.3205
	LDAC	$0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	$1.1231		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$254.00	$254.00	$254.00
	All usage	$0.1262	$0.1511	$1.1213
	LDAC	$0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	$0.9702		

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	$0.3326
	All usage over 75 therms		$0.2007	$0.2256
	LDAC		$0.0249	
C&I Low Annual/Low Winter	**Tariff Rate T 50:**			
	Monthly Customer Charge		$18.70	$18.70
	First 75 therms		$0.3018	$0.3267
	All usage over 75 therms		$0.1969	$0.2218
	LDAC		$0.0249	
C&I Medium Annual/High Winter	**Tariff Rate T 41:**			
	Monthly Customer Charge		$60.30	$60.30
	All usage		$0.1942	$0.2191
	LDAC		$0.0249	
C&I Medium Annual/Low Winter	**Tariff Rate T 51:**			
	Monthly Customer Charge		$60.30	$60.30
	First 1300 therms		$0.1862	$0.2111
	All usage over 1300 therms		$0.1467	$0.1716
	LDAC		$0.0249	
C&I High Annual/High Winter	**Tariff Rate T 42:**			
	Monthly Customer Charge		$254.00	$254.00
	All usage		$0.1725	$0.1974
	LDAC		$0.0249	
C&I High Annual/Low Winter	**Tariff Rate T 52:**			
	Monthly Customer Charge		$254.00	$254.00
	All usage		$0.1262	$0.1511
	LDAC		$0.0249	
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: **$17.68 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:	6.79%	65.39%
Storage:	33.79%	12.54%
Peaking:	59.43%	22.06%

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:	$ 312.12
25% - Annual Charge for Re-Entry Fee:	$ 78.03
Monthly Unit Charge for Re-Entry Fee:	$ 6.50

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~~	$ 1,916,476		
Supply Costs:	~~$ 4,171,677~~	$ 5,588,474		
Storage & Peaking Gas:				
Demand, Capacity:	~~$ 583,148~~	$ 13,349,125		
Commodity Costs:	~~$ 26,514~~	$ 7,057,012		
Hedging (Gain)/Loss	~~$ 343,585~~	$ 1,120,010		
Interruptible Included Above	~~$~~	$ -		
Inventory Finance Charge	~~$~~	$ 12,234		
Capacity Release, Asset Management, PNGTS Cost	~~$~~	$ (1,761,855)		
PNGTS Refund				
Total Anticipated Direct Cost of Gas			~~$ 5,599,797~~	27,281,475
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)~~	$ 99,469		
Refunds	~~$~~			
~~Capacity Reserve Charge Revenue~~	~~$ (90,228)~~			
Interruptible Margins	$ -			
Total Adjustments			~~$ (120,823)~~	$ 2,626,872
Working Capital:				
Total Anticipated Direct Cost of Gas	~~$ 5,599,797~~	$ 27,281,475		
Working Capital Percentage	0.190%			
Working Capital Allowance	~~$ 10,640~~	$ 51,835		
Plus: Working Capital Reconciliation (Acct 182.11)	~~$ (8,299)~~	$ (83,069)		
Total Working Capital Allowance			~~$ 2,341~~	$ (31,234)
Bad Debt:				
Total Anticipated Direct Cost of Gas	~~$ 5,599,797~~	$ 27,281,475		
~~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~~	$ (31,234)		
Subtotal	~~$ 5,498,825~~	$ 29,777,645		
Bad Debt Percentage	0.450%			
Bad Debt Allowance	~~$ 24,745~~	$ 133,999		
Plus: Bad Debt Reconciliation (Acct 182.16)	~~$ (4,888)~~	$ (2,655)		
Total Bad Debt Allowance			~~$ 19,857~~	$ 131,344
Local Production and Storage Capacity			$ -	686673
Miscellaneous Overhead-25.15% Allocated to Winter Season			~~$ 31,261~~	$98,333
Total Anticipated Indirect Cost of Gas			~~$ (67,365)~~	$3,511,989
Total Cost of Gas			~~$ 5,532,433~~	$30,793,464

Issued: ~~April 30, 2010~~ October 14, 2010

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

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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~~	$27,281,475		
Projected Prorated Sales (~~05/01/10 - 10/31/10~~ 11/1/10 - 04/30/11)	~~8,452,584~~	28,028,950		
Direct Cost of Gas Rate			~~$ 0.6625~~	$0.9733 per therm
Demand Cost of Gas Rate	~~$ 1,058,022~~	$13,503,746	~~$ 0.1252~~	$0.4818 per therm
Commodity Cost of Gas Rate	~~$ 4,541,776~~	$13,777,730	~~$ 0.5373~~	$0.4916 per therm
Total Direct Cost of Gas Rate	~~$ 5,599,798~~	$27,281,475	~~$ 0.6625~~	$0.9734 per therm
Total Anticipated Indirect Cost of Gas	~~$ (67,365)~~	$3,511,989		
Projected Prorated Sales (~~05/01/10 - 10/31/10~~ 11/1/10 - 04/30/11)	~~8,452,584~~	28,028,950		
Indirect Cost of Gas			~~$ (0.0080)~~	$0.1253 per therm
TOTAL PERIOD AVERAGE COST OF GAS			~~$ 0.6545~~	$1.0987 per therm
~~Period Ending Over-collection as determined on 5/25/10[1]~~	~~$ (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~~	$1.0987 per therm
		Maximum (COG+25%)	~~$ 0.8181~~	$1.3734
~~RESIDENTIAL COST OF GAS RATE - 05/01/10~~			~~$ 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~~	$0.9702 per therm
		Maximum (COG+25%)	~~$ 0.7594~~	$1.2128
~~COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/10~~			~~$ 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	$702,159			
PLUS: Residential Demand Relocation to C&I HLF	$12,353			
C&I HLF Total Adjusted Demand Costs	$714,512			
C&I HLF Projected Prorated Sales (11/01/10-04/20/11)	2,402,246			
Demand Cost of Gas Rate	$0.2974			
C&I HLF Commodity Costs Allocated per SMBA	$1,314,829			
PLUS: Residential Commodity Reallocation to C&I HLF	$387			
C&I HLF Total Adjusted Commodity Costs	$1,315,216			
C&I HLF Projected Prorated Sales (11/01/10-04/30/11)	2,402,246			
Commodity Cost of Gas Rate	$0.5475			
Indirect Cost of Gas	$0.1253			
Total C&I HLF Cost of Gas Rate	$0.9702			
COM/IND HIGH WINTER USE COST OF GAS RATE - ~~07/01/10~~ 11/01/10		COGwh	~~$ 0.7640~~	$1.1231 per therm
		Maximum (COG+25%)	~~$ 0.8631~~	$1.4039
~~COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/10~~			~~$ 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	$6,396,599			
PLUS: Residential Demand Reallocation to C&I LLF	$112,536			
C&I LLF Total Adjusted Demand Costs	$6,509,135			
C&I LLF Projected Prorated Sales (11/01/10-04/30/11)	12,591,463			
Demand Cost of Gas Rate	$0.5169			
C&I LLF Commodity Costs Allocated per SMBA	$6,053,212			
PLUS: Residential Commodity Reallocation to C&I LLF	$1,783			
C&I LLF Total Adjusted Commodity Costs	$6,054,995			
C&I LLF Projected Prorated Sales (11/01/10-04/30/11)	12,591,463			
Commodity Cost of Gas Rate	$0.4809			
Indirect Cost of Gas	$0.1253			
Total C&I LLF Cost of Gas Rate	$1.1231			

Issued: ~~June 25, 2010~~ October 14, 2010
Effective Date: ~~July 1, 2010~~ November 1, 2010
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Local Delivery Adjustment Clause

Rate Schedule	RLIAP	DSM	ERC	ITM	WLNG	CCE	RCE	LDAC
Residential Heating	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0359	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0297~~ $0.0458
Residential Non-Heating	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0359	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0297~~ $0.0458
Small C&I	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0152	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0166~~ $0.0251
Medium C&I	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0152	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0166~~ $0.0251
Large C&I	~~$0.0055~~ $0.0043	~~$0.0201~~ $0.0152	~~$0.0057~~ $0.0056	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0166~~ $0.0251
No Previous Sales Service								

Issued: ~~October 15, 2009~~ October 14, 2010
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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~~ $0.4558	~~$1.1679~~ $1.5545
	All usage over 50 therms		$0.2990	~~$0.3287~~ $0.3446	~~$1.0567~~ $1.4433
	LDAC		~~$0.0297~~ $0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.0987		

Residential Heating Low Income	Tariff Rate R 10:				
	Monthly Customer Charge		$3.80	$3.80	$3.80
	First 50 therms		$0.1641	~~$0.1938~~ $0.2097	~~$0.9218~~ $1.3084
	All usage over 50 therms		$0.1196	~~$0.1493~~ $0.1652	~~$0.8773~~ $1.2639
	LDAC		~~$0.0297~~ $0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.0987		

Residential Non-Heating	Tariff Rate R 6:				
	Bi-monthly Customer Charge		$19.00	$19.00	$19.00
	First 20 therms		$0.4067	~~$0.4364~~ $0.4523	~~$1.1644~~ $1.5510
	All usage over 20 therms		$0.3082	~~$0.3379~~ $0.3538	~~$1.0659~~ $1.4525
	Monthly Customer Charge		$9.50	$9.50	$9.50
	First 10 therms		$0.4067	~~$0.4364~~ $0.4523	~~$1.1644~~ $1.5510
	All usage over 10 therms		$0.3082	~~$0.3379~~ $0.3538	~~$1.0659~~ $1.4525
	LDAC		~~$0.0297~~ $0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.0987		

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~~ $0.3540	~~$1.0661~~ $1.4527
	All usage over 20 therms		$0.2335	~~$0.2632~~ $0.2791	~~$0.9912~~ $1.3778
	Monthly Customer Charge		$6.90	$6.90	$6.90
	First 10 therms		$0.3084	~~$0.3381~~ $0.3540	~~$1.0661~~ $1.4527
	All usage over 10 therms		$0.2335	~~$0.2632~~ $0.2791	~~$0.9912~~ $1.3778
	LDAC		~~$0.0297~~ $0.0456		
	Gas Cost Adjustment:				
	Cost of Gas		~~$0.7280~~ $1.0987		

Issued: ~~June 25,~~ October 14, 2010 Issued by: ____________
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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~~ $0.3326	~~$1.0883~~ $1.4557
	All usage over 75 therms	$0.2007	~~$0.2173~~ $ 0.2256	~~$0.9813~~ $1.3487
	LDAC	~~$0.0166~~ $0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.764~~ $1.1231		
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~~ $0.3267	~~$0.9994~~ $1.2969
	All usage over 75 therms	$0.1969	~~$0.2135~~ $0.2218	~~$0.8945~~ $1.1920
	LDAC	~~$0.0166~~ $0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.681~~ $0.9702		
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~~ $0.2191	~~$0.8930~~ $1.3422
	LDAC	~~$0.0166~~ $0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.764~~ $1.1231		
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~~ $0.2111	~~$0.8088~~ $1.1813
	All usage over ~~1000~~ 1300 therms	~~$0.078~~ $0.1467	~~$0.0946~~ $0.1716	~~$0.7756~~ $1.1418
	LDAC	~~$0.0166~~ $0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.681~~ $0.9702		
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~~ $0.1974	~~$0.8770~~ $1.3205
	LDAC	~~$0.0166~~ $0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.764~~ $1.1231		
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~~ $0.1511	~~$0.7629~~ $1.1213
	LDAC	~~$0.0166~~ $0.0249		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.681~~ $0.9702		

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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~~** $0.3326
	All usage over 75 therms		$0.2007	**~~$0.2173~~** $0.2256
	LDAC		**~~$0.0166~~** $0.0249	
C&I Low Annual/Low Winter	**Tariff Rate T 50:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3018	**~~$0.3184~~** $0.3267
	All usage over 75 therms		$0.1969	**~~$0.2135~~** $0.2218
	LDAC		**~~$0.0166~~** $0.0249	
C&I Medium Annual/High Winter	**Tariff Rate T 41:**			
	Monthly Customer Charge		$60.30	**$60.30**
	All usage		~~$0.1124~~ $0.1942	**~~$.1290~~** $0.2191
	LDAC		**~~$0.0166~~** $0.0249	
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~~** $0.2111
	All usage over ~~1000~~ 1300 therms		~~$0.078~~ $0.1467	**~~$0.0946~~** $0.1716
	LDAC		**~~$0.0166~~** $0.0249	
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~~** $0.1974
	LDAC		**~~$0.0166~~** $0.0249	
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~~** $0.1511
	LDAC		**~~$0.0166~~** $0.0249	
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**

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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: **$17.68 per MMBtu** per MDPQ per month for November 2010 through April 2011.

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- 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

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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.

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Commercial and Industrial

	High Winter Use	Low Winter Use
Pipeline:	6.79%	65.39%
Storage:	33.79%	12.54%
Peaking:	59.43%	22.06%

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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.

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Effective Dates:	**November 1, 2010 – October 31, 2011**
Annual Average Unit Cost:	$ 312.12
25% - Annual Charge for Re-Entry Fee:	$ 78.03
Monthly Unit Charge for Re-Entry Fee:	$ 6.50

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Effective: November 1, 2010 Treasurer
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Summary

Unitil
Northern Utilities, Inc.

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:	$ 1,916,476	
4	Supply Costs:	$ 5,588,474	
5			
6	**Storage & Peaking Gas for Sales Service:**		
7	Demand, Capacity:	$ 13,349,125	
8	Commodity Costs:	$ 7,057,012	
9			
10	**Hedging (Gain)/Loss**	$ 1,120,010	
11			
12	**Interruptible Sendout Cost**	$ -	
13			
14	**Inventory Finance Charge**	$ 12,234	
15			
16	**Capacity Release, Asset Management, PNGTS Cost,**	$ (1,761,855)	
17	**PNGTS Refund**		
18	**Adjustment for Actual Costs**	$ -	
19			
20	**Total Anticipated Direct Cost of Gas**		$ 27,281,475
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	$ 99,469	
27	Refunds	$ -	
28	Interruptible Margins	$ -	
29	Total Adjustments		$ 2,626,872
30			
31	**Working Capital:**		
32	Total Anticipated Direct Cost of Gas	$ 27,281,475	
33	Working Capital Percentage	0.190%	
34	Working Capital Allowance	$ 51,835	
35			
36	Plus: Working Capital Reconciliation (Acct 182.11)	$ (83,069)	
37			
38	Total Working Capital Allowance		$ (31,234)
39			
40	**Bad Debt:**		
41	Total Anticipated Direct Cost of Gas	$ 27,281,475	
42	Plus: Prior Period Under/(Over) Collection	$ 2,527,403	
43	Plus: Prior Period Adjustment (ATV Reconciliation)	$ -	
45	Plus: Total Working Capital	$ (31,234)	
46	Subtotal	$ 29,777,645	
47			
48	Bad Debt Percentage	0.450%	
49	Bad Debt Allowance	$ 133,999	
50	Plus: Bad Debt Reconciliation (Acct 182.16)	$ (2,655)	
51	Total Bad Debt Allowance		$ 131,344
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**		$ 3,511,989
58			
59	**Total Cost of Gas**		$ 30,793,464
60			
61			
62			

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

Summary

Anticipated Cost of Gas

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

LN	Column A	Reference Column D
1	ANTICIPATED DIRECT COST OF GAS	
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	ANTICIPATED INDIRECT COST OF GAS	
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	Interruptible Margins	-(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		$ 27,281,475		
Projected Prorated Sales (11/01/10 - 04/30/11)		28,028,950		
Direct Cost of Gas Rate			$ 0.9733	per therm
Demand Cost of Gas Rate		$ 13,503,746	$ 0.4818	per therm
Commodity Cost of Gas Rate		$ 13,777,730	$ 0.4916	per therm
Total Direct Cost of Gas Rate		$ 27,281,475	$ 0.9734	per therm
Total Anticipated Indirect Cost of Gas		$ 3,511,989		
Projected Prorated Sales (11/01/10 - 04/30/11)		28,028,950		
Indirect Cost of Gas			$ 0.1253	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/2010			**$ 1.0987**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/10		**COGwr**	**$ 1.0987**	**per therm**
	Maximum (COG+25%)		**$ 1.3734**	
COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10		**COGwl**	**$ 0.9702**	**per therm**
	Maximum (COG+25%)		**$ 1.2128**	
C&I HLF Demand Costs Allocated per SMBA	$ 702,159			
PLUS: Residential Demand Reallocation to C&I HLF	$ 12,353			
C&I HLF Total Adjusted Demand Costs	$ 714,512			
C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	2,402,246			
Demand Cost of Gas Rate	**$ 0.2974**			
C&I HLF Commodity Costs Allocated per SMBA	$ 1,314,829			
PLUS: Residential Commodity Reallocation to C&I HLF	$ 387			
C&I HLF Total Adjusted Commodity Costs	$ 1,315,216			
C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	2,402,246			
Commodity Cost of Gas Rate	**$ 0.5475**			
Indirect Cost of Gas	**$ 0.1253**			
Total C&I HLF Cost of Gas Rate	**$ 0.9702**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/10		**COGwh**	**$ 1.1231**	**per therm**
	Maximum (COG+25%)		**$ 1.4039**	
C&I LLF Demand Costs Allocated per SMBA	$ 6,396,599			
PLUS: Residential Demand Reallocation to C&I LLF	$ 112,536			
C&I LLF Total Adjusted Demand Costs	$ 6,509,135			
C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	12,591,463			
Demand Cost of Gas Rate	**$ 0.5169**			
C&I LLF Commodity Costs Allocated per SMBA	$ 6,053,212			
PLUS: Residential Commodity Reallocation to C&I LLF	$ 1,783			
C&I LLF Total Adjusted Commodity Costs	$ 6,054,995			
C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	12,591,463			
Commodity Cost of Gas Rate	**$ 0.4809**			
Indirect Cost of Gas	**$ 0.1253**			
Total C&I LLF Cost of Gas Rate	**$ 1.1231**			

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 23, 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 23, 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 23, 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 23, 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)

Supplemental Testimony of Francis X. Wells

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

WINTER 2010-2011 COST OF GAS

DG 10-250

Supplemental Prefiled Testimony of Francis X. Wells

October 14, 2010

I. Introduction

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

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

Q. What is the purpose of this supplemental prefiled testimony?

A. The purpose of this testimony is to provide the Commission with information relating to the updates and corrections to the initial cost of gas ("COG") filing made by Northern Utilities, Inc. ("Northern") for its New Hampshire Division on September 15, 2010. These updates and corrections are reflected a filing made by Northern contemporaneously with this supplemental prefiled testimony.

Q. Please summarize the updates and corrections that you made in connection with Northern's revised COG filing in this docket.

A. 1. First, I have recalculated Northern's estimated commodity costs using Sendout® with the following updates/changes to the estimated commodity costs which I provided in the initial filing.

a. The Lost and Unaccounted For ("LAUF") estimates in the initial filing were overstated. The LAUF in the initial filing for the New Hampshire Division was based on erroneous city-gate receipts data. The initial filing reflected a LAUF of 2.22% and the updated filing reflects a LAUF of 0.98%. This correction has the effect of reducing the volume of the estimated city-gate receipts for the New Hampshire Division, resulting in lower costs due to the lower volumes purchased. Please refer to Revised Page 3 of Attachment 2 to Schedule 10B, showing the estimated the New Hampshire Division city-gate requirements for Sales Service deliveries.

b. The NYMEX price forecast on the Attachment to Schedule 6B was updated from settlement prices as of July 22, 2010 to settlement prices as of October 6, 2010. (Please note that the September 15, 2010 initial filing included adjustments to the estimated commodity costs to account for movement in prices between the July 22, 2010 NYMEX settlement prices and the September 2, 2010 NYMEX settlement prices.) Please refer to Revised Page 1 of the Attachment to Schedule 6B.

c. The Beginning Inventory Rate as of November 1, 2010 for Washington 10 storage has been updated from $4.18 per Dth in the initial filing to $4.20 per Dth. The Beginning Inventory Rate as of November 1, 2010 for Tennessee storage has been updated from $4.32 per Dth in the initial filing to $4.46 per Dth. The Distrigas commodity rate for the 2010-2011 gas year has been updated from $3.97 per Dth in the initial filing to $3.83 per Dth. These updates are based on actual, observed September and October 2010 prices and are the Company's best estimates of the commodity prices for these resources. Schedule 14 has been revised to reflect these changes.

2. Second, I have prepared Revised Schedule 2, Attachments 6A and 6B, which reflect the updated Sendout® estimated commodity cost, resulting from the updates discussed in item 1, above. Referring to line 21 of Schedule 22 of the initial filing, Northern projected total commodity costs for the upcoming winter season to be $24,500,032 at an average city-gate delivered rate per Dth equal to $4.54 per Dth.[1] The updated commodity budget for Northern for the upcoming winter season is equal to $23,907,700 at an average city-gate price equal to $4.46 per Dth.

3. Third, I have prepared a Revised Schedule 7, which reflects updated impacts of the Company's Hedging Program, based on October 6, 2010 NYMEX settlement prices. Time Triggered Hedging Losses changed from $546,240 in the initial

[1] I calculated the city-gate delivered rate in the initial filing by dividing $24,500,032 by Northern's total city-gate requirements equal to 5,391,907 Dth, found on page 2 of Schedule 6A in the initial filing.

filing to $889,530 in this updated filing. Price Triggered Hedging Losses changed from $396,920 in the initial filing to $651,450 in this updated filing.

