Summary

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

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2012 - April 30, 2013

	Column A	Column B	Column C
1	**ANTICIPATED DIRECT COST OF GAS**		
2	**Purchased Gas for Sales Service:**		
3	Demand Costs:	$ 2,023,753	
4	Supply Costs:	$ 8,117,009	
5			
6	**Storage & Peaking Gas for Sales Service:**		
7	Demand, Capacity:	$ 12,098,754	
8	Commodity Costs:	$ 3,182,658	
9			
10	**Hedging (Gain)/Loss**	$ 822,275	
11			
12	**Interruptible Sendout Cost**	$ -	
13			
14	**Inventory Finance Charge**	$ 4,654	
15			
16	**Capacity Release**	$ (2,180,758)	
17			
18	**Adjustment for Actual Costs**	$ -	
19			
20	**Total Anticipated Direct Cost of Gas**		$ 24,068,344
21			
22	**ANTICIPATED INDIRECT COST OF GAS**		
23	**Adjustments:**		
24	Prior Period Under/(Over) Collection	$ (3,105,739)	
25	Miscellaneous	$ -	
26	Interest	$ (10,976)	
27	Refunds	$ (168,825)	
28	Interruptible Margins	$ -	
29	Total Adjustments		$ (3,285,540)
30			
31	**Working Capital:**		
32	Total Anticipated Direct Cost of Gas	$ 24,068,344	
33	Working Capital Percentage	0.0824%	
34	Working Capital Allowance	$ 19,823	
35			
36	Plus: Working Capital Reconciliation (Acct 182.11)	$ (9,592)	
37			
38	Total Working Capital Allowance		$ 10,231
39			
40	**Bad Debt:**		
41	Bad Debt Allowance	$ 271,636	
42	Plus: Bad Debt Reconciliation (Acct 182.16)	$ (142,934)	
43	Total Bad Debt Allowance		$ 128,702
44			
45	**Local Production and Storage Capacity**		$ 307,762
46			
47	**Miscellaneous Overhead-78.17% Allocated to Winter Season**		$ 321,744
48			
49	**Total Anticipated Indirect Cost of Gas**		$ (2,517,100)
50			
51	**Total Cost of Gas**		$ 21,551,244
52			

CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: November 1, 2012 - April 30, 2013

Column A		**Column B**	**Column C**	
Total Anticipated Direct Cost of Gas		$ 24,068,344		
Projected Prorated Sales (11/01/12 - 04/30/13)		27,305,924		
Direct Cost of Gas Rate			$ 0.8814	per therm
Demand Cost of Gas Rate		$ 11,941,749	$ 0.4373	per therm
Commodity Cost of Gas Rate		$ 12,126,595	$ 0.4441	per therm
Total Direct Cost of Gas Rate		$ 24,068,344	$ 0.8814	per therm
Total Anticipated Indirect Cost of Gas		$ (2,517,100)		
Projected Prorated Sales (11/01/12 - 04/30/13)		27,305,924		
Indirect Cost of Gas			$ (0.0922)	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/05			**$ 0.7892**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/12		**COGwr**	**$ 0.7892**	**per therm**
	Maximum (COG+25%)		**$ 0.9865**	
COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/12		**COGwl**	**$ 0.7111**	**per therm**
	Maximum (COG+25%)		**$ 0.8889**	
C&I HLF Demand Costs Allocated per SMBA	$ 710,730			
PLUS: Residential Demand Reallocation to C&I HLF	$ 16,345			
C&I HLF Total Adjusted Demand Costs	$ 727,075			
C&I HLF Projected Prorated Sales (11/01/12 - 04/30/13)	2,179,467			
Demand Cost of Gas Rate	**$ 0.3336**			
C&I HLF Commodity Costs Allocated per SMBA	$ 1,026,424			
PLUS: Residential Commodity Reallocation to C&I HLF	$ (2,721)			
C&I HLF Total Adjusted Commodity Costs	$ 1,023,703			
C&I HLF Projected Prorated Sales (11/01/12 - 04/30/13)	2,179,467			
Commodity Cost of Gas Rate	**$ 0.4697**			
Indirect Cost of Gas	**$ (0.0922)**			
Total C&I HLF Cost of Gas Rate	**$ 0.7111**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/12		**COGwh**	**$ 0.8037**	**per therm**
	Maximum (COG+25%)		**$ 1.0046**	
C&I LLF Demand Costs Allocated per SMBA	$ 5,258,837			
PLUS: Residential Demand Reallocation to C&I LLF	$ 120,941			
C&I LLF Total Adjusted Demand Costs	$ 5,379,778			
C&I LLF Projected Prorated Sales (11/01/12 - 04/30/13)	11,784,423			
Demand Cost of Gas Rate	**$ 0.4565**			
C&I LLF Commodity Costs Allocated per SMBA	$ 5,191,440			
PLUS: Residential Commodity Reallocation to C&I LLF	$ (13,762)			
C&I LLF Total Adjusted Commodity Costs	$ 5,177,678			
C&I LLF Projected Prorated Sales (11/01/12 - 04/30/13)	11,784,423			
Commodity Cost of Gas Rate	**$ 0.4394**			
Indirect Cost of Gas	**$ (0.0922)**			
Total C&I LLF Cost of Gas Rate	**$ 0.8037**			

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

Summary

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2012 - April 30, 2013

	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 14
5		
6	**Storage & Peaking Gas for Sales Service:**	
7	Demand, Capacity:	Schedule 1A, LN 73
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**	-(Schedule 1A, LN 76)
17		
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	Miscellaneous	
26	Interest	Schedule 3, LN 113
27	Refunds	Schedule 25, PG 2, LN 5 + PG 4, LN 5 Nov - Apr
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)	Schedule 3, LN 84: April
37		
38	Total Working Capital Allowance	Sum (LN 34 : LN 36)
39		
40	**Bad Debt:**	
41	Bad Debt Allowance	Schedule 3B, LN 19
42	Plus: Bad Debt Reconciliation (Acct 182.16)	Schedule 3, LN 95: April
43	Total Bad Debt Allowance	LN 41 + LN 42
44		
45	**Local Production and Storage Capacity**	Schedule 1A, LN 84
46		
47	**Miscellaneous Overhead-78.17% Allocated to Winter Season**	Schedule 1A, LN 83
48		
49	**Total Anticipated Indirect Cost of Gas**	Sum (LN 29 : LN 47)
50		
51	**Total Cost of Gas**	LN 49 + LN 20
52		

LN	Description	Reference
53		
54		
55	CALCULATION OF FIRM SALES COST OF GAS RATE	
56	Period Covered: November 1, 2012 - April 30, 2013	
57		
58	**Column A**	**Column D**
59		
60	Total Anticipated Direct Cost of Gas	LN 20
61	Projected Prorated Sales (11/01/12 - 04/30/13)	Schedule 10B, LN 11
62	**Direct Cost of Gas Rate**	LN 60 / LN 61
63		
64	**Demand Cost of Gas Rate**	Column B : SUM (LN 3 , LN 7 , LN 16)
65	**Commodity Cost of Gas Rate**	Column B : SUM (LN 4 , LN 8 , LN 10 , LN 12 , LN 14)
66	**Total Direct Cost of Gas Rate**	SUM (LN 64 : LN 65)
67		
68	Total Anticipated Indirect Cost of Gas	LN 49
69	Projected Prorated Sales (11/01/12 - 04/30/13)	LN 61
70	**Indirect Cost of Gas**	LN 68 / LN 69
71		
72		
73	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/05**	LN 66 + LN 70
74		
75	**RESIDENTIAL COST OF GAS RATE - 11/01/12**	LN 73
76		LN 75 * 1.25
77		
78		
79	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/12**	LN 96
80		LN 79 * 1.25
81		
82	C&I HLF Demand Costs Allocated per SMBA	Schedule 10A, LN 169
83	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 23, LN 16
84	C&I HLF Total Adjusted Demand Costs	Sum (LN 82 : LN 83)
85	C&I HLF Projected Prorated Sales (11/01/12 - 04/30/13)	Schedule 10B, LN 14
86	**Demand Cost of Gas Rate**	LN 84 / LN 85
87		
88	C&I HLF Commodity Costs Allocated per SMBA	Schedule 10C, LN 139
89	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 23, LN 26
90	C&I HLF Total Adjusted Commodity Costs	Sum (LN 88 : LN 89)
91	C&I HLF Projected Prorated Sales (11/01/12 - 04/30/13)	LN 85
92	**Commodity Cost of Gas Rate**	LN 90 / LN 91
93		
94	**Indirect Cost of Gas**	LN 70
95		
96	**Total C&I HLF Cost of Gas Rate**	Sum (LN 86, LN 92, LN 94)
97		
98		
99	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/12**	LN 116
100		LN 99 * 1.25
101		
102	C&I LLF Demand Costs Allocated per SMBA	Schedule 10A, LN 170
103	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 23, LN 17
104	C&I LLF Total Adjusted Demand Costs	Sum (LN 102 : LN 103)
105	C&I LLF Projected Prorated Sales (11/01/12 - 04/30/13)	Schedule 10B, LN 15
106	**Demand Cost of Gas Rate**	LN 104 / LN 105
107		
108	C&I LLF Commodity Costs Allocated per SMBA	Schedule 10C, LN 140
109	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 23, LN 27
110	C&I LLF Total Adjusted Commodity Costs	Sum (LN 108 : LN 109)
111	C&I LLF Projected Prorated Sales (11/01/12 - 04/30/13)	LN 105
112	**Commodity Cost of Gas Rate**	LN 110 / LN 111
113		
114	**Indirect Cost of Gas**	LN 70
115		
116	**Total C&I LLF Cost of Gas Rate**	Sum (LN 106, LN 112, LN 114)

Schedules 1A and 1B

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

NH Division Total Annual Demand Cost Allocation

Line	Resource	Costs
2	Pipeline & Product Demand	$ 3,379,796
3	Storage	$ 15,100,715
4	Peaking	$ 1,112,694
5	Total Gross Demand Cost	$ 19,593,206
6		
7	Capacity Assignment Demand Revenue Estimate	$ 4,513,535
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 19,593,206
9	Capacity Assignment as % of Total Gross Demand Cost	23.04%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 778,577
14	Storage	$ 3,478,635
15	Peaking	$ 256,323
16	Total Capacity Assignment Credit	$ 4,513,535
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,601,219
21	Storage	$ 11,622,081
22	Peaking	$ 856,371
23	Total Net Demand Cost (Less Capacity Assignment)	$ 15,079,671
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,201
28	Less 23.04% NH Transp. Capacity Assignment	(2,580)
29	Net Pipeline MDQ	8,621
30		
31	Net Pipeline MDQ	8,621
32	Less: Firm Sales Base Use	3,517
33	Remaining Pipeline MDQ	5,104
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$301.73
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,601,219
40	Less: Base Pipeline Use	$ 1,061,211
41	Remaining Pipeline Use	$ 1,540,007

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	Schedule 5B, Page 1
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 DEMAND (**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 23.04% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

Line		Nov	Dec	Jan	Feb	Mar	Apr
45	**All Months**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
46	Remaining Load for All Months	2,477,390	4,103,796	4,877,822	4,218,975	3,457,242	1,974,053
47	Rank	5	3	1	2	4	6
48	% Max Month	50.79%	84.13%	100.00%	86.49%	70.88%	40.47%
49	PR	2.06%	4.42%	13.51%	1.18%	5.02%	4.40%
50	CumPR	8.30%	17.74%	32.43%	18.92%	13.32%	6.24%
51							
52	**Peak Months Only**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
53	Remaining Load for Peak Months Only	2,477,390	4,103,796	4,877,822	4,218,975	3,457,242	1,974,053
54	Rank	5	3	1	2	4	6
55	% Max Month	50.79%	84.13%	100.00%	86.49%	70.88%	40.47%
56	PR	2.06%	4.42%	13.51%	1.18%	5.02%	6.74%
57	CumPR	8.81%	18.25%	32.94%	19.43%	13.83%	6.74%

59 **DEMAND COST PR ALLOCATORS**

Line		Nov	Dec	Jan	Feb	Mar	Apr
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
62	Pipeline - Remaining	8.30%	17.74%	32.43%	18.92%	13.32%	6.24%
63	Storage & Peaking	8.30%	17.74%	32.43%	18.92%	13.32%	6.24%
64	Capacity Release	8.81%	18.25%	32.94%	19.43%	13.83%	6.74%
65	Interr. Margins & Off Sys Sales	8.81%	18.25%	32.94%	19.43%	13.83%	6.74%

67 **DEMAND COSTS ALLOCATED TO MONTHS**

Line		Nov	Dec	Jan	Feb	Mar	Apr
69	Pipeline - Base	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 88,434
70	Pipeline - Remaining	$ 127,846	$ 273,227	$ 499,417	$ 291,409	$ 205,185	$ 96,063
71	Total Pipeline	$ 216,280	$ 361,661	$ 587,852	$ 379,843	$ 293,619	$ 184,498
72							
73	Storage & Peaking	$ 1,035,916	$ 2,213,919	$ 4,046,707	$ 2,361,244	$ 1,662,580	$ 778,388
74							
75	Less Credits to Demand Cost						
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 192,098	$ 397,968	$ 718,270	$ 423,715	$ 301,615	$ 147,092
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
79							
80	Total Direct Demand Costs	$ 1,060,098	$ 2,177,612	$ 3,916,289	$ 2,317,372	$ 1,654,584	$ 815,794
81							
82	Indirect Demand Costs/(Credits)						
83	Miscellaneous Overhead						
84	Local Production & Storage						
85	Subtotal						

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

42 **NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR /**
43 (Based on NH Firm Sales Sendout for Remaining Temperature Sensit
44

45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**
46	Remaining Load for All Months	314,158	61,603	0	17,239	142,328	684,994	22,329,601	21,109,278	1,220,323
47	Rank	8	10	12	11	9	7			
48	% Max Month	6.44%	1.26%	0.00%	0.35%	2.92%	14.04%			
49	PR	0.44%	0.09%	0.00%	0.03%	0.18%	1.09%	32.43%		
50	CumPR	0.75%	0.12%	0.00%	0.03%	0.31%	1.83%	100.00%	96.96%	3.04%

51

52	**Peak Months Only**	**Total**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only	21,109,278	21,109,278	
54	Rank			
55	% Max Month			
56	PR	32.94%		
57	CumPR	100.00%	100.00%	0.00%

58

59 **DEMAND COST PR ALLOCATORS**

60		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
62	Pipeline - Remaining	0.75%	0.12%	0.00%	0.03%	0.31%	1.83%	100.00%	96.96%	3.04%
63	Storage & Peaking	0.75%	0.12%	0.00%	0.03%	0.31%	1.83%	100.00%	96.96%	3.04%
64	Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

66

67 **DEMAND COSTS ALLOCATED TO MONTHS**

68		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**	**Winter**
69	Pipeline - Base	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 1,061,211	$ 530,606	$ 530,606	50.00%
70	Pipeline - Remaining	$ 11,508	$ 1,895	$ -	$ 495	$ 4,727	$ 28,234	$ 1,540,007	$ 1,493,147	$ 46,860	96.96%
71	Total Pipeline	$ 99,943	$ 90,330	$ 88,434	$ 88,929	$ 93,162	$ 116,668	$ 2,601,219	$ 2,023,753	$ 577,466	77.80%
72											
73	Storage & Peaking	$ 93,251	$ 15,358	$ -	$ 4,009	$ 38,304	$ 228,776	$ 12,478,452	$ 12,098,754	$ 379,698	96.96%
74											
75	Less Credits to Demand Cost										
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$2,180,758	$ 2,180,758	$ -	100.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
79											
80	Total Direct Demand Costs	$ 193,194	$ 105,688	$ 88,434	$ 92,938	$ 131,466	$ 345,444	$ 12,898,912	$ 11,941,749	$ 957,164	92.58%
81											
82	Indirect Demand Costs/(Credits)										
83	Miscellaneous Overhead							$ 411,600	$ 321,744	$ 89,856	78.17%
84	Local Production & Storage							$ 307,762	$ 307,762	$ -	100.00%
85	Subtotal							$ 719,362	$ 629,506	$ 89,856	87.51%

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

42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR /**	
43	(Based on NH Firm Sales Sendout for Remaining Temperature Sensit	
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	Schedule 1A, Page 6, Line 6
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	
1	Asset Management	($2,233,221)	Schedule 21, Line 89
2	Capacity Release Revenues	($99,458)	Schedule 21, Line 88
3	PNGTS Litigation	$151,922	Schedule 5A
4	PNGTS Refund	$0	
5	PNGTS litigation net of Refund	$151,922	
6	Total NH Cap Rel and Asset Management	($2,180,758)	Sum(D1 + D2 + D5)