4. Fourth, I have updated the New Hampshire Design Year City-Gate Requirements and the Design Year Sendout Volumes to reflect the changes to the New Hampshire Division LAUF, discussed above. The New Hampshire Design Year City-Gate Requirements were overstated in the original filing due to use of the higher LAUF assumption. The impact of this correction is a revision to the capacity cost allocators to the New Hampshire and Maine Divisions, as calculated in Schedule 21. The corrected New Hampshire Design Year City-Gate Requirements appear on Line 66 of Page 3 of a Revised Schedule 21. The revised New Hampshire Design Year City-Gate Requirements were entered into a new run of Sendout® model in order to recalculate the Design Year Sendout Volumes provided in Revised Schedule 11B and Revised Page 2 of Schedule 11C. These revised Sendout Volumes are also utilized in the Revised Schedule 21. In the revised filing, the New Hampshire Capacity Cost Allocator is reduced from 48.95% to 48.64%.

5. Lastly, I have updated the forecast of New Hampshire Capacity Assignment Demand Revenue, presented in Revised Schedule 5B, to reflect the updated demand cost allocator and to correct the Peaking Demand Rate calculation. In the initial filing, the Capacity Assignment Demand Revenue was $2,600,137. The Capacity Assignment Demand Revenue has been updated to $2,709,073 in the revised filing.

Q. Does this conclude your supplemental testimony?

A. Yes it does.

Supplemental Testimony of Joseph F. Conneely

Unitil
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

WINTER 2010-2011 COST OF GAS

DG 10-250

Supplemental Prefiled Testimony of Joseph F. Conneely

October 14, 2010

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. I am a senior regulatory analyst.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe updates to Northern Utilities, Inc.'s, ("Northern") proposed changes to its Local Delivery Adjustment

Clause. I also present the impact the updated Cost of Gas ("COG") will have on bills to Northern's typical customers.

Q. Please describe the update to the RLIAP rate.

A. Northern has provided actual data for the month of August 2010 which changes the estimated beginning balance in November 2010. This is reflected in Revised Schedule 16, RLIAP, A, to an over collection in the amount of $34,047. This update does not change the RLIAP rate that was proposed on September 15, 2010 for effect November 1, 2010.

Q. What have you updated with regard to the DSM charges?

A. The Company proposed in the September 15th 2010 filing to increase the DSM charge for the residential classes from the currently approved $0.0185 to $0.0359 per therm, and increase the charge for the commercial and industrial ("C&I") customer classes from the currently approved $0.0054 to $0.0152 per therm. After updating the actual data for the month of August 2010, Northern is proposing a DSM rate for the residential classes of $0.0359 and a rate of $0.0152 for C&I classes. These updates are provided on Revised Schedule 16, DSM, B, for Residential and Revised Schedule 16, DSM, for C&I.

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

A. Northern has added August 2010 actual data to Revised Schedule 16, ERC, in the "Less Current (Over) Collection (Estimated)" line item. Northern proposes to decrease this charge to $0.0054 per therm from its September 15, 2010 rate of $0.0056.

Q. Have you prepared updated 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, Revised Schedule 8 provides the updated analyses.

Q. Does this conclude your testimony?

A. Yes, it does.

Revised Schedule 1A

Allocation of Northern Fixed Capacity Costs

To New Hampshire and Maine

Unitil
Northern Utilities, Inc.

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	$ 2,722,994
3	Storage	$ 13,319,084
4	Peaking	$ 2,995,813
5	Total Gross Demand Cost	$ 19,037,891
6		
7	Capacity Assignment Demand Revenue Estimate	$ 2,709,073
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 19,037,891
9	Capacity Assignment as % of Total Gross Demand Cost	14.23%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 387,479
14	Storage	$ 1,895,292
15	Peaking	$ 426,301
16	Total Capacity Assignment Credit	$ 2,709,073
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,335,514
21	Storage	$ 11,423,792
22	Peaking	$ 2,569,512
23	Total Net Demand Cost (Less Capacity Assignment)	$ 16,328,818
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,489
28	Less 14.23% NH Transp. Capacity Assignment	(1,635)
29	Net Pipeline MDQ	9,854
30		
31	Net Pipeline MDQ	9,854
32	Less: Firm Sales Base Use	2,895
33	Remaining Pipeline MDQ	6,959
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$237.01
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,335,514
40	Less: Base Pipeline Use	$ 686,227
41	Remaining Pipeline Use	$ 1,649,287

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 21, LN 84 + Schedule 21, LN 87
3	Storage	Schedule 21, LN 85
4	Peaking	Schedule 21, 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 14.23% 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

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

All Months	Nov	Dec	Jan	Feb	Mar	Apr
Remaining Load for All Months	2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209
Rank	6	4	1	2	3	5
% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
PR	3.91%	6.85%	15.73%	2.32%	3.20%	0.51%
CumPR	5.91%	13.27%	34.53%	18.80%	16.47%	6.42%

Peak Months Only	Nov	Dec	Jan	Feb	Mar	Apr
Remaining Load for Peak Months Only	2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209
Rank	6	4	1	2	3	5
% Max Month	40.04%	70.02%	100.00%	84.27%	79.62%	42.60%
PR	6.67%	6.85%	15.73%	2.32%	3.20%	0.51%
CumPR	6.67%	14.04%	35.30%	19.56%	17.24%	7.19%

DEMAND COST PR ALLOCATORS

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

DEMAND COSTS ALLOCATED TO MONTHS

	Nov	Dec	Jan	Feb	Mar	Apr
Pipeline - Base	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186
Pipeline - Remaining	$ 97,412	$ 218,912	$ 569,467	$ 309,997	$ 271,710	$ 105,864
Total Pipeline	$ 154,598	$ 276,098	$ 626,652	$ 367,183	$ 328,896	$ 163,049
Storage & Peaking	$ 826,492	$ 1,857,350	$ 4,831,616	$ 2,630,159	$ 2,305,313	$ 898,195
Less Credits to Demand Cost						
Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 117,579	$ 247,371	$ 621,852	$ 344,673	$ 303,773	$ 126,607
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
Total Direct Demand Costs	$ 863,511	$ 1,886,077	$ 4,836,416	$ 2,652,669	$ 2,330,436	$ 934,637

Indirect Demand Costs/(Credits)	
Miscellaneous Overhead	
Local Production & Storage	
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

		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
45	**All Months**									
46	Remaining Load for All Months	764,485	190,519	28,120	90,665	282,509	920,625	25,432,233	23,155,310	2,276,922
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							23,155,310		
54	Rank									
55	% Max Month									
56	PR							35.30%		
57	CumPR							100.00%	100.00%	0.00%
58										

59 **DEMAND COST PR ALLOCATORS**

		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
60										
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**

		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer	Winter	Summer
68												
69	Pipeline - Base	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 686,227	$ 343,114	$ 343,114	50.00%	50.00%
70	Pipeline - Remaining	$ 26,253	$ 5,345	$ 695	$ 2,382	$ 8,378	$ 32,871	$ 1,649,287	$ 1,573,363	$ 75,925	95.40%	4.60%
71	Total Pipeline	$ 83,439	$ 62,531	$ 57,881	$ 59,568	$ 65,563	$ 90,057	$ 2,335,514	$ 1,916,476	$ 419,038	82.06%	17.94%
72												
73	Storage & Peaking	$ 222,743	$ 45,349	$ 5,899	$ 20,212	$ 71,080	$ 278,895	$ 13,993,304	$ 13,349,125	$ 644,179	95.40%	4.60%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$1,761,855	$ 1,761,855	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 306,182	$ 107,880	$ 63,780	$ 79,780	$ 136,643	$ 368,952	$ 14,566,963	$ 13,503,746	$ 1,063,217	92.70%	7.30%
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		
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 21 LN 88, Schedule 21 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	($1,215,826)	($71,945)	($1,143,881)
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			($1,556,380)
6	Capacity Release Revenues			($205,475)
7	Total NH Cap Rel and Asset Management			($1,761,855)

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

Revised Schedule 1B

Commodity Costs

Northern Utilities, Inc.

P

COMMODITY COSTS

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	2,940,365	2,145,202	1,301,920	917,277	1,832,789	2,702,038	19,226,433	11,839,590
2	New Hampshire Sales Storage	0	1,991,158	4,461,290	3,947,004	2,791,775	13,154	13,257,930	13,204,380
3	New Hampshire Sales Peaking	141,065	642,320	682,820	621,419	687,407	509,318	3,329,637	3,284,349
4	Total New Hampshire Firm Sales Sendout	3,081,430	4,778,680	6,446,030	5,485,700	5,311,970	3,224,510	35,814,000	28,328,320
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	3,081,430	4,778,680	6,446,030	5,485,700	5,311,970	3,224,510	35,814,000	28,328,320
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)	34,330	56,163	65,801	55,721	54,441	32,914	384,409	299,370
11	Percent Difference	1.11%	1.18%	1.02%	1.02%	1.02%	1.02%	1.07%	1.06%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 1,303,600	$ 1,014,583	$ 645,038	$ 461,723	$ 897,374	$ 1,266,156	$ 9,160,351	$ 5,588,474
15	New Hampshire Hedging (Gains) Losses	$ 236,059	$ 221,635	$ 133,907	$ 164,587	$ 159,721	$ 204,099	$ 1,158,819	$ 1,120,010
16	New Hampshire Total Storage	$ -	$ 870,613	$ 1,952,015	$ 1,729,328	$ 1,223,055	$ 6,203	$ 5,806,463	$ 5,781,213
17	New Hampshire Total Peaking	$ 56,488	$ 249,252	$ 264,904	$ 240,948	$ 266,374	$ 197,832	$ 1,302,377	$ 1,275,799
18	New Hampshire Inventory Finance Charge	$ 1,176	$ 2,057	$ 2,937	$ 2,475	$ 2,339	$ 1,251	$ 12,234	$ 12,234
19	Total New Hampshire Sales Variable Costs	$ 1,597,323	$ 2,358,140	$ 2,998,800	$ 2,599,062	$ 2,548,863	$ 1,675,542	$ 17,440,245	$ 13,777,730
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,361,263	$ 2,136,505	$ 2,864,894	$ 2,434,474	$ 2,389,142	$ 1,471,442	$ 16,281,426	$ 12,657,720
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 1,597,323	$ 2,358,140	$ 2,998,800	$ 2,599,062	$ 2,548,863	$ 1,675,542	$ 17,440,245	$ 13,777,730
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	0.4433	0.4730	0.4955	0.5034	0.4896	0.4686	$ 0.4764	$ 0.4720
27	New Hampshire Hedging (Gains) Losses	0.0803	0.1033	0.1029	0.1794	0.0871	0.0755	$ 0.0603	$ 0.0946
28	New Hampshire Storage Excld Inventory Finance Costs	0.0000	0.4372	0.4375	0.4381	0.4381	0.4715	$ 0.4380	$ 0.4378
29	New Hampshire Peaking Excld Inventory Finance Costs	0.4004	0.3881	0.3880	0.3877	0.3875	0.3884	$ 0.3911	$ 0.3884
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	0.0083	0.0008	0.0006	0.0005	0.0007	0.0024	$ 0.0007	$ 0.0007
31	Weighted Average Cost per Dth Sendout	0.5184	0.4935	0.4652	0.4738	0.4798	0.5196	$ 0.4870	$ 0.4864
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	855,638	886,408	887,317	801,496	885,850	856,301	10,381,767	5,173,010
37	Base Commodity Cost Excld Hedging	$ 379,344	$ 419,231	$ 439,622	$ 403,443	$ 433,732	$ 401,257	$ 4,991,615	$ 2,476,628
38	Base Hedging Commodity Cost	$ 68,693	$ 91,581	$ 91,263	$ 143,813	$ 77,199	$ 64,681	$ 557,835	$ 537,229
39	Remaining Commodity Excld Hedging	$ 981,919	$ 1,717,274	$ 2,425,271	$ 2,031,031	$ 1,955,410	$ 1,070,186	$ 11,289,811	$ 10,181,092
40	Remaining Hedging Commodity	$ 167,367	$ 130,055	$ 42,643	$ 20,775	$ 82,522	$ 139,418	$ 600,984	$ 582,780
41	Total Commodity Excld Hedging	$ 1,361,263	$ 2,136,505	$ 2,864,894	$ 2,434,474	$ 2,389,142	$ 1,471,442	$ 16,281,426	$ 12,657,720
42	Total Hedging	$ 236,059	$ 221,635	$ 133,907	$ 164,587	$ 159,721	$ 204,099	$ 1,158,819	$ 1,120,010
43	Total Commodity (Incl Hedging)	$ 1,597,323	$ 2,358,140	$ 2,998,800	$ 2,599,062	$ 2,548,863	$ 1,675,542	$ 17,440,245	$ 13,777,730

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

LN	Description	Source
	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

Revised Schedule 2

Unitil
Northern Utilities, Inc.

Estimated Delivered City-Gate Commodity Costs and Volumes May 1, 2010 through October 31, 2010			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Peaking Supply 1	$2,357,594	612,436	$3.8495
Washington 10 Storage	$10,679,534	2,442,492	$4.3724
Chicago	$1,756,821	378,381	$4.6430
Tennessee Production	$7,125,600	1,527,666	$4.6644
Niagara	$659,834	141,353	$4.6680
Tennessee Storage	$216,087	46,128	$4.6845
PNGTS - Delivered	$1,058,054	199,100	$5.3142
LNG	$54,177	8,426	$6.4299
Total System	$23,907,700	5,355,981	$4.4637

Revised Schedule 3

Unitil
Northern Utilities, Inc.

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
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								$1.0987	$1.0987	$1.0987	$1.0987	$1.0987	$1.0987	
8	Sales HLF Classes CGA								$1.0987	$1.0987	$1.0987	$1.0987	$1.0987	$1.0987	
9	Sales LLF Classes CGA								$1.0987	$1.0987	$1.0987	$1.0987	$1.0987	$1.0987	
10	Revenues														
11	Residential Heat & Non Heat								$ (1,554,093)	$ (2,265,775)	$ (3,281,104)	$ (2,773,941)	$ (2,750,132)	$ (1,696,774)	$ (14,321,819)
12	Sales HLF Classes								$ (385,287)	$ (466,889)	$ (511,521)	$ (448,521)	$ (471,862)	$ (355,266)	$ (2,639,347)
13	Sales LLF Classes								$ (1,408,468)	$ (2,455,965)	$ (3,217,333)	$ (2,743,456)	$ (2,554,453)	$ (1,454,566)	$ (13,834,241)
14	Total Sales Revenues								$ (3,347,848)	$ (5,188,630)	$ (7,009,958)	$ (5,965,918)	$ (5,776,447)	$ (3,506,606)	$ (30,795,407)
15															

			Summer						Winter						
16															
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		$ 162,645	$ 162,645	$ 162,645	$ 162,645	$ 162,645	$ 162,645	$ 142,620	$ 147,401	$ 162,645	$ 162,645	$ 162,645	$ 162,645	$ 1,916,476
21	Storage		$ 506,135	$ 506,135	$ 506,135	$ 506,135	$ 506,135	$ 506,135	$ 1,195,209	$ 1,516,127	$ 1,542,778	$ 1,542,778	$ 1,542,778	$ 506,135	$ 10,882,616
22	Peaking		$ 145,118	$ 145,118	$ 145,118	$ 145,118	$ 145,118	$ 145,118	$ 268,796	$ 268,796	$ 299,270	$ 299,270	$ 299,270	$ 145,118	$ 2,451,225
23	Total Demand Costs		$ 813,898	$ 813,898	$ 813,898	$ 813,898	$ 813,898	$ 813,898	$ 1,606,625	$ 1,932,324	$ 2,004,693	$ 2,004,693	$ 2,004,693	$ 813,898	$ 15,250,317
24	NUI Commodity Costs														
25	NUI Total Pipeline Volumes								561,589	426,146	245,249	170,119	340,205	503,193	2,246,500
26	Pipeline Costs Modeled in Sendout™								$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	$ 10,600,308
27	NYMEX Price Used for Forecast								$ 3.8650	$ 4.1870	$ 4.3730	$ 4.3980	$ 4.3370	$ 4.3060	
28	NYMEX Price Used for Update								$ 3.8650	$ 4.1870	$ 4.3730	$ 4.3980	$ 4.3370	$ 4.3060	
29	Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
30	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
31	Updated Pipeline Costs								$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	
32	Interruptible Volumes - NH								0	0	0	0	0	0	
33	Average Supply Cost ($/MMBtu)								$ 4.43	$ 4.73	$ 4.95	$ 5.03	$ 4.90	$ 4.69	
34	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Updated Pipeline Costs								$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	
36	New Hampshire Allocated Percentage								52.36%	50.34%	53.09%	53.92%	53.87%	53.70%	
37	NH Updated Pipeline Costs								$ 1,303,600	$ 1,014,583	$ 645,038	$ 461,723	$ 897,374	$ 1,266,156	$ 5,588,474
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								$ 3.8650	$ 4.1870	$ 4.3730	$ 4.3980	$ 4.3370	$ 4.3060	
43	NYMEX Price Used for Update								$ 3.8650	$ 4.1870	$ 4.3730	$ 4.3980	$ 4.3370	$ 4.3060	
44	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
45	NUI Futures Hedging (Gain)/Loss - Allocate								$ 176,400	$ 195,940	$ 104,730	$ 125,200	$ 118,800	$ 168,460	$ 889,530
46	New Hampshire Allocated Percentage								52.36%	50.34%	53.09%	53.92%	53.87%	53.70%	
47	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 92,359	$ 98,635	$ 55,597	$ 67,507	$ 64,001	$ 90,459	$ 468,560

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								$ 3.8650	$ 4.1870	$ 4.3730	$ 4.3980	$ 4.3370	$ 4.3060	
52	NYMEX Price Used for Update								$ 3.8650	$ 4.1870	$ 4.3730	$ 4.3980	$ 4.3370	$ 4.3060	
53	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
54	NUI Futures Hedging (Gain)/Loss - Allocate								$ 143,700	$ 123,000	$ 78,310	$ 97,080	$ 95,720	$ 113,640	$ 651,450
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								$ 143,700	$ 123,000	$ 78,310	$ 97,080	$ 95,720	$ 113,640	$ 651,450
57	NH Commodity Costs														
58	Pipeline Excl Hedging								$ 1,303,600	$ 1,014,583	$ 645,038	$ 461,723	$ 897,374	$ 1,266,156	$ 5,588,474
59	Hedging (Gain)/Loss Estimate								$ 236,059	$ 221,635	$ 133,907	$ 164,587	$ 159,721	$ 204,099	$ 1,120,010
60	Storage								$ -	$ 870,613	$ 1,952,015	$ 1,729,328	$ 1,223,055	$ 6,203	$ 5,781,213
61	Peaking								$ 56,488	$ 249,252	$ 264,904	$ 240,948	$ 266,374	$ 197,832	$ 1,275,799
62	Total Commodity Costs								$ 1,596,147	$ 2,356,084	$ 2,995,863	$ 2,596,587	$ 2,546,524	$ 1,674,291	$ 13,765,495
63	Inventory Finance Charge		$ 1,077	$ 1,094	$ 1,157	$ 1,045	$ 1,014	$ 960	$ 1,043	$ 1,002	$ 1,031	$ 971	$ 883	$ 956	$ 12,234
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		$ (79,980)	$ (79,980)	$ (79,980)	$ (79,980)	$ (79,980)	$ (79,980)	$ (82,890)	$ (82,890)	$ (82,890)	$ (82,890)	$ (82,890)	$ (79,980)	$ (974,311)
70	NH Capacity Release		$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (17,123)	$ (205,475)
	NH PNGTS Refund											($583,255)			
71	NH Total Asset Management and Capacity Release		$ (97,103)	$ (97,103)	$ (97,103)	$ (97,103)	$ (97,103)	$ (97,103)	$ (100,013)	$ (100,013)	$ (100,013)	$ (683,268)	$ (100,013)	$ (97,103)	$ (1,763,041)