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

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	3,525,757	4,119,456	2,695,303	2,332,848	2,688,084	2,957,449	25,950,506	18,318,897
2	New Hampshire Sales Storage	0	1,067,542	3,265,744	2,864,527	1,852,449	65,090	9,115,351	9,115,351
3	New Hampshire Sales Peaking	6,808	7,091	7,039	6,361	7,022	6,703	84,069	41,023
4	Total New Hampshire Firm Sales Sendout	3,532,565	5,194,088	5,968,086	5,203,736	4,547,555	3,029,241	35,149,926	27,475,272
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	3,532,565	5,194,088	5,968,086	5,203,736	4,547,555	3,029,241	35,149,926	27,475,272
9	Total Firm Sales	3,510,752	5,162,091	5,931,347	5,171,697	4,519,520	3,010,516	34,931,833	27,305,924
10	Difference (LAUF & Company Use)	21,813	31,997	36,739	32,039	28,035	18,725	218,093	169,348
11	Percent Difference	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 1,472,681	$ 1,790,165	$ 1,329,819	$ 1,167,692	$ 1,326,087	$ 1,030,564	$ 8,262,612	$ 8,117,009
15	New Hampshire Hedging (Gains) Losses	$ 95,316	$ 145,679	$ 198,374	$ 153,587	$ 151,012	$ 78,307	$ 826,628	$ 822,275
16	New Hampshire Total Storage	$ -	$ 376,278	$ 1,135,041	$ 995,172	$ 637,017	$ 19,512	$ 3,163,020	$ 3,163,020
17	New Hampshire Total Peaking	$ 3,074	$ 3,221	$ 3,368	$ 3,169	$ 3,501	$ 3,305	$ 40,774	$ 19,638
18	New Hampshire Inventory Finance Charge	$ 546	$ 905	$ 1,075	$ 930	$ 762	$ 435	$ 4,654	$ 4,654
19	Total New Hampshire Sales Variable Costs	$ 1,571,618	$ 2,316,248	$ 2,667,679	$ 2,320,549	$ 2,118,379	$ 1,132,124	$ 12,297,688	$ 12,126,595
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,476,301	$ 2,170,569	$ 2,469,304	$ 2,166,963	$ 1,967,367	$ 1,053,817	$ 11,471,060	$ 11,304,321
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 1,571,618	$ 2,316,248	$ 2,667,679	$ 2,320,549	$ 2,118,379	$ 1,132,124	$ 12,297,688	$ 12,126,595
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	0.4177	0.4346	0.4934	0.5005	0.4933	0.3485	$ 0.3184	$ 0.4431
27	New Hampshire Hedging (Gains) Losses	0.0270	0.0354	0.0736	0.0658	0.0562	0.0265	$ 0.0319	$ 0.0449
28	New Hampshire Storage Excld Inventory Finance Costs	0.0000	0.3525	0.3476	0.3474	0.3439	0.2998	$ 0.3470	$ 0.3470
29	New Hampshire Peaking Excld Inventory Finance Costs	0.4515	0.4542	0.4785	0.4982	0.4986	0.4931	$ 0.4850	$ 0.4787
30	New Hampshire Inventory Finance Costs per Dth Stor and F	0.0802	0.0008	0.0003	0.0003	0.0004	0.0061	$ 0.0005	$ 0.0005
31	Weighted Average Cost per Dth Sendout	0.4449	0.4459	0.4470	0.4459	0.4658	0.3737	$ 0.3499	$ 0.4414
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	1,055,129	1,090,300	1,090,300	984,787	1,090,300	1,055,129	12,820,158	6,365,942
37	Base Commodity Cost Excld Hedging	$ 440,719	$ 473,804	$ 537,936	$ 492,928	$ 537,867	$ 367,674	$ 2,971,869	$ 2,850,929
38	Base Hedging Commodity Cost	$ 28,525	$ 38,557	$ 80,246	$ 64,835	$ 61,251	$ 27,937	$ 304,357	$ 301,351
39	Remaining Commodity Excld Hedging	$ 1,035,582	$ 1,696,764	$ 1,931,368	$ 1,674,034	$ 1,429,500	$ 686,143	$ 8,499,191	$ 8,453,391
40	Remaining Hedging Commodity	$ 66,792	$ 107,122	$ 118,128	$ 88,752	$ 89,761	$ 50,369	$ 522,271	$ 520,924
41	Total Commodity Excld Hedging	$ 1,476,301	$ 2,170,569	$ 2,469,304	$ 2,166,963	$ 1,967,367	$ 1,053,817	$ 11,471,060	$ 11,304,321
42	Total Hedging	$ 95,316	$ 145,679	$ 198,374	$ 153,587	$ 151,012	$ 78,307	$ 826,628	$ 822,275
43	Total Commodity (Incl Hedging)	$ 1,571,618	$ 2,316,248	$ 2,667,679	$ 2,320,549	$ 2,118,379	$ 1,132,124	$ 12,297,688	$ 12,126,595

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

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

Schedule 2

Estimated Delivered City-Gate Commodity Costs and Volumes November 2012 through April 2013			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage	$563,423	187,947	$2.998
Tenn Zone 4 Spot	$561,321	172,378	$3.256
Tennessee Production	$3,537,890	1,066,617	$3.317
Algonquin Receipts	$279,438	82,610	$3.383
Niagara	$13,839	3,987	$3.471
Chicago	$837,772	238,936	$3.506
Washington 10 Storage	$5,702,266	1,617,793	$3.525
TGP Zone 6 Spot	$8,711	2,432	$3.581
LNG	$38,997	8,145	$4.788
TGP Zone 6	$5,298,725	1,102,330	$4.807
PNGTS	$691,765	135,725	$5.097
Lewiston Baseload	$4,871,191	830,500	$5.865
Total Delivered Commodity Cost	$22,405,337	5,449,399	$4.112

Schedules 3A &3B

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-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
2	Residential Heat & Non Heat								1,714,224	2,522,640	2,899,263	2,527,797	2,208,243	1,469,868	13,342,035
3	Sales HLF Classes								282,431	411,315	471,294	411,211	360,836	242,379	2,179,467
4	Sales LLF Classes								1,514,097	2,228,135	2,560,789	2,232,690	1,950,442	1,298,269	11,784,423
5	Total								3,510,752	5,162,091	5,931,347	5,171,697	4,519,520	3,010,516	27,305,924
6	Rates														
7	Residential Heat & Non Heat CGA								$0.7892	$0.7892	$0.7892	$0.7892	$0.7892	$0.7892	
8	Sales HLF Classes CGA								$0.7111	$0.7111	$0.7111	$0.7111	$0.7111	$0.7111	
9	Sales LLF Classes CGA								$0.8037	$0.8037	$0.8037	$0.8037	$0.8037	$0.8037	
10	Revenues														
11	Residential Heat & Non Heat								$ (1,352,865)	$ (1,990,868)	$ (2,288,098)	$ (1,994,937)	$ (1,742,745)	$ (1,160,020)	$(10,529,534)
12	Sales HLF Classes								$ (200,837)	$ (292,486)	$ (335,137)	$ (292,412)	$ (256,590)	$ (172,356)	$ (1,549,819)
13	Sales LLF Classes								$ (1,216,880)	$ (1,790,752)	$ (2,058,106)	$ (1,794,413)	$ (1,567,570)	$ (1,043,419)	$ (9,471,141)
14	Total Sales Revenues								$ (2,770,582)	$ (4,074,106)	$ (4,681,342)	$ (4,081,762)	$ (3,566,906)	$ (2,375,795)	$(21,550,493)

15

			Summer						Winter						
16															
17	**Gas Costs and Credits**		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18			May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline		$ 168,364	$ 168,364	$ 168,364	$ 169,493	$ 169,493	$ 169,493	$ 168,364	$ 168,364	$ 168,364	$ 168,364	$ 168,364	$ 168,364	$ 2,023,753
21	Storage		$ 562,290	$ 562,290	$ 562,290	$ 564,642	$ 564,642	$ 564,642	$ 1,462,953	$ 1,462,953	$ 1,462,953	$ 1,462,953	$ 1,462,953	$ 562,290	$ 11,257,847
22	Peaking		$ 49,302	$ 49,302	$ 49,302	$ 52,166	$ 52,166	$ 52,166	$ 91,850	$ 97,636	$ 97,636	$ 97,636	$ 91,850	$ 49,302	$ 830,313
23	Total Demand Costs		$ 779,955	$ 779,955	$ 779,955	$ 786,300	$ 786,300	$ 786,300	$ 1,723,167	$ 1,728,953	$ 1,728,953	$ 1,728,953	$ 1,723,167	$ 779,955	$ 14,111,914
24	NUI Commodity Costs														
25	NUI Total Pipeline Volumes								699,185	810,382	534,130	462,099	534,049	595,669	3,635,515
26	Pipeline Costs Modeled in Sendout™								$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 16,100,651
27	NYMEX Price Used for Forecast								$ 2.8110	$ 3.0770	$ 3.2210	$ 3.2390	$ 3.2310	$ 3.2270	
28	NYMEX Price Used for Update								$ 2.8110	$ 3.0770	$ 3.2210	$ 3.2390	$ 3.2310	$ 3.2270	
29	Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
30	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
31	Updated Pipeline Costs								$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	
32	Interruptible Volumes - NH								0	0	0	0	0	0	
33	Average Supply Cost ($/MMBtu)								$ 4.18	$ 4.35	$ 4.93	$ 5.01	$ 4.93	$ 3.48	
34	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Updated Pipeline Costs								$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	
36	New Hampshire Allocated Percentage								50.43%	50.83%	50.46%	50.48%	50.33%	49.65%	
37	NH Updated Pipeline Costs								$ 1,472,681	$ 1,790,165	$ 1,329,819	$ 1,167,692	$ 1,326,087	$ 1,030,564	$ 8,117,009
38	Hedging (Gain)/Loss Estimate														
39	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
40	NYMEX NG Futures Contracts								13	21	28	23	23	14	
41	Average Purchase Price								$ 4.2650	$ 4.4417	$ 4.6250	$ 4.5617	$ 4.5354	$ 4.3536	
42	NYMEX Price Used for Forecast								$ 2.8110	$ 3.0770	$ 3.2210	$ 3.2390	$ 3.2310	$ 3.2270	
43	NYMEX Price Used for Update								$ 2.8110	$ 3.0770	$ 3.2210	$ 3.2390	$ 3.2310	$ 3.2270	
44	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
45	NUI Futures Hedging (Gain)/Loss - Allocate								$ 189,020	$ 286,580	$ 393,120	$ 304,230	$ 300,020	$ 157,720	$ 1,630,690
46	New Hampshire Allocated Percentage								50.43%	50.83%	50.46%	50.48%	50.33%	49.65%	
47	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 95,316	$ 145,679	$ 198,374	$ 153,587	$ 151,012	$ 78,307	$ 822,275
48	Price Triggered NYMEX Contracts (NH Only)														
49	NYMEX NG Futures Contracts								0	0	0	0	0	0	
50	Average Purchase Price								$ -	$ -	$ -	$ -	$ -	$ -	
51	NYMEX Price Used for Forecast								$ 2.8110	$ 3.0770	$ 3.2210	$ 3.2390	$ 3.2310	$ 3.2270	
52	NYMEX Price Used for Update								$ 2.8110	$ 3.0770	$ 3.2210	$ 3.2390	$ 3.2310	$ 3.2270	
53	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
54	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
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								$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	NH Commodity Costs														
58	Pipeline Excl Hedging								$ 1,472,681	$ 1,790,165	$ 1,329,819	$ 1,167,692	$ 1,326,087	$ 1,030,564	$ 8,117,009
59	Hedging (Gain)/Loss Estimate								$ 95,316	$ 145,679	$ 198,374	$ 153,587	$ 151,012	$ 78,307	$ 822,275
60	Storage								$ -	$ 376,278	$ 1,135,041	$ 995,172	$ 637,017	$ 19,512	$ 3,163,020
61	Peaking								$ 3,074	$ 3,221	$ 3,368	$ 3,169	$ 3,501	$ 3,305	$ 19,638
62	Total Commodity Costs								$ 1,571,071	$ 2,315,343	$ 2,666,603	$ 2,319,619	$ 2,117,617	$ 1,131,688	$ 12,121,941
63	Inventory Finance Charge		$ 119	$ 242	$ 371	$ 500	$ 628	$ 684	$ 547	$ 549	$ 464	$ 315	$ 165	$ 70	$ 4,654

Northern Utilities, Inc.
New Hampshire Division
Schedule 3
Page 2 of 2

64	Asset Management and Capacity Release													
65	NUI AMA Revenue		$ (397,917)	$ (397,917)	$ (397,917)	$ (397,917)	$ (397,917)	$ (397,917)	$ (404,917)	$ (404,917)	$ (404,917)	$ (404,917)	$ (404,917)	$ (397,917)	$ (4,810,000)
66	PNGTS Litigation Cost		$ -	$ -	$ -	$ -	$ -	$ -	$ 25,320.33	$ 25,320.33	$ 25,320.33	$ 25,320.33	$ 25,320.33	$ 25,320.33	$ 151,922
67	NUI Capacity Release		$ (22,348)	$ (22,348)	$ (38,048)	$ (38,048)	$ (38,048)	$ (21,258)	$ (5,558)	$ (5,558)	$ (5,558)	$ (5,558)	$ (5,558)	$ (5,558)	$ (213,450)
68	NUI AMA Rev & Cap. Release Subtotal		$ (420,265)	$ (420,265)	$ (435,965)	$ (435,965)	$ (435,965)	$ (419,175)	$ (385,155)	$ (385,155)	$ (385,155)	$ (385,155)	$ (385,155)	$ (378,155)	$ (4,871,528)
69	NH AMA Revenue		$ (184,748)	$ (184,748)	$ (184,748)	$ (184,748)	$ (184,748)	$ (184,748)	$ (162,677)	$ (162,677)	$ (162,677)	$ (162,677)	$ (162,677)	$ (159,427)	$ (2,081,299)
70	NH Capacity Release		$ (10,413)	$ (10,413)	$ (17,729)	$ (17,729)	$ (17,729)	$ (9,905)	$ (2,590)	$ (2,590)	$ (2,590)	$ (2,590)	$ (2,590)	$ (2,590)	$ (99,458)
71	NH Total Asset Management and Capacity Release		$ (195,161)	$ (195,161)	$ (202,476)	$ (202,476)	$ (202,476)	$ (194,653)	$ (165,267)	$ (165,267)	$ (165,267)	$ (165,267)	$ (165,267)	$ (162,017)	$ (2,180,758)
72														
73	**Total Anticipated Direct Cost of Gas**		$ 584,913	$ 585,036	$ 577,850	$ 584,324	$ 584,452	$ 592,332	$ 3,129,518	$ 3,879,577	$ 4,230,753	$ 3,883,620	$ 3,675,681	$ 1,749,696	$ 24,057,752
74					Winter							Summer			
75			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
76		Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
77	Working Capital														
78	Total Anticipated Direct Cost of Gas		$ 584,913	$ 585,036	$ 577,850	$ 584,324	$ 584,452	$ 592,332	$ 3,129,518	$ 3,879,577	$ 4,230,753	$ 3,883,620	$ 3,675,681	$ 1,749,696	$ 24,057,752
79	Working Capital Percentage		0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
80	Working Capital Allowance		$ 482	$ 482	$ 476	$ 481	$ 481	$ 488	$ 2,578	$ 3,195	$ 3,485	$ 3,199	$ 3,027	$ 1,441	$ 19,815
81	Beginning Period Working Capital Balance		$ (9,592)	$ (9,127)	$ (8,662)	$ (8,201)	$ (7,734)	$ (7,267)	$ (6,791)	$ (4,224)	$ (1,033)	$ 2,452	$ 5,659	$ 8,699	
82	End of Period Working Capital Allowance		$ (9,110)	$ (8,645)	$ (8,186)	$ (7,720)	$ (7,253)	$ (6,779)	$ (4,214)	$ (1,029)	$ 2,451	$ 5,651	$ 8,686	$ 10,140	
83	Interest		$ (17)	$ (16)	$ (15)	$ (15)	$ (14)	$ (13)	$ (10)	$ (5)	$ 1	$ 7	$ 13	$ 17	$ (65)
84	End of period with Interest	$ (9,592)	$ (9,127)	$ (8,662)	$ (8,201)	$ (7,734)	$ (7,267)	$ (6,791)	$ (4,224)	$ (1,033)	$ 2,452	$ 5,659	$ 8,699	$ 10,157	
85	Bad Debt														
89															$ -
90	Bad Debt Percentage	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
91	Bad Debt Allowance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,272.67	$ 45,272.67	$ 45,272.67	$ 45,272.67	$ 45,272.67	$ 45,272.67	$ 271,636
92	Beginning Period Bad Debt Balance		$ (142,934)	$ (143,194)	$ (143,455)	$ (143,717)	$ (143,979)	$ (144,241)	$ (144,504)	$ (99,453)	$ (54,320)	$ (9,105)	$ 36,192	$ 81,572	
93	End of Period Bad Debt Balance		$ (142,934)	$ (143,194)	$ (143,455)	$ (143,717)	$ (143,979)	$ (144,241)	$ (99,231)	$ (54,180)	$ (9,048)	$ 36,167	$ 81,465	$ 126,845	
94	Interest		$ (260)	$ (261)	$ (261)	$ (262)	$ (262)	$ (263)	$ (222)	$ (140)	$ (58)	$ 25	$ 107	$ 190	$ (1,668)
95	End of Period Bad Debt Balance with Interest	$ (142,934)	$ (143,194)	$ (143,455)	$ (143,717)	$ (143,979)	$ (144,241)	$ (144,504)	$ (99,453)	$ (54,320)	$ (9,105)	$ 36,192	$ 81,572	$ 127,034	
96	Local Production and Storage Capacity								$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 307,762
97	Miscellaneous Overhead								$ 53,624	$ 53,624	$ 53,624	$ 53,624	$ 53,624	$ 53,624	$ 321,744
	Refunds								$ (21,599)	$ (31,874)	$ (36,425)	$ (31,948)	$ (28,336)	$ (18,643)	$ (168,825)
98	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
99	Beginning Balance Over/Under Collection		$ (3,105,739)	$ (2,525,951)	$ (1,944,984)	$ (1,370,151)	$ (787,792)	$ (204,243)	$ 388,256	$ 853,239	$ 765,101	$ 420,508	$ 327,965	$ 542,450	
100	Net Costs - Revenues		$ 584,913	$ 585,036	$ 577,850	$ 584,324	$ 584,452	$ 592,332	$ 463,853	$ (89,611)	$ (345,671)	$ (93,224)	$ 213,693	$ (521,180)	
101	Ending Balance before Interest		$ (2,520,826)	$ (1,940,915)	$ (1,367,134)	$ (785,828)	$ (203,340)	$ 388,089	$ 852,109	$ 763,628	$ 419,429	$ 327,284	$ 541,658	$ 21,270	
102	Average Balance		$ (2,813,282)	$ (2,233,433)	$ (1,656,059)	$ (1,077,990)	$ (495,566)	$ 91,923	$ 620,183	$ 808,433	$ 592,265	$ 373,896	$ 434,812	$ 281,860	
103	Interest Rate		2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
104	Interest Expense		$ (5,126)	$ (4,069)	$ (3,017)	$ (1,964)	$ (903)	$ 167	$ 1,130	$ 1,473	$ 1,079	$ 681	$ 792	$ 514	$ (9,243)
105	Ending Balance Incl Interest Expense	$ (3,105,739)	$ (2,525,951)	$ (1,944,984)	$ (1,370,151)	$ (787,792)	$ (204,243)	$ 388,256	$ 853,239	$ 765,101	$ 420,508	$ 327,965	$ 542,450	$ 21,783	
106	**Total Over/Under Collection Ending Balance**		$ (2,678,273)	$ (2,097,101)	$ (1,522,069)	$ (939,504)	$ (355,750)	$ 236,961	$ 749,562	$ 709,747	$ 413,855	$ 369,816	$ 632,721	$ 158,975	
107	ATV Reconciliation														$ -
108															
109	**Total Indirect Cost of Gas**	$ (3,258,265)	$ (4,921)	$ (3,864)	$ (2,818)	$ (1,759)	$ (697)	$ 380	$ 132,067	$ 122,840	$ 118,272	$ 122,155	$ 125,794	$ 133,709	$ (2,517,109)
110															
111	**Total Cost of Gas**	$ (3,258,265)	$ 579,992	$ 581,172	$ 575,032	$ 582,565	$ 583,754	$ 592,711	$ 3,261,584	$ 4,002,417	$ 4,349,025	$ 4,005,775	$ 3,801,475	$ 1,883,406	$ 21,540,643
112															
113	**Total Interest**	$ -	$ (5,403)	$ (4,346)	$ (3,294)	$ (2,240)	$ (1,179)	$ (108)	$ 898	$ 1,328	$ 1,023	$ 713	$ 912	$ 721	$ (10,976)