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**		$ 717,872	$ 717,889	$ 717,953	$ 717,840	$ 717,809	$ 717,755	$ 3,103,802	$ 4,189,397	$ 4,901,575	$ 3,918,983	$ 4,452,087	$ 2,392,042	$ 27,265,005
77	Working Capital														
78	Total Anticipated Direct Cost of Gas		$ 717,872	$ 717,889	$ 717,953	$ 717,840	$ 717,809	$ 717,755	$ 3,103,802	$ 4,189,397	$ 4,901,575	$ 3,918,983	$ 4,452,087	$ 2,392,042	$ 27,265,005
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		$ 1,364	$ 1,364	$ 1,364	$ 1,364	$ 1,364	$ 1,364	$ 5,897	$ 7,960	$ 9,313	$ 7,446	$ 8,459	$ 4,545	$ 51,804
81	Beginning Period Working Capital Balance		$ (83,069)	$ (81,866)	$ (80,661)	$ (79,454)	$ (78,244)	$ (77,032)	$ (75,818)	$ (70,063)	$ (62,233)	$ (53,032)	$ (45,683)	$ (37,305)	
82	End of Period Working Capital Allowance		$ (81,705)	$ (80,502)	$ (79,297)	$ (78,090)	$ (76,880)	$ (75,668)	$ (69,920)	$ (62,103)	$ (52,920)	$ (45,586)	$ (37,224)	$ (32,760)	
83	Interest		$ (161)	$ (159)	$ (157)	$ (154)	$ (152)	$ (149)	$ (143)	$ (129)	$ (113)	$ (97)	$ (81)	$ (69)	$ (1,563)
84	End of period with Interest	$ (83,069)	$ (81,866)	$ (80,661)	$ (79,454)	$ (78,244)	$ (77,032)	$ (75,818)	$ (70,063)	$ (62,233)	$ (53,032)	$ (45,683)	$ (37,305)	$ (32,829)	
85	Bad Debt														
86	Total Anticipated Direct Cost of Gas		$ 717,872	$ 717,889	$ 717,953	$ 717,840	$ 717,809	$ 717,755	$ 3,103,802	$ 4,189,397	$ 4,901,575	$ 3,918,983	$ 4,452,087	$ 2,392,042	$ 27,265,005
87	Prior Period Over/Under Collection (Incld AT	$ 2,527,403	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,527,403
88	Working Capital Allowance		$ (81,705)	$ (80,341)	$ (78,977)	$ (77,613)	$ (76,249)	$ (74,885)	$ (68,988)	$ (61,028)	$ (51,715)	$ (44,269)	$ (35,810)	$ (31,265)	$ (762,848)
89	Subtotal	$ 2,527,403	$ 636,167	$ 637,548	$ 638,976	$ 640,227	$ 641,560	$ 642,870	$ 3,034,814	$ 4,128,369	$ 4,849,859	$ 3,874,714	$ 4,416,277	$ 2,360,777	$ 29,029,561
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	$ 2,863	$ 2,869	$ 2,875	$ 2,881	$ 2,887	$ 2,893	$ 13,657	$ 18,578	$ 21,824	$ 17,436	$ 19,873	$ 10,623	$ 130,633
92	Beginning Period Bad Debt Balance		$ (2,655)	$ 205	$ 3,078	$ 5,962	$ 8,857	$ 11,764	$ 14,683	$ 28,382	$ 47,033	$ 68,971	$ 86,559	$ 106,622	
93	End of Period Bad Debt Balance		$ 208	$ 3,074	$ 5,953	$ 8,843	$ 11,744	$ 14,657	$ 28,340	$ 46,960	$ 68,858	$ 86,407	$ 106,433	$ 117,245	
94	Interest		$ (2)	$ 3	$ 9	$ 14	$ 20	$ 26	$ 42	$ 74	$ 113	$ 152	$ 189	$ 219	$ 860
95	End of Period Bad Debt Balance with Interest	$ (2,655)	$ 205	$ 3,078	$ 5,962	$ 8,857	$ 11,764	$ 14,683	$ 28,382	$ 47,033	$ 68,971	$ 86,559	$ 106,622	$ 117,464	
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	$ 3,250,926	$ 3,975,881	$ 4,702,319	$ 5,430,067	$ 6,159,208	$ 6,889,722	$ 6,789,886	$ 5,933,930	$ 3,966,061	$ 2,055,849	$ 865,180	
100	Net Costs - Revenues		$ 717,872	$ 717,889	$ 717,953	$ 717,840	$ 717,809	$ 717,755	$ (113,212)	$ (868,398)	$ (1,977,549)	$ (1,916,100)	$ (1,193,525)	$ (983,730)	
101	Ending Balance before Interest		$ 3,245,276	$ 3,968,815	$ 4,693,834	$ 5,420,159	$ 6,147,876	$ 6,876,963	$ 6,776,511	$ 5,921,488	$ 3,956,381	$ 2,049,961	$ 862,324	$ (118,550)	
102	Average Balance		$ 2,886,340	$ 3,609,870	$ 4,334,858	$ 5,061,239	$ 5,788,971	$ 6,518,086	$ 6,833,117	$ 6,355,687	$ 4,945,155	$ 3,008,011	$ 1,459,086	$ 373,315	
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		$ 5,650	$ 7,066	$ 8,485	$ 9,907	$ 11,332	$ 12,759	$ 13,376	$ 12,441	$ 9,680	$ 5,888	$ 2,856	$ 731	$ 100,173
105	Ending Balance Incl Interest Expense	$ 2,527,403	$ 3,250,926	$ 3,975,881	$ 4,702,319	$ 5,430,067	$ 6,159,208	$ 6,889,722	$ 6,789,886	$ 5,933,930	$ 3,966,061	$ 2,055,849	$ 865,180	$ (117,819)	
106	**Total Over/Under Collection Ending Balance**		$ 3,169,265	$ 3,898,298	$ 4,628,828	$ 5,360,680	$ 6,093,940	$ 6,828,588	$ 6,748,205	$ 5,918,730	$ 3,982,000	$ 2,096,726	$ 934,496	$ (33,184)	
107	ATV Reconciliation														$ -
108															
109	**Total Indirect Cost of Gas**	$ 2,453,053	$ 9,713	$ 11,144	$ 12,577	$ 14,013	$ 15,451	$ 16,892	$ 163,664	$ 169,758	$ 171,653	$ 161,660	$ 162,131	$ 146,884	$ 3,508,591
110															
111	**Total Cost of Gas**	$ 2,453,053	$ 727,585	$ 729,033	$ 730,530	$ 731,852	$ 733,261	$ 734,648	$ 3,267,466	$ 4,359,155	$ 5,073,227	$ 4,080,644	$ 4,614,218	$ 2,538,926	$ 30,773,597
112															
113	**Total Interest**	$ -	$ 5,486	$ 6,911	$ 8,338	$ 9,768	$ 11,200	$ 12,636	$ 13,275	$ 12,386	$ 9,681	$ 5,944	$ 2,964	$ 881	$ 99,469
114															

Revised Schedule 5B

Unitil
Northern Utilities, Inc.

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	$ (501,740)	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	$ (2,709,073)	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

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	$ 17.68	$ (83,623)
Dec-10	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Jan-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Feb-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Mar-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)
Apr-11	681	683	228	2,791	80	268	4,731	$ 17.68	$ (83,623)

Total Division Peaking Demand Revenue $ (501,740)

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
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

Revised Schedule 6A

Unitil
Northern Utilities, Inc.

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	$ 574,230	$ 272,034	$ 4,784	$ 58,231	$ 39,144	$ 808,398	$ 1,756,821
PNGTS - Delivered	$ 167,673	$ 184,242	$ 190,585	$ 172,911	$ 189,357	$ 153,285	$ 1,058,054
Niagara	$ 353,231	$ -	$ -	$ 40,679	$ 31,942	$ 233,982	$ 659,834
Tennessee Production	$ 1,394,647	$ 1,559,200	$ 1,019,721	$ 584,497	$ 1,405,275	$ 1,162,260	$ 7,125,600
Storage							
Tennessee Storage	$ -	$ -	$ 38,748	$ 99,112	$ 66,676	$ 11,551	$ 216,087
Washington 10 Storage	$ -	$ 1,729,478	$ 3,638,360	$ 3,108,121	$ 2,203,575	$ -	$ 10,679,534
Peaking							
Peaking Supply 1	$ 98,519	$ 485,821	$ 489,782	$ 438,806	$ 485,821	$ 358,846	$ 2,357,594
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 9,368	$ 9,321	$ 9,231	$ 8,060	$ 8,627	$ 9,571	$ 54,177
Total Commodity Cost	$ 2,597,669	$ 4,240,096	$ 5,391,210	$ 4,510,417	$ 4,430,416	$ 2,737,893	$ 23,907,700

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	126,638	56,891	965	11,567	7,860	174,459	378,381
PNGTS - Delivered	33,000	34,100	34,100	30,800	34,100	33,000	199,100
Niagara	77,607	0	0	7,984	6,346	49,417	141,353
Tennessee Production	324,343	335,155	210,184	119,768	291,899	246,316	1,527,666
Storage							
Tennessee Storage	0	0	8,275	21,165	14,238	2,450	46,128
Washington 10 Storage	0	395,545	832,121	710,851	503,975	0	2,442,492
Peaking							
Peaking Supply 1	25,592	126,202	127,231	113,989	126,202	93,218	612,436
Peaking Supply 2	0	0	0	0	0	0	0
LNG	1,350	1,395	1,395	1,260	1,395	1,631	8,426
Total Delivered (Dth)	588,531	949,288	1,214,271	1,017,385	986,015	600,491	5,355,981

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	$ 4.5344	$ 4.7817	$ 4.9591	$ 5.0341	$ 4.9801	$ 4.6337	$ 4.6430
PNGTS - Delivered	$ 5.0810	$ 5.4030	$ 5.5890	$ 5.6140	$ 5.5530	$ 4.6450	$ 5.3142
Niagara	$ 4.5516			$ 5.0953	$ 5.0334	$ 4.7348	$ 4.6680
Tennessee Production	$ 4.2999	$ 4.6522	$ 4.8516	$ 4.8802	$ 4.8143	$ 4.7186	$ 4.6644
Storage							
Tennessee Storage			$ 4.6828	$ 4.6828	$ 4.6828	$ 4.7152	$ 4.6845
Washington 10 Storage		$ 4.3724	$ 4.3724	$ 4.3724	$ 4.3724		$ 4.3724
Peaking							
Peaking Supply 1	$ 3.8495	$ 3.8495	$ 3.8495	$ 3.8495	$ 3.8495	$ 3.8495	$ 3.8495
Peaking Supply 2							
LNG	$ 6.9394	$ 6.6814	$ 6.6169	$ 6.3965	$ 6.1843	$ 5.8691	$ 6.4299
Total System	$ 4.4138	$ 4.4666	$ 4.4399	$ 4.4333	$ 4.4933	$ 4.5594	$ 4.4637

Revised Attachment to Schedule 6B
NYMEX Price Forecast

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for October 6, 2010

Line	Item	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
1	NYMEX	$3.865	$4.187	$4.373	$4.398	$4.337	$4.306
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	

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
2	Purchased Volumes	Line 9	132,844	59,109	999	12,065	8,207	182,593	395,818
3	City Gate Delivered Volume	Sum Lines 55, 75 and 95	126,638	56,891	965	11,567	7,860	174,459	378,381
4	Total Purchase Cost	Line 14	$ 565,519	$ 270,661	$ 4,762	$ 57,790	$ 38,810	$ 795,375	$ 1,732,917
5	Variable Transportation Costs	Sum Lines 27, 37, 47, 57, 67, 77, 87 and 97	$ 8,712	$ 1,373	$ 23	$ 441	$ 333	$ 13,022	$ 23,904
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 574,230	$ 272,034	$ 4,784	$ 58,231	$ 39,144	$ 808,398	$ 1,756,821
7	Average Delivered Price	Line 5 divided by Line 2	$ 4.534	$ 4.782	$ 4.959	$ 5.034	$ 4.980	$ 4.634	$ 4.643
8									
9	Chicago Supply Costs								
10	Purchased Volumes	Sendout Optimization	132,844	59,109	999	12,065	8,207	182,593	395,818
11	Monthly NYMEX Price	Att to Sch 6B, Line 1 of Page 1	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306	$ 4.144
12	NYMEX Cost	Line 9 times Line 10	$ 513,444	$ 247,490	$ 4,370	$ 53,061	$ 35,593	$ 786,246	$ 1,640,203
13	NYMEX Basis Price	Att to Sch 6B, Line 3 of Page 1	$ 0.392	$ 0.392	$ 0.392	$ 0.392	$ 0.392	$ 0.050	$ 0.234
14	NYMEX Basis Costs	Line 9 times Line 12	$ 52,075	$ 23,171	$ 392	$ 4,729	$ 3,217	$ 9,130	$ 92,714
15	Total Purchase Price	Line 10 plus Line 12	$ 4.257	$ 4.579	$ 4.765	$ 4.790	$ 4.729	$ 4.356	$ 4.378
16	Total Purchase Cost	Line 11 plus Line 13	$ 565,519	$ 270,661	$ 4,762	$ 57,790	$ 38,810	$ 795,375	$ 1,732,917
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1&2								
20	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
21	Receipt Point: Alliance								
22	Delivery Point: Dawn (Interconnects with TransCanada)								
23	Received Volume	Line 9	132,844	59,109	999	12,065	8,207	182,593	395,818
24	Fuel Loss Rate	Att to Sch 6B, Line 17 of Page 2	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%
25	Delivered Volume	Line 22 times (1 - Line 23)	131,529	58,524	989	11,945	8,126	180,785	391,899
26	Variable Transportation Rate	Att to Sch 6B, Line 17 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
27	Variable Transportation Costs	Line 24 times Line 25	$ 250	$ 111	$ 2	$ 23	$ 15	$ 343	$ 745
28									
29	Transportation Segment 3								
30	TransCanada Pipeline (Contract 29594)								
31	Receipt Point: Dawn								
32	Delivery Point: Parkway (Interconnects with Iroquois)								
33	Received Volume	Line 25	131,529	58,524	989	11,945	8,126	180,785	391,899
34	Fuel Loss Rate	Att to Sch 6B, Line 14 of Page 2	1.45%	1.45%	1.45%	1.45%	1.45%	1.25%	1.36%
35	Delivered Volume	Line 33 times (1 - Line 34)	129,622	57,675	975	11,772	8,008	178,526	386,578
36	Variable Transportation Rate	Att to Sch 6B, Line 14 of Page 2	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141
37	Variable Transportation Costs	Line 35 times Line 36	$ 1,828	$ 813	$ 14	$ 166	$ 113	$ 2,517	$ 5,451
38									
39	Transportation Segment 4								
40	Iroquois Pipeline (Contract R181001)								
41	Receipt Point: Parkway								
42	Delivery Point: Wright (Interconnection with Tennessee)								
43	Received Volume	Line 35	129,622	57,675	975	11,772	8,008	178,526	386,578
44	Fuel Loss Rate	Att to Sch 6B, Line 4 of Page 2	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
45	Delivered Volume	Line 43 times (1 - Line 44)	129,492	57,618	974	11,760	8,000	178,347	386,191
46	Variable Transportation Rate	Att to Sch 6B, Line 4 of Page 2	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052
47	Variable Transportation Costs	Line 45 times Line 46	$ 673	$ 300	$ 5	$ 61	$ 42	$ 927	$ 2,008
48									
49	Transporation Segment 5A								
50	Tennessee Gas Pipeline (Contract 31861)								
51	Receipt Point: Mendon								
52	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
53	Received Volume	Line 45	34,578	35,731	974	6,110	4,000	39,208	120,600
54	Fuel Loss Rate	Att to Sch 6B, Line 12 of Page 2	0.96%	0.96%	0.96%	0.96%	0.96%	0.96%	0.96%
55	City Gate Delivered Volume	Line 53 times (1 - Line 54)	34,246	35,387	965	6,051	3,961	38,831	119,442
56	Variable Transportation Rate	Att to Sch 6B, Line 12 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
57	Variable Transportation Costs	Line 55 times Line 56	$ 65	$ 67	$ 2	$ 11	$ 8	$ 74	$ 227
58									
59	Transportation Segment 5B								
60	Tennessee Gas Pipeline (Contract 31861)								
61	Receipt Point: Mendon								
62	Delivery Point: Pleasant St. (Interconnection with Granite)								
63	Received Volume	Line 45	20,908	21,887	-	3,530	2,118	24,017	72,461
64	Fuel Loss Rate	Att to Sch 6B, Line 13 of Page 2	1.26%	1.26%	#DIV/0!	1.26%	1.26%	1.26%	1.26%
65	Delivered Volume	Line 63 times (1 - Line 64)	20,645	21,611	-	3,486	2,091	23,715	71,548
66	Variable Transportation Rate	Att to Sch 6B, Line 13 of Page 2	$ 0.0019	$ 0.0019	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
67	Variable Transportation Costs	Line 65 times Line 66	$ 39	$ 41	$ -	$ 7	$ 4	$ 45	$ 136
68									
69	Transportation Segment 6B								
70	Granite State Gas Transmission (Contract 09-006-FT-NN)								
71	Receipt Point: Pleasant St.								
72	Delivery Point: Northern City Gates								
73	Received Volume	Line 65	20,645	21,611	-	3,486	2,091	23,715	71,548
74	Fuel Loss Rate	Att to Sch 6B, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
75	City Gate Delivered Volume	Line 73 times (1 - Line 74)	20,542	21,503	-	3,468	2,081	23,596	71,190
76	Variable Transportation Rate	Att to Sch 6B, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
77	Variable Transportation Costs	Line 75 times Line 76	$ 39	$ 41	$ -	$ 7	$ 4	$ 45	$ 135
78									
79	Transportation Segment 5C								
80	Tennessee Gas Pipeline (Contract 41099)								
81	Receipt Point: Wright								
82	Delivery Point: Mendon (Interconnection with Algonquin)								
83	Received Volume	Line 45	74,006	-	-	2,120	1,882	115,122	193,130
84	Fuel Loss Rate	Att to Sch 6B, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	1.95%
85	Delivered Volume	Line 83 times (1 - Line 84)	72,459	-	-	2,076	1,843	112,981	189,358
86	Variable Transportation Rate	Att to Sch 6B, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
87	Variable Transportation Costs	Line 85 times Line 86	$ 5,681	$ -	$ -	$ 163	$ 144	$ 8,858	$ 14,846
88									
89	Transportation Segment 6C								
90	Algonquin Gas Transmission (Contract 93200F)								
91	Receipt Point: Mendon								
92	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
93	Received Volume	Line 85	72,459	-	-	2,076	1,843	112,981	189,358
94	Fuel Loss Rate	Att to Sch 6B, Line 1 of Page 2	0.84%	#DIV/0!	#DIV/0!	1.35%	1.35%	0.84%	0.85%
95	City Gate Delivered Volume	Line 93 times (1 - Line 94)	71,851	-	-	2,048	1,818	112,032	187,748
96	Variable Transportation Rate	Att to Sch 6B, Line 1 of Page 2	$ 0.0019	#DIV/0!	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
97	Variable Transportation Costs	Line 95 times Line 96	$ 137	$ -	$ -	$ 4	$ 3	$ 213	$ 357

Source of Supply: Empress, Alberta
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
2	Purchased Volumes	Line 9	33,000	34,100	34,100	30,800	34,100	33,000	199,100
3	City Gate Delivered Volume	Line 45	33,000	34,100	34,100	30,800	34,100	33,000	199,100
4	Total Purchase Cost	Line 14	$ 167,673	$ 184,242	$ 190,585	$ 172,911	$ 189,357	$ 153,285	$ 1,058,054
5	Variable Transportation Costs	Sum Lines 27, 37 and 47	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 167,673	$ 184,242	$ 190,585	$ 172,911	$ 189,357	$ 153,285	$ 1,058,054
7	Average Delivered Price	Line 5 divided by Line 2	$ 5.081	$ 5.403	$ 5.589	$ 5.614	$ 5.553	$ 4.645	$ 5.314
8									
9	Portland Supply Costs								
10	Purchased Volumes	Sendout Optimization	33,000	34,100	34,100	30,800	34,100	33,000	199,100
11	Monthly NYMEX Price	Att to Sch 6B, Line 1 of Page 1	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306	$ 4.244
12	NYMEX Cost	Line 9 times Line 10	$ 127,545	$ 142,777	$ 149,119	$ 135,458	$ 147,892	$ 142,098	$ 844,889
13	NYMEX Basis Price	Att to Sch 6B, Line 4 of Page 1	$ 1.216	$ 1.216	$ 1.216	$ 1.216	$ 1.216	$ 0.339	$ 1.071
14	NYMEX Basis Costs	Line 9 times Line 12	$ 40,128	$ 41,466	$ 41,466	$ 37,453	$ 41,466	$ 11,187	$ 213,165
15	Total Purchase Price	Line 10 plus Line 12	$ 5.081	$ 5.403	$ 5.589	$ 5.614	$ 5.553	$ 4.645	$ 5.314
16	Total Purchase Cost	Line 11 plus Line 13	$ 167,673	$ 184,242	$ 190,585	$ 172,911	$ 189,357	$ 153,285	$ 1,058,054
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1								
20	TransCanada Pipeline (Contract 29833)								
21	Receipt Point: Empress								
22	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)								
23	Received Volume	Line 9	-	-	-	-	-	-	-
24	Fuel Loss Rate	Att to Sch 6B, Line 16 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
25	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Att to Sch 6B, Line 16 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
27	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28									
29	Transportation Segment 2								
30	PNGTS (Contract 1997-003)								
31	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
32	Delivery Point: Granite (Westbrook)								
33	Received Volume	Line 25	-	-	-	-	-	-	-
34	Fuel Loss Rate	Att to Sch 6B, Line 5 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	Att to Sch 6B, Line 5 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Transportation Segment 3								
40	Granite State Gas Transmission (Contract 09-006-FT-NN)								
41	Receipt Point: Granite (Westbrook)								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	-	-	-	-	-	-	
44	Fuel Loss Rate	Att to Sch 6B, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	-	-	-	-	-	-	
46	Variable Transportation Rate	Att to Sch 6B, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	
47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ -	$ -	$ -	$ -	$ -	

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
2	Purchased Volumes	Line 9	79,373	-	-	8,163	6,489	50,362	144,388
3	City Gate Delivered Volume	Sum Lines 25, 55 and 45	77,607	-	-	7,984	6,346	49,417	141,353
4	Total Purchase Cost	Line 14	$ 347,098	$ -	$ -	$ 40,049	$ 31,441	$ 230,104	$ 648,691
5	Variable Transportation Costs	Sum Lines 27, 57, 37 and 47	$ 6,133	$ -	$ -	$ 630	$ 501	$ 3,878	$ 11,143
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 353,231	$ -	$ -	$ 40,679	$ 31,942	$ 233,982	$ 659,834
7	Average Delivered Price	Line 5 divided by Line 2	$ 4.552	#DIV/0!	#DIV/0!	$ 5.095	$ 5.033	$ 4.735	$ 4.668
8									
9	Niagara Supply Costs								
10	Purchased Volumes	Sendout Optimization	79,373	-	-	8,163	6,489	50,362	144,388
11	Monthly NYMEX Price	Att to Sch 6B, Line 1 of Page 1	$ 3.865	#DIV/0!	#DIV/0!	$ 4.398	$ 4.337	$ 4.306	$ 4.070
12	NYMEX Cost	Line 9 times Line 10	$ 306,777	$ -	$ -	$ 35,902	$ 28,144	$ 216,859	$ 587,681
13	NYMEX Basis Price	Att to Sch 6B, Line 5 of Page 1	$ 0.508	#DIV/0!	#DIV/0!	$ 0.508	$ 0.508	$ 0.263	$ 0.423
14	NYMEX Basis Costs	Line 9 times Line 12	$ 40,321	$ -	$ -	$ 4,147	$ 3,297	$ 13,245	$ 61,010
15	Total Purchase Price	Line 10 plus Line 12	$ 4.373	#DIV/0!	#DIV/0!	$ 4.906	$ 4.845	$ 4.569	$ 4.493
16	Total Purchase Cost	Line 11 plus Line 13	$ 347,098	$ -	$ -	$ 40,049	$ 31,441	$ 230,104	$ 648,691
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1A								
20	Tennessee Gas Pipeline (Contract 5292)								
21	Receipt Point: Niagara								
22	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
23	Received Volume	Line 9	34,186	-	-	3,558	3,319	27,523	68,587
24	Fuel Loss Rate	Att to Sch 6B, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	2.00%
25	City Gate Delivered Volume	Line 23 times (1 - Line 24)	33,472	-	-	3,484	3,250	27,011	67,216
26	Variable Transportation Rate	Att to Sch 6B, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
27	Variable Transportation Costs	Line 25 times Line 26	$ 2,624	$ -	$ -	$ 273	$ 255	$ 2,118	$ 5,270
28									
29	Transportation Segment 1B								
30	Tennessee Gas Pipeline (Contract 39375)								
31	Receipt Point: Niagara								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 9	21,945	-	-	1,836	1,567	1,680	27,027
34	Fuel Loss Rate	Att to Sch 6B, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	2.08%
35	Delivered Volume	Line 33 times (1 - Line 34)	21,486	-	-	1,798	1,535	1,648	26,466
36	Variable Transportation Rate	Att to Sch 6B, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
37	Variable Transportation Costs	Line 35 times Line 36	$ 1,684	$ -	$ -	$ 141	$ 120	$ 129	$ 2,075
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 09-006-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	21,486	-	-	1,798	1,535	1,648	26,466
44	Fuel Loss Rate	Att to Sch 6B, 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)	21,378	-	-	1,789	1,527	1,640	26,334
46	Variable Transportation Rate	Att to Sch 6B, 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	$ 41	$ -	$ -	$ 3	$ 3	$ 3	$ 50
48									
49	Transportation Segment 1C								
50	Tennessee Gas Pipeline (Contract 46314)								
51	Receipt Point: Niagara								
52	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
53	Received Volume	Line 9	23,242	-	-	2,769	1,603	21,160	48,773
54	Fuel Loss Rate	Att to Sch 6B, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	1.99%
55	City Gate Delivered Volume	Line 53 times (1 - Line 54)	22,756	-	-	2,711	1,569	20,766	47,803
56	Variable Transportation Rate	Att to Sch 6B, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
57	Variable Transportation Costs	Line 55 times Line 56	$ 1,784	$ -	$ -	$ 213	$ 123	$ 1,628	$ 3,748

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	117,326	41,050	29,475	79,634	29,256	410,283
2	City Gate Volumes - Z1	Line 2 of Page 6	210,802	217,829	169,134	90,293	212,265	217,060	1,117,383
3	Total City Gate Volumes	Line 1 plus Line 2	324,343	335,155	210,184	119,768	291,899	246,316	1,527,666
4	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ 489,779	$ 547,697	$ 200,034	$ 144,441	$ 384,895	$ 138,517	$ 1,905,364
5	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 904,868	$ 1,011,504	$ 819,686	$ 440,055	$ 1,020,380	$ 1,023,744	$ 5,220,236
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 1,394,647	$ 1,559,200	$ 1,019,721	$ 584,497	$ 1,405,275	$ 1,162,260	$ 7,125,600
7	Average Delivered Price	Line 6 divided by Line 3	$ 4.300	$ 4.652	$ 4.852	$ 4.880	$ 4.814	$ 4.719	$ 4.664

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
2	Purchased Volumes	Line 33	124,999	129,166	45,193	32,450	87,670	31,760	451,238
3	City Gate Delivered Volume	Line 45	113,541	117,326	41,050	29,475	79,634	29,256	410,283
4	Total Purchase Price	Line 25	$ 3.768	$ 4.090	$ 4.276	$ 4.301	$ 4.240	$ 4.209	$ 4.083
5	Total Purchase Cost	Line 2 times Line 3	$ 470,998	$ 528,289	$ 193,244	$ 139,566	$ 371,722	$ 133,677	$ 1,837,495
6	Variable Transportation Costs	Sum Lines 37 and 47	$ 18,782	$ 19,408	$ 6,790	$ 4,876	$ 13,173	$ 4,839	$ 67,868
7	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 489,779	$ 547,697	$ 200,034	$ 144,441	$ 384,895	$ 138,517	$ 1,905,364
8	Average Delivered Price	Line 6 divided by Line 2	$ 4.314	$ 4.668	$ 4.873	$ 4.900	$ 4.833	$ 4.735	$ 4.644
9									
10	**Tennessee Northern Storage Injection Meter Deliveries**								
11	Purchased Volumes	Line 53	-	-	-	-	-	39,752	39,752
12	Storage Delivered Volume	Line 55	-	-	-	-	-	37,446	37,446
13	Total Purchase Price	Line 25	$ 3.768	$ 4.090	$ 4.276	$ 4.301	$ 4.240	$ 4.209	$ 4.083
14	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 167,316	$ 167,316
15	Variable Transportation Costs	Line 57	$ -	$ -	$ -	$ -	$ -	$ 4,258	$ 4,258
16	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ 171,574	$ 171,574
17	Average Delivered Price	Line 15 divided by Line 11	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 4.582	$ 4.582
18									
19	Tennessee Zone 0 Supply Costs								
20	Purchased Volumes	Sendout Optimization	124,999	129,166	45,193	32,450	87,670	71,512	490,990
21	Monthly NYMEX Price	Att to Sch 6B, Line 1 of Page 1	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306	$ 4.180
22	NYMEX Cost	Line 25 times Line 26	$ 483,122	$ 540,818	$ 197,628	$ 142,713	$ 380,226	$ 307,930	$ 2,052,438
23	NYMEX Basis Price	Att to Sch 6B, Line 6 of Page 1	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)	$ (0.097)
24	NYMEX Basis Costs	Line 25 times Line 28	$ (12,125)	$ (12,529)	$ (4,384)	$ (3,148)	$ (8,504)	$ (6,937)	$ (47,626)
25	Total Purchase Price	Line 26 plus Line 28	$ 3.768	$ 4.090	$ 4.276	$ 4.301	$ 4.240	$ 4.209	$ 4.083
26	Total Purchase Cost	Line 27 plus Line 29	$ 470,998	$ 528,289	$ 193,244	$ 139,566	$ 371,722	$ 300,993	$ 2,004,811
27									
28	Transportation Fuel Losses and Variable Charges								
29	Transportation Segment 1A								
30	Tennessee Gas Pipeline (Contract 5083)								
31	Receipt Point: Tennessee Zone 0								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 20	124,999	129,166	45,193	32,450	87,670	31,760	451,238
34	Fuel Loss Rate	Att to Sch 6B, Line 7 of Page 2	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	8.62%
35	Delivered Volume	Line 33 times (1 - Line 34)	114,112	117,916	41,256	29,623	80,034	29,403	412,345
36	Variable Transportation Rate	Att to Sch 6B, Line 7 of Page 2	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627	$ 0.1627
37	Variable Transportation Costs	Line 35 times Line 36	$ 18,566	$ 19,185	$ 6,712	$ 4,820	$ 13,022	$ 4,784	$ 67,088
38									
39	Transportation Segment 2A								
40	Granite State Gas Transmission (Contract 09-006-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	114,112	117,916	41,256	29,623	80,034	29,403	412,345
44	Fuel Loss Rate	Att to Sch 6B, 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)	113,541	117,326	41,050	29,475	79,634	29,256	410,283
46	Variable Transportation Rate	Att to Sch 6B, 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	$ 216	$ 223	$ 78	$ 56	$ 151	$ 56	$ 780
48									
49	Transportation Segment 3								
50	Tennessee Gas Pipeline (Contract 5083)								
51	Receipt Point: Tennessee Zone 0								
52	Delivery Point: Tennessee Market Area Storage								
53	Received Volume	Line 25 minus Line 38	-	-	-	-	-	39,752	39,752
54	Fuel Loss Rate	Att to Sch 6B, Line 6 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	5.80%	5.80%
55	Storage Delivered Volume	Line 53 times (1 - Line 54)	-	-	-	-	-	37,446	37,446
56	Variable Transportation Rate	Att to Sch 6B, Line 6 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1137	$ 0.1137
57	Variable Transportation Costs	Line 55 times Line 56	$ -	$ -	$ -	$ -	$ -	$ 4,258	$ 4,258

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	184,405	98,445	231,429	233,741	1,215,351
3	City Gate Delivered Volume	Line 45	210,802	217,829	169,134	90,293	212,265	217,060	1,117,383
4	Total Purchase Price	Line 25	$ 3.795	$ 4.117	$ 4.303	$ 4.328	$ 4.267	$ 4.236	$ 4.154
5	Total Purchase Cost	Line 2 times Line 3	$ 872,222	$ 977,770	$ 793,493	$ 426,072	$ 987,507	$ 990,129	$ 5,047,193
6	Variable Transportation Costs	Sum Lines 37 and 47	$ 32,646	$ 33,734	$ 26,193	$ 13,983	$ 32,872	$ 33,615	$ 173,043
7	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 904,868	$ 1,011,504	$ 819,686	$ 440,055	$ 1,020,380	$ 1,023,744	$ 5,220,236
8	Average Delivered Price	Line 6 divided by Line 2	$ 4.292	$ 4.644	$ 4.846	$ 4.874	$ 4.807	$ 4.716	$ 4.672
9									
10	**Tennessee Northern Storage Injection Meter Deliveries**								
11	Purchased Volumes	Line 53	-	-	-	48,188	-	11,219	59,408
12	Storage Delivered Volume	Line 55	-	-	-	45,750	-	10,652	56,402
13	Total Purchase Price	Line 25	$ 3.795	$ 4.117	$ 4.303	$ 4.328	$ 4.267	$ 4.236	$ 4.154
14	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ 208,558	$ -	$ 47,526	$ 256,084
15	Variable Transportation Costs	Line 57	$ -	$ -	$ -	$ 4,726	$ -	$ 1,100	$ 5,826
16	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ 213,284	$ -	$ 48,626	$ 261,910
17	Average Delivered Price	Line 15 divided by Line 11	#DIV/0!	#DIV/0!	#DIV/0!	$ 4.662	#DIV/0!	$ 4.565	$ 4.644
18									
19	Tennessee Zone L Supply Costs								
20	Purchased Volumes	Sendout Optimization	229,835	237,496	184,405	98,445	231,429	244,961	1,226,570
21	Monthly NYMEX Price	Att to Sch 6B, Line 1 of Page 1	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306	$ 4.224
22	NYMEX Cost	Line 25 times Line 26	$ 888,310	$ 994,394	$ 806,402	$ 432,963	$ 1,003,707	$ 1,054,802	$ 5,180,578
23	NYMEX Basis Price	Att to Sch 6B, Line 7 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)	$ (12,908)	$ (6,891)	$ (16,200)	$ (17,147)	$ (85,860)
25	Total Purchase Price	Line 26 plus Line 28	$ 3.795	$ 4.117	$ 4.303	$ 4.328	$ 4.267	$ 4.236	$ 4.154
26	Total Purchase Cost	Line 27 plus Line 29	$ 872,222	$ 977,770	$ 793,493	$ 426,072	$ 987,507	$ 1,037,654	$ 5,094,718
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	184,405	98,445	231,429	233,741	1,215,351
34	Fuel Loss Rate	Att to Sch 6B, 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	169,984	90,747	213,331	218,151	1,122,998
36	Variable Transportation Rate	Att to Sch 6B, 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	$ 25,872	$ 13,812	$ 32,469	$ 33,203	$ 170,920
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 09-006-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	211,861	218,923	169,984	90,747	213,331	218,151	1,122,998
44	Fuel Loss Rate	Att to Sch 6B, 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	169,134	90,293	212,265	217,060	1,117,383
46	Variable Transportation Rate	Att to Sch 6B, 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	$ 321	$ 172	$ 403	$ 412	$ 2,123
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	-	-	-	48,188	-	11,219	59,408
54	Fuel Loss Rate	Att to Sch 6B, Line 7 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	5.06%	#DIV/0!	5.06%	5.06%
55	Storage Delivered Volume	Line 53 times (1 - Line 54)	-	-	-	45,750	-	10,652	56,402
56	Variable Transportation Rate	Att to Sch 6B, Line 7 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1033	#DIV/0!	$ 0.1033	$ 0.1033
57	Variable Transportation Costs	Line 55 times Line 56	$ -	$ -	$ -	$ 4,726	$ -	$ 1,100	$ 5,826
						1.49%			
						45068.11154			
						0.0102			
						459.6947377			
						$ 213,744			

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	2010-2011 Peak
2	Gross Withdrawn Volume	Line 10	-	-	8,501	21,743	14,627	2,510	47,381
3	City Gate Delivered Volume	Line 36	-	-	8,275	21,165	14,238	2,450	46,128
4	Total Withdrawal Costs	Line 17	$ -	$ -	$ 38,023	$ 97,257	$ 65,428	$ 11,336	$ 212,045
5	Variable Transportation Costs	Sum Lines 28 and 38	$ -	$ -	$ 725	$ 1,855	$ 1,248	$ 215	$ 4,042
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ 38,748	$ 99,112	$ 66,676	$ 11,551	$ 216,087
7	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	$ 4.683	$ 4.683	$ 4.683	$ 4.715	$ 4.685
8									
9	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
10	Gross Withdrawn Volume	Sendout Optimization	-	-	8,501	21,743	14,627	2,510	47,381
11	Withdrawal Rate		#DIV/0!	#DIV/0!	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0102
12	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ 87	$ 222	$ 149	$ 26	$ 483
13	Inventory Rate	Sch 14, Page 1	#DIV/0!	#DIV/0!	$ 4.4628	$ 4.4628	$ 4.4628	$ 4.5059	$ 4.4651
14	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ 37,937	$ 97,036	$ 65,279	$ 11,311	$ 211,562
15	Withdrawal Fuel Losses		-	-	-	-	-	-	100.00%
16	Net Withdrawn Volume	Line 9 minus Line 14	-	-	8,501	21,743	14,627	2,510	47,381
17	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ 38,023	$ 97,257	$ 65,428	$ 11,336	212,045
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	-	-	8,501	21,743	14,627	2,510	
25	Fuel Loss Rate	Att to Sch 6B, Line 10 of Page 2	#DIV/0!	#DIV/0!	2.17%	2.17%	2.17%	1.92%	#DIV/0!
26	Delivered Volume	Line 24 times (1 - Line 25)	-	-	8,316	21,271	14,310	2,462	#DIV/0!
27	Variable Transportation Rate	Att to Sch 6B, Line 10 of Page 2	#DIV/0!	#DIV/0!	$ 0.0853	$ 0.0853	$ 0.0853	$ 0.0853	#DIV/0!
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ -	$ 709	$ 1,814	$ 1,221	$ 210	#DIV/0!
29									$ -
30	Transportation Segment 3								
31	Granite State Gas Transmission (Contract 09-006-FT-NN)								
32	Receipt Point: Pleasant St.								
33	Delivery Point: Northern City Gates								
34	Received Volume	Line 26	-	-	8,316	21,271	14,310	2,462	
35	Fuel Loss Rate	Att to Sch 6B, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0
36	City Gate Delivered Volume	Line 34 times (1 - Line 35)	-	-	8,275	21,165	14,238	2,450	62.00%
37	Variable Transportation Rate	Att to Sch 6B, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	0
38	Variable Transportation Costs	Line 36 times Line 37	$ -	$ -	$ 16	$ 40	$ 27	$ 5	$ -
									$ -

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
2	Gross Withdrawn Volume	Line 10	-	405,109	852,241	728,039	516,160	-	2,501,550
3	City Gate Delivered Volume	Line 66	-	395,545	832,121	710,851	503,975	-	2,442,492
4	Total Withdrawal Costs	Line 17	$ -	$ 1,702,997	$ 3,582,652	$ 3,060,532	$ 2,169,835	$ -	$ 10,516,016
5	Variable Transportation Costs	Sum Lines 28, 38, 48, 58 and 68	$ -	$ 26,481	$ 55,708	$ 47,589	$ 33,740	$ -	$ 163,518
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ 1,729,478	$ 3,638,360	$ 3,108,121	$ 2,203,575	$ -	$ 10,679,534
7	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	$ 4.372	$ 4.372	$ 4.372	$ 4.372	#DIV/0!	$ 4.372
8									
9	Washington 10 Withdrawn Inventory (Segment 1)								
10	Gross Withdrawn Volume	Sendout Optimization	-	405,109	852,241	728,039	516,160	-	2,501,550
11	Withdrawal Rate		#DIV/0!	$ -	$ -	$ -	$ -	#DIV/0!	$ -
12	Withdrawal Charges	Line 9 times Line 10	-	-	-	-	-	-	$ -
13	Inventory Rate	Sch 14, Page 1	#DIV/0!	$ 4.2038	$ 4.2038	$ 4.2038	$ 4.2038	#DIV/0!	$ 4.2038
14	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ 1,702,997	$ 3,582,652	$ 3,060,532	$ 2,169,835	$ -	$ 10,516,016
15	Withdrawal Fuel Losses		-	1,620	3,409	2,912	2,065	-	99.60%
16	Net Withdrawn Volume	Line 9 minus Line 14	-	403,489	848,832	725,127	514,096	-	2,491,544
17	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ 1,702,997	$ 3,582,652	$ 3,060,532	$ 2,169,835	$ -	10,516,016
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	-	122,954	422,963	345,191	296,125	-	
25	Fuel Loss Rate	Att to Sch 6B, Line 10 of Page 2	#DIV/0!	0.34%	0.34%	0.34%	0.34%	#DIV/0!	#DIV/0!
26	Delivered Volume	Line 24 times (1 - Line 25)	-	122,536	421,525	344,018	295,118	-	#DIV/0!
27	Variable Transportation Rate	Att to Sch 6B, Line 18 of Page 2	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!	#DIV/0!
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ 233	$ 801	$ 654	$ 561	$ -	#DIV/0!
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	-	280,534	425,869	379,936	217,971	-	
35	Fuel Loss Rate	Att to Sch 6B, Line 18 of Page 2	#DIV/0!	0.34%	0.34%	0.34%	0.34%	#DIV/0!	#DIV/0!
36	Delivered Volume	Line 34 times (1 - Line 35)	-	279,580	424,422	378,644	217,230	-	#DIV/0!
37	Variable Transportation Rate	Att to Sch 6B, Line 18 of Page 2	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!	#DIV/0!
38	Variable Transportation Costs	Line 36 times Line 37	$ -	$ 531	$ 806	$ 719	$ 413	$ -	#DIV/0!
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	-	402,117	845,946	722,662	512,348	-	
45	Fuel Loss Rate	Att to Sch 6B, Line 15 of Page 2	#DIV/0!	1.14%	1.14%	1.14%	1.14%	#DIV/0!	#DIV/0!
46	Delivered Volume	Line 44 times (1 - Line 45)	-	397,533	836,302	714,423	506,507	-	#DIV/0!
47	Variable Transportation Rate	Att to Sch 6B, Line 15 of Page 2	#DIV/0!	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	#DIV/0!	#DIV/0!
48	Variable Transportation Costs	Line 46 times Line 47	$ -	$ 24,210	$ 50,931	$ 43,508	$ 30,846	$ -	#DIV/0!
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	-	397,533	836,302	714,423	506,507	-	
55	Fuel Loss Rate	Att to Sch 6B, Line 5 of Page 2	#DIV/0!	0.00%	0.00%	0.00%	0.00%	#DIV/0!	#DIV/0!
56	Delivered Volume	Line 54 times (1 - Line 55)	-	397,533	836,302	714,423	506,507	-	#DIV/0!
57	Variable Transportation Rate	Att to Sch 6B, Line 5 of Page 2	#DIV/0!	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!	#DIV/0!
58	Variable Transportation Costs	Line 56 times Line 57	$ -	$ 755	$ 1,589	$ 1,357	$ 962	$ -	#DIV/0!
59									$ -
60	Transportation Segment 5								
61	Granite State Gas Transmission (Contract 09-006-FT-NN)								
62	Receipt Point: Westbrook, Newington, Eliot								
63	Delivery Point: Northern City Gates								
64	Received Volume	Line 56	-	397,533	836,302	714,423	506,507	-	
65	Fuel Loss Rate	Att to Sch 6B, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0
66	City Gate Delivered Volume	Line 64 times (1 - Line 65)	-	395,545	832,121	710,851	503,975	-	62.00%
67	Variable Transportation Rate	Att to Sch 6B, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	0
68	Variable Transportation Costs	Line 66 times Line 67	$ -	$ 752	$ 1,581	$ 1,351	$ 958	$ -	$ -
									$ -