Northern Utilities Inc.
Calculation of Bad Debt Expense

Ln	Description			Amount	Source
1	**Actual Bad Debt Expense 12 Months Ended July 31, 2012**				
2					
3	Total		$	416,437	Company Analysis
4	Distribution		$	141,686	Company Analysis
5	Distribution (%)			34.02%	
6	Non-Distribution		$	274,751	Company Analysis
7	Non-Distribution(%)			65.98%	LN 6 / LN 3
8					
9	Non-Distribution		$	274,751	LN 6
10	Peak Period		$	257,090	Company Analysis
11	Peak Period (%)			93.57%	LN 10/ LN 9
12	Off-Peak Period		$	17,661	LN 9 - LN 10
13	Off-Peak Period (%)			6.43%	LN 12 / LN 9
14					
15	**Forecast Bad Debt Expense 12 Months Ended December 31, 2013**				
16					
17	Annual Total		$	440,000	Company Forecast
18	Annual Non-Distribution		$	290,297	LN 17* LN 7
19	Winter Non-Distribution		**$**	**271,636**	LN 18* LN 11
20	Summer Non-Distribution		$	18,660	LN 18* LN 13

Schedules 4

Reserved for Future Use

Schedules 5A & Attachments, 5B and 5C

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2012 through October 31, 2013			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,397,821	Sch 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 28,394,226	Sch 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,035,662	Sch 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,728,786	Sch 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 662,750	Sch 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (5,023,450)	Sch 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 37,195,794	Sum Lines 1 through 6.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2012 through October 31, 2013

Pipeline	Contract ID	Rate	Negotiated Rate	MDQ (Dth)	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Months Per Year	Support for Demand Rate	Monthly Demand	Annual Demand
Algonquin	93002F	AFT-1 (AFT-2)	No	4,211	Mendon, MA	Brockton, MA	$ 6.1138	12	Line 1 of Page 2, Att NUI-FXW-10	$ 25,745	$ 308,943
Algonquin	93201A1C	AFT-1 (F-2/F-3)	No	1,251	Centerville, NJ	Taunton, MA	$ 6.5734	12	Line 2 of Page 2, Att NUI-FXW-10	$ 8,223	$ 98,680
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.2913	9	Line 3 of Page 2, Att NUI-FXW-10	$ 329,130	$ 2,962,170
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.4825	3	Line 3 of Page 2, Att NUI-FXW-10	$ 348,250	$ 1,044,750
Iroquois	R181001	RTS-1	No	6,569	Zone 1	Zone 1	$ 6.5971	12	Line 4 of Page 2, Att NUI-FXW-10	$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Pittsburgh	GSGT	$ 40.2456	12	Line 5 of Page 2, Att NUI-FXW-10	$ 44,270	$ 531,242
PNGTS	1997-004	FT	Yes	33,000	Pittsburgh	GSGT	$ 76.4666	5	Line 6 of Page 2, Att NUI-FXW-10	$ 2,523,398	$ 12,616,989
Tennessee	5083	FT-A	No	4,605	Zone 0	Zone 6	$ 24.4547	12	Line 7 of Page 2, Att NUI-FXW-10	$ 112,614	$ 1,351,367
Tennessee	5083	FT-A	No	8,550	Zone L	Zone 6	$ 21.6916	12	Line 8 of Page 2, Att NUI-FXW-10	$ 185,463	$ 2,225,558
Tennessee	5265	FT-A	No	2,653	Zone 4	Zone 6	$ 8.4896	12	Line 9 of Page 2, Att NUI-FXW-10	$ 22,523	$ 270,275
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att NUI-FXW-10	$ 10,460	$ 125,521
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att NUI-FXW-10	$ 16,561	$ 198,727
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att NUI-FXW-10	$ 6,911	$ 82,937
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att NUI-FXW-10	$ 31,745	$ 380,937
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.7640	12	Line 11 of Page 2, Att NUI-FXW-10	$ 5,562	$ 66,747
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 29.7221	12	Line 12 of Page 2, Att NUI-FXW-10	$ 1,010,551	$ 12,126,617
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 12.1808	12	Line 13 of Page 2, Att NUI-FXW-10	$ 72,317	$ 867,809
Union	M12205	M12	No	6,003	Dawn	Parkway	$ 2.5252	12	Line 14 of Page 2, Att NUI-FXW-10	$ 15,159	$ 181,905
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	Line 15 of Page 2, Att NUI-FXW-10	$ 130,579	$ 1,566,952
Vector	CRL-NUI-0727	FT-1	Yes	17,086	W-10	Dawn	$ 4.5625	5	Line 16 of Page 2, Att NUI-FXW-10	$ 77,955	$ 389,774
Vector	FT-1-NUI-0122	FT-1	Yes	6,070	Alliance	St. Clair	$ 7.7745	12	Line 17 of Page 2, Att NUI-FXW-10	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	$ 0.5025	12	Line 18 of Page 2, Att NUI-FXW-10	$ 3,050	$ 36,602

Total Annual Demand Costs $ 38,520,832

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2012 through October 31, 2013

Pipeline	Contract ID	MDQ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Algonquin	93002F	4,211	4,211			100%	0%	0%	$ 308,943	$ 308,943	$ -	$ -
Algonquin	93201A1C	1,251	1,251			100%	0%	0%	$ 98,680	$ 98,680	$ -	$ -
Granite	10-010-FT-NN	100,000	21,326	35,529	43,145	21%	36%	43%	$ 2,962,170	$ 631,712	$ 1,052,429	$ 1,278,028
Granite	10-010-FT-NN	100,000	21,326	35,529	43,145	21%	36%	43%	$ 1,044,750	$ 222,803	$ 371,189	$ 450,757
Iroquois	R181001	6,569	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	1,100			100%	0%	0%	$ 531,242	$ 531,242	$ -	$ -
PNGTS	1997-004	33,000		33,000		0%	100%	0%	$ 12,616,989	$ -	$ 12,616,989	$ -
Tennessee	5083	4,605	4,605			100%	0%	0%	$ 1,351,367	$ 1,351,367	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 2,225,558	$ 2,225,558	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 270,275	$ -	$ 270,275	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 125,521	$ 125,521	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 198,727	$ 198,727	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 82,937	$ 82,937	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 380,937	$ 380,937	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 66,747	$ 66,747	$ -	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 12,126,617	$ -	$ 12,126,617	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 867,809	$ 867,809	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 181,905	$ 181,905	$ -	$ -
Vector	CRL-NUI-0725	17,172		17,172		0%	100%	0%	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086		17,086		0%	100%	0%	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	6,070	-		100%	0%	0%	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,070	6,070	-		100%	0%	0%	$ 36,602	$ 36,602	$ -	$ -
Annual Total Demand Costs									$ 38,520,832	$ 8,397,821	$ 28,394,226	$ 1,728,786

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2012 through October 31, 2013

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Support for Demand Rates	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0211	$ 1.5400	12	Line 1 of Page 3, FXW-10	$ 65,664	$ 78,411	$ 144,075
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.5480	12	Line 2 of Page 3, FXW-10	$ 189	$ 1,398	$ 1,587
W-10	01052	Storage	Yes	3,400,000		34,000			12	Line 3 of Page 3, FXW-10	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges $ 3,035,662

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2012 through October 31, 2013

Resource	Contract Quantity	Maximum Daily Quantity	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Fixed Charges
LNG Supply	125,000	5,000	5	FXW-10, Page 4	[redacted]	[redacted]
Peaking Supply 1	70,000	10,000	5	FXW-10, Page 4		
Peaking Supply 2	30,000	5,000	5	FXW-10, Page 4		
Peaking Supply 3	30,000	5,000	5	FXW-10, Page 4		
Peaking Supply 4	1,440,000	16,000	3	FXW-10, Page 4		
Total Peaking Supply Contract Demand Costs						$ 662,750

REDACTED

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2012 through October 31, 2013

Asset Management Agreeement Revenue	
Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin Algonquin Contract #93201A1C (1,251 Dth) Wash 10 via Vector, TCPL, PNGTS Tennessee Niagara Tennessee Long-Haul	[redacted]
Total Asset Management	$ (4,810,000)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (66,701)
Tennessee 5265	$ (83,950)
Granite 10-010-FT-NN	$ (62,800)
Total Capacity Release	$ (213,450)

Total Asset Management and Capacity Release Revenue	$ (5,023,450)

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for July 16, 2012

Line	Supply Source	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
	Estimated Adders to NYMEX Last Day Settlement												
1	Chicago	$0.225	$0.225	$0.225	$0.225	$0.225	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084
2	PNGTS Baseload	$1.960	$1.960	$1.960	$1.960	$1.960	$0.390	$0.390	$0.390	$0.390	$0.390	$0.390	$0.390
3	Lewiston Baseload	$2.750	$2.750	$2.750	$2.750	$2.750	NA	NA	NA	NA	NA	NA	NA
4	Tennessee Zone 6 Baseload	$2.260	$2.260	$2.260	$2.260	$2.260	$0.299	$0.284	$0.391	$0.423	$0.520	$0.333	$0.411
5	Niagara	$0.535	$0.535	$0.535	$0.535	$0.535	$0.341	$0.341	$0.341	$0.341	$0.341	$0.341	$0.341
6	Tennessee Production (Zone 0)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)
7	Tennessee Production (Zone L)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)
8	Tennessee Production (Zone 4)	($0.010)	($0.010)	($0.010)	($0.010)	($0.010)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	Tenessee Zone 4 Spot	$0.062	$0.062	$0.062	$0.062	$0.062	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10	Peaking Supply 1	$9.579	$9.579	$9.579	$9.579	$9.579	NA	NA	NA	NA	NA	NA	NA
11	Peaking Supply 2	$10.788	$10.788	$10.788	$10.788	$10.788	NA	NA	NA	NA	NA	NA	NA
12	Peaking Supply 3	NA	$9.479	$9.479	$9.479	NA	NA	NA	NA	NA	NA	NA	NA
13	LNG	$0.756	$2.616	$2.356	$2.332	$0.614	$0.299	$0.284	$0.391	$0.423	$0.520	$0.333	$0.411
14	W10 Supply (Injection)	$0.225	$0.225	$0.225	$0.225	$0.225	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084
15	TGP FS Supply (Injection)	NA	NA	NA	NA	NA	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015
16	W10 AMA Spot	$0.856	$2.716	$2.456	$2.432	$0.714	$0.399	$0.384	$0.491	$0.523	$0.620	$0.433	$0.511
17	Tennessee Zone 6 Spot	$0.756	$2.616	$2.356	$2.332	$0.614	$0.299	$0.284	$0.391	$0.423	$0.520	$0.333	$0.411
18	AGT Receipts	$0.306	$1.316	$0.956	$0.452	$0.234	$0.139	$0.154	$0.161	$0.333	$0.300	$0.223	$0.221
	Estimated NYMEX Last Day Settlement												
19	NYMEX Forecast	$3.040	$3.322	$3.471	$3.489	$3.461	$3.443	$3.469	$3.507	$3.553	$3.574	$3.577	$3.611

Northern Utilities, Inc.
Transportation Contract Rates
November 2012 through October 2013

Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Demand Rate Support	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 5	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734
3	Granite	FT-NN	N/A	N/A		Page 7, 8	$ 3.2913	$ 3.2913	$ 3.2913	$ 3.2913	$ 3.2913	$ 3.2913	$ 3.2913	$ 3.2913	$ 3.2913	$ 3.4825	$ 3.4825	$ 3.4825
4	Iroquois	RTS-1	Zone 1	Zone 1		Page 9	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971
5	PNGTS	FT	N/A	N/A		Page 17	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456
6	PNGTS	FT (Seasonal)	N/A	N/A		Page 17	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666							
7	Tennessee	FT-A	Zone 0	Zone 6		Page 19	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547	$ 24.4547
8	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916	$ 21.6916
9	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896	$ 8.4896
10	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396	$ 7.4396
11	Texas Eastern	FT-1/FTS	M3	M3	1	Pages 23, 24	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640	$ 5.7640
12	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221	$ 29.7221
13	TransCanada	FT	Parkway	Iroquois		Page 26	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808	$ 12.1808
14	Union	M12	Dawn	Parkway		Page 26	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252	$ 2.5252
15	Vector	FT-1	Alliance	Dawn		Page 36	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042
16	Vector	FT-1	W-10 Storage	Dawn		Page 37	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625							
17	Vector	FT-1	Alliance	St. Clair	2	Pages 33, 34	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745
18	Vector Canada	FT-1	St. Clair	Dawn		Page 26	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025	$ 0.5025

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Commodity Rate Support	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
19	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
20	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 5	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130
21	Granite	FT-NN	N/A	N/A		Page 7	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
22	Iroquois	RTS-1	Zone 1	Zone 1	3	Pages 9, 11	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048
23	LNG Trucking		Everett, MA	LNG Plant		Page 13	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700
24	PNGTS	FT	N/A	N/A		Page 17	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
25	Tennessee	FT-A	Zone 0	Zone 4	4	Page 20, 21	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081	$ 0.3081
26	Tennessee	FT-A	Zone 0	Zone 6	4	Page 20, 21	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568	$ 0.3568
27	Tennessee	FT-A	Zone L	Zone 4	4	Page 20, 21	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619	$ 0.2619
28	Tennessee	FT-A	Zone L	Zone 6	4	Page 20, 21	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109	$ 0.3109
29	Tennessee	FT-A	Zone 4	Zone 6	4	Page 20, 21	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197
30	Tennessee	FT-A	Zone 5	Zone 6	4	Page 20, 21	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902
31	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882
32	TransCanada	FT	Parkway	Iroquois		Page 26	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215
33	Union	M12	Dawn	Parkway		Page 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Vector	FT-1	Alliance	W-10		Page 34	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
35	Vector	FT-1	Alliance	Dawn		Page 34	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Vector	FT-1	W-10 Storage	Dawn		Page 34	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018

Transportation Fuel Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Fuel Rate Support	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
37	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 6	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
38	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 6	0.93%	1.00%	1.00%	1.00%	1.00%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
39	Granite	FT-NN	N/A	N/A		Page 7	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
40	Iroquois	RTS-1	Zone 1	Zone 1	5	Page 12	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%
41	PNGTS	FT	N/A	N/A	5	Page 18	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	Tennessee	FT-A	Zone 0	Zone 4		Page 21	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%
43	Tennessee	FT-A	Zone 0	Zone 6		Page 21	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
44	Tennessee	FT-A	Zone L	Zone 4		Page 21	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%
45	Tennessee	FT-A	Zone L	Zone 6		Page 21	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%
46	Tennessee	FT-A	Zone 4	Zone 6		Page 21	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
47	Tennessee	FT-A	Zone 5	Zone 6		Page 21	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%
48	TransCanada	FT	Dawn	E. Hereford	5	Page 38	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%
49	TransCanada	FT	Parkway	Iroquois	5	Page 38	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%
50	Union	M12	Dawn	Parkway		Page 32	1.14%	1.14%	1.14%	1.14%	1.14%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%	0.52%
51	Vector	FT-1	Alliance	W-10	5	Page 39	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%
52	Vector	FT-1	Alliance	Dawn	5	Page 39	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%
53	Vector	FT-1	W-10 Storage	Dawn	5	Page 39	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%

Note 1 FT-1 Demand Rate = $5.1040 plus FT-1 / FTS Rate = $0.66, totals to $5.764.
Note 2 Negotiated Rate Agreement = $8.0908 per Dth, which is higher than max rate, so max rate prevails.
Note 3 RTS-1 Commodity Rate = $0.003 per Dth and ACA = $0.0018 per Dth. Total equals $0.0048
Note 4 Tennessee Variable Transportation Commodity Rates are calculated by adding the Maximum Commodity Rates found on Page 20 to the applicable EPCR found on page 21.
Note 5 Fuel Rates Estiamted based on 12 months historic averages.

Northern Utilities, Inc. Underground Storage Contract Rates										
Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		Page 22	$ 0.0211	$ 1.5400	$ 0.0087	0.00%	$ 0.0087	1.91%
2	Texas Eastern	SS-1		Page 24	$ 0.1293	$ 5.5480				
3	W-10	Storage	1	Pages 40, 41, 42			$ -	0.40%	$ -	1.10%

Note 1 The demand charge for W-10 Storage shall be $240,833.34 per month.

REDACTED

Northern Utilities, Inc. Peaking Supply Demand Cost				
Line	Peaking Supply Contract	Notes	Reference	Monthly Demand Cost
1	LNG Supply		Page 43	[redacted]
2	Peaking Supply 1	1		
3	Peaking Supply 2	1		
4	Peaking Supply 3	1		
5	Peaking Supply 4	1		

Note 1 Contracts for Peaking Supplies are pending.

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2011

•RATE SCHEDULE AFT-1

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
(F-1/WS-1)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(F-2/F-3)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(F-4)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(STB/SS-3)	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(FTP)	$11.8368	$0.0018	$0.0018	$0.3910	$0.0018	$0.3892
(PSS-T)	$ 9.7854	$0.0018	$0.0018	$0.3235	$0.0018	$0.3217
(AFT-2)	$ 6.1138	$0.0018	$0.0018	$0.2028	$0.0018	$0.2010
(AFT-3)	$10.7554	$0.0018	$0.0018	$0.3554	$0.0018	$0.3536
(AFT-5)	$12.6265	$0.0018	$0.0018	$0.4169	$0.0018	$0.4151
(ITP)	$13.0110	$0.0018	$0.0018	$0.4296	$0.0018	$0.4278
(X-35)	$10.2027	$0.0018	$0.0018	$0.3372	$0.0018	$0.3354
X-39	$13.2089	$0.0018	$0.0018	$0.4361	$0.0018	$0.4343
Incremental Surcharges						
Hubline	$ 1.8607	$0.0000	$0.0000	$0.0000	$0.0000	$0.0612
Secondary 1/		$0.0612	$0.0000			
Tiverton	$ 1.6424	$0.0000	$0.0000	$0.0000	$0.0000	$0.0540
Ramapo	$ 7.5608	$0.0000	$0.0000	$0.2486	$0.0000	$0.2486

•RATE SCHEDULE AFT-1S

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
(F-1/WS-1)	$ 2.6294	$0.2291	$0.0130	$0.2291	$0.0130	$0.0864
(F-2/F-3)	$ 2.6294	$0.2291	$0.0130	$0.2291	$0.0130	$0.0864
(F-4)	$ 2.6294	$0.2291	$0.0130	$0.2291	$0.0030	$0.0864
(STB/SS-3)	$ 2.6294	$0.2291	$0.0130	$0.2291	$0.0130	$0.0864
(Hubline) 1/		$0.0612	$0.0000			

•OTHER FIRM RATE SCHEDULES

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
AFT-E	$ 6.5734	$0.0130	$0.0130	$0.2291	$0.0130	$0.2161
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6294	$0.2291	$0.0130	$0.2291	$0.0130	$0.0864
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0057		$0.0599		
AFT-4	$ 3.5211	$0.0031		$0.1189		
AFT-CL:						
Canal	$ 2.0858	$0.0018	$0.0018	$0.0704	$0.0018	$0.0686
Middletown	$ 3.2764	$0.0018	$0.0018	$0.1095	$0.0018	$0.1077
Cleary	$ 1.4529	$0.0018	$0.0018	$0.0496	$0.0018	$0.0478
Lake Road	$ 0.6476	$0.0018	$0.0018	$0.0231	$0.0018	$0.0213
Brayton Pt.	$ 1.2700	$0.0018	$0.0018	$0.0436	$0.0018	$0.0418
Manchester	$ 2.4500	$0.0018	$0.0018	$0.0823	$0.0018	$0.0805
Bellingham	$ 0.9714	$0.0018	$0.0018	$0.0337	$0.0018	$0.0319
Phelps Dodge	$ 0.0000	$0.0184	$0.0018	$0.0184	$0.0018	$0.0000
Cape Cod	$ 9.0501	$0.0018	$0.0018	$0.2993	$0.0018	$0.2975
Northeast Gateway	$ 4.3449	$0.0018	$0.0018	$0.1446	$0.0018	$0.1428
J-2 Facility	$ 4.6346	$0.0018	$0.0018	$0.1542	$0.0018	$0.1524
Kleen Energy	$ 1.2247	$0.0018	$0.0018	$0.0421	$0.0018	$0.0403
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min
AIT-1	$0.2439	$0.0094	$0.2439	$0.0094
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0436	$0.0018	$0.0436	$0.0018
Manchester	$0.0823	$0.0018	$0.0823	$0.0018
Canal	$0.0704	$0.0018	$0.0704	$0.0018
Cape Cod	$0.2993	$0.0018	$0.2993	$0.0018
Northeast Gateway	$0.1446	$0.0018	$0.1446	$0.0018
J-2 Facility	$0.1542	$0.0018	$0.1542	$0.0018
Kleen Energy	$0.0421	$0.0018	$0.0421	$0.0018
PAL	$0.2439	$0.0000	$0.0000	$0.0000

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charge of $0.0018.