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
2	Purchased Volumes	Line 11	25,721	126,837	127,871	114,562	126,837	93,686	615,513
3	City Gate Delivered Volume	Line 34	25,592	126,202	127,231	113,989	126,202	93,218	612,436
4	Total Purchase Price	Line 25	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828
5	Total Purchase Cost	Line 1 times Line 3	$ 98,470	$ 485,581	$ 489,540	$ 438,589	$ 485,581	$ 358,669	$ 2,356,430
6	Variable Transportation Costs	Line 36	$ 49	$ 240	$ 242	$ 217	$ 240	$ 177	$ 1,164
7	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 98,519	$ 485,821	$ 489,782	$ 438,806	$ 485,821	$ 358,846	$ 2,357,594
8	Average Delivered Price	Line 6 divided by Line 2	$ 3.850	$ 3.850	$ 3.850	$ 3.850	$ 3.850	$ 3.850	$ 3.850
9									
10	**LNG Storage Deliveries**								
11	Purchased Volumes	Line 42	2,023	1,395	361	1,260	1,395	2,665	9,098
12	Storage Delivered Volume	Line 44	2,023	1,395	361	1,260	1,395	2,665	9,098
13	Total Purchase Price	Line 25	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828
14	Total Purchase Cost	Line 10 times Line 12	$ 7,743	$ 5,341	$ 1,382	$ 4,824	$ 5,341	$ 10,202	$ 34,832
15	Variable Transportation Costs	Line 46	$ 1,901	$ 1,311	$ 339	$ 1,184	$ 1,311	$ 2,505	$ 8,552
16	Total Storage Delivered Costs	Line 13 plus Line 14	$ 9,645	$ 6,652	$ 1,721	$ 6,008	$ 6,652	$ 12,707	$ 43,385
17	Average Delivered Price	Line 15 divided by Line 11	$ 4.768	$ 4.768	$ 4.768	$ 4.768	$ 4.768	$ 4.768	$ 4.768
18									
19	Peaking Supply 1 Costs (Segment 1)								
20	Purchased Volumes	Sendout Optimization	27,744	128,232	128,232	115,822	128,232	96,351	624,612
21	Peaking Supply 1 Prices	Contract Rate	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828
22	Peaking Supply 1 Costs	Line 19 times Line 20	$ 106,214	$ 490,921	$ 490,921	$ 443,413	$ 490,921	$ 368,872	$ 2,391,263
23	NYMEX Basis Price	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	NYMEX Basis Costs	Line 19 times Line 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Total Purchase Price	Att to Sch 6B, Line 10 of Page 2	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828	$ 3.828
26	Total Purchase Cost	Line 24 times (1 - Line 25)	$ 106,214	$ 490,921	$ 490,921	$ 443,413	$ 490,921	$ 368,872	$ 2,391,263
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 09-006-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Sendout Optimization	25,721	126,837	127,871	114,562	126,837	93,686	615,513
33	Fuel Loss Rate	Att to Sch 6B, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	25,592	126,202	127,231	113,989	126,202	93,218	612,436
35	Variable Transportation Rate	Att to Sch 6B, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
36	Variable Transportation Costs	Line 34 times Line 35	$ 49	$ 240	$ 242	$ 217	$ 240	$ 177	$ 1,164
37									
38	Transportation Segment 3								
39	Trucking Contract (TransGas)								
40	Receipt Point: Distrigas Terminal								
41	Delivery Point: Northern LNG Facility (Lewiston, ME)								
42	Received Volume	Line 19 minus Line 31	2,023	1,395	361	1,260	1,395	2,665	9,098
43	Fuel Loss Rate	Company Forecast	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
44	Storage Delivered Volume	Line 42 times (1 - Line 43)	2,023	1,395	361	1,260	1,395	2,665	9,098
45	Variable Transportation Rate	Company Forecast	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400	$ 0.9400
46	Variable Transportation Costs	Line 44 times Line 45	$ 1,901	$ 1,311	$ 339	$ 1,184	$ 1,311	$ 2,505	$ 8,552

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	1,395	1,631	8,426
3	City Gate Delivered Volume	Line 16	1,350	1,395	1,395	1,260	1,395	1,631	8,426
4	Total Withdrawal Costs	Line 17	$ 9,368	$ 9,321	$ 9,231	$ 8,060	$ 8,627	$ 9,571	$ 54,177
5	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 9,368	$ 9,321	$ 9,231	$ 8,060	$ 8,627	$ 9,571	$ 54,177
7	Average Delivered Price	Line 5 divided by Line 2	$ 6.939	$ 6.681	$ 6.617	$ 6.396	$ 6.184	$ 5.869	$ 6.430
8									
9	Northern LNG Withdrawn Inventory								
10	Gross Withdrawn Volume	Sendout Optimization	1,350	1,395	1,395	1,260	1,395	1,631	8,426
11	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Withdrawal Charges	Line 9 times Line 10	-	-	-	-	-	-	$ -
13	Inventory Rate	Sch 14, Page 1	$ 6.9394	$ 6.6814	$ 6.6169	$ 6.3965	$ 6.1843	$ 5.8691	$ 6.4299
14	Withdrawn Inventory Value	Line 9 times Line 12	$ 9,368	$ 9,321	$ 9,231	$ 8,060	$ 8,627	$ 9,571	$ 54,177
15	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
16	Net Withdrawn Volume	Line 9 minus Line 14	1,350	1,395	1,395	1,260	1,395	1,631	8,426
17	Total Withdrawal Costs	Line 11 plus Line 13	$ 9,368	$ 9,321	$ 9,231	$ 8,060	$ 8,627	$ 9,571	$ 54,177

Att to Sch 6B, Line 10 of Page 2

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
2	Purchased Volumes	Line 9	-	-	-	-	-	-	-
3	City Gate Delivered Volume	Line 25	-	-	-	-	-	-	-
4	Total Purchase Cost	Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
8									
9	<u>Peaking Supply 2 Costs</u>								
10	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
11	Monthly NYMEX Price		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Price		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
14	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Purchase Price	Line 10 plus Line 12	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
16	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 1								
20	Granite State Gas Transmission (Contract 09-006-FT-NN)								
21	Receipt Point: Newington or Westbrook								
22	Delivery Point: Northern City Gates								
23	Received Volume	Line 9	-	-	-	-	-	-	-
24	Fuel Loss Rate	Att to Sch 6B, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	#DIV/0!
25	City Gate Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Att to Sch 6B, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Revised Schedule 7

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc. Hedging Gains and Losses November 2010 through April 2011 As of 10/6/2010							
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	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306	$ 4.223
Hedging (Gains) or Losses - Allocate	$ 176,400	$ 195,940	$ 104,730	$ 125,200	$ 118,800	$ 168,460	$ 889,530
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	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306	$ 5.731
Hedging (Gains) or Losses - NH ONLY	$ 143,700	$ 123,000	$ 78,310	$ 97,080	$ 95,720	$ 113,640	$ 651,450

Revised Schedule 9

Variance Analysis

Unitil
Northern Utilities, Inc.

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 4		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
5							
6	Demand Charges (Pipeline & Storage)		$ 11,198,728	$ 0.4041		$ 15,265,601	$ 0.5446
7							
8	Purchased Gas (Pipeline Commodity)		10,694,244	0.3859		5,588,474	0.1994
9							
10	Storage & Peaking Gas (Commodity)		2,920,424	0.1054		7,057,012	0.2518
11							
12	Hedging (Gain)/Loss		2,884,703	0.1041		1,120,010	0.0400
13							
14							
15	Total Volumes and Cost	$ -	$ 27,698,099	$ 0.9995	$ -	$ 29,031,096	$ 1.0358
16							
17	Prior Period Balance		$2,464,908	$ 0.0889		$ 2,527,403	$ 0.0902
18	ATV Reconciliation		-	$ -		-	$ -
19	Interest		$ 105,685	$ 0.0038		99,469	$ 0.0035
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)		(1,761,855)	$ (0.0629)
25	Working Capital Allowance		(83,069)	$ (0.0030)		(31,234)	$ (0.0011)
26	Bad Debt Allowance		(2,655)	$ (0.0001)		131,344	$ 0.0047
27	Fuel Inventory Financing		7,801	$ 0.0003		12,234	$ 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		1,762,368	$ 0.0629
32	Total Adjusted Cost	-	29,315,161	$ 1.0579		30,793,464	$ 1.0987

Revised Schedule 10A

Allocation of Demand Costs to Customer Classes

Unitil
Northern Utilities, Inc.

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

Base Capacity Costs

LN		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
1	**BASE SENDOUT BY CLASS**	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
2	**Total Therms**								
3	Res Heat	386,086	398,955	398,955	360,347	398,955	386,086	2,329,385	Schedule 10B, LN 52
4	Res General	15,443	15,958	15,958	14,414	15,958	15,443	93,174	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	109,908	113,572	113,572	102,581	113,572	109,908	663,114	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	64,751	66,910	66,910	60,435	66,910	64,751	390,667	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	141,497	146,213	146,213	132,064	146,213	141,497	853,698	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	118,256	122,197	122,197	110,372	122,197	118,256	713,475	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	8,381	10,909	11,818	10,723	10,351	9,044	61,227	Schedule 10B, LN 58
10	G42 High Annual-High Winter	11,315	11,693	11,693	10,561	11,693	11,315	68,270	Schedule 10B, LN 59
11	Total Firm Sales	855,638	886,408	887,317	801,496	885,850	856,301	5,173,010	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									
24	**PIPELINE BASE DEMAND COSTS**	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
25	TOTAL PIPELINE BASE DEMAND COST	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 57,186	$ 343,114	Schedule 1A, LN 69
26	Res Heat	$ 25,804	$ 25,738	$ 25,712	$ 25,710	$ 25,754	$ 25,784	$ 154,502	LN 25 * LN 14
27	Res General	$ 1,032	$ 1,030	$ 1,028	$ 1,028	$ 1,030	$ 1,031	$ 6,180	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 7,346	$ 7,327	$ 7,319	$ 7,319	$ 7,332	$ 7,340	$ 43,983	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 4,328	$ 4,317	$ 4,312	$ 4,312	$ 4,319	$ 4,324	$ 25,912	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 9,457	$ 9,433	$ 9,423	$ 9,423	$ 9,439	$ 9,449	$ 56,623	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 7,903	$ 7,883	$ 7,875	$ 7,875	$ 7,888	$ 7,897	$ 47,323	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 560	$ 704	$ 762	$ 765	$ 668	$ 604	$ 4,063	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 756	$ 754	$ 754	$ 754	$ 755	$ 756	$ 4,528	LN 25 * LN 21
34									
35	Residential	$ 26,836	$ 26,768	$ 26,740	$ 26,739	$ 26,785	$ 26,815	$ 160,682	LN 26 + LN 27
36	SALES HLF CLASSES	$ 17,363	$ 17,464	$ 17,504	$ 17,507	$ 17,439	$ 17,393	$ 104,669	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 12,987	$ 12,954	$ 12,941	$ 12,940	$ 12,963	$ 12,977	$ 77,763	LN 29 + LN 31 + LN 33
38									

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

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						

50 **REMAINING PIPELINE DEMAND**

LN		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	$ 97,412	$ 218,912	$ 569,467	$ 309,997	$ 271,710	$ 105,864	$ 1,573,363	Schedule 1A, LN 70
53									
54	Res Heat	$ 45,736	$ 102,780	$ 267,368	$ 145,546	$ 127,569	$ 49,704	$ 738,703	LN 40 Col D * LN 52
55	Res General	$ 483	$ 1,086	$ 2,826	$ 1,538	$ 1,348	$ 525	$ 7,808	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 1,631	$ 3,666	$ 9,536	$ 5,191	$ 4,550	$ 1,773	$ 26,348	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 22,697	$ 51,007	$ 132,686	$ 72,230	$ 63,309	$ 24,666	$ 366,595	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 2,738	$ 6,153	$ 16,005	$ 8,713	$ 7,637	$ 2,975	$ 44,220	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 21,773	$ 48,931	$ 127,286	$ 69,290	$ 60,732	$ 23,662	$ 351,674	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 53	$ 120	$ 312	$ 170	$ 149	$ 58	$ 862	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 2,300	$ 5,169	$ 13,447	$ 7,320	$ 6,416	$ 2,500	$ 37,152	LN 47 Col D * LN 52
62	TOTAL	$ 97,412	$ 218,912	$ 569,467	$ 309,997	$ 271,710	$ 105,864	$ 1,573,363	Sum LN 54 : LN 61
63									
64	Residential	$ 46,219	$ 103,867	$ 270,194	$ 147,084	$ 128,918	$ 50,229	$ 746,511	LN 54 + LN 55
65	SALES HLF CLASSES	$ 4,423	$ 9,939	$ 25,854	$ 14,074	$ 12,336	$ 4,806	$ 71,430	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 46,771	$ 105,107	$ 273,419	$ 148,840	$ 130,457	$ 50,828	$ 755,421	LN 57 + LN 59 + LN 61
67									

68 **PEAKING AND STORAGE DEMAND**

LN		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	$ 826,492	$ 1,857,350	$ 4,831,616	$ 2,630,159	$ 2,305,313	$ 898,195	$ 13,349,125	Schedule 1A, LN 73
71									
72	Res Heat	$ 388,042	$ 872,036	$ 2,268,471	$ 1,234,875	$ 1,082,358	$ 421,707	$ 6,267,489	LN 40 Col D * LN 70
73	Res General	$ 4,102	$ 9,218	$ 23,979	$ 13,053	$ 11,441	$ 4,458	$ 66,250	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 13,841	$ 31,104	$ 80,912	$ 44,046	$ 38,606	$ 15,041	$ 223,549	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 192,573	$ 432,764	$ 1,125,770	$ 612,829	$ 537,140	$ 209,280	$ 3,110,357	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 23,229	$ 52,202	$ 135,796	$ 73,922	$ 64,792	$ 25,244	$ 375,186	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 184,735	$ 415,150	$ 1,079,951	$ 587,887	$ 515,278	$ 200,762	$ 2,983,763	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 453	$ 1,017	$ 2,647	$ 1,441	$ 1,263	$ 492	$ 7,313	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 19,516	$ 43,858	$ 114,091	$ 62,107	$ 54,436	$ 21,209	$ 315,218	LN 47 Col D * LN 70
80	TOTAL	$ 826,492	$ 1,857,350	$ 4,831,616	$ 2,630,159	$ 2,305,313	$ 898,195	$ 13,349,125	Sum LN 72 : LN 79
81									
82	Residential	$ 392,144	$ 881,254	$ 2,292,450	$ 1,247,928	$ 1,093,799	$ 426,165	$ 6,333,740	LN 72 + LN 73
83	SALES HLF CLASSES	$ 37,523	$ 84,323	$ 219,354	$ 119,409	$ 104,661	$ 40,778	$ 606,048	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 396,825	$ 891,773	$ 2,319,812	$ 1,262,823	$ 1,106,854	$ 431,252	$ 6,409,338	LN 75 + LN 77 + LN 79
85									

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

86 **CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**

LN		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
87									
88	NH DIVISION - MONTHLY CAP. RELEASE	$ (117,579)	$ (247,371)	$ (621,852)	$ (344,673)	$ (303,773)	$ (126,607)	$ (1,761,855)	Schedule 1A, LN 76
89									
90	Res Heat	$ (55,204)	$ (116,142)	$ (291,963)	$ (161,826)	$ (142,623)	$ (59,443)	$ (827,201)	LN 40 Col D * LN 88
91	Res General	$ (584)	$ (1,228)	$ (3,086)	$ (1,711)	$ (1,508)	$ (628)	$ (8,744)	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ (1,969)	$ (4,143)	$ (10,414)	$ (5,772)	$ (5,087)	$ (2,120)	$ (29,505)	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ (27,396)	$ (57,638)	$ (144,892)	$ (80,309)	$ (70,779)	$ (29,499)	$ (410,514)	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ (3,305)	$ (6,953)	$ (17,478)	$ (9,687)	$ (8,538)	$ (3,558)	$ (49,518)	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ (26,281)	$ (55,292)	$ (138,995)	$ (77,041)	$ (67,899)	$ (28,299)	$ (393,805)	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ (64)	$ (136)	$ (341)	$ (189)	$ (166)	$ (69)	$ (965)	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ (2,776)	$ (5,841)	$ (14,684)	$ (8,139)	$ (7,173)	$ (2,990)	$ (41,603)	LN 47 Col D * LN 88
98	TOTAL	$ (117,579)	$ (247,371)	$ (621,852)	$ (344,673)	$ (303,773)	$ (126,607)	$ (1,761,855)	Sum LN 90 : LN 97
99									
100	Residential	$ (55,787)	$ (117,370)	$ (295,049)	$ (163,537)	$ (144,131)	$ (60,071)	$ (835,945)	LN 90 + LN 91
101	SALES HLF CLASSES	$ (5,338)	$ (11,231)	$ (28,232)	$ (15,648)	$ (13,791)	$ (5,748)	$ (79,988)	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ (56,453)	$ (118,771)	$ (298,571)	$ (165,489)	$ (145,851)	$ (60,788)	$ (845,923)	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

LN		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
105									
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

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

122 **REMAINING RE-ENTRY FEE CREDIT**

LN		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**

LN		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
142	Res Heat	$ 378,574	$ 858,675	$ 2,243,875	$ 1,218,594	$ 1,067,304	$ 411,968	$ 6,178,991	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 4,002	$ 9,077	$ 23,719	$ 12,881	$ 11,282	$ 4,355	$ 65,315	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 13,503	$ 30,627	$ 80,035	$ 43,465	$ 38,069	$ 14,694	$ 220,392	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 187,874	$ 426,133	$ 1,113,565	$ 604,750	$ 529,669	$ 204,447	$ 3,066,438	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 22,662	$ 51,402	$ 134,323	$ 72,948	$ 63,891	$ 24,661	$ 369,888	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 180,228	$ 408,789	$ 1,068,242	$ 580,136	$ 508,111	$ 196,126	$ 2,941,632	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 442	$ 1,002	$ 2,618	$ 1,422	$ 1,245	$ 481	$ 7,209	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 19,040	$ 43,186	$ 112,854	$ 61,288	$ 53,679	$ 20,720	$ 310,767	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 806,325	$ 1,828,891	$ 4,779,230	$ 2,595,484	$ 2,273,251	$ 877,452	$ 13,160,632	Sum LN 142 : LN 149
151									
152	Residential	$ 382,576	$ 867,751	$ 2,267,594	$ 1,231,475	$ 1,078,586	$ 416,323	$ 6,244,306	LN 142 + LN 143
153	SALES HLF CLASSES	$ 36,607	$ 83,031	$ 216,976	$ 117,834	$ 103,205	$ 39,836	$ 597,490	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 387,142	$ 878,109	$ 2,294,660	$ 1,246,174	$ 1,091,460	$ 421,292	$ 6,318,836	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
158	Res Heat	$ 404,378	$ 884,413	$ 2,269,587	$ 1,244,304	$ 1,093,058	$ 437,752	$ 6,333,493	LN 142 + LN 26
159	Res General	$ 5,034	$ 10,106	$ 24,747	$ 13,910	$ 12,312	$ 5,386	$ 71,495	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 20,849	$ 37,954	$ 87,354	$ 50,784	$ 45,400	$ 22,034	$ 264,375	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 192,202	$ 430,450	$ 1,117,877	$ 609,062	$ 533,989	$ 208,771	$ 3,092,350	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 32,119	$ 60,835	$ 143,747	$ 82,370	$ 73,330	$ 34,111	$ 426,512	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 188,131	$ 416,673	$ 1,076,117	$ 588,011	$ 516,000	$ 204,023	$ 2,988,954	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,002	$ 1,706	$ 3,380	$ 2,187	$ 1,913	$ 1,085	$ 11,272	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 19,796	$ 43,941	$ 113,607	$ 62,042	$ 54,434	$ 21,475	$ 315,295	LN 149 + LN 33
166	TOTAL	$ 863,511	$ 1,886,077	$ 4,836,416	$ 2,652,669	$ 2,330,436	$ 934,637	$ 13,503,746	Sum LN 158 : LN 165
167									
168	Residential	$ 409,412	$ 894,519	$ 2,294,335	$ 1,258,214	$ 1,105,370	$ 443,138	$ 6,404,988	LN 158 + LN 159
169	SALES HLF CLASSES	$ 53,970	$ 100,495	$ 234,480	$ 135,341	$ 120,644	$ 57,229	$ 702,159	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 400,130	$ 891,063	$ 2,307,601	$ 1,259,114	$ 1,104,422	$ 434,270	$ 6,396,599	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)

Revised Schedule 10B

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
2010 - 2011 Period

Line No.	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	1,401,734	2,052,664	2,971,122	2,509,339	2,487,974	1,529,262	16,149,760	12,952,095
22	Res General	28,686	34,095	46,027	41,317	41,023	31,012	336,661	222,160
23	G50 Low Annual-Low Winter	127,430	162,133	187,253	169,748	171,715	131,227	1,683,931	949,506
24	G40 Low Annual-High Winter	555,829	965,591	1,571,210	1,352,155	1,199,238	676,930	7,204,555	6,320,953
25	G51 Med Annual-Low Winter	218,815	256,958	271,300	231,948	251,855	186,415	2,394,963	1,417,290
26	G41 Med Annual-High Winter	636,339	1,141,225	1,234,351	1,041,275	1,046,548	600,932	7,026,040	5,700,670
27	G52 High Annual-Low Winter	8,381	10,909	11,818	10,723	10,351	9,044	204,505	61,227
28	G42 High Annual-High Winter	104,216	155,105	152,948	129,196	103,267	59,687	813,584	704,420
29	**Subtotal**								
30	Residential	1,430,420	2,086,758	3,017,150	2,550,656	2,528,997	1,560,273	16,486,421	13,174,255
31	SALES HLF CLASSES	354,626	430,001	470,371	412,418	433,920	326,686	4,283,399	2,428,023
32	SALES LLF CLASSES	1,296,384	2,261,921	2,958,509	2,522,625	2,349,053	1,337,550	15,044,180	12,726,042
33	**Total Firm Sales**	3,081,430	4,778,680	6,446,030	5,485,700	5,311,970	3,224,510	35,814,000	28,328,320

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	12,870
37	Res General	515
38	G50 Low Annual-Low Winter	3,664
39	G40 Low Annual-High Winter	2,158
40	G51 Med Annual-Low Winter	4,717
41	G41 Med Annual-High Winter	3,942
42	G52 High Annual-Low Winter	712
43	G42 High Annual-High Winter	377
44	**Subtotal**	
45	Residential	13,384
46	SALES HLF CLASSES	9,092
47	SALES LLF CLASSES	6,477
48	**Total Firm Sales**	**28,954**

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		386,086	398,955	398,955	360,347	398,955	386,086	4,669,512	2,329,385
53	Res General		15,443	15,958	15,958	14,414	15,958	15,443	185,605	93,174
54	G50 Low Annual-Low Winter		109,908	113,572	113,572	102,581	113,572	109,908	1,319,141	663,114
55	G40 Low Annual-High Winter		64,751	66,910	66,910	60,435	66,910	64,751	766,639	390,667
56	G51 Med Annual-Low Winter		141,497	146,213	146,213	132,064	146,213	141,497	1,705,228	853,698
57	G41 Med Annual-High Winter		118,256	122,197	122,197	110,372	122,197	118,256	1,405,965	713,475
58	G52 High Annual-Low Winter		8,381	10,909	11,818	10,723	10,351	9,044	192,201	61,227
59	G42 High Annual-High Winter		11,315	11,693	11,693	10,561	11,693	11,315	137,477	68,270
60	**Subtotal**									
61	Residential		401,529	414,913	414,913	374,761	414,913	401,529	4,855,117	2,422,559
62	SALES HLF CLASSES		259,787	270,695	271,604	245,367	270,137	260,449	3,216,570	1,578,039
63	SALES LLF CLASSES		194,322	200,800	200,800	181,368	200,800	194,322	2,310,081	1,172,412
64	**Total Firm Sales**		855,638	886,408	887,317	801,496	885,850	856,301	10,381,767	5,173,010
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		1,015,648	1,653,708	2,572,167	2,148,992	2,089,019	1,143,176	11,480,248	10,622,710
69	Res General		13,243	18,137	30,069	26,903	25,065	15,568	151,056	128,986
70	G50 Low Annual-Low Winter		17,522	48,561	73,681	67,167	58,142	21,319	364,790	286,392
71	G40 Low Annual-High Winter		491,077	898,681	1,504,300	1,291,720	1,132,328	612,179	6,437,916	5,930,286
72	G51 Med Annual-Low Winter		77,318	110,745	125,087	99,884	105,641	44,918	689,735	563,592
73	G41 Med Annual-High Winter		518,083	1,019,027	1,112,154	930,903	924,350	482,677	5,620,075	4,987,195
74	G52 High Annual-Low Winter		-	-	-	-	-	-	12,304	-
75	G42 High Annual-High Winter		92,901	143,413	141,255	118,635	91,574	48,372	676,108	636,150
76	**Subtotal**									
77	Residential		1,028,891	1,671,845	2,602,236	2,175,896	2,114,084	1,158,744	11,631,304	10,751,696
78	SALES HLF CLASSES		94,839	159,306	198,767	167,051	163,784	66,237	1,066,829	849,984
79	SALES LLF CLASSES		1,102,061	2,061,121	2,757,709	2,341,258	2,148,253	1,143,228	12,734,099	11,553,630
80	**Total Firm Sales**		2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209	25,432,233	23,155,310

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
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)	Original Filed Estimate	Change
Nov-10	586,642	0.07%	413	268,881	35,829	304,710	305,123	0.98%	3,020	308,143	312,051	-3,908
Dec-10	851,652	0.11%	933	406,199	66,053	472,252	473,184	0.98%	4,684	477,868	483,928	-6,060
Jan-11	1,045,034	0.03%	263	613,974	24,049	638,023	638,286	0.98%	6,317	644,603	652,778	-8,175
Feb-11	912,462	0.02%	197	627,345	-84,347	542,998	543,194	0.98%	5,376	548,570	555,527	-6,957
Mar-11	892,658	0.03%	239	513,420	12,333	525,753	525,992	0.98%	5,205	531,197	537,934	-6,737
Apr-11	599,363	0.02%	131	382,950	-63,791	319,160	319,291	0.98%	3,160	322,451	326,540	-4,089
May-11	383,221	0.02%	59	201,206	-36,687	164,519	164,577	0.98%	1,629	166,206	168,314	-2,108
Jun-11	308,155	0.07%	208	137,389	-32,722	104,668	104,876	0.98%	1,038	105,914	107,258	-1,344
Jul-11	279,541	0.04%	112	86,314	-3,742	82,572	82,684	0.98%	819	83,503	84,562	-1,059
Aug-11	285,914	0.08%	227	91,055	3,789	94,844	95,071	0.98%	941	96,012	97,230	-1,218
Sep-11	329,429	0.09%	296	90,390	23,299	113,688	113,985	0.98%	1,128	115,113	116,572	-1,459
Oct-11	447,305	0.06%	264	123,386	56,388	179,773	180,038	0.98%	1,782	181,820	184,125	-2,305
Nov-11	600,602	0.07%	423	272,343	36,495	308,838	309,261	0.98%	3,061	312,322	316,282	-3,960
Dec-11	868,484	0.11%	951	411,711	67,239	478,951	479,902	0.98%	4,749	484,651	490,797	-6,146
Jan-12	1,103,189	0.03%	278	637,377	24,434	661,812	662,089	0.98%	6,553	668,642	677,121	-8,479
Feb-12	990,635	0.02%	213	660,313	-77,236	583,076	583,289	0.98%	5,773	589,062	596,533	-7,471
Mar-12	943,479	0.03%	252	542,513	4,116	546,629	546,881	0.98%	5,413	552,294	559,298	-7,004
Apr-12	643,831	0.02%	141	401,791	-65,021	336,770	336,911	0.98%	3,334	340,245	344,560	-4,315
Peak	4,887,810	0.04%	2,175	2,812,769	-9,874	2,802,895	2,805,070	0.98%	27,762	2,832,832	2,868,758	-35,926
Off-Peak	2,033,565	0.06%	1,167	729,739	10,325	740,064	741,231	0.98%	7,337	748,568	758,061	-9,493
Annual	6,921,375	0.05%	3,343	3,542,509	450	3,542,959	3,546,302	0.98%	35,098	3,581,400	3,626,819	-45,419

Revised Schedule 10C

Unitil
Northern Utilities, Inc.

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

Base Commodity Costs

1	BASE SENDOUT BY CLASS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
2	Total Therms								
3	Res Heat	386,086	398,955	398,955	360,347	398,955	386,086	4,669,512	2,329,385
4	Res General	15,443	15,958	15,958	14,414	15,958	15,443	185,605	93,174
5	G50 Low Annual-Low Winter	109,908	113,572	113,572	102,581	113,572	109,908	1,319,141	663,114
6	G40 Low Annual-High Winter	64,751	66,910	66,910	60,435	66,910	64,751	766,639	390,667
7	G51 Med Annual-Low Winter	141,497	146,213	146,213	132,064	146,213	141,497	1,705,228	853,698
8	G41 Med Annual-High Winter	118,256	122,197	122,197	110,372	122,197	118,256	1,405,965	713,475
9	G52 High Annual-Low Winter	8,381	10,909	11,818	10,723	10,351	9,044	192,201	61,227
10	G42 High Annual-High Winter	11,315	11,693	11,693	10,561	11,693	11,315	137,477	68,270
11	Total Firm Sales	855,638	886,408	887,317	801,496	885,850	856,301	10,381,767	5,173,010
12	% of Total								
13	Res Heat	45.12%	45.01%	44.96%	44.96%	45.04%	45.09%		
14	Res General	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%		
15	G50 Low Annual-Low Winter	12.85%	12.81%	12.80%	12.80%	12.82%	12.84%		
16	G40 Low Annual-High Winter	7.57%	7.55%	7.54%	7.54%	7.55%	7.56%		
17	G51 Med Annual-Low Winter	16.54%	16.50%	16.48%	16.48%	16.51%	16.52%		
18	G41 Med Annual-High Winter	13.82%	13.79%	13.77%	13.77%	13.79%	13.81%		
19	G52 High Annual-Low Winter	0.98%	1.23%	1.33%	1.34%	1.17%	1.06%		
20	G42 High Annual-High Winter	1.32%	1.32%	1.32%	1.32%	1.32%	1.32%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	BASE COMMODITY COSTS Excld Hedging	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
23	TOTAL BASE COMMODITY Excld Hedging	$ 379,344	$ 419,231	$ 439,622	$ 403,443	$ 433,732	$ 401,257	$ 4,991,615	$ 2,476,628
24	Res Heat	$ 171,170	$ 188,688	$ 197,663	$ 181,385	$ 195,337	$ 180,917	$ 2,244,839	$ 1,115,160
25	Res General	$ 6,847	$ 7,547	$ 7,906	$ 7,255	$ 7,813	$ 7,237	$ 89,239	$ 44,606
26	G50 Low Annual-Low Winter	$ 48,727	$ 53,714	$ 56,269	$ 51,636	$ 55,607	$ 51,502	$ 634,251	$ 317,457
27	G40 Low Annual-High Winter	$ 28,707	$ 31,645	$ 33,151	$ 30,421	$ 32,761	$ 30,342	$ 368,630	$ 187,026
28	G51 Med Annual-Low Winter	$ 62,732	$ 69,152	$ 72,442	$ 66,476	$ 71,589	$ 66,304	$ 819,867	$ 408,696
29	G41 Med Annual-High Winter	$ 52,428	$ 57,794	$ 60,543	$ 55,557	$ 59,831	$ 55,414	$ 676,029	$ 341,566
30	G52 High Annual-Low Winter	$ 3,716	$ 5,159	$ 5,855	$ 5,397	$ 5,068	$ 4,238	$ 92,666	$ 29,434
31	G42 High Annual-High Winter	$ 5,017	$ 5,530	$ 5,793	$ 5,316	$ 5,725	$ 5,302	$ 66,094	$ 32,683
32									
33	Residential	$ 178,016	$ 196,235	$ 205,569	$ 188,640	$ 203,151	$ 188,154	$ 2,334,078	$ 1,159,766
34	SALES HLF CLASSES	$ 115,175	$ 128,026	$ 134,566	$ 123,509	$ 132,265	$ 122,045	$ 1,546,784	$ 755,587
35	SALES LLF CLASSES	$ 86,152	$ 94,969	$ 99,487	$ 91,294	$ 98,316	$ 91,058	$ 1,110,753	$ 561,276

36	NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS								
37	TOTAL BASE HEDGING COMMODITY	$ 68,693	$ 91,581	$ 91,263	$ 143,813	$ 77,199	$ 64,681	$ 557,835	$ 537,229
38	Res Heat	$ 30,996	$ 41,219	$ 41,034	$ 64,657	$ 34,768	$ 29,163	$ 250,995	$ 241,836
39	Res General	$ 1,240	$ 1,649	$ 1,641	$ 2,586	$ 1,391	$ 1,167	$ 10,040	$ 9,673
40	G50 Low Annual-Low Winter	$ 8,824	$ 11,734	$ 11,681	$ 18,406	$ 9,897	$ 8,302	$ 71,452	$ 68,844
41	G40 Low Annual-High Winter	$ 5,198	$ 6,913	$ 6,882	$ 10,844	$ 5,831	$ 4,891	$ 42,095	$ 40,559
42	G51 Med Annual-Low Winter	$ 11,360	$ 15,106	$ 15,039	$ 23,696	$ 12,742	$ 10,688	$ 91,987	$ 88,631
43	G41 Med Annual-High Winter	$ 9,494	$ 12,625	$ 12,568	$ 19,804	$ 10,649	$ 8,932	$ 76,878	$ 74,073
44	G52 High Annual-Low Winter	$ 673	$ 1,127	$ 1,216	$ 1,924	$ 902	$ 683	$ 7,032	$ 6,525
45	G42 High Annual-High Winter	$ 908	$ 1,208	$ 1,203	$ 1,895	$ 1,019	$ 855	$ 7,356	$ 7,088
46									
47	Residential	$ 32,236	$ 42,868	$ 42,675	$ 67,243	$ 36,158	$ 30,330	$ 261,035	$ 251,510
48	SALES HLF CLASSES	$ 20,856	$ 27,967	$ 27,935	$ 44,026	$ 23,541	$ 19,673	$ 170,471	$ 164,000
49	SALES LLF CLASSES	$ 15,601	$ 20,746	$ 20,653	$ 32,543	$ 17,499	$ 14,678	$ 126,330	$ 121,720

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

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

Remaining Commodity Costs

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
50	**REMAINING SENDOUT BY CLASS**								
51	**Total Therms**								
52	Res Heat	1,015,648	1,653,708	2,572,167	2,148,992	2,089,019	1,143,176	11,480,248	10,622,710
53	Res General	13,243	18,137	30,069	26,903	25,065	15,568	151,056	128,986
54	G50 Low Annual-Low Winter	17,522	48,561	73,681	67,167	58,142	21,319	364,790	286,392
55	G40 Low Annual-High Winter	491,077	898,681	1,504,300	1,291,720	1,132,328	612,179	6,437,916	5,930,286
56	G51 Med Annual-Low Winter	77,318	110,745	125,087	99,884	105,641	44,918	689,735	563,592
57	G41 Med Annual-High Winter	518,083	1,019,027	1,112,154	930,903	924,350	482,677	5,620,075	4,987,195
58	G52 High Annual-Low Winter	-	-	-	-	-	-	12,304	-
59	G42 High Annual-High Winter	92,901	143,413	141,255	118,635	91,574	48,372	676,108	636,150
60	Total Firm Sales	2,225,792	3,892,272	5,558,713	4,684,204	4,426,120	2,368,209	25,432,233	23,155,310
61	**% of Total**								
62	Res Heat	45.63%	42.49%	46.27%	45.88%	47.20%	48.27%		
63	Res General	0.59%	0.47%	0.54%	0.57%	0.57%	0.66%		
64	G50 Low Annual-Low Winter	0.79%	1.25%	1.33%	1.43%	1.31%	0.90%		
65	G40 Low Annual-High Winter	22.06%	23.09%	27.06%	27.58%	25.58%	25.85%		
66	G51 Med Annual-Low Winter	3.47%	2.85%	2.25%	2.13%	2.39%	1.90%		
67	G41 Med Annual-High Winter	23.28%	26.18%	20.01%	19.87%	20.88%	20.38%		
68	G52 High Annual-Low Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
69	G42 High Annual-High Winter	4.17%	3.68%	2.54%	2.53%	2.07%	2.04%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
71	**REMAINING COMMODITY COSTS EXCLD HEDGING**								
72	REMAINING COMMODITY Excld Hedging	$ 981,919	$ 1,717,274	$ 2,425,271	$ 2,031,031	$ 1,955,410	$ 1,070,186	$ 11,289,811	$ 10,181,092
73	Res Heat	$ 448,058	$ 729,618	$ 1,122,239	$ 931,785	$ 922,905	$ 516,597	$ 5,087,051	$ 4,671,202
74	Res General	$ 5,842	$ 8,002	$ 13,119	$ 11,665	$ 11,073	$ 7,035	$ 67,424	$ 56,737
75	G50 Low Annual-Low Winter	$ 7,730	$ 21,425	$ 32,147	$ 29,123	$ 25,687	$ 9,634	$ 164,078	$ 125,746
76	G40 Low Annual-High Winter	$ 216,641	$ 396,499	$ 656,327	$ 560,079	$ 500,250	$ 276,642	$ 2,852,428	$ 2,606,438
77	G51 Med Annual-Low Winter	$ 34,109	$ 48,861	$ 54,575	$ 43,309	$ 46,671	$ 20,298	$ 309,869	$ 247,823
78	G41 Med Annual-High Winter	$ 228,555	$ 449,596	$ 485,234	$ 403,632	$ 408,368	$ 218,120	$ 2,503,565	$ 2,193,504
79	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,002	$ -
80	G42 High Annual-High Winter	$ 40,984	$ 63,274	$ 61,630	$ 51,439	$ 40,456	$ 21,859	$ 299,394	$ 279,642
81									
82	Residential	$ 453,900	$ 737,619	$ 1,135,358	$ 943,450	$ 933,978	$ 523,633	$ 5,154,475	$ 4,727,939
83	SALES HLF CLASSES	$ 41,839	$ 70,286	$ 86,722	$ 72,432	$ 72,358	$ 29,932	$ 479,949	$ 373,569
84	SALES LLF CLASSES	$ 486,180	$ 909,369	$ 1,203,191	$ 1,015,150	$ 949,074	$ 516,621	$ 5,655,387	$ 5,079,584

85	**REMAINING COMMODITY HEDGING COSTS**								
86	TOTAL REMAINING COMMODITY HEDGING	$ 167,367	$ 130,055	$ 42,643	$ 20,775	$ 82,522	$ 139,418	$ 600,984	$ 582,780
87	Res Heat	$ 76,371	$ 55,256	$ 19,732	$ 9,531	$ 38,949	$ 67,300	$ 275,145	$ 267,139
88	Res General	$ 996	$ 606	$ 231	$ 119	$ 467	$ 917	$ 3,494	$ 3,336
89	G50 Low Annual-Low Winter	$ 1,318	$ 1,623	$ 565	$ 298	$ 1,084	$ 1,255	$ 6,564	$ 6,142
90	G40 Low Annual-High Winter	$ 36,926	$ 30,028	$ 11,540	$ 5,729	$ 21,112	$ 36,039	$ 145,651	$ 141,374
91	G51 Med Annual-Low Winter	$ 5,814	$ 3,700	$ 960	$ 443	$ 1,970	$ 2,644	$ 16,309	$ 15,531
92	G41 Med Annual-High Winter	$ 38,957	$ 34,049	$ 8,532	$ 4,129	$ 17,234	$ 28,416	$ 135,571	$ 131,316
93	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ 86	$ -
94	G42 High Annual-High Winter	$ 6,986	$ 4,792	$ 1,084	$ 526	$ 1,707	$ 2,848	$ 18,164	$ 17,942
95								$ -	$ -
96	Residential	$ 77,367	$ 55,862	$ 19,963	$ 9,650	$ 39,416	$ 68,216	$ 278,638	$ 270,474
97	SALES HLF CLASSES	$ 7,131	$ 5,323	$ 1,525	$ 741	$ 3,054	$ 3,899	$ 22,960	$ 21,673
98	SALES LLF CLASSES	$ 82,869	$ 68,869	$ 21,156	$ 10,384	$ 40,053	$ 67,303	$ 299,386	$ 290,633

Northern Utilities - NEW HAMPSHIRE 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