• **FUEL REIMBURSEMENT PERCENTAGES**

Period	Duration	FRP
System Services		
Winter	Dec 1 - Mar 31	1.00%
Spring, Summer and Fall	Apr 1 - Nov 30	0.93%
Incremental Ramapo Services		
Winter	Dec 1 - Mar 31	2.16%
Spring, Summer and Fall	Apr 1 - Nov 30	1.60%

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

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

4.1 Rate Schedule FT-1
Firm Transportation Service
Currently Effective Rates

	$/Dth		
	Base Tariff Rate	ACA Adj.	Total Current Rate
Reservation Charge:			
Maximum	$3.2913		$3.2913
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0018	$0.0018
Minimum	$0.0000	$0.0018	$0.0018
Authorized Overrun Commodity Charge:			
Maximum	$0.1082	$0.0018	$0.1100
Minimum	$0.0000	$0.0018	$0.0018
Fuel and Losses			
Percentage			0.35%
Volumetric Reservation Charge			
Maximum	$0.1082	$0.0018	$0.1100
Minimum	$0.0000	$0.0018	$0.0018

Projected Granite Reservation Charge 8/1/2013

Line	Description		Value	Reference
1	Projected Big Three Incremental Cost of Service 8/1/2013	$	617,150	RP12-838, Sch. 1, L8
2	Total Billing Determinants		1,613,324	RP12-838, Sch. 1, L9
3	Projected Big Three Incremental Reservation Charge	$	0.3825	Line 1 divided by Line 2
4	Granite Reservation Charge 8/1/2012	$	3.1000	FT Base Rate (RP10-896)
5	Projected Granite Reservation Charge 8/1/2013	$	3.4825	Line 3 plus Line 4

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

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

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

(Footnotes continued on Sheet 4.01)

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

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

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

4/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:	
Commodity	0.0018
MEASUREMENT VARIANCE/FUEL USE FACTOR:	
Minimum	0.00%
Maximum (Non-Eastchester Shipper)	1.00%
Maximum (Eastchester Shipper)	4.50%
Maximum (Brookfield Shipper)	1.20%

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Average
Iroquois	Zone 1	Zone 1	0.00%	0.30%	0.20%	0.00%	0.00%	0.00%	0.40%	0.40%	0.20%	0.00%	0.00%	0.00%	0.13%

REDACTED

Line	Item	Value	Reference
1	LNG Trucking Rate	[redacted]	Page 14
2	Diesel Adjustment		
3	Current Diesel Rate per Gallon		Page 16
4	Forecast Diesel Rate per Gallon		Estimate
5	Diesel Fuel Adjustment per Load		Page 15
6	Average Load (Dth)		
7	Diesel Fuel Adjustment per Dth		Line 5 divided by Line 6
8			
9	Average LNG Trucking Cost	$ 1.17	Line 1 plus Line 7

REDACTED

LNG TRANSPORTATION RATE AGREEMENT

DATE: October 17, 2011

CONFIDENTIAL

CARRIER:

[redacted]

CONFIDENTIAL INFORMATION

SHIPPER:

Northern Utilities Inc.
d/b/a Unitil Services Corp.
6 Liberty Lane West
Hampton, NH 03842

EFFECTIVE DATE: 11/01/11

EXPIRATION DATE: 10/31/12

ORIGIN	DESTINATION	DATE	COMMODITY RATE
Everett, MA	Lewiston, ME	11/01/11 to 10/31/12	[redacted]

CONFIDENTIAL INFORMATION

OTHER TERMS AND CONDITIONS:

[redacted]

CONFIDENTIAL INFORMATION

[redacted]

SHIPPER: **Northern Utilities Inc.**

By: ______________________ RCW

Robert Furino

Its: **Director of Energy Contracts**

K:\Unitil 2011-12\Northern Utilities-LNG Trnsptn Rate Agrmnt 11-12

REDACTED

[redacted]

CONFIDENTIAL
INFORMATION

CONFIDENTIAL

EXHIBIT 2

Unitil LNG Transportation Rate Agreement dated October 17, 2011

DIESEL FUEL ADJUSTMENT TABLE

If the DOE posted price per gallon for diesel fuel is:		The surcharge per load will be:
[redacted]		

CONFIDENTIAL
INFORMATION

The diesel fuel price referenced above is the price posted by the U.S. Department of Energy on the Energy Information Administration website at http://tonto.eia.doe.gov/oog/info/wohdp/diesel.asp for the "Weekly Retail On-Highway Diesel Prices for New England" published each Monday, and the corresponding surcharge applies for the 7-day period commencing on that Monday.

[redacted]

CONFIDENTIAL INFORMATION

Experience you can count on

U.S. Energy Information Administration

Petroleum & Other Liquids

Gasoline and Diesel Fuel Update

Gasoline Release Date: June 18, 2012 | **Next Release Date:** June 25, 2012

Diesel Fuel Release Date: June 18, 2012 | **Next Release Date:** June 25, 2012

Data Revision - The Retail Gasoline Prices for May 21, 28, and June 4 included an error in the calculation of the average prices for New York City and New York State reformulated gasoline. EIA has corrected this error and provides a revision to the affected three weeks.

Notice: Changes to Petroleum Marketing Survey Forms for 2013

U.S. Regular Gasoline Prices* (dollars per gallon)full history

				Change from	
	06/04/12	06/11/12	06/18/12	week ago	year ago
U.S.	3.613	3.572	3.533	-0.039	-0.119
East Coast (PADD1)	3.515	3.450	3.402	-0.048	-0.253
New England (PADD1A)	3.676	3.611	3.558	-0.053	-0.232
Central Atlantic (PADD1B)	3.603	3.534	3.477	-0.057	-0.250
Lower Atlantic (PADD1C)	3.400	3.340	3.301	-0.039	-0.260
Midwest (PADD2)	3.519	3.539	3.561	0.022	-0.055
Gulf Coast (PADD3)	3.371	3.311	3.267	-0.044	-0.243
Rocky Mountain (PADD4)	3.728	3.708	3.690	-0.018	0.066
West Coast (PADD5)	4.185	4.093	3.964	-0.129	0.115
West Coast less California	4.055	3.972	3.853	-0.119	0.092

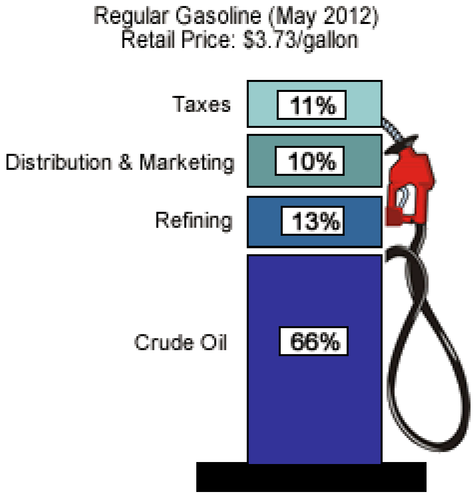
[+] See more

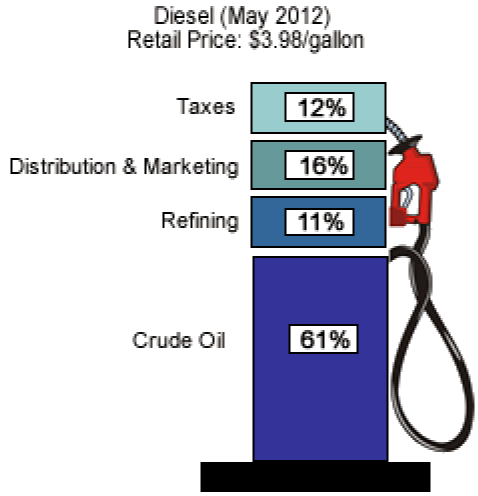
U.S. On-Highway Diesel Fuel Prices* (dollars per gallon)full history

				Change from	
	06/04/12	06/11/12	06/18/12	week ago	year ago
U.S.	3.846	3.781	3.729	-0.052	-0.221
East Coast (PADD1)	3.886	3.818	3.766	-0.052	-0.196
New England (PADD1A)	4.036	3.974	3.923	-0.051	-0.154
Central Atlantic (PADD1B)	3.968	3.909	3.868	-0.041	-0.206
Lower Atlantic (PADD1C)	3.797	3.721	3.660	-0.061	-0.244
Midwest (PADD2)	3.746	3.696	3.655	-0.041	-0.249
Gulf Coast (PADD3)	3.757	3.698	3.654	-0.044	-0.242
Rocky Mountain (PADD4)	3.919	3.873	3.832	-0.041	-0.127
West Coast (PADD5)	4.101	3.991	3.899	-0.092	-0.257
West Coast less California	4.022	3.902	3.820	-0.082	NA
California	4.169	4.066	3.966	-0.100	-0.270

*prices include all taxes

What we pay for in a gallon of:





Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$40.2456	---------	$\boxed{\$40.2456}$
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$76.4666	---------	$\boxed{\$76.4666}$
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0018	$\boxed{\$00.0018}$
	-- Minimum	$00.0000	$00.0018	$00.0018
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$27.0128	---------	$27.0128
	--Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.4350	$00.0018	$00.4369
	--Minimum	$00.0000	$00.0018	$00.0018

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Average
PNGTS	N/A	N/A	0.00%	0.00%	0.00%	-0.25%	-0.20%	-0.20%	-0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.06%

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

Daily Base Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1891		$0.3986	$0.5372	$0.5468	$0.6033	$0.6406	$0.8040
L		$0.1675						
1	$0.2862		$0.2742	$0.3660	$0.5198	$0.5137	$0.5798	$0.7131
2	$0.5372		$0.3638	$0.1877	$0.1752	$0.2258	$0.3119	$0.4030
3	$0.5468		$0.2875	$0.1892	$0.1356	$0.2107	$0.3838	$0.4434
4	$0.6951		$0.6406	$0.2421	$0.3696	$0.1798	$0.1948	$0.2791
5	$0.8294		$0.5819	$0.2541	$0.3082	$0.2002	$0.1875	$0.2446
6	$0.9595		$0.6683	$0.4588	$0.5058	$0.3573	$0.1861	$0.1606

Maximum Reservation Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

Notes:

1/ Applicable to demand charge credits and secondary points under discounted rate agreements.

2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.

3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2751	$0.2625	$0.3124
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2339	$0.2385	$0.2723
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0757	$0.1214	$0.1345
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.1012	$0.1400	$0.1528
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0468	$0.0662	$0.1073
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0659	$0.0653	$0.0811
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.1014	$0.0549	$0.0334

Minimum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0050		$0.0133	$0.0195	$0.0237	$0.0268	$0.0302	$0.0364
L		$0.0030						
1	$0.0060		$0.0099	$0.0165	$0.0197	$0.0228	$0.0274	$0.0318
2	$0.0185		$0.0105	$0.0030	$0.0046	$0.0074	$0.0118	$0.0161
3	$0.0225		$0.0187	$0.0044	$0.0020	$0.0099	$0.0136	$0.0181
4	$0.0268		$0.0223	$0.0105	$0.0123	$0.0046	$0.0064	$0.0110
5	$0.0302		$0.0274	$0.0118	$0.0136	$0.0064	$0.0064	$0.0084
6	$0.0364		$0.0318	$0.0161	$0.0181	$0.0104	$0.0059	$0.0038

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0050		$0.0133	$0.0195	$0.0237	$0.2769	$0.2643	$0.3142
L		$0.0030						
1	$0.0060		$0.0099	$0.0165	$0.0197	$0.2357	$0.2403	$0.2741
2	$0.0185		$0.0105	$0.0030	$0.0046	$0.0775	$0.1232	$0.1363
3	$0.0225		$0.0187	$0.0044	$0.0020	$0.1030	$0.1418	$0.1546
4	$0.0268		$0.0223	$0.0105	$0.0123	$0.0486	$0.0680	$0.1091
5	$0.0302		$0.0274	$0.0118	$0.0136	$0.0677	$0.0671	$0.0829
6	$0.0364		$0.0318	$0.0161	$0.0181	$0.1032	$0.0567	$0.0352

Notes:

1/ Includes a per Dth charge for (ACA) Annual Charge Adjustment of $0.0018
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

FUEL AND EPCR

F&LR 1/, 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.56%		1.46%	2.11%	2.55%	3.02%	3.39%	4.00%
L		0.35%						
1	0.67%		1.10%	1.80%	2.13%	2.58%	3.09%	3.51%
2	2.15%		1.16%	0.34%	0.52%	0.86%	1.36%	1.77%
3	2.61%		2.17%	0.52%	0.24%	1.14%	1.57%	2.03%
4	3.10%		2.41%	1.15%	1.35%	0.53%	0.75%	1.20%
5	3.50%		3.09%	1.37%	1.58%	0.75%	0.74%	0.91%
6	4.15%		3.51%	1.79%	2.03%	1.13%	0.62%	0.38%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0035		$0.0134	$0.0208	$0.0258	$0.0312	$0.0355	$0.0426
L		$0.0012						
1	$0.0047		$0.0094	$0.0172	$0.0211	$0.0262	$0.0320	$0.0368
2	$0.0208		$0.0101	$0.0011	$0.0031	$0.0068	$0.0124	$0.0169
3	$0.0258		$0.0211	$0.0031	$0.0000	$0.0099	$0.0147	$0.0196
4	$0.0312		$0.0242	$0.0100	$0.0122	$0.0032	$0.0056	$0.0106
5	$0.0355		$0.0320	$0.0124	$0.0147	$0.0056	$0.0055	$0.0073
6	$0.0426		$0.0368	$0.0169	$0.0196	$0.0098	$0.0041	$0.0015

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.21%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.8100	$2.8100 1/		
Space Rate	$0.0286	$0.0286 1/		
Injection Rate	$0.0073	$0.0073	1.91%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.3372	$0.3372 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.5400	$1.5400 1/		
Space Rate	$0.0211	$0.0211 1/		
Injection Rate	$0.0087	$0.0087	1.91%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1848	$0.1848 1/		

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.21%.

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

CURRENTLY EFFECTIVE RATES 2/01/2012

•RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.8050	6.5820	2.7220
WLA-AAB	2.8250	2.6020	1.1300
ELA-AAB	2.3750	2.1520	0.9500
ETX-AAB	2.1890	1.9660	0.8760
STX-STX	5.7350	5.5120	2.2930
STX-WLA	5.8940	5.6710	2.3560
STX-ELA	6.8090	6.5860	2.7220
STX-ETX	6.8100	6.5870	2.7220
WLA-WLA	2.0570	1.8340	0.8220
WLA-ELA	2.8300	2.6070	1.1300
WLA-ETX	2.8300	2.6070	1.1300
ELA-ELA	2.3780	2.1550	0.9500
ETX-ETX	2.1920	1.9690	0.8760
ETX-ELA	2.3780	2.1550	0.9500
M1-M1	4.5560	4.3330	1.8200
M1-M2	8.4700	8.2470	3.3840
M1-M3	11.1410	10.9180	4.4520
M2-M2	6.5700	6.3470	2.6250
M2-M3	9.3780	9.1550	3.7480
M3-M3	5.3270	$\boxed{5.1040}$	2.1280

7(C) RATE SCHEDULES	
FTS	5.3510
FTS-2	7.9590
FTS-4	7.7290
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0100

SCT DEMAND CHARGES	
Access Area	0.0020
M1-M1	0.0030
M1-M2	0.0050
M1-M3	0.0060

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0104	0.0113	0.0164	0.0164	0.0414	0.0823	0.1105
from WLA		0.0071	0.0122	0.0122	0.0372	0.0781	0.1063
from ELA			0.0103	0.0103	0.0353	0.0762	0.1044
from ETX				0.0103	0.0353	0.0762	0.1044
from M1					0.0250	0.0659	0.0941
from M2						0.0460	0.0743
from M3							0.0332

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0088						
from WLA	0.0096	0.0059					
from ELA	0.0140	0.0103	0.0087				
from ETX	0.0140	0.0103	0.0087	0.0087			
from M1	0.0375	0.0338	0.0322	0.0322	0.0235		
from M2	0.0772	0.0735	0.0719	0.0719	0.0632	0.0439	
from M3	0.1045	0.1008	0.0992	0.0992	0.0905	0.0712	0.0314

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1915	0.1976	0.2328	0.2328	0.4000	0.5695	0.6854
from WLA		0.0673	0.0978	0.0978	0.2650	0.4345	0.5504
from ELA			0.0811	0.0811	0.2483	0.4178	0.5337
from ETX				0.0749	0.2422	0.4116	0.5276
from M1					0.1672	0.3367	0.4527
from M2						0.2544	0.3750
from M3							0.2008

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1899						
from WLA	0.1959	0.0661					
from ELA	0.2304	0.0959	0.0795				
from ETX	0.2304	0.0959	0.0795	0.0733			
from M1	0.3961	0.2616	0.2452	0.2391	0.1657		
from M2	0.5644	0.4299	0.4135	0.4073	0.3340	0.2523	
from M3	0.6794	0.5449	0.5285	0.5224	0.4491	0.3719	0.1990

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1916	0.1977	0.2330	0.2330	0.4004	0.5700	0.6861
from WLA		0.0674	0.0979	0.0979	0.2653	0.4349	0.5510
from ELA			0.0812	0.0812	0.2486	0.4182	0.5343
from ETX				0.0750	0.2424	0.4120	0.5281
from M1					0.1674	0.3370	0.4531
from M2						0.2547	0.3753
from M3							0.2010

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1900						

from WLA	0.1960	0.0662					
from ELA	0.2306	0.0960	0.0796				
from ETX	0.2306	0.0960	0.0796	0.0734			
from M1	0.3965	0.2619	0.2455	0.2393	0.1659		
from M2	0.5649	0.4303	0.4139	0.4077	0.3343	0.2526	
from M3	0.6801	0.5455	0.5291	0.5229	0.4495	0.3722	0.1992

• OTHER TRANSPORTATION SERVICES

	Reservation	Usage-1	Shrinkage In Path	Shrinkage Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3410 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	0.6600		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	10.6360		0.36%	
FT-1/NC	6.5600		0.00%	
FT-1/RIV	10.4380		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	0.6040 2/		0.00%	
FT-1/TME	13.5005		4.50%	5.39%
FT-1/TME2	21.8408		3.29%	4.09%
FT-1/TME3	22.7280	0.0411	1.92%	
FT-1/MX	3.1240		0.24%	
MLS-1/FH	0.6340		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270	0.0305 3/	0.01%	
MLS-1/HS	6.1130	0.2010 3/	0.01%	
			Primary Rec Pt	Secondary Rec Pt
FT-1/TMX	18.0640	0.0267	1.20%	Winter 4.80%/Summer 3.98%

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

• STORAGE SERVICES

	RES.	SPACE	INJ.	WITH.
SS	5.4680	0.1293	0.0346	0.0634
SS-1	5.5650	0.1293	0.0346	0.0633
X-28	4.8690	0.1293	0.0346	0.0591
FSS-1	0.8950	0.1293	0.0346	0.0346
ISS-1		0.0323	0.1903	0.0346

• SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.49%	2.70%	3.82%	3.82%	6.15%	8.22%	9.59%
from WLA	1.72%	1.72%	2.87%	2.87%	5.20%	7.27%	8.64%
from ELA	2.44%	2.44%	2.44%	2.44%	4.77%	6.84%	8.21%
from ETX	2.49%	2.44%	2.44%	2.44%	4.77%	6.84%	8.21%
from M1					2.33%	4.40%	5.77%
from M2						3.41%	4.80%
from M3							2.74%

April 1 through November 30

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.29%	2.44%	3.26%	3.26%	5.43%	6.94%	7.95%
from WLA	1.73%	1.73%	2.56%	2.56%	4.73%	6.24%	7.25%
from ELA	2.26%	2.26%	2.26%	2.26%	4.43%	5.94%	6.95%
from ETX	2.29%	2.26%	2.26%	2.26%	4.43%	5.94%	6.95%
from M1					2.17%	3.68%	4.69%
from M2						2.96%	3.98%
from M3							2.47%

NON-ASA RATE SCHEDULES

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

ASA STORAGE RATE SCHEDULES

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	3.28%	3.08%
FSS-1,ISS-1	0.77%	0.77%
INJECTIONS	0.77%	0.77%
INVENTORY LEVEL	0.08%	0.08%

FTS-8 M1 & M2 0.00%

- **SURCHARGES**

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  ACA Surcharge
Commodity  0.0018
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- **The Summary of Rates serves as a handy reference and does not replace Texas Eastern's Tariff.**

Canadian Fixed Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Demand Toll	$CAD / GJ	$ 10.16778	Page 30
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 1.03785	Page 28
4	Total Demand Toll	$CAD / GJ	$ 11.20563	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.0303	Page 27
6	Total Demand Toll	$US / GJ	$ 11.5452	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Total Demand Toll	$US / Dth	$ 12.1808	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Demand Toll	$CAD / GJ	$ 22.70383	Page 29
12	Union Dawn Surcharge	$CAD / GJ	$ 0.09828	Page 28
13	Delivery Pressure Demand Toll	$CAD / GJ	$ 4.54054	Page 28
14	Total Demand Toll	$CAD / GJ	$ 27.34265	Sum Lines Above.
15	$CAD to $US	Ratio	1.0303	Page 27
16	Total Demand Toll	$US / GJ	$ 28.1711	Line 13 times Line 14
17	GJ per Dth	Ratio	1.0551	
18	Total Demand Toll	$US / Dth	$ 29.7221	Line 15 divided by Line 16
19				
20	Dawn to Parkway on Union Pipeline			
21	Total Demand Toll	$CAD / GJ	$ 2.3230	Page 31
22	$CAD to $US	Ratio	1.0303	Page 27
23	Total Demand Toll	$US / GJ	$ 2.3934	Line 13 times Line 14
24	GJ per Dth	Ratio	1.0551	
25	Total Demand Toll	$US / Dth	$ 2.5252	Line 15 divided by Line 16
26				
27	St. Clair to Dawn on Vector Canada			
28	Total Demand Toll	$CAD / GJ	$ 0.4623	Page 35
29	$CAD to $US	Ratio	1.0303	Page 27
30	Total Demand Toll	$US / GJ	$ 0.4763	Line 13 times Line 14
31	GJ per Dth	Ratio	1.0551	
32	Total Demand Toll	$US / Dth	$ 0.5025	Line 15 divided by Line 16

Canadian Variable Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Variable Toll	$CAD / GJ	$ 0.01983	Page 30
3	Delivery Pressure Commodity Toll	$CAD / GJ	$ -	Page 28
4	Variable Transportation Rate	$CAD / GJ	$ 0.01983	Line 2 plus Line 3
5	$CAD to $US	Ratio	1.0303	Page 27
6	Variable Transportation Rate	$US / GJ	$ 0.0204	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ 0.0215	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Commodity Rate	$CAD / GJ	$ 0.04889	Page 29
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ 0.03226	Page 28
13	Variable Transportation Rate	$CAD / GJ	$ 0.08115	Line 11 plus Line 12
14	$CAD to $US	Ratio	1.0303	Page 27
15	Variable Transportation Rate	$US / GJ	$ 0.0836	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ 0.0882	Line 15 divided by Line 16

Daily currency converter

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

Currency Converter

Amount: 1.00 **cash rate:**

From: U.S. dollar

To: Canadian Dollar

Convert

Answer: 1.03

Exchange Rate: 1.0303

Summary: On June 25, 2012, 1.00 U.S. dollar(s) = 1.03 Canadian Dollar(s), at an exchange rate of 1.0303 (using nominal rate).

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Transportation Tolls
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System Average Unit Cost of Transportation

Line No	Particulars	Net Revenue Requirement ($000's)	Allocation Base		Annual Unit Cost		Daily Unit Cost	
	(a)	(b)	(c)		(d)		(e)	
1	Fixed Energy	76,148	3,938,676	GJ	19.3333983638	$/GJ	0.0529682147	$/GJ
2	Transmission - Fixed	1,169,509	4,862,440,154	GJ-KM	0.2405190214	$/GJ-Km	0.0006589562	$/GJ-Km
3	Transmission - Variable	48,954	1,053,676,682,785	GJ-KM	-	$/GJ-Km	0.0000464601	$/GJ-Km

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
4	Centram MDA	4.46187	0.00722	0.1539
5	Union WDA	31.41463	0.06896	1.1018
6	Union NDA	12.30579	0.02546	0.4300
7	Union EDA	8.00131	0.01505	0.2781
8	KPUC EDA	7.70246	0.01412	0.2674
9	GMIT EDA	14.16801	0.02929	0.4951
10	Enbridge CDA	1.69730	0.00024	0.0560
11	Enbridge EDA	4.84530	0.00757	0.1669
12	Cornwall	10.94987	0.02165	0.3816
13	Philipsburg	14.44301	0.02974	0.5046

Firm Transportation - Short Notice

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
14	Kirkwall to Thorold - CDA	3.87336	0.00487	0.1322
15	Parkway to Goreway - CDA	2.39507	0.00144	0.0802
16	Parkway to Victoria Square #2 CDA	3.17490	0.00326	0.1077

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
17	Emerson - 1 (Viking)	0.09571	0.00000	0.0032
18	Emerson - 2 (Great Lakes)	0.14114	0.00000	0.0046
19	Dawn	0.08038	0.00000	0.0026
20	Niagara Falls	0.59443	0.00000	0.0195
21	Iroquois	1.03785	0.00000	0.0341
22	Chippawa	1.03444	0.00000	0.0340
23	East Hereford	4.54054	0.03226	0.1815

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

Union Dawn Receipt Point Surcharge

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
24	Union Dawn Receipt Point Surcharge	0.09828	0.00000	0.0032

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FT, STFT and Interruptible Transportation Tolls
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Line No.		Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) [ii] (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls) ($/GJ)
1	(i)	Union Dawn	Empress	53.99115	0.12142	1.8965	2.0862
2	(i)	Union Dawn	Transgas SSDA	45.27755	0.10213	1.5907	1.7498
3	(i)	Union Dawn	Centram SSDA	41.73330	0.09300	1.4651	1.6116
4	(i)	Union Dawn	Centram MDA	36.35048	0.08114	1.2762	1.4038
5	(i)	Union Dawn	Centrat MDA	36.32483	0.08047	1.2747	1.4022
6	(i)	Union Dawn	Union WDA	35.43270	0.07837	1.2433	1.3676
7	(i)	Union Dawn	Nipigon WDA	31.91972	0.07026	1.1197	1.2317
8	(i)	Union Dawn	Union NDA	16.85361	0.03600	0.5901	0.6491
9	(i)	Union Dawn	Calstock NDA	25.29041	0.05489	0.8864	0.9750
10	(i)	Union Dawn	Tunis NDA	20.07115	0.04279	0.7027	0.7730
11	(i)	Union Dawn	GMIT NDA	16.23988	0.03373	0.5676	0.6244
12	(i)	Union Dawn	Union SSMDA	13.80764	0.02827	0.4822	0.5304
13	(i)	Union Dawn	Union NCDA	9.84488	0.01915	0.3429	0.3772
14	(i)	Union Dawn	Union CDA	6.30424	0.01066	0.2180	0.2398
15	(i)	Union Dawn	Enbridge CDA	7.49321	0.01360	0.2600	0.2860
16	(i)	Union Dawn	Union EDA	12.70526	0.02589	0.4436	0.4880
17	(i)	Union Dawn	Enbridge EDA	15.52514	0.03229	0.5427	0.5970
18	(i)	Union Dawn	GMIT EDA	18.81384	0.03999	0.6585	0.7244
19	(i)	Union Dawn	KPUC EDA	12.24987	0.02466	0.4274	0.4701
20	(i)	Union Dawn	North Bay Junction	13.36368	0.02724	0.4666	0.5133
21	(i)	Union Dawn	Enbridge SWDA	1.61112	0.00000	0.0530	0.0583
22	(i)	Union Dawn	Union SWDA	1.81836	0.00025	0.0601	0.0661
23	(i)	Union Dawn	Spruce	36.32483	0.08047	1.2747	1.4022
24	(i)	Union Dawn	Emerson 1	33.48049	0.07387	1.1746	1.2921
25	(i)	Union Dawn	Emerson 2	33.48049	0.07387	1.1746	1.2921
26	(i)	Union Dawn	St. Clair	2.08875	0.00111	0.0698	0.0768
27	(i)	Union Dawn	Dawn Export	1.61112	0.00000	0.0530	0.0583
28	(i)	Union Dawn	Kirkwall	5.39268	0.00877	0.1861	0.2047
29	(i)	Union Dawn	Niagara Falls	7.62509	0.01394	0.2646	0.2911
30	(i)	Union Dawn	Chippawa	7.67300	0.01405	0.2664	0.2930
31	(i)	Union Dawn	Iroquois	14.71519	0.03038	0.5142	0.5656
32	(i)	Union Dawn	Cornwall	15.56423	0.03234	0.5440	0.5984
33	(i)	Union Dawn	Napierville	18.64367	0.03948	0.6524	0.7176
34	(i)	Union Dawn	Philipsburg	18.99363	0.04029	0.6647	0.7312
35	(i)	Union Dawn	East Hereford	22.70383	0.04889	0.7953	0.8748
36	(i)	Union Dawn	Welwyn	41.73330	0.09300	1.4651	1.6116
37		Enbridge CDA	Empress	59.63212	0.13449	2.0950	2.3045
38		Enbridge CDA	Transgas SSDA	50.91651	0.11520	1.7892	1.9681
39		Enbridge CDA	Centram SSDA	47.37427	0.10608	1.6636	1.8300
40		Enbridge CDA	Centram MDA	41.98183	0.09419	1.4744	1.6218
41		Enbridge CDA	Centrat MDA	40.25370	0.08955	1.4130	1.5543
42		Enbridge CDA	Union WDA	31.07610	0.06816	1.0899	1.1989
43		Enbridge CDA	Nipigon WDA	27.28392	0.05947	0.9565	1.0522
44		Enbridge CDA	Union NDA	12.21780	0.02521	0.4269	0.4696
45		Enbridge CDA	Calstock NDA	20.65481	0.04410	0.7232	0.7955
46		Enbridge CDA	Tunis NDA	15.43555	0.03200	0.5395	0.5935
47		Enbridge CDA	GMIT NDA	11.60428	0.02294	0.4044	0.4448
48		Enbridge CDA	Union SSMDA	19.68772	0.04187	0.6892	0.7581
49		Enbridge CDA	Union NCDA	5.20928	0.00836	0.1797	0.1977
50		Enbridge CDA	Union CDA	3.45710	0.00387	0.1176	0.1294
51		Enbridge CDA	Enbridge CDA	1.61112	0.00000	0.0530	0.0583
52		Enbridge CDA	Union EDA	7.63512	0.01407	0.2651	0.2916
53		Enbridge CDA	Enbridge EDA	10.44758	0.02045	0.3640	0.4004
54		Enbridge CDA	GMIT EDA	13.74250	0.02816	0.4800	0.5280
55		Enbridge CDA	KPUC EDA	7.18033	0.01283	0.2489	0.2738
56		Enbridge CDA	North Bay Junction	8.73008	0.01646	0.3035	0.3339
57		Enbridge CDA	Enbridge SWDA	7.49100	0.01360	0.2599	0.2859
58		Enbridge CDA	Union SWDA	7.69845	0.01385	0.2670	0.2937
59		Enbridge CDA	Spruce	40.25370	0.08955	1.4130	1.5543
60		Enbridge CDA	Emerson 1	39.36098	0.08747	1.3816	1.5198
61		Enbridge CDA	Emerson 2	39.36098	0.08747	1.3816	1.5198
62		Enbridge CDA	St. Clair	7.97064	0.01471	0.2767	0.3044
63		Enbridge CDA	Dawn Export	7.49321	0.01360	0.2600	0.2860
64		Enbridge CDA	Kirkwall	3.71165	0.00484	0.1268	0.1395
65		Enbridge CDA	Niagara Falls	5.05535	0.00803	0.1742	0.1916
66		Enbridge CDA	Chippawa	5.11849	0.00817	0.1765	0.1942
67		Enbridge CDA	Iroquois	9.64565	0.01855	0.3357	0.3693
68		Enbridge CDA	Cornwall	10.49469	0.02052	0.3655	0.4021
69		Enbridge CDA	Napierville	13.57413	0.02766	0.4740	0.5214
70		Enbridge CDA	Philipsburg	13.92409	0.02847	0.4863	0.5349
71		Enbridge CDA	East Hereford	17.63429	0.03707	0.6169	0.6786
72		Enbridge CDA	Welwyn	47.37427	0.10608	1.6636	1.8300
73		Enbridge EDA	Empress	61.58233	0.13902	2.1636	2.3800
74		Enbridge EDA	Transgas SSDA	52.86873	0.11974	1.8579	2.0437
75		Enbridge EDA	Centram SSDA	49.32448	0.11061	1.7322	1.9054
76		Enbridge EDA	Centram MDA	43.96591	0.09881	1.5443	1.6987
77		Enbridge EDA	Centrat MDA	41.50601	0.09248	1.4571	1.6028
78		Enbridge EDA	Union WDA	32.19772	0.07081	1.1294	1.2423