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**								
100	TOTAL COMMODITY Excld Hedging	$ 1,361,263	$ 2,136,505	$ 2,864,894	$ 2,434,474	$ 2,389,142	$ 1,471,442	$ 16,281,426	$ 12,657,720
101	Res Heat	$ 619,228	$ 918,305	$ 1,319,902	$ 1,113,170	$ 1,118,242	$ 697,515	$ 7,331,889	$ 5,786,362
102	Res General	$ 12,689	$ 15,549	$ 21,026	$ 18,920	$ 18,887	$ 14,272	$ 156,664	$ 101,343
103	G50 Low Annual-Low Winter	$ 56,457	$ 75,140	$ 88,416	$ 80,758	$ 81,294	$ 61,136	$ 798,329	$ 443,202
104	G40 Low Annual-High Winter	$ 245,349	$ 428,144	$ 689,478	$ 590,499	$ 533,010	$ 306,984	$ 3,221,058	$ 2,793,464
105	G51 Med Annual-Low Winter	$ 96,841	$ 118,013	$ 127,017	$ 109,785	$ 118,260	$ 86,603	$ 1,129,736	$ 656,519
106	G41 Med Annual-High Winter	$ 280,983	$ 507,390	$ 545,777	$ 459,189	$ 468,198	$ 273,534	$ 3,179,594	$ 2,535,070
107	G52 High Annual-Low Winter	$ 3,716	$ 5,159	$ 5,855	$ 5,397	$ 5,068	$ 4,238	$ 98,668	$ 29,434
108	G42 High Annual-High Winter	$ 46,000	$ 68,804	$ 67,423	$ 56,755	$ 46,181	$ 27,161	$ 365,488	$ 312,325
109									
110	Residential	$ 631,917	$ 933,855	$ 1,340,927	$ 1,132,090	$ 1,137,129	$ 711,786	$ 7,488,553	$ 5,887,705
111	SALES HLF CLASSES	$ 157,014	$ 198,312	$ 221,289	$ 195,941	$ 204,623	$ 151,977	$ 2,026,733	$ 1,129,156
112	SALES LLF CLASSES	$ 572,332	$ 1,004,338	$ 1,302,678	$ 1,106,443	$ 1,047,390	$ 607,679	$ 6,766,140	$ 5,640,859

113	**TOTAL HEDGING COMMODITY COSTS**								
114	TOTAL HEDGING COMMODITY	$ 236,059	$ 221,635	$ 133,907	$ 164,587	$ 159,721	$ 204,099	$ 1,158,819	$ 1,120,010
115	Res Heat	$ 107,367	$ 96,475	$ 60,766	$ 74,188	$ 73,716	$ 96,463	$ 526,140	$ 508,975
116	Res General	$ 2,236	$ 2,255	$ 1,872	$ 2,706	$ 1,858	$ 2,083	$ 13,534	$ 13,009
117	G50 Low Annual-Low Winter	$ 10,141	$ 13,357	$ 12,246	$ 18,704	$ 10,981	$ 9,557	$ 78,016	$ 74,987
118	G40 Low Annual-High Winter	$ 42,125	$ 36,941	$ 18,422	$ 16,573	$ 26,943	$ 40,931	$ 187,746	$ 181,933
119	G51 Med Annual-Low Winter	$ 17,174	$ 18,807	$ 15,998	$ 24,139	$ 14,712	$ 13,332	$ 108,296	$ 104,162
120	G41 Med Annual-High Winter	$ 48,451	$ 46,674	$ 21,100	$ 23,933	$ 27,883	$ 37,348	$ 212,449	$ 205,389
121	G52 High Annual-Low Winter	$ 673	$ 1,127	$ 1,216	$ 1,924	$ 902	$ 683	$ 7,118	$ 6,525
122	G42 High Annual-High Winter	$ 7,894	$ 6,000	$ 2,286	$ 2,421	$ 2,726	$ 3,702	$ 25,520	$ 25,030
123									
124	Residential	$ 109,602	$ 98,730	$ 62,638	$ 76,894	$ 75,574	$ 98,546	$ 539,673	$ 521,984
125	SALES HLF CLASSES	$ 27,988	$ 33,290	$ 29,460	$ 44,767	$ 26,595	$ 23,573	$ 193,430	$ 185,673
126	SALES LLF CLASSES	$ 98,469	$ 89,615	$ 41,808	$ 42,926	$ 57,552	$ 81,981	$ 425,716	$ 412,353

127	TOTAL COMMODITY	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
128	Res Heat	$ 726,595	$ 1,014,780	$ 1,380,668	$ 1,187,358	$ 1,191,958	$ 793,977	$ 7,858,029	$ 6,295,337
129	Res General	$ 14,924	$ 17,804	$ 22,898	$ 21,626	$ 20,745	$ 16,355	$ 170,197	$ 114,352
130	G50 Low Annual-Low Winter	$ 66,599	$ 88,496	$ 100,663	$ 99,462	$ 92,276	$ 70,693	$ 876,344	$ 518,189
131	G40 Low Annual-High Winter	$ 287,473	$ 465,085	$ 707,900	$ 607,072	$ 559,953	$ 347,914	$ 3,408,804	$ 2,975,398
132	G51 Med Annual-Low Winter	$ 114,015	$ 136,820	$ 143,015	$ 133,924	$ 132,972	$ 99,935	$ 1,238,033	$ 760,681
133	G41 Med Annual-High Winter	$ 329,434	$ 554,064	$ 566,877	$ 483,121	$ 496,081	$ 310,882	$ 3,392,043	$ 2,740,459
134	G52 High Annual-Low Winter	$ 4,389	$ 6,287	$ 7,071	$ 7,321	$ 5,970	$ 4,921	$ 105,786	$ 35,959
135	G42 High Annual-High Winter	$ 53,894	$ 74,804	$ 69,709	$ 59,176	$ 48,908	$ 30,864	$ 391,008	$ 337,355
136	Total Firm Sales	$ 1,597,323	$ 2,358,140	$ 2,998,800	$ 2,599,062	$ 2,548,863	$ 1,675,542	$ 17,440,245	$ 13,777,730
137									
138	Residential	$ 741,519	$ 1,032,585	$ 1,403,565	$ 1,208,984	$ 1,212,703	$ 810,332	$ 8,028,226	$ 6,409,689
139	SALES HLF CLASSES	$ 185,002	$ 231,603	$ 250,749	$ 240,708	$ 231,218	$ 175,550	$ 2,220,163	$ 1,314,829
140	SALES LLF CLASSES	$ 670,801	$ 1,093,953	$ 1,344,486	$ 1,149,370	$ 1,104,942	$ 689,660	$ 7,191,856	$ 6,053,212
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								17.85%
144	SALES LLF CLASSES								82.15%

Northern Utilities - NEW HAMPSHIRE 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)

Revised Schedule 11B

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc. Design Year Sendout Volumes (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	404,016	374,386	2,349,073
Subtotal Pipeline Volumes	699,251	721,983	721,983	652,114	711,142	679,730	4,186,203
Storage							
Tennessee Storage	1,831	26,368	65,228	34,317	46,333	67,559	241,636
Washington 10 Storage	134,431	652,989	978,082	696,039	572,759	118,334	3,152,634
Subtotal Storage Volumes	136,263	679,357	1,043,310	730,355	619,092	185,893	3,394,270
Peaking							
Peaking Supply 1	126,589	122,897	108,428	105,708	84,731	119,340	667,693
Peaking Supply 2	0	2,300	6,730	43,959	31,606	0	84,595
LNG	1,350	1,395	45,810	1,882	1,395	19,641	71,472
Subtotal Peaking Volumes	127,939	126,593	160,968	151,548	117,732	138,981	823,761
Total Delivered (Dth)	963,453	1,527,933	1,926,261	1,534,017	1,447,966	1,004,604	8,404,234

Revised Schedule 11C
Capacity Utilization

Unitil
Northern Utilities, Inc.

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	2,349,073	13,089	2,369,109	99%
Subtotal Pipeline Volumes	4,186,203	23,902	4,326,262	97%
Storage				
Tennessee Storage	241,636	2,640	252,452	96%
Washington 10 Storage	3,152,634	32,835	3,283,500	96%
Subtotal Storage Volumes	3,394,270	35,475	3,535,952	96%
Peaking				
Peaking Supply 1	667,693	4,975	751,225	89%
Peaking Supply 2	84,595	57,113	1,427,825	6%
LNG	71,472	10,000	9,669	739%
Subtotal Peaking Volumes	823,761	72,088	2,188,719	38%
Total Delivered (Dth)	8,404,234	131,465	10,050,933	84%

Revised Schedule 14

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Northern Utilities, Inc.

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	$ 946,149	$ 4.46	NA	$ -	$ 4.46	$ -	$ 946,149	2.35%	$ 1,852	$ 946,149	$ -
Dec-10	212,008	-	-	212,008	$ 946,149	$ 4.46	NA	$ -	$ 4.46	$ -	$ 946,149	2.35%	$ 1,852	$ 946,149	$ -
Jan-11	212,008	-	8,501	203,507	$ 946,149	$ 4.46	NA	$ -	$ 4.46	$ 37,937	$ 908,213	2.35%	$ 1,815	$ 908,213	$ 37,937
Feb-11	203,507	-	21,743	181,764	$ 908,213	$ 4.46	NA	$ -	$ 4.46	$ 97,036	$ 811,177	2.35%	$ 1,683	$ 811,177	$ 97,036
Mar-11	181,764	-	14,627	167,137	$ 811,177	$ 4.46	NA	$ -	$ 4.46	$ 65,279	$ 745,898	2.35%	$ 1,524	$ 745,898	$ 65,279
Apr-11	167,137	47,381	2,510	212,008	$ 745,898	$ 4.46	$ 4.66	$ 220,690	$ 4.51	$ 11,311	$ 955,278	2.35%	$ 1,665	$ 955,278	$ 11,311
May-11	212,008	-	-	212,008	$ 955,278	$ 4.51	NA	$ -	$ 4.51	$ -	$ 955,278	2.35%	$ 1,870	$ 955,278	$ -
Jun-11	212,008	-	-	212,008	$ 955,278	$ 4.51	NA	$ -	$ 4.51	$ -	$ 955,278	2.35%	$ 1,870	$ 955,278	$ -
Jul-11	212,008	-	-	212,008	$ 955,278	$ 4.51	NA	$ -	$ 4.51	$ -	$ 955,278	2.35%	$ 1,870	$ 955,278	$ -
Aug-11	212,008	-	-	212,008	$ 955,278	$ 4.51	NA	$ -	$ 4.51	$ -	$ 955,278	2.35%	$ 1,870	$ 955,278	$ -
Sep-11	212,008	-	-	212,008	$ 955,278	$ 4.51	NA	$ -	$ 4.51	$ -	$ 955,278	2.35%	$ 1,870	$ 955,278	$ -
Oct-11	212,008	-	10,600	201,408	$ 955,278	$ 4.51	NA	$ -	$ 4.51	$ 47,764	$ 907,514	2.35%	$ 1,823	$ 907,514	$ 47,764

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	$ 11,684,462	$ 4.20	NA	$ -	$ 4.20	$ -	$ 11,684,462	2.35%		$ 11,684,462	$ -
Dec-10	2,779,500	-	405,109	2,374,391	$ 11,684,462	$ 4.20	NA	$ -	$ 4.20	$ 1,702,997	$ 9,981,465	2.35%		$ 9,981,465	$ 1,702,997
Jan-11	2,374,391	-	852,241	1,522,150	$ 9,981,465	$ 4.20	NA	$ -	$ 4.20	$ 3,582,652	$ 6,398,813	2.35%		$ 6,398,813	$ 3,582,652
Feb-11	1,522,150	-	728,039	794,110	$ 6,398,813	$ 4.20	NA	$ -	$ 4.20	$ 3,060,532	$ 3,338,281	2.35%		$ 3,338,281	$ 3,060,532
Mar-11	794,110	-	516,160	277,950	$ 3,338,281	$ 4.20	NA	$ -	$ 4.20	$ 2,169,835	$ 1,168,446	2.35%		$ 1,168,446	$ 2,169,835
Apr-11	277,950	-	-	277,950	$ 1,168,446	$ 4.20	NA	$ -	$ 4.20	$ -	$ 1,168,446	2.35%		$ 1,168,446	$ -
May-11	277,950	484,222	-	762,172	$ 1,168,446	$ 4.20	$ 4.48	$ 2,169,113	$ 4.38	$ -	$ 3,337,560	2.35%		$ 3,337,560	$ -
Jun-11	762,172	468,602	-	1,230,775	$ 3,337,560	$ 4.38	$ 4.54	$ 2,128,304	$ 4.44	$ -	$ 5,465,863	2.35%		$ 5,465,863	$ -
Jul-11	1,230,775	484,222	-	1,714,997	$ 5,465,863	$ 4.44	$ 4.62	$ 2,236,792	$ 4.49	$ -	$ 7,702,655	2.35%		$ 7,702,655	$ -
Aug-11	1,714,997	484,222	-	2,199,219	$ 7,702,655	$ 4.49	$ 4.67	$ 2,262,480	$ 4.53	$ -	$ 9,965,135	2.35%		$ 9,965,135	$ -
Sep-11	2,199,219	468,602	-	2,667,821	$ 9,965,135	$ 4.53	$ 4.69	$ 2,199,536	$ 4.56	$ -	$ 12,164,672	2.35%		$ 12,164,672	$ -
Oct-11	2,667,822	111,679	-	2,779,500	$ 12,164,672	$ 4.56	$ 4.78	$ 533,314	$ 4.57	$ -	$ 12,697,986	2.35%		$ 12,697,986	$ -

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	$ 9,645	$ 6.94	$ 9,368	$ 71,762	2.35%	$ 140	$ 71,762	$ 9,368
Dec-10	10,341	1,395	1,395	10,341	$ 71,762	$ 6.94	$ 4.77	$ 6,652	$ 6.68	$ 9,321	$ 69,094	2.35%	$ 138	$ 69,094	$ 9,321
Jan-11	10,341	361	1,395	9,307	$ 69,094	$ 6.68	$ 4.77	$ 1,721	$ 6.62	$ 9,231	$ 61,584	2.35%	$ 128	$ 61,584	$ 9,231
Feb-11	9,307	1,260	1,260	9,307	$ 61,584	$ 6.62	$ 4.77	$ 6,008	$ 6.40	$ 8,060	$ 59,533	2.35%	$ 119	$ 59,533	$ 8,060
Mar-11	9,307	1,395	1,395	9,307	$ 59,533	$ 6.40	$ 4.77	$ 6,652	$ 6.18	$ 8,627	$ 57,558	2.35%	$ 115	$ 57,558	$ 8,627
Apr-11	9,307	2,665	1,631	10,341	$ 57,558	$ 6.18	$ 4.77	$ 12,707	$ 5.87	$ 9,571	$ 60,694	2.35%	$ 116	$ 60,694	$ 9,571
May-11	10,341	-	1,395	8,946	$ 60,694	$ 5.87	NA	$ -	$ 5.87	$ 8,187	$ 52,506	2.35%	$ 111	$ 52,506	$ 8,187
Jun-11	8,946	-	1,350	7,596	$ 52,506	$ 5.87	NA	$ -	$ 5.87	$ 7,923	$ 44,583	2.35%	$ 95	$ 44,583	$ 7,923
Jul-11	7,596	-	1,395	6,201	$ 44,583	$ 5.87	NA	$ -	$ 5.87	$ 8,187	$ 36,396	2.35%	$ 79	$ 36,396	$ 8,187
Aug-11	6,201	-	1,395	4,806	$ 36,396	$ 5.87	NA	$ -	$ 5.87	$ 8,187	$ 28,208	2.35%	$ 63	$ 28,208	$ 8,187
Sep-11	4,806	-	1,350	3,456	$ 28,208	$ 5.87	NA	$ -	$ 5.87	$ 7,923	$ 20,285	2.35%	$ 47	$ 20,285	$ 7,923
Oct-11	3,456	-	1,395	2,061	$ 20,285	$ 5.87	NA	$ -	$ 5.87	$ 8,187	$ 12,098	2.35%	$ 32	$ 12,098	$ 8,187

Revised Schedule 16

Unitil
Northern Utilities, Inc.

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	$ (34,047)	$ (36,657)	$ (42,016)	$ (49,264)	$ (50,043)	$ (43,345)	$ (22,068)	$ (9,294)	$ 237	$ 1,503	$ 2,293	$ (177)
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	$ (36,561)	$ (41,910)	$ (49,141)	$ (49,908)	$ (43,219)	$ (21,980)	$ (9,251)	$ 249	$ 1,501	$ 2,288	$ (180)	$ (6,114)
Average Balance	$ (35,304)	$ (39,283)	$ (45,579)	$ (49,586)	$ (46,631)	$ (32,663)	$ (15,660)	$ (4,522)	$ 869	$ 1,896	$ 1,057	$ (3,146)
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	$ (95.62)	$ (106.39)	$ (123.44)	$ (134.30)	$ (126.29)	$ (88.46)	$ (42.41)	$ (12.25)	$ 2.35	$ 5.13	$ 2.86	$ (8.52)

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	$ 188	$ 253	$ 312	$ 314	$ 244	$ 197	$ 111	$ 74	$ 45	$ 45	$ 59	$ 91	
Avg Monthly Residential Low Income Customer Bill	$ 160	$ 217	$ 269	$ 271	$ 205	$ 164	$ 86	$ 55	$ 32	$ 32	$ 43	$ 69	
Avg Monthly RLIAP Customer Discount	$ 29	$ 36	$ 43	$ 43	$ 39	$ 33	$ 25	$ 19	$ 13	$ 13	$ 16	$ 22	
Avg. Monthly RLIAP Customer Discount as a % to Avg. Monthly Residential Customer Bill	15%	14%	14%	14%	16%	17%	23%	26%	29%	29%	27%	24%	
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.

Revised Schedule 16
DSM
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Northern Utilities, Inc. -- New Hampshire Division

Energy Efficiency Budget

	Residential	Low-Income	Gen Service	Total
August-10	$13,894	$31,981	$30,130	$76,004
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	$374,201	$144,941	$624,226	$1,143,368

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

	Residential	Low-Income	Gen Service	Total
August-10	$19,126	0	$56,878	$76,004
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	$409,264	$0	$734,105	$1,143,368

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	Actual	163,600	$0.0185	5,809	13,894	1,724	5,232	107	178,749	171,175	3.25%	472	179,221	313,978	31
September-10	Forecast	179,221	$0.0185	7,814	5,722	1,724	860	126	179,838	179,530	3.25%	480	180,318	422,359	30
October-10	Forecast	180,318	$0.0185	9,175	5,722	1,724	841	123	179,552	179,935	3.25%	497	180,049	495,952	31
November-10	Forecast	180,049	$0.0359	40,460	5,722	1,724	1,163	170	148,368	164,208	3.25%	439	148,807	1,126,635	30
December-10	Forecast	148,807	$0.0359	68,240	27,464	1,724	5,827	177	115,758	132,282	3.25%	365	116,123	1,900,203	31
January-11	Forecast	116,123	$0.0359	100,699	22,231	2,964	1,733	231	42,583	79,353	3.25%	219	42,802	2,804,066	31
February-11	Forecast	42,802	$0.0359	105,145	26,677	2,964	2,234	248	(30,220)	6,291	3.25%	16	(30,204)	2,927,871	28
March-11	Forecast	(30,204)	$0.0359	87,765	31,123	2,964	2,519	240	(81,124)	(55,664)	3.25%	(154)	(81,278)	2,443,900	31
April-11	Forecast	(81,278)	$0.0359	65,447	31,123	2,964	2,490	237	(109,910)	(95,594)	3.25%	(255)	(110,165)	1,822,428	30
May-11	Forecast	(110,165)	$0.0359	39,715	22,231	2,964	1,794	239	(122,652)	(116,408)	3.25%	(321)	(122,973)	1,105,900	31
June-11	Forecast	(122,973)	$0.0359	23,543	75,585	2,964	4,967	195	(62,805)	(92,889)	3.25%	(248)	(63,053)	655,568	30
July-11	Forecast	(63,053)	$0.0359	15,086	17,785	2,964	983	164	(56,243)	(59,648)	3.25%	(165)	(56,408)	420,094	31
August-11	Forecast	(56,408)	$0.0359	13,148	44,462	2,964	2,327	155	(19,649)	(38,029)	3.25%	(105)	(19,754)	366,114	31
September-11	Forecast	(19,754)	$0.0359	15,279	22,231	2,964	1,059	141	(8,637)	(14,196)	3.25%	(38)	(8,675)	425,454	30
October-11	Forecast	(8,675)	$0.0359	17,939	22,231	2,964	1,034	138	(248)	(4,462)	3.25%	(12)	(260)	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	Actual	(149,529)	$0.0054	8,669	30,130	2,659	26,749	546	(98,114)	(123,822)	3.25%	(342)	(98,456)	1,605,354	31
September-10	Forecast	(98,456)	$0.0054	9,574	82,030	2,659	3,609	527	(19,205)	(58,831)	3.25%	(157)	(19,362)	1,772,983	30
October-10	Forecast	(19,362)	$0.0054	11,559	41,015	2,659	3,629	530	16,911	(1,225)	3.25%	(3)	16,908	2,140,510	31
November-10	Forecast	16,908	$0.0152	48,590	54,686	2,659	3,306	483	29,453	23,181	3.25%	62	29,515	3,202,347	30
December-10	Forecast	29,515	$0.0152	77,322	54,686	2,659	15,626	475	25,640	27,577	3.25%	76	25,716	5,095,925	31
January-11	Forecast	25,716	$0.0152	92,503	25,834	2,871	3,767	502	(33,813)	(4,048)	3.25%	(11)	(33,824)	6,096,372	31
February-11	Forecast	(33,824)	$0.0152	86,830	34,446	2,871	4,366	485	(78,486)	(56,155)	3.25%	(140)	(78,626)	5,722,498	28
March-11	Forecast	(78,626)	$0.0152	76,285	25,834	2,871	5,181	493	(120,531)	(99,578)	3.25%	(275)	(120,806)	5,027,531	31
April-11	Forecast	(120,806)	$0.0152	57,841	43,057	2,871	5,210	496	(127,014)	(123,910)	3.25%	(331)	(127,345)	3,812,030	30
May-11	Forecast	(127,345)	$0.0152	34,651	25,834	2,871	3,706	494	(129,091)	(128,218)	3.25%	(354)	(129,445)	2,283,685	31
June-11	Forecast	(129,445)	$0.0152	27,501	60,280	2,871	13,733	538	(79,524)	(104,484)	3.25%	(279)	(79,803)	1,812,458	30
July-11	Forecast	(79,803)	$0.0152	22,156	17,223	2,871	3,417	569	(77,879)	(78,841)	3.25%	(218)	(78,097)	1,460,200	31
August-11	Forecast	(78,097)	$0.0152	20,707	51,668	2,871	8,673	578	(35,013)	(56,555)	3.25%	(156)	(35,169)	1,364,700	31
September-11	Forecast	(35,169)	$0.0152	27,061	51,668	2,871	4,441	592	(2,658)	(18,914)	3.25%	(51)	(2,709)	1,783,427	30
October-11	Forecast	(2,709)	$0.0152	32,733	25,834	2,871	4,466	595	(1,676)	(2,193)	3.25%	(6)	(1,682)	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)	($47,645)
Total ERC Cost to be Recovered	$319,543
Forcasted Firm Sales & Firm Transportation Volumes	58,898,383
ERC Recovery Rate	**$0.0054**

Revised Schedule 21

Northern Utilities, Inc.