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Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) [ii] (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Parkway Belt	Centrat MDA	40.47278	0.09008	1.4207	1.5628
2	Union Parkway Belt	Union WDA	31.16449	0.06841	1.0930	1.2023
3	Union Parkway Belt	Nipigon WDA	27.37231	0.05971	0.9596	1.0556
4	Union Parkway Belt	Union NDA	12.30620	0.02546	0.4301	0.4731
5	Union Parkway Belt	Calstock NDA	20.74300	0.04435	0.7264	0.7990
6	Union Parkway Belt	Tunis NDA	15.52374	0.03225	0.5427	0.5970
7	Union Parkway Belt	GMIT NDA	11.69247	0.02319	0.4076	0.4484
8	Union Parkway Belt	Union SSMDA	18.35505	0.03881	0.6423	0.7065
9	Union Parkway Belt	Union NCDA	5.29747	0.00861	0.1828	0.2011
10	Union Parkway Belt	Union CDA	2.07011	0.00053	0.0686	0.0755
11	Union Parkway Belt	Enbridge CDA	3.14523	0.00350	0.1069	0.1176
12	Union Parkway Belt	Union EDA	8.15784	0.01535	0.2836	0.3120
13	Union Parkway Belt	Enbridge EDA	10.97773	0.02175	0.3827	0.4210
14	Union Parkway Belt	GMIT EDA	14.26643	0.02945	0.4985	0.5484
15	Union Parkway Belt	KPUC EDA	7.70246	0.01412	0.2673	0.2940
16	Union Parkway Belt	North Bay Junction	8.81626	0.01670	0.3065	0.3372
17	Union Parkway Belt	Enbridge SWDA	6.15853	0.01054	0.2130	0.2343
18	Union Parkway Belt	Union SWDA	6.36578	0.01079	0.2201	0.2421
19	Union Parkway Belt	Spruce	40.47278	0.09008	1.4207	1.5628
20	Union Parkway Belt	Emerson 1	38.02790	0.08441	1.3346	1.4681
21	Union Parkway Belt	Emerson 2	38.02790	0.08441	1.3346	1.4681
22	Union Parkway Belt	St. Clair	6.63616	0.01165	0.2299	0.2529
23	Union Parkway Belt	Dawn Export	6.15853	0.01054	0.2130	0.2343
24	Union Parkway Belt	Kirkwall	2.37697	0.00178	0.0799	0.0879
25	Union Parkway Belt	Niagara Falls	4.27106	0.00617	0.1466	0.1613
26	Union Parkway Belt	Chippawa	4.31896	0.00628	0.1483	0.1631
27	Union Parkway Belt	Iroquois	10.16778	0.01983	0.3541	0.3895
28	Union Parkway Belt	Cornwall	11.01681	0.02180	0.3840	0.4224
29	Union Parkway Belt	Napierville	14.09626	0.02894	0.4923	0.5415
30	Union Parkway Belt	Philipsburg	14.44621	0.02975	0.5047	0.5552
31	Union Parkway Belt	East Hereford	18.15642	0.03835	0.6353	0.6988
32	Union Parkway Belt	Welwyn	46.28071	0.10354	1.6251	1.7876
33	Union NCDA	Empress	56.87397	0.12803	1.9978	2.1976
34	Union NCDA	Transgas SSDA	48.16057	0.10875	1.6922	1.8614
35	Union NCDA	Centram SSDA	44.61612	0.09962	1.5664	1.7230
36	Union NCDA	Centram MDA	39.26096	0.08782	1.3786	1.5165
37	Union NCDA	Centrat MDA	36.78642	0.08147	1.2909	1.4200
38	Union NCDA	Union WDA	27.47814	0.05979	0.9632	1.0595
39	Union NCDA	Nipigon WDA	23.68595	0.05110	0.8298	0.9128
40	Union NCDA	Union NDA	8.61984	0.01685	0.3003	0.3303
41	Union NCDA	Calstock NDA	17.05665	0.03574	0.5965	0.6562
42	Union NCDA	Tunis NDA	11.83738	0.02364	0.4128	0.4541
43	Union NCDA	GMIT NDA	8.00632	0.01458	0.2778	0.3056
44	Union NCDA	Union SSMDA	22.04140	0.04742	0.7720	0.8492
45	Union NCDA	Union NCDA	1.61112	0.00000	0.0530	0.0583
46	Union NCDA	Union CDA	5.75646	0.00915	0.1985	0.2184
47	Union NCDA	Enbridge CDA	5.20928	0.00836	0.1797	0.1977
48	Union NCDA	Union EDA	9.89018	0.01945	0.3447	0.3792
49	Union NCDA	Enbridge EDA	11.86043	0.02382	0.4137	0.4551
50	Union NCDA	GMIT EDA	15.84503	0.03319	0.5541	0.6095
51	Union NCDA	KPUC EDA	9.52199	0.01840	0.3315	0.3647
52	Union NCDA	North Bay Junction	5.12991	0.00809	0.1768	0.1945
53	Union NCDA	Enbridge SWDA	9.84488	0.01915	0.3429	0.3772
54	Union NCDA	Union SWDA	10.05213	0.01940	0.3499	0.3849
55	Union NCDA	Spruce	36.78642	0.08147	1.2909	1.4200
56	Union NCDA	Emerson 1	39.62795	0.08806	1.3909	1.5300
57	Union NCDA	Emerson 2	39.62795	0.08806	1.3909	1.5300
58	Union NCDA	St. Clair	10.32252	0.02026	0.3597	0.3957
59	Union NCDA	Dawn Export	9.84488	0.01915	0.3429	0.3772
60	Union NCDA	Kirkwall	6.06332	0.01039	0.2097	0.2307
61	Union NCDA	Niagara Falls	7.95741	0.01478	0.2764	0.3040
62	Union NCDA	Chippawa	8.00531	0.01489	0.2781	0.3059
63	Union NCDA	Iroquois	11.79008	0.02368	0.4113	0.4524
64	Union NCDA	Cornwall	12.59522	0.02554	0.4396	0.4836
65	Union NCDA	Napierville	15.67466	0.03268	0.5480	0.6028
66	Union NCDA	Philipsburg	16.02462	0.03349	0.5603	0.6163
67	Union NCDA	East Hereford	19.73483	0.04209	0.6909	0.7600
68	Union NCDA	Welwyn	44.61612	0.09962	1.5664	1.7230
69	Union SSMDA	Empress	45.07892	0.10076	1.5828	1.7411
70	Union SSMDA	Transgas SSDA	36.36551	0.08147	1.2771	1.4048
71	Union SSMDA	Centram SSDA	32.82107	0.07234	1.1513	1.2664
72	Union SSMDA	Centram MDA	27.43845	0.06048	0.9626	1.0589
73	Union SSMDA	Centrat MDA	27.41259	0.05981	0.9610	1.0571
74	Union SSMDA	Union WDA	37.50337	0.08335	1.3164	1.4480
75	Union SSMDA	Nipigon WDA	40.51306	0.09017	1.4221	1.5643
76	Union SSMDA	Union NDA	29.05013	0.06427	1.0194	1.1213
77	Union SSMDA	Calstock NDA	37.48693	0.08316	1.3156	1.4472
78	Union SSMDA	Tunis NDA	32.26767	0.07106	1.1320	1.2452

unionGas

Effective
2012-04-01
Rate M12
Page 1 of 5

TRANSPORTATION RATES

(A) Applicability

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Oakville facilities.

(C) Rates

The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

	Monthly Demand Charge (applied to daily contract demand) Rate/GJ	Commodity and Fuel Charges: Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1)				
Dawn to Oakville/Parkway	$\boxed{\$2.323}$			
Dawn to Kirkwall	$1.978	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Kirkwall to Parkway	$0.345			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$2.868	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$5.576	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$5.576			
Parkway (TCPL) to Parkway (Cons) (2)		0.328%		

Authorized Overrun (3)

Authorized overrun rates will be payable on all quantities in excess of Union's obligation on any day. The overrun charges payable will be calculated at the following rates. Overrun will be authorized at Union's sole discretion.

Transportation Overrun	If Union supplies fuel Commodity Charge Rate/GJ	Commodity and Fuel Charges: Fuel Ratio %	AND	Commodity Charge Rate/GJ
Dawn to Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.076
Dawn to Kirkwall				$0.065
Kirkwall to Parkway				$0.011
Parkway to Dawn				$0.076
Parkway (TCPL) Overrun (4)	n/a	0.256%		n/a
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.094

Current M12 Rates and Fuel

Current OEB approved rates effective April 1, 2012

Receipt Point	Delivery Point	Contracted Quantity: Daily Demand Charge $CDN/GJ	Contracted Quantity: Month	Contracted Quantity: Fuel %	Authorized Overrun: Daily Variable Charge $CDN/GJ	Authorized Overrun: Fuel %
Dawn	Parkway	$0.076	January	1.305%	$0.076	1.903%
			February	1.206%		1.803%
			March	1.045%		1.643%
			April	0.763%		1.360%
			May	0.623%		1.221%
			June	0.416%		1.014%
			July	0.357%		0.955%
			August	0.349%		0.947%
			September	0.367%		0.965%
			October	0.745%		1.342%
			November	0.947%		1.545%
			December	1.173%		1.770%
Dawn	Kirkwall	$0.065	January	1.075%	$0.065	1.673%
			February	0.990%		1.588%
			March	0.853%		1.451%
			April	0.763%		1.360%
			May	0.623%		1.221%
			June	0.328%		0.926%
			July	0.328%		0.926%
			August	0.328%		0.926%
			September	0.347%		0.945%
			October	0.696%		1.294%
			November	0.764%		1.362%
			December	0.949%		1.547%
Kirkwall	Parkway	$0.011	January	0.558%	$0.011	1.156%
			February	0.543%		1.141%
			March	0.520%		1.118%
			April	0.328%		0.926%
			May	0.328%		0.926%
			June	0.416%		1.014%
			July	0.357%		0.955%
			August	0.350%		0.948%
			September	0.348%		0.946%
			October	0.376%		0.974%
			November	0.510%		1.108%
			December	0.551%		1.149%

Service	Description	Daily Demand Charge $CDN/GJ
F24-T	Firm All Day Transportation	$0.02265

Notes:

The above Rate Summary is **not** intended to replace the regulated M12 rate schedule
In the case of a discrepancy between these summaries and the regulated rate schedules, the **rate schedule** will be deemed correct
All services are subject to any applicable taxes

If you have any questions please contact your Account Manager

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

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

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

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/ Maximum	Minimum	Zone 2 2/ Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.2501	0.0000	$7.7745	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0018	0.0018	0.0018	0.0018
Usage and ACA Charge	0.0018	0.0018	0.0018	0.0018

Negotiated Rates:

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

Rate Schedule FT-L 1/

Recourse Rates:

	Zone 1 2/ Maximum	Minimum	Zone 2 2/ Maximum	Minimum
Reservation Charge ($ per Dth per month)	$0.8391	0.0000	$5.2182	0.0000
Usage Charge ($ per Dth)	0.0135	0.0000	0.0840	0.0000
ACA Charge	0.0018	0.0018	0.0018	0.0018
Usage and ACA Charge	0.0153	0.0018	0.0858	0.0018

Negotiated Rates:

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

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

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

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

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

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

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

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

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

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

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

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

   Alliance Interconnect **17,172**

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

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

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DTeD

Name: DON TUCHFARSKY

Title: ANALYST

Telephone: (508) 836-7259

Fax: ( ) 508-870-2294

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s):

	Maximum Daily Reservation Quantity Dth
Washington 10 Interconnect	**17,086**

8. Primary Delivery Point(s):

	Maximum Daily Reservation Quantity Dth
St. Clair (US) Interconnect	**17,086**

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DT

Name: DON JULCHINSKY

Title: ANALYST

Telephone: (___) 508-836 7257

Fax: (___) 508-870-2294

Historic TransCanada Fuel Loss Percentages

	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Last 12 Months
Union Parkway Belt - Iroquois	0.95%	1.07%	1.07%	0.80%	0.77%	1.02%	1.09%	1.36%	1.30%	1.00%	0.88%	0.81%	1.01%
Union Dawn - East Hereford	0.84%	0.72%	0.72%	0.40%	0.36%	0.62%	1.09%	1.43%	1.49%	0.73%	0.45%	0.43%	0.76%

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Average
Vector	Alliance	W-10 Storage	1.01%	1.33%	1.36%	1.36%	1.36%	1.30%	1.01%	0.77%	0.65%	0.71%	1.40%	1.54%	1.15%
Vector	Alliance	Dawn	1.01%	1.33%	1.36%	1.36%	1.36%	1.30%	1.01%	0.77%	0.65%	0.71%	1.40%	1.54%	1.15%
Vector	W-10 Stora	Dawn	0.34%	0.44%	0.45%	0.45%	0.45%	0.43%	0.34%	0.26%	0.22%	0.24%	0.47%	0.51%	0.38%

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

SHIPPER:

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

INVOICES, STATEMENTS AND NOMINATIONS

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

ALL OTHER MATTERS

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

ARTICLE VIII: FURTHER AGREEMENT

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

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

EXHIBIT I

Rates:

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

Service Parameters:

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

Maximum Daily Injection Quantity (MDIQ):

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

Maximum Daily Withdrawal Quantity (MDWQ):

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

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

Northern Utilities, Inc.
New Hampshire Division
Attachment to Schedule 5A
Page 43 of 44

DTE Energy

Gas Midstream Services

DTE Gas Storage - Washington 10 Historic Fuel Rates

Effective Date	Injection	Withdrawal	Wheel From Hub to MichCon	Wheel From Hub to Vector
Apr 1, 2012	1.10%	0.40%	0.00%	0.50%
Nov 1, 2011	1.10%	0.40%	0.00%	0.50%
Apr 1, 2011	1.10%	0.40%	0.60%	0.60%
Feb 1, 2011	1.00%	0.50%	0.60%	0.60%
Nov 1, 2010	1.00%	0.50%	0.30%	0.30%
Apr 1, 2010	1.00%	0.40%	0.30%	0.30%
Mar 10, 2010	1.00%	0.40%	0.45%	0.45%
Mar 3, 2010	1.00%	0.40%	0.00%	0.00%
Mar 1, 2010	1.00%	0.40%	0.45%	0.45%
Nov 1, 2009	0.00%	0.40%	n/a	n/a
Apr 1, 2009	0.95%	0.00%	n/a	n/a
Nov 1, 2008	0.00%	0.55%	n/a	n/a
Apr 1, 2008	0.70%	0.50%	n/a	n/a
Nov 1, 2007	0.00%	0.70%	n/a	n/a
Apr 1, 2007	0.70%	0.00%	n/a	n/a
Dec 1, 2006	0.00%	0.30%	n/a	n/a
Apr 1, 2006	0.50%	0.00%	n/a	n/a
Nov 1, 2005	0.00%	0.50%	n/a	n/a
Apr 1, 2005	0.72%	0.00%	n/a	n/a
Nov 1, 2004	0.00%	0.50%	n/a	n/a
Apr 1, 2004	0.58%	0.00%	n/a	n/a

REDACTED

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

[redacted]	Date: July 26, 2011 Transaction Confirmation: [redacted]

This Transaction Confirmation is subject to the Base Contract between [redacted] and Northern dated July 26, 2011. The terms of this Transaction Confirmation are binding unless disputed in writing within two (2) Business Days of receipt unless otherwise specified in the Base Contract.

SELLER: [redacted]	**BUYER:** Northern Utilities, Inc. 6 Liberty Lane West Hampton, NH 03842 Attn: Energy Contracts Phone: (603) 773-6430 Fax: (603) 773-6647 Base Contract No.: [redacted]

Contract Price: Buyer shall pay to Seller a Contract Price equal to components (i) Commodity Rate and (ii) Call Payment as follows:

(i) Commodity Rate:

[redacted]

(ii) Call Payment:

[redacted]

(Components (i) Commodity Rate, and (ii) Call Payment referenced herein is hereinafter collectively referred to as the "Contract Price").

Delivery Period: November 1, 2011, through and including October 31, 2012.

Performance Obligation and Contract Quantity: Firm Liquid Service:

[redacted]

Delivery Point(s): For firm delivery service of LNG, at the truck loading flange of Distrigas of Massachusetts LLC's marine LNG terminal located in Everett, Massachusetts.

Special Conditions:

Transportation of LNG from Seller's marine LNG terminal in Everett, Massachusetts shall be scheduled by Buyer. Seller may require Buyer to schedule such deliveries of LNG from Seller's marine LNG terminal any time within a twenty-four (24) hour per day, seven (7) day per week schedule. All costs associated with such transportation, including any surcharges, shall be the responsibility of Buyer. Notwithstanding anything contained in the preceding sentence, upon request by Buyer, Seller shall use commercially reasonable efforts to accommodate Buyer's preferred delivery schedule of its LNG purchases herein.

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2012 through October 2013		
Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (4,240,984)	Page 2
NH Division Storage Contract Capacity Assignment	$ (313,407)	Page 3
NH Division Peaking Demand	$ (288,052)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 344,864	Page 5
NH Division Net PNGTS Litigation Costs Assigned to Retail Suppliers	$ (15,956)	Page 6
NH Division Capacity Assignment Demand Revenue - Updated Forecast	$ (4,513,535)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2012 through October 31, 2013

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	Assigned Pipeline Credits	Assigned Storage Credits	NH Annual Cap Assign Credit
Algonquin	93002F	$ 308,943	$ -	Y	4,211	-	(661)	-	$ (48,495)	$ -	$ (48,495)
Algonquin	93201A1C	$ 98,680	$ -	Y	1,251	-	(196)	-	$ (15,461)	$ -	$ (15,461)
Granite	10-010-FT-NN	$ 631,712	$ 1,052,429	Y	21,326	35,529	(3,347)	(3,670)	$ (99,144)	$ (108,712)	$ (207,855)
Granite	10-010-FT-NN	$ 222,803	$ 371,189	Y	21,326	35,529	(3,347)	(3,670)	$ (34,968)	$ (38,342)	$ (73,310)
Iroquois	R181001	$ 520,036	$ -	Y	6,569	-	(1,031)	-	$ (81,619)	$ -	$ (81,619)
PNGTS	1997-003	$ 531,242	$ -	Y	1,100	-	(173)	-	$ (83,550)	$ -	$ (83,550)
PNGTS	1997-004	$ -	$ 12,616,989	Y	-	33,000	-	(3,409)	$ -	$ (1,303,373)	$ (1,303,373)
Tennessee	5083	$ 1,351,367	$ -	Y	4,605	-	(723)	-	$ (212,169)	$ -	$ (212,169)
Tennessee	5083	$ 2,225,558	$ -	Y	8,550	-	(1,342)	-	$ (349,322)	$ -	$ (349,322)
Tennessee	5265	$ -	$ 270,275	Y	-	2,653	-	(274)	$ -	$ (27,914)	$ (27,914)
Tennessee	5292	$ 125,521	$ -	Y	1,406	-	(221)	-	$ (19,730)	$ -	$ (19,730)
Tennessee	31861	$ 198,727	$ -	Y	2,226	-	(349)	-	$ (31,157)	$ -	$ (31,157)
Tennessee	39735	$ 82,937	$ -	Y	929	-	(146)	-	$ (13,034)	$ -	$ (13,034)
Tennessee	41099	$ 380,937	$ -	Y	4,267	-	(670)	-	$ (59,814)	$ -	$ (59,814)
Texas Eastern	800384	$ 66,747	$ -	N	NA	NA	-	-	$ -	$ -	$ -
TransCanada	33322	$ -	$ 12,126,617	Y	-	34,000	-	(3,512)	$ -	$ (1,252,608)	$ (1,252,608)
TransCanada	29594	$ 867,809	$ -	Y	5,937	-	(932)	-	$ (136,230)	$ -	$ (136,230)
Union	M12205	$ 181,905	$ -	Y	6,003	-	(942)	-	$ (28,545)	$ -	$ (28,545)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	Y	-	17,172	-	(1,774)	$ -	$ (161,878)	$ (161,878)
Vector	CRL-NUI-0727	$ -	$ 389,774	Y	-	17,086	-	(1,765)	$ -	$ (40,264)	$ (40,264)
Vector	FT-1-NUI-0122	$ 566,295	$ -	Y	6,070	-	(953)	-	$ (88,909)	$ -	$ (88,909)
Vector	FT-1-NUI-C0122	$ 36,602	$ -	Y	6,070	-	(953)	-	$ (5,747)	$ -	$ (5,747)
Total NH Capacity Assignment Credits									$ (1,307,893)	$ (2,933,091)	$ (4,240,984)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 2012 through October 2013

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 144,075	Y	N	(26,788)	(438)	$ (14,882)
W-10	01052	$ 2,890,000	Y	Y	(351,206)	(3,512)	$ (298,525)

Total NH Division Storage Capacity Assignment $ (313,407)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
New Hampshire Division
Peaking Demand Capacity Assignment Revenues
November 2012 through October 2013

Month	Total Peaking Demand TCQ	Rate	Demand Revenue
Nov-11	4,329	$ 11.09	$ (48,009)
Dec-11	4,329	$ 11.09	$ (48,009)
Jan-12	4,329	$ 11.09	$ (48,009)
Feb-12	4,329	$ 11.09	$ (48,009)
Mar-12	4,329	$ 11.09	$ (48,009)
Apr-12	4,329	$ 11.09	$ (48,009)

Total Division Peaking Demand Revenue $ (288,052)

REDACTED

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2012 through October 2013

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	[redacted]	Yes	Pipeline	15.69%	[redacted]
Algonquin Contract #93201A1C (1,251 Dth)		Yes	Pipeline	15.69%	
Wash 10 via Vector, TCPL, PNGTS		Yes	Storage	10.33%	
Tennessee Niagara		No	Pipeline	15.69%	
Tennessee Long-Haul		No	Pipeline	15.69%	
Total Asset Management	$ -				$ 344,864

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	15.69%	$ -
Tennessee 5265	$ (83,950)	No	Pipeline	15.69%	$ -
Granite 10-010-FT-NN	$ (62,800)	No	Pipeline	10.33%	$ -
Total Capacity Release	$ (213,450)				$ -

Total Asset Management and Capacity Release Revenue	$ (213,450)	$ 344,864

Northern Utilities, Inc.
New Hampshire Division
PNGTS Litigation Costs Assigned to Retail Suppliers
November 2012 through October 2013

PNGTS Litigation Costs	$ 151,922

PNGTS Contract	MDQ	Percentage MDQ	Allocated PNGTS Litigation Items	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ 4,901	Pipeline	15.69%	$ (769)
PNGTS Contract 1997-004	33,000	97%	$ 147,021	Storage	10.33%	$ (15,187)
PNGTS Total	34,100	100%	$ 151,922			$ (15,956)

Northern Utilities, Inc.
NH Division Peaking Capacity Assignment Demand Rate
November 2012 through April 2013

Line	Description	Northern	NH Division
1	Capacity Allocation Factor		46.40%
2	Peaking Contracts	35,910	16,662
3	Peaking Plants	10,000	4,640
4	Total	45,910	21,302
5	Peaking Contracts Costs	$ 662,750	$ 307,516
6	Peaking Allocated Pipeline Demand Costs	$ 1,728,786	$ 802,157
7	Peaking Plants		$ 307,762
8	Capacity Costs (Before Cap Assignment)		$ 1,417,435
9	NH Division Peaking Capacity Assignment Rate		$ 11.09

Northern Utilities, Inc.
Summary of PNGTS Litigation Expenses, 8/1/2011 - 7/31/2012
New Hampshire Division

Period	NH Division Amount	Reference
8/1/2011 - 7/31/2012	$ 151,921.65	Page 2 of 2
Period Total	$ 151,921.65	

Northern Utilities, Inc.
Expenses Incurred to Oppose Proposed PNGTS Rate Increases
Amounts Paid from August 1, 2011 through July 31, 2012

Service Provider	Expense	New Hampshire Allocated Expenses
BATES WHITE LLC	$ 16,479.01	$ 8,007.19
BENJAMIN SCHLESINGER AND ASSOCIATES INC	$ 547.00	$ 266.06
JEFFRY FINK	$ 2,416.80	$ 1,156.49
SNAKE HILL ENERGY RESOURCES INC	$ 5,888.64	$ 2,864.23
WINSTEAD PC	$ 267,667.63	$ 127,963.62
Grand Total	$ 292,999.08	$ 140,257.60
Adjustment to True Up for Demand Allocators		$ 11,664.05
Total Allocated NH PNGTS Litigation Expenses		$ 151,921.65

Schedules 6A and 6B

Northern Utilities, Inc.
Commodity Cost by Supply Source
November 2012 through April 2013

Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Season
Pipeline Supplies							
Chicago	$ 282,056	$ 443,616	$ 81,326	$ 7,323	$ -	$ 23,451	$ 837,772
Lewiston Baseload	$ 917,565	$ 993,504	$ 1,018,056	$ 922,306	$ 1,019,761	$ -	$ 4,871,191
TGP Zone 6	$ 760,919	$ 827,513	$ 849,833	$ 770,111	$ 851,383	$ 1,238,966	$ 5,298,725
PNGTS	$ 129,201	$ 140,945	$ 144,972	$ 131,397	$ 145,251	$ -	$ 691,765
Niagara	$ 13,839	$ -	$ -	$ -	$ -	$ -	$ 13,839
Tennessee Production	$ 573,550	$ 916,350	$ 541,127	$ 474,560	$ 524,150	$ 508,153	$ 3,537,890
Algonquin Receipts	$ 71,243	$ -	$ -	$ 7,310	$ 92,969	$ 107,917	$ 279,438
Tenn Zone 4 Spot	$ 163,358	$ 199,695	$ -	$ -	$ 1,061	$ 197,206	$ 561,321
TGP Zone 6 Spot	$ 8,711	$ -	$ -	$ -	$ -	$ -	$ 8,711
W10 AMA Spot	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Pipeline	$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 16,100,651
Underground Storage							
Tennessee Storage	$ -	$ -	$ 180,847	$ 163,346	$ 179,929	$ 39,300	$ 563,423
Washington 10 Storage	$ -	$ 740,217	$ 2,068,473	$ 1,807,926	$ 1,085,651	$ -	$ 5,702,266
Subtotal Storage	$ -	$ 740,217	$ 2,249,320	$ 1,971,272	$ 1,265,580	$ 39,300	$ 6,265,689
Peaking Supplies							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 38,997
Subtotal Peaking	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 38,997
Total Commodity Cost	$ 2,926,537	$ 4,268,176	$ 4,891,309	$ 4,290,556	$ 3,907,110	$ 2,121,650	$ 22,405,337

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) November 2012 through April 2013							
Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Season
Pipeline Supplies							
Chicago	85,197	123,455	21,755	1,958	0	6,572	238,936
Lewiston Baseload	165,000	170,500	170,500	154,000	170,500	0	830,500
TGP Zone 6	149,475	154,458	154,458	139,510	154,458	349,972	1,102,330
PNGTS	26,965	27,864	27,864	25,168	27,864	0	135,725
Niagara	3,987	0	0	0	0	0	3,987
Tennessee Production	189,843	273,778	159,553	139,510	154,457	149,475	1,066,617
AGT Receipts	22,551	0	0	1,954	26,464	31,642	82,610
Tenn Zone 4 Spot	53,736	60,327	0	0	306	58,009	172,378
TGP Zone 6 Spot	2,432	0	0	0	0	0	2,432
W10 AMA Spot	0	0	0	0	0	0	0
Subtotal Pipeline	699,185	810,382	534,130	462,099	534,049	595,669	3,635,515
Underground Storage							
Tennessee Storage	0	0	60,327	54,489	60,021	13,110	187,947
Washington 10 Storage	0	210,007	586,848	512,927	308,010	0	1,617,793
Subtotal Storage	0	210,007	647,175	567,416	368,031	13,110	1,805,740
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
LNG	1,350	1,395	1,395	1,260	1,395	1,350	8,145
Subtotal Peaking	1,350	1,395	1,395	1,260	1,395	1,350	8,145
Total Delivered (Dth)	700,535	1,021,784	1,182,700	1,030,775	903,476	610,129	5,449,399

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2012 through April 2013

Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Season
Pipeline Supplies							
Chicago	$ 3.311	$ 3.593	$ 3.738	$ 3.741		$ 3.568	$ 3.506
Lewiston Baseload	$ 5.561	$ 5.827	$ 5.971	$ 5.989	$ 5.981		$ 5.865
TGP Zone 6	$ 5.091	$ 5.358	$ 5.502	$ 5.520	$ 5.512	$ 3.540	$ 4.807
PNGTS	$ 4.791	$ 5.058	$ 5.203	$ 5.221	$ 5.213		$ 5.097
Niagara	$ 3.471						$ 3.471
Tennessee Production	$ 3.021	$ 3.347	$ 3.392	$ 3.402	$ 3.393	$ 3.400	$ 3.317
AGT Receipts	$ 3.159			$ 3.741	$ 3.513	$ 3.411	$ 3.383
Tenn Zone 4 Spot	$ 3.040	$ 3.310			$ 3.467	$ 3.400	$ 3.256
TGP Zone 6 Spot	$ 3.581						$ 3.581
W10 AMA Spot							
Subtotal Pipeline	$ 4.177	$ 4.346	$ 4.934	$ 5.005	$ 4.933	$ 3.485	$ 4.429
Underground Storage							
Tennessee Storage			$ 2.998	$ 2.998	$ 2.998	$ 2.998	$ 2.998
Washington 10 Storage		$ 3.525	$ 3.525	$ 3.525	$ 3.525		$ 3.525
Subtotal Storage		$ 3.525	$ 3.476	$ 3.474	$ 3.439	$ 2.998	$ 3.470
Peaking Supplies							
Peaking Supply 1							
Peaking Supply 2							
Peaking Supply 3							
LNG	$ 4.515	$ 4.542	$ 4.785	$ 4.982	$ 4.986	$ 4.931	$ 4.788
Subtotal Peaking	$ 4.515	$ 4.542	$ 4.785	$ 4.982	$ 4.986	$ 4.931	$ 4.788
Total Cost per Dth	$ 4.178	$ 4.177	$ 4.136	$ 4.162	$ 4.325	$ 3.477	$ 4.112

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

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	89,519	129,831	22,840	2,047	-	6,845	251,082
2	City Gate Delivered Volume	Sum Lines 64, 84 and 104	85,197	123,455	21,755	1,958	-	6,572	238,936
3	Total Purchase Cost	Line 15	$ 271,780	$ 428,703	$ 78,707	$ 7,089	$ -	$ 22,663	$ 808,942
4	Variable Transportation Costs	Sum Lines 26, 46, 56, 66, 76, 86, 96 and 106	$ 10,276	$ 14,914	$ 2,619	$ 233	$ -	$ 788	$ 28,830
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 282,056	$ 443,616	$ 81,326	$ 7,323	$ -	$ 23,451	$ 837,772
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.311	$ 3.593	$ 3.738	$ 3.741		$ 3.568	$ 3.506
7									
8	Chicago Supply Costs								
9	Purchased Volumes	Sendout Optimization	89,519	129,831	22,840	2,047	-	6,845	251,082
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.001
11	NYMEX Cost	Line 9 times Line 10	$ 251,638	$ 399,491	$ 73,568	$ 6,629	$ -	$ 22,088	$ 753,414
12	NYMEX Basis Price	Att to Sch 5A, Line 1 of Page 1	$ 0.225	$ 0.225	$ 0.225	$ 0.225		$ 0.084	$ 0.221
13	NYMEX Basis Costs	Line 9 times Line 12	$ 20,142	$ 29,212	$ 5,139	$ 460	$ -	$ 575	$ 55,528
14	Total Purchase Price	Line 10 plus Line 12	$ 3.036	$ 3.302	$ 3.446	$ 3.464		$ 3.311	$ 3.222
15	Total Purchase Cost	Line 11 plus Line 13	$ 271,780	$ 428,703	$ 78,707	$ 7,089	$ -	$ 22,663	$ 808,942
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with Union)								
22	Received Volume	Line 9	89,519	129,831	22,840	2,047	-	6,845	251,082
23	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	1.15%	1.15%	1.15%	1.15%		1.15%	1.15%
24	Delivered Volume	Line 22 times (1 - Line 23)	88,490	128,338	22,578	2,023	-	6,766	248,194
25	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 159	$ 231	$ 41	$ 4	$ -	$ 12	$ 447
27									
28	Transportation Segment 3								
29	Union Pipeline (Contract M12205)								
30	Receipt Point: Dawn								
31	Delivery Point: Parkway (Interconnects with TransCanada)								
32	Received Volume	Line 24	88,490	128,338	22,578	2,023	-	6,766	248,194
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	1.14%	1.14%	1.14%	1.14%		0.52%	1.12%
34	Delivered Volume	Line 32 times (1 - Line 33)	87,481	126,875	22,320	2,000	-	6,731	245,407
35	Variable Transportation Rate	Att to Sch 5A, Line 33 of Page 2	$ -	$ -	$ -	$ -		$ -	$ -
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37									
38	Transportation Segment 4								
39	TransCanada Pipeline (Contract 41235)								
40	Receipt Point: Parkway								
41	Delivery Point: Iroquois								
42	Received Volume	Line 34	87,481	126,875	22,320	2,000	-	6,731	245,407
43	Fuel Loss Rate	Att to Sch 5A, Line 49 of Page 2	1.01%	1.01%	1.01%	1.01%		1.01%	1.01%
44	Delivered Volume	Line 42 times (1 - Line 43)	86,597	125,594	22,095	1,980	-	6,663	242,928
45	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2	$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215		$ 0.0215	$ 0.0215
46	Variable Transportation Costs	Line 44 times Line 45	$ 1,862	$ 2,700	$ 475	$ 43	$ -	$ 143	$ 5,223
47									
48	Transportation Segment 5								
49	Iroquois Pipeline (Contract R181001)								
50	Receipt Point: Waddington								
51	Delivery Point: Wright (Interconnection with Tennessee)								
52	Received Volume	Line 44	86,597	125,594	22,095	1,980	-	6,663	242,928
53	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.13%	0.13%	0.13%	0.13%		0.13%	0.13%
54	Delivered Volume	Line 52 times (1 - Line 53)	86,485	125,430	22,066	1,977	-	6,654	242,612
55	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048		$ 0.0048	$ 0.0048
56	Variable Transportation Costs	Line 54 times Line 55	$ 415	$ 602	$ 106	$ 9	$ -	$ 32	$ 1,165
57									
58	Transporation Segment 6A								
59	Tennessee Gas Pipeline (Contract 95196)								
60	Receipt Point: Mendon								
61	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
62	Received Volume	Line 54	24,152	29,504	8,013	1,498	-	3,482	66,649
63	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%	0.91%	0.91%	0.91%		0.91%	0.91%
64	City Gate Delivered Volume	Line 62 times (1 - Line 63)	23,932	29,235	7,940	1,484	-	3,451	66,043
65	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902		$ 0.0902	$ 0.0902
66	Variable Transportation Costs	Line 64 times Line 65	$ 2,159	$ 2,637	$ 716	$ 134	$ -	$ 311	$ 5,957
67									
68	Transportation Segment 6B								
69	Tennessee Gas Pipeline (Contract 95196)								
70	Receipt Point: Mendon								
71	Delivery Point: Pleasant St. (Interconnection with Granite)								
72	Received Volume	Line 64	12,830	18,018	4,558	479	-	1,286	37,171
73	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%	0.91%	0.91%	0.91%		0.91%	0.91%
74	Delivered Volume	Line 72 times (1 - Line 73)	12,713	17,854	4,517	475	-	1,274	36,833
75	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902		$ 0.0902	$ 0.0902
76	Variable Transportation Costs	Line 74 times Line 75	$ 1,147	$ 1,610	$ 407	$ 43	$ -	$ 115	$ 3,322
77									
78	Transportation Segment 7B								
79	Granite State Gas Transmission (Contract 10-010-FT-NN)								
80	Receipt Point: Pleasant St.								
81	Delivery Point: Northern City Gates								
82	Received Volume	Line 74	12,713	17,854	4,517	475	-	1,274	36,833
83	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
84	City Gate Delivered Volume	Line 82 times (1 - Line 83)	12,669	17,792	4,501	473	-	1,270	36,704
85	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
86	Variable Transportation Costs	Line 84 times Line 85	$ 23	$ 32	$ 8	$ 1	$ -	$ 2	$ 66
87									
88	Transportation Segment 6C								
89	Tennessee Gas Pipeline (Contract 41099)								
90	Receipt Point: Wright								
91	Delivery Point: Mendon (Interconnection with Algonquin)								
92	Received Volume	Line 54	49,503	77,908	9,495	-	-	1,886	138,792
93	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%	0.91%	0.91%			0.91%	0.91%
94	Delivered Volume	Line 92 times (1 - Line 93)	49,052	77,199	9,408	-	-	1,869	137,529
95	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902	$ 0.0902	$ 0.0902			$ 0.0902	$ 0.0902
96	Variable Transportation Costs	Line 94 times Line 95	$ 4,425	$ 6,963	$ 849	$ -	$ -	$ 169	$ 12,405
97									
98	Transportation Segment 7C								
99	Algonquin Gas Transmission (Contract 93200F)								
100	Receipt Point: Mendon								
101	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
102	Received Volume	Line 94	49,052	77,199	9,408	-	-	1,869	137,529
103	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2	0.93%	1.00%	1.00%			0.93%	0.97%
104	City Gate Delivered Volume	Line 102 times (1 - Line 103)	48,596	76,427	9,314	-	-	1,852	136,189
105	Variable Transportation Rate	Att to Sch 5A, Line 19 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018			$ 0.0018	$ 0.0018
106	Variable Transportation Costs	Line 104 times Line 105	$ 87	$ 138	$ 17	$ -	$ -	$ 3	$ 245

Source of Supply: Lewiston, ME City-Gate (Maritimes)
City-Gate Delivered Supply

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	165,000	170,500	170,500	154,000	170,500	-	830,500
2	City Gate Delivered Volume	Line 1	165,000	170,500	170,500	154,000	170,500	-	830,500
3	Total Purchase Cost	Line 15	$ 917,565	$ 993,504	$ 1,018,056	$ 922,306	$ 1,019,761	$ -	$ 4,871,191
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 917,565	$ 993,504	$ 1,018,056	$ 922,306	$ 1,019,761	$ -	$ 4,871,191
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.561	$ 5.827	$ 5.971	$ 5.989	$ 5.981		$ 5.865
7									
8	<u>Lewiston Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	165,000	170,500	170,500	154,000	170,500	-	830,500
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.115
11	NYMEX Cost	Line 9 times Line 10	$ 463,815	$ 524,629	$ 549,181	$ 498,806	$ 550,886	$ -	$ 2,587,316
12	NYMEX Basis Price	Att to Sch 5A, Line 3 of Page 1	$ 2.750	$ 2.750	$ 2.750	$ 2.750	$ 2.750		$ 2.750
13	NYMEX Basis Costs	Line 9 times Line 12	$ 453,750	$ 468,875	$ 468,875	$ 423,500	$ 468,875	$ -	$ 2,283,875
14	Total Purchase Price	Line 10 plus Line 12	$ 5.561	$ 5.827	$ 5.971	$ 5.989	$ 5.981		$ 5.865
15	Total Purchase Cost	Line 11 plus Line 13	$ 917,565	$ 993,504	$ 1,018,056	$ 922,306	$ 1,019,761	$ -	$ 4,871,191