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
50	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
51	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
52	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
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (5,214)	$ (277,309)	$ (201,445)	$ (180,942)	$ (188,867)	$ (198,195)	$ (285,364)	$ (1,337,337)
54	Less: Capacity Release	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ (84,906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (424,530)
55	Less: Asset Mgmt net of Current PNGTS	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ (355,027)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,130,160)
56	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

57

58 **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
59														
60	**Therms**													
61	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
62	New Hampshire	451,012	725,852	941,537	754,644	718,372	492,061	327,795	231,682	156,234	167,196	207,705	302,779	5,476,869
63	Total	963,453	1,527,933	1,926,261	1,534,017	1,447,966	1,004,604	662,095	431,664	367,877	391,847	423,919	663,886	11,345,522

		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
64	**Percentage of Total**													
65	Maine	53.19%	52.49%	51.12%	50.81%	50.39%	51.02%	50.49%	46.33%	57.53%	57.33%	51.00%	54.39%	51.36%
66	New Hampshire	46.81%	47.51%	48.88%	49.19%	49.61%	48.98%	49.51%	53.67%	42.47%	42.67%	49.00%	45.61%	48.64%
67	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%

68

69 **Allocation of Demand Costs by Division**

70	Maine	$825,914	$2,710,781	$7,492,819	$3,030,842	$2,297,382	$985,479	$373,877	$167,559	$172,846	$184,394	$180,059	$374,178	$18,796,131
71	New Hampshire	$726,908	$2,453,151	$7,164,207	$2,934,675	$2,262,046	$946,098	$366,602	$194,119	$127,595	$137,235	$172,973	$313,739	$17,799,347
72	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

73 **Detailed Allocation of Demand Costs by Division**

		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	
74	**Maine**														
75	Pipeline & Product Demand	$ 387,718	$ 430,219	$ 418,962	$ 319,342	$ 386,735	$ 348,255	$ 298,019	$ 165,948	$ 170,766	$ 182,320	$ 178,286	$ 337,112	$ 3,623,682	51.92%
76	Storage Incld Injection Fees	$ 295,200	$ 2,164,165	$ 6,149,777	$ 2,365,215	$ 1,849,880	$ 430,117	$ 181,865	$ 93,326	$ 104,098	$ 108,280	$ 101,086	$ 185,110	$ 14,028,120	51.30%
77	Peaking	$ 376,987	$ 347,338	$ 1,148,978	$ 569,798	$ 282,438	$ 390,900	$ 34,010	$ 1,611	$ 2,080	$ 2,073	$ 1,773	$ 7,174	$ 3,165,160	51.37%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,660)	$ (140,017)	$ (93,326)	$ (104,098)	$ (108,280)	$ (101,086)	$ (155,218)	$ (704,685)	
79	Capacity Release (Credit)	$ (45,160)	$ (44,571)	$ (43,405)	$ (43,137)	$ (42,782)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (219,055)	51.60%
80	Asset Management - PNGTS (Credit)	$ (188,831)	$ (186,370)	$ (181,493)	$ (180,375)	$ (178,889)	$ (181,132)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,097,091)	51.50%
81	**Total Allocated Demand**	$ 825,914	$ 2,710,781	$ 7,492,819	$ 3,030,842	$ 2,297,382	$ 985,479	$ 373,877	$ 167,559	$ 172,846	$ 184,394	$ 180,059	$ 374,178	$ 18,796,131	51.36%

82

		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	
83	**New Hampshire**														
84	Pipeline & Product Demand	$ 341,241	$ 389,331	$ 400,588	$ 309,209	$ 380,786	$ 334,338	$ 292,220	$ 192,253	$ 126,059	$ 135,692	$ 171,269	$ 282,660	$ 3,355,645	48.08%
85	Storage Incld Injection Fees	$ 259,813	$ 1,958,485	$ 5,880,066	$ 2,290,168	$ 1,821,427	$ 412,929	$ 178,326	$ 108,119	$ 76,844	$ 80,587	$ 97,108	$ 155,210	$ 13,319,084	48.70%
86	Peaking	$ 331,795	$ 314,327	$ 1,098,587	$ 551,718	$ 278,094	$ 375,279	$ 33,348	$ 1,866	$ 1,536	$ 1,543	$ 1,704	$ 6,015	$ 2,995,813	48.63%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,554)	$ (137,292)	$ (108,119)	$ (76,844)	$ (80,587)	$ (97,108)	$ (130,146)	$ (632,652)	
88	Capacity Release	$ (39,746)	$ (40,335)	$ (41,501)	$ (41,769)	$ (42,124)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (205,475)	48.40%
89	Asset Management - PNGTS (Credit)	$ (166,195)	$ (168,657)	$ (173,533)	$ (174,652)	$ (176,138)	$ (173,894)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,033,069)	48.50%
90	**Total Allocated Demand**	$ 726,908	$ 2,453,151	$ 7,164,207	$ 2,934,675	$ 2,262,046	$ 946,098	$ 366,602	$ 194,119	$ 127,595	$ 137,235	$ 172,973	$ 313,739	$ 17,799,347	48.64%

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)

Revised Schedule 22

Unitil
Northern Utilities, Inc.

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	561,589	426,146	245,249	170,119	340,205	503,193	3,610,876	2,246,500
3	Total Storage	0	395,545	840,396	732,016	518,213	2,450	2,498,964	2,488,619
4	Total Peaking	26,942	127,597	128,626	115,249	127,597	94,849	629,141	620,861
5	Subtotal	588,531	949,288	1,214,271	1,017,385	986,015	600,491	6,738,982	5,355,981
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	588,531	949,288	1,214,271	1,017,385	986,015	600,491	6,738,982	5,355,981
9	Total Firm Pipeline Sendout	561,589	426,146	245,249	170,119	340,205	503,193	3,610,876	2,246,500
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	$ 17,201,980	$ 10,600,308
12	NYMEX Price Used for Forecast	$3.865	$4.187	$4.373	$4.398	$4.337	$4.306		
13	NYMEX Price Used for Update	$3.865	$4.187	$4.373	$4.398	$4.337	$4.306		
14	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
15	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -		
16	Total Updated Pipeline Costs	$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	$ 17,201,980	$ 10,600,308
17									
18	Total Pipeline	$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	$ 17,201,980	$ 10,600,308
19	Total Storage	$ -	$ 1,729,478	$ 3,677,109	$ 3,207,234	$ 2,270,251	$ 11,551	$ 10,944,401	$ 10,895,622
20	Total Peaking	$ 107,887	$ 495,142	$ 499,013	$ 446,866	$ 494,448	$ 368,417	$ 2,460,366	$ 2,411,772
21	Subtotal	$ 2,597,669	$ 4,240,096	$ 5,391,211	$ 4,510,417	$ 4,430,416	$ 2,737,894	$ 30,606,747	$ 23,907,703
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	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306		
28	NYMEX Price Used for Update	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306		
29	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
30	Futures Hedging (Gain)/Loss - Allocate	$ 176,400	$ 195,940	$ 104,730	$ 125,200	$ 118,800	$ 168,460	$ 962,210	$ 889,530
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	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306		
35	NYMEX Price Used for Update	$ 3.865	$ 4.187	$ 4.373	$ 4.398	$ 4.337	$ 4.306		
36	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ 143,700	$ 123,000	$ 78,310	$ 97,080	$ 95,720	$ 113,640	$ 651,450	$ 651,450
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	$ 17,201,980	$ 10,600,308
41	Average Supply Cost ($/MMBtu)	$ 4.433	$ 4.730	$ 4.955	$ 5.034	$ 4.896	$ 4.686		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	$ 17,201,980	$ 10,600,308
46	Total Storage	$ -	$ 1,729,478	$ 3,677,109	$ 3,207,234	$ 2,270,251	$ 11,551	$ 10,944,401	$ 10,895,622
47	Total Peaking	$ 107,887	$ 495,142	$ 499,013	$ 446,866	$ 494,448	$ 368,417	$ 2,460,366	$ 2,411,772
48	Firm Sales Variable Costs Excld Hedge	$ 2,597,669	$ 4,240,096	$ 5,391,211	$ 4,510,417	$ 4,430,416	$ 2,737,894	$ 30,606,747	$ 23,907,703
49	Plus Hedging (Gain)/Loss	$ 176,400	$ 195,940	$ 104,730	$ 125,200	$ 118,800	$ 168,460	$ 962,210	$ 889,530
50	Total Firm Sales Variable Costs	$ 2,774,069	$ 4,436,036	$ 5,495,941	$ 4,635,617	$ 4,549,216	$ 2,906,354	$ 31,568,957	$ 24,797,233

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

51 **Commodity Allocation Factors**
52 Firm Sales Sendout for Normal Winter, MMBtu

Line		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
53									
54	Maine	280,388	471,420	569,668	468,815	454,818	278,040	3,157,582	2,523,149
55	New Hampshire	308,143	477,868	644,603	548,570	531,197	322,451	3,581,400	2,832,832
56	Total	588,531	949,288	1,214,271	1,017,385	986,015	600,491	6,738,982	5,355,981
57									
58	**Percentage of Total**								
59	Maine	47.64%	49.66%	46.91%	46.08%	46.13%	46.30%	46.86%	47.11%
60	New Hampshire	52.36%	50.34%	53.09%	53.92%	53.87%	53.70%	53.14%	52.89%
61	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
62									

63 **Commodity Allocation by Jurisdiction**

Line		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
64	**Maine**								
65	Firm Sales Pipeline Commodity Excld Hedge	$ 1,186,182	$ 1,000,893	$ 570,052	$ 394,595	$ 768,344	$ 1,091,769	$ 8,041,630	$ 5,011,835
66	Hedging (Gains) Losses	$ 84,041	$ 97,305	$ 49,133	$ 57,693	$ 54,799	$ 78,001	$ 454,841	$ 420,970
67	Storage	$ -	$ 858,865	$ 1,725,094	$ 1,477,906	$ 1,047,196	$ 5,348	$ 5,137,938	$ 5,114,409
68	Peaking	$ 51,400	$ 245,889	$ 234,109	$ 205,917	$ 228,073	$ 170,585	$ 1,157,989	$ 1,135,973
69	Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Total Maine Commodity Costs	$ 1,321,622	$ 2,202,952	$ 2,578,388	$ 2,136,111	$ 2,098,411	$ 1,345,703	$ 14,792,397	$ 11,683,188
71	Maine Inventory Finance Costs	$ 1,058	$ 1,995	$ 2,483	$ 2,016	$ 1,913	$ 1,047	$ 10,512	$ 10,512
72	Total Maine Variable Costs	$ 1,322,680	$ 2,204,948	$ 2,580,871	$ 2,138,126	$ 2,100,324	$ 1,346,750	$ 14,802,909	$ 11,693,700
73	**New Hampshire**								
74	Firm Sales Pipeline Commodity Excld Hedge	$ 1,303,600	$ 1,014,583	$ 645,038	$ 461,723	$ 897,374	$ 1,266,156	$ 9,160,351	$ 5,588,474
75	Hedging (Gains) Losses	$ 236,059	$ 221,635	$ 133,907	$ 164,587	$ 159,721	$ 204,099	$ 1,158,819	$ 1,120,010
76	Storage	$ -	$ 870,613	$ 1,952,015	$ 1,729,328	$ 1,223,055	$ 6,203	$ 5,806,463	$ 5,781,213
77	Peaking	$ 56,488	$ 249,252	$ 264,904	$ 240,948	$ 266,374	$ 197,832	$ 1,302,377	$ 1,275,799
78	New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Total New Hampshire Commodity Costs	$ 1,596,147	$ 2,356,084	$ 2,995,863	$ 2,596,587	$ 2,546,524	$ 1,674,291	$ 17,428,011	$ 13,765,495
80	New Hampshire Inventory Finance Costs	$ 1,176	$ 2,057	$ 2,937	$ 2,475	$ 2,339	$ 1,251	$ 12,234	$ 12,234
81	Total New Hampshire Variable Costs	$ 1,597,323	$ 2,358,140	$ 2,998,800	$ 2,599,062	$ 2,548,863	$ 1,675,542	$ 17,440,245	$ 13,777,730
82	**Northern Utilities**								
83	Firm Sales Pipeline Commodity Excld Hedge	$ 2,489,782	$ 2,015,477	$ 1,215,090	$ 856,318	$ 1,665,718	$ 2,357,925	$ 17,201,980	$ 10,600,308
84	Hedging (Gains) Losses	$ 320,100	$ 318,940	$ 183,040	$ 222,280	$ 214,520	$ 282,100	$ 1,613,660	$ 1,540,980
85	Storage	$ -	$ 1,729,478	$ 3,677,109	$ 3,207,234	$ 2,270,251	$ 11,551	$ 10,944,401	$ 10,895,622
86	Peaking	$ 107,887	$ 495,142	$ 499,013	$ 446,866	$ 494,448	$ 368,417	$ 2,460,366	$ 2,411,772
87	Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Total Northern Commodity Costs	$ 2,917,769	$ 4,559,036	$ 5,574,251	$ 4,732,697	$ 4,644,936	$ 3,019,994	$ 32,220,407	$ 25,448,683
89	Northern Inventory Finance Costs	$ 2,234	$ 4,052	$ 5,420	$ 4,491	$ 4,252	$ 2,298	$ 22,746	$ 22,746
90	Total Northern Variable Costs	$ 2,920,003	$ 4,563,088	$ 5,579,671	$ 4,737,188	$ 4,649,187	$ 3,022,292	$ 32,243,154	$ 25,471,429
91									

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

LN	Description	Source
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	Col O
Inventory Finance Charge	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	
Storage	$ 1,852	$ 1,852	$ 1,815	$ 1,683	$ 1,524	$ 1,665	$ 21,564	
Peaking	$ 140	$ 138	$ 128	$ 119	$ 115	$ 116	$ 1,182	
Total	$ 1,992	$ 1,990	$ 1,943	$ 1,801	$ 1,639	$ 1,781	$ 22,746	
Inventory Finance Charge Allocation by Jurisdiction								
Maine	$ 949	$ 988	$ 911	$ 830	$ 756	$ 825	$ 10,512	
New Hampshire	$ 1,043	$ 1,002	$ 1,031	$ 971	$ 883	$ 956	$ 12,234	
Total	$ 1,992	$ 1,990	$ 1,943	$ 1,801	$ 1,639	$ 1,781	$ 22,746	
Inventory Finance Charge Allocation by Month								
Maine								
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	$ 1,058	$ 1,995	$ 2,483	$ 2,016	$ 1,913	$ 1,047	$ 10,512	$ 10,512
New Hampshire								
Firm Sales Normal Remaining Sendout	222,579	389,227	555,871	468,420	442,612	236,821	2,315,531	2,315,531
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	$ 1,176	$ 2,057	$ 2,937	$ 2,475	$ 2,339	$ 1,251	$ 12,234	$ 12,234

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**
95
96
97

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

Revised Schedule 23

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Supporting Detail to Proposed Tariff Sheets
Average Cost of Gas Calculation

		Winter	Summer	Total	
1	Demand	$ 13,503,746	$ 1,063,217	$ 14,566,963	Schedule 1A, LN 80
2	Commodity	$ 13,777,730	$ 3,662,515	$ 17,440,245	Schedule 1B, LN 0
3	Total	$ 27,281,475	$ 4,725,732	$ 32,007,208	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	$0.4818	$0.1437		LN 1 / LN 5
9	Average Commodity Rate	$0.4916	$0.4949		LN 2 / LN 5
10	Average Rate	$0.9733	$0.6386		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 6,404,988	$ 502,104	$ 6,907,092	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 6,280,099	$ 470,573	$ 6,750,672	LN 8 * LN 6
15	**Demand Reallocation:**	$ 124,889	$ 31,531	$ 156,420	LN 13 - LN 14
16	**HLF Allocation**	$ 12,353	$ 7,901	$ 20,254	LN 15 / LN 20
17	**LLF Allocation**	$ 112,536	$ 23,631	$ 136,166	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	9.89%	25.06%		Schedule 10A, LN 173
21	LLF	90.11%	74.94%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 6,409,689	$ 1,618,538	$ 8,028,226	Schedule 10A, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 6,407,519	$ 1,620,644	$ 8,028,163	LN 18 * LN 16
25	**Commodity Reallocation:**	$ 2,170	$ (2,107)	$ 64	LN 23 - LN 24
26	**HLF Allocation**	$ 387	$ (933)	$ (546)	LN 25 / LN 30
27	**LLF Allocation**	$ 1,783	$ (1,173)	$ 609	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	17.85%	44.29%		Schedule 10C, LN 143
31	LLF	82.15%	55.71%		Schedule 10C, LN 144

Variance Analysis

Effect of Revision

Unitil
Northern Utilities, Inc.

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

		2010 / 2011 Winter (Pre Revision)			2010 / 2011 Winter (Post Revision)			Variance		
1	Therm Sales	28,028,950			28,028,950					
2 3 4		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	Total $ Difference	Per Therm Difference	% Change
5										
6	Demand Charges (Pipeline & Storage)		$ 15,483,102	$ 0.5524		$ 15,265,601	$ 0.5446	$ (217,501)	$ (0.0078)	-1.40%
7										
8	Purchased Gas (Pipeline Commodity)		5,408,538	0.1930		5,588,474	0.1994	179,936	0.0064	3.33%
9										
10	Storage & Peaking Gas (Commodity)		7,629,178	0.2722		7,057,012	0.2518	(572,166)	(0.0204)	-7.50%
11										
12	Hedging (Gain)/Loss		1,054,446	0.0376		1,120,010	0.0400	65,564	0.0023	6.22%
13										
14										
15	Total Volumes and Cost	$ -	$ 29,575,264	$ 1.0552	$ -	$ 29,031,096	$ 1.0358	$ (544,168)	$ (0.0194)	-1.84%
16										
17	Prior Period Balance		$2,527,403	$ 0.0902		$ 2,527,403	$ 0.0902	0	-	0.00%
18	ATV Reconciliation		-	$ -		-	$ -			
19	Interest		$ 99,245	$ 0.0035		99,469	$ 0.0035	224	0.0000	0.23%
20	Refunds from Suppliers		-	$ -		-	$ -			
21										
22	Prior Period Adjustment									
23	Interruptible Sales Margin		-	$ -		-	$ -			
24	Capacity Release, Asset Mgmt, PNGTS		(1,771,080)	$ (0.0632)		(1,761,855)	$ (0.0629)	9,225	0.0003	-0.52%
25	Working Capital Allowance		(30,222)	$ (0.0011)		(31,234)	$ (0.0011)	-1,012	(0.0000)	3.35%
26	Bad Debt Allowance		133,747	$ 0.0048		131,344	$ 0.0047	-2,402	(0.0001)	-1.80%
27	Fuel Inventory Financing		10,094	$ 0.0004		12,234	$ 0.0004	2,141	0.0001	21.21%
28	Local Production and Storage		686,673	$ 0.0245		686,673	$ 0.0245	0	-	0.00%
29	Misc Overhead		98,333	$ 0.0035		98,333	$ 0.0035	0	-	0.00%
30										
31	Total Anticipated Indirect Cost of Gas		$1,754,193	$ 0.0626		1,762,368	$ 0.0629	8,175	0.0003	0.47%
32	Total Adjusted Cost		31,329,457	$ 1.1178		30,793,464	$ 1.0987	-535,993	(0.0191)	-1.71%