Source of Supply: Tennessee Gas Pipeline Zone 6 Baseload Supply
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	150,000	155,000	155,000	140,000	155,000	351,201	1,106,201
2	City Gate Delivered Volume	Line 24	149,475	154,458	154,458	139,510	154,458	349,972	1,102,330
3	Total Purchase Cost	Line 15	$ 760,650	$ 827,235	$ 849,555	$ 769,860	$ 851,105	$ 1,238,336	$ 5,296,741
4	Variable Transportation Costs	Line 26	$ 269	$ 278	$ 278	$ 251	$ 278	$ 630	$ 1,984
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 760,919	$ 827,513	$ 849,833	$ 770,111	$ 851,383	$ 1,238,966	$ 5,298,725
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.091	$ 5.358	$ 5.502	$ 5.520	$ 5.512	$ 3.540	$ 4.807
7									
8	Tennessee Zone 6 Supply								
9	Purchased Volumes	Sendout Optimization	150,000	155,000	155,000	140,000	155,000	351,201	1,106,201
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.151
11	NYMEX Cost	Line 9 times Line 10	$ 421,650	$ 476,935	$ 499,255	$ 453,460	$ 500,805	$ 1,133,327	$ 3,485,432
12	NYMEX Basis Price	Att to Sch 5A, Line 4 of Page 1	$ 2.260	$ 2.260	$ 2.260	$ 2.260	$ 2.260	$ 0.299	$ 1.637
13	NYMEX Basis Costs	Line 9 times Line 12	$ 339,000	$ 350,300	$ 350,300	$ 316,400	$ 350,300	$ 105,009	$ 1,811,309
14	Total Purchase Price	Line 10 plus Line 12	$ 5.071	$ 5.337	$ 5.481	$ 5.499	$ 5.491	$ 3.526	$ 4.788
15	Total Purchase Cost	Line 11 plus Line 13	$ 760,650	$ 827,235	$ 849,555	$ 769,860	$ 851,105	$ 1,238,336	$ 5,296,741
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	150,000	155,000	155,000	140,000	155,000	351,201	1,106,201
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	149,475	154,458	154,458	139,510	154,458	349,972	1,102,330
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 269	$ 278	$ 278	$ 251	$ 278	$ 630	$ 1,984

Source of Supply: PNGTS (Westbrook, ME)
Delivered to Northern via PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	27,060	27,962	27,962	25,256	27,962	-	136,202
2	City Gate Delivered Volume	Line 34	26,965	27,864	27,864	25,168	27,864	-	135,725
3	Total Purchase Cost	Line 15	$ 129,103	$ 140,845	$ 144,871	$ 131,306	$ 145,151	$ -	$ 691,276
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 97	$ 100	$ 100	$ 91	$ 100	$ -	$ 489
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 129,201	$ 140,945	$ 144,972	$ 131,397	$ 145,251	$ -	$ 691,765
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.791	$ 5.058	$ 5.203	$ 5.221	$ 5.213		$ 5.097
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	27,060	27,962	27,962	25,256	27,962	-	136,202
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.115
11	NYMEX Cost	Line 9 times Line 10	$ 76,066	$ 86,039	$ 90,066	$ 81,804	$ 90,345	$ -	$ 424,320
12	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1	$ 1.960	$ 1.960	$ 1.960	$ 1.960	$ 1.960		$ 1.960
13	NYMEX Basis Costs	Line 9 times Line 12	$ 53,038	$ 54,806	$ 54,806	$ 49,502	$ 54,806	$ -	$ 266,956
14	Total Purchase Price	Line 10 plus Line 12	$ 4.771	$ 5.037	$ 5.181	$ 5.199	$ 5.191		$ 5.075
15	Total Purchase Cost	Line 11 plus Line 13	$ 129,103	$ 140,845	$ 144,871	$ 131,306	$ 145,151	$ -	$ 691,276
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	PNGTS (Contract 1997-003)								
20	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
21	Delivery Point: Granite (Westbrook)								
22	Received Volume	Line 9	27,060	27,962	27,962	25,256	27,962	-	136,202
23	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	27,060	27,962	27,962	25,256	27,962	-	136,202
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 49	$ 50	$ 50	$ 45	$ 50	$ -	$ 245
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	27,060	27,962	27,962	25,256	27,962	-	136,202
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	26,965	27,864	27,864	25,168	27,864	-	135,725
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 49	$ 50	$ 50	$ 45	$ 50	$ -	$ 244

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-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	4,028	-	-	-	-	-	4,028
2	City Gate Delivered Volume	Sum Lines 24 and 44	3,987	-	-	-	-	-	3,987
3	Total Purchase Cost	Line 15	$ 13,477	$ -	$ -	$ -	$ -	$ -	$ 13,477
4	Variable Transportation Costs	Sum Lines 26, 36 and 46	$ 362	$ -	$ -	$ -	$ -	$ -	$ 362
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 13,839	$ -	$ -	$ -	$ -	$ -	$ 13,839
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.471						$ 3.471
7									
8	<u>Niagara Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	4,028	-	-	-	-	-	4,028
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 2.811
11	NYMEX Cost	Line 9 times Line 10	$ 11,322	$ -	$ -	$ -	$ -	$ -	$ 11,322
12	NYMEX Basis Price	Att to Sch 5A, Line 5 of Page 1	$ 0.535						$ 0.535
13	NYMEX Basis Costs	Line 9 times Line 12	$ 2,155	$ -	$ -	$ -	$ -	$ -	$ 2,155
14	Total Purchase Price	Line 10 plus Line 12	$ 3.346						$ 3.346
15	Total Purchase Cost	Line 11 plus Line 13	$ 13,477	$ -	$ -	$ -	$ -	$ -	$ 13,477
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1A								
19	Tennessee Gas Pipeline (Contract 5292)								
20	Receipt Point: Niagara								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 9	2,748	-	-	-	-	-	2,748
23	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%						0.91%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	2,723	-	-	-	-	-	2,723
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902						$ 0.0902
26	Variable Transportation Costs	Line 24 times Line 25	$ 246	$ -	$ -	$ -	$ -	$ -	$ 246
27									
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 39375)								
30	Receipt Point: Niagara								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 9	1,280	-	-	-	-	-	1,280
33	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%						0.91%
34	Delivered Volume	Line 32 times (1 - Line 33)	1,268	-	-	-	-	-	1,268
35	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902						$ 0.0902
36	Variable Transportation Costs	Line 34 times Line 35	$ 114	$ -	$ -	$ -	$ -	$ -	$ 114
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	1,268	-	-	-	-	-	1,268
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	1,263	-	-	-	-	-	1,263
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 2	$ -	$ -	$ -	$ -	$ -	$ 2

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

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	City Gate Volumes - Z0	Line 2 of Page 5	24,186	32,568	1,491	-	-	-	58,245
2	City Gate Volumes - Z1	Line 2 of Page 6	17,785	86,753	3,605	-	-	-	108,142
3	City Gate Volumes - Z4	Line 2 of Page 7	147,872	154,457	154,457	139,510	154,457	149,475	900,230
4	Total City Gate Volumes	Sum Lines 1 through 3	189,843	273,778	159,553	139,510	154,457	149,475	1,066,617
5	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ 77,698	$ 113,683	$ 5,429	$ -	$ -	$ -	$ 196,810
6	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 57,131	$ 302,677	$ 13,117	$ -	$ -	$ -	$ 372,924
7	City Gate Delivered Costs - Z4	Line 5 of Page 7	$ 438,721	$ 499,990	$ 522,581	$ 474,560	$ 524,150	$ 508,153	$ 2,968,156
8	Total City Gate Delivered Costs	Sum Lines 5 through 7	$ 573,550	$ 916,350	$ 541,127	$ 474,560	$ 524,150	$ 508,153	$ 3,537,890
9	Average Delivered Price	Line 8 divided by Line 4	$ 3.021	$ 3.347	$ 3.392	$ 3.402	$ 3.393	$ 3.400	$ 3.317

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

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 32	25,282	34,045	1,559	-	-	-	60,885
2	City Gate Delivered Volume	Line 44	24,186	32,568	1,491	-	-	-	58,245
3	Total Purchase Price	Line 24	$ 2.729	$ 2.995	$ 3.139				$ 2.888
4	Total Purchase Cost	Line 2 times Line 3	$ 68,994	$ 101,963	$ 4,892	$ -	$ -	$ -	$ 175,850
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 8,703	$ 11,720	$ 537	$ -	$ -	$ -	$ 20,960
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 77,698	$ 113,683	$ 5,429	$ -	$ -	$ -	$ 196,810
7	Average Delivered Price	Line 6 divided by Line 2	$ 3.213	$ 3.491	$ 3.641				$ 3.379
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	-	-
11	Storage Delivered Volume	Line 54	-	-	-	-	-	-	-
12	Total Purchase Price	Line 24	$ 2.729	$ 2.995	$ 3.139				$ 2.888
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Average Delivered Price	Line 15 divided by Line 11							
17									
18	Tennessee Zone 0 Supply Costs								
19	Purchased Volumes	Sendout Optimization	25,282	34,045	1,559	-	-	-	60,885
20	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 2.970
21	NYMEX Cost	Line 9 times Line 10	$ 71,068	$ 104,755	$ 5,020	$ -	$ -	$ -	$ 180,843
22	NYMEX Basis Price	Att to Sch 5A, Line 6 of Page 1	$ (0.082)	$ (0.082)	$ (0.082)				$ (0.082)
23	NYMEX Basis Costs	Line 9 times Line 12	$ (2,073)	$ (2,792)	$ (128)	$ -	$ -	$ -	$ (4,993)
24	Total Purchase Price	Line 10 plus Line 12	$ 2.729	$ 2.995	$ 3.139				$ 2.888
25	Total Purchase Cost	Line 11 plus Line 13	$ 68,994	$ 101,963	$ 4,892	$ -	$ -	$ -	$ 175,850
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1A								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone 0								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	25,282	34,045	1,559	-	-	-	60,885
33	Fuel Loss Rate	Att to Sch 5A, Line 43 of Page 2	4.00%	4.00%	4.00%				4.00%
34	Delivered Volume	Line 32 times (1 - Line 33)	24,271	32,683	1,496	-	-	-	58,450
35	Variable Transportation Rate	Att to Sch 5A, Line 26 of Page 2	$ 0.3568	$ 0.3568	$ 0.3568				$ 0.3568
36	Variable Transportation Costs	Line 34 times Line 35	$ 8,660	$ 11,661	$ 534	$ -	$ -	$ -	$ 20,855
37									
38	Transportation Segment 2A								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	24,271	32,683	1,496	-	-	-	58,450
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	24,186	32,568	1,491	-	-	-	58,245
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 44	$ 59	$ 3	$ -	$ -	$ -	$ 105
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 42 of Page 2							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 25 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 32	18,497	90,224	3,749	-	-	-	112,470
2	City Gate Delivered Volume	Line 44	17,785	86,753	3,605	-	-	-	108,142
3	Total Purchase Price	Line 24	$ 2.787	$ 3.053	$ 3.197				$ 3.014
4	Total Purchase Cost	Line 2 times Line 3	$ 51,550	$ 275,454	$ 11,986	$ -	$ -	$ -	$ 338,990
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 5,581	$ 27,222	$ 1,131	$ -	$ -	$ -	$ 33,934
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 57,131	$ 302,677	$ 13,117	$ -	$ -	$ -	$ 372,924
7	Average Delivered Price	Line 6 divided by Line 2	$ 3.212	$ 3.489	$ 3.639				$ 3.448
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	-	-
11	Storage Delivered Volume	Line 54	-	-	-	-	-	-	-
12	Total Purchase Price	Line 24	$ 2.787	$ 3.053	$ 3.197				$ 3.014
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Average Delivered Price	Line 15 divided by Line 11							
17									
18	Tennessee Zone L Supply Costs								
19	Purchased Volumes	Sendout Optimization	18,497	90,224	3,749	-	-	-	112,470
20	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.038
21	NYMEX Cost	Line 9 times Line 10	$ 51,994	$ 277,620	$ 12,076	$ -	$ -	$ -	$ 341,689
22	NYMEX Basis Price	Att to Sch 5A, Line 7 of Page 1	$ (0.024)	$ (0.024)	$ (0.024)				$ (0.024)
23	NYMEX Basis Costs	Line 9 times Line 12	$ (444)	$ (2,165)	$ (90)	$ -	$ -	$ -	$ (2,699)
24	Total Purchase Price	Line 10 plus Line 12	$ 2.787	$ 3.053	$ 3.197				$ 3.014
25	Total Purchase Cost	Line 11 plus Line 13	$ 51,550	$ 275,454	$ 11,986	$ -	$ -	$ -	$ 338,990
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone L								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	18,497	90,224	3,749	-	-	-	112,470
33	Fuel Loss Rate	Att to Sch 5A, Line 45 of Page 2	3.51%	3.51%	3.51%				3.51%
34	Delivered Volume	Line 32 times (1 - Line 33)	17,847	87,057	3,617	-	-	-	108,522
35	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2	$ 0.3109	$ 0.3109	$ 0.3109				$ 0.3109
36	Variable Transportation Costs	Line 34 times Line 35	$ 5,549	$ 27,066	$ 1,125	$ -	$ -	$ -	$ 33,740
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	17,847	87,057	3,617	-	-	-	108,522
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	17,785	86,753	3,605	-	-	-	108,142
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 32	$ 156	$ 6	$ -	$ -	$ -	$ 195
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone L								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 44 of Page 2							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Tennessee Zone 4 200 Leg Pool
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	150,194	156,883	156,883	141,700	156,883	151,822	914,364
2	City Gate Delivered Volume	Sum Lines 34	147,872	154,457	154,457	139,510	154,457	149,475	900,230
3	Total Purchase Cost	Line 15	$ 420,693	$ 481,159	$ 503,750	$ 457,551	$ 505,319	$ 489,929	$ 2,858,400
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 18,029	$ 18,832	$ 18,832	$ 17,009	$ 18,832	$ 18,224	$ 109,756
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 438,721	$ 499,990	$ 522,581	$ 474,560	$ 524,150	$ 508,153	$ 2,968,156
6	Average Delivered Price	Line 5 divided by Line 2	$ 2.967	$ 3.237	$ 3.383	$ 3.402	$ 3.393	$ 3.400	$ 3.297
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	150,194	156,883	156,883	141,700	156,883	151,822	914,364
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.134
11	NYMEX Cost	Line 9 times Line 10	$ 422,195	$ 482,728	$ 505,319	$ 458,968	$ 506,888	$ 489,929	$ 2,866,026
12	NYMEX Basis Price	Att to Sch 5A, Line 8 of Page 1	$ (0.010)	$ (0.010)	$ (0.010)	$ (0.010)	$ (0.010)	$ -	$ (0.008)
13	NYMEX Basis Costs	Line 9 times Line 12	$ (1,502)	$ (1,569)	$ (1,569)	$ (1,417)	$ (1,569)	$ -	$ (7,625)
14	Total Purchase Price	Line 10 plus Line 12	$ 2.801	$ 3.067	$ 3.211	$ 3.229	$ 3.221	$ 3.227	$ 3.126
15	Total Purchase Cost	Line 11 plus Line 13	$ 420,693	$ 481,159	$ 503,750	$ 457,551	$ 505,319	$ 489,929	$ 2,858,400
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5083)								
20	Receipt Point: Tennessee Zone 4 200 Leg Pool								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	150,194	156,883	156,883	141,700	156,883	151,822	914,364
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	148,391	155,000	155,000	140,000	155,000	150,000	903,391
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197
26	Variable Transportation Costs	Line 24 times Line 25	$ 17,762	$ 18,553	$ 18,553	$ 16,758	$ 18,553	$ 17,955	$ 108,136
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	148,391	155,000	155,000	140,000	155,000	150,000	903,391
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	147,872	154,457	154,457	139,510	154,457	149,475	900,230
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 266	$ 278	$ 278	$ 251	$ 278	$ 269	$ 1,620

Source of Supply: Algonquin Receipts
Delivered to Northern via Algonquin Pipeline and Bay State Exchange

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	22,762	-	-	1,974	26,731	31,939	83,406
2	City Gate Delivered Volume	Sum Lines 24	22,551	-	-	1,954	26,464	31,642	82,610
3	Total Purchase Cost	Line 15	$ 70,950	$ -	$ -	$ 7,285	$ 92,625	$ 107,505	$ 278,364
4	Variable Transportation Costs	Sum Lines 26	$ 293	$ -	$ -	$ 25	$ 344	$ 411	$ 1,074
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 71,243	$ -	$ -	$ 7,310	$ 92,969	$ 107,917	$ 279,438
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.159			$ 3.741	$ 3.513	$ 3.411	$ 3.383
7									
8	<u>Algonquin Receipts Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	22,762	-	-	1,974	26,731	31,939	83,406
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.115
11	NYMEX Cost	Line 9 times Line 10	$ 63,985	$ -	$ -	$ 6,393	$ 86,369	$ 103,066	$ 259,812
12	NYMEX Basis Price	Att to Sch 5A, Line 18 of Page 1	$ 0.306			$ 0.452	$ 0.234	$ 0.139	$ 0.222
13	NYMEX Basis Costs	Line 9 times Line 12	$ 6,965	$ -	$ -	$ 892	$ 6,255	$ 4,439	$ 18,552
14	Total Purchase Price	Line 10 plus Line 12	$ 3.117			$ 3.691	$ 3.465	$ 3.366	$ 3.337
15	Total Purchase Cost	Line 11 plus Line 13	$ 70,950	$ -	$ -	$ 7,285	$ 92,625	$ 107,505	$ 278,364
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Algonquin Pipeline (Contract 93201A1C)								
20	Receipt Point: Algonquin Receipt Points								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 15	22,762	-	-	1,974	26,731	31,939	83,406
23	Fuel Loss Rate	Att to Sch 5A, Line 38 of Page 2	0.93%			1.00%	1.00%	0.93%	1.20%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	22,551	-	-	1,954	26,464	31,642	82,610
25	Variable Transportation Rate	Att to Sch 5A, Line 20 of Page 2	$ 0.0130			$ 0.0130	$ 0.0130	$ 0.0130	$ 0.0130
26	Variable Transportation Costs	Line 24 times Line 25	$ 293	$ -	$ -	$ 25	$ 344	$ 411	$ 1,074

Source of Supply: Tennessee Zone 4
Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	54,579	61,274	-	-	311	58,920	175,084
2	City Gate Delivered Volume	Sum Lines 34	53,736	60,327	-	-	306	58,009	172,378
3	Total Purchase Cost	Line 15	$ 156,806	$ 192,340	$ -	$ -	$ 1,024	$ 190,133	$ 540,304
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 6,551	$ 7,355	$ -	$ -	$ 37	$ 7,072	$ 21,016
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 163,358	$ 199,695	$ -	$ -	$ 1,061	$ 197,206	$ 561,321
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.040	$ 3.310			$ 3.467	$ 3.400	$ 3.256
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	54,579	61,274	-	-	311	58,920	175,084
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.045
11	NYMEX Cost	Line 9 times Line 10	$ 153,423	$ 188,541	$ -	$ -	$ 1,005	$ 190,133	$ 533,102
12	NYMEX Basis Price	Att to Sch 5A, Line 9 of Page 1	$ 0.062	$ 0.062			$ 0.062	$ -	$ 0.041
13	NYMEX Basis Costs	Line 9 times Line 12	$ 3,384	$ 3,799	$ -	$ -	$ 19	$ -	$ 7,202
14	Total Purchase Price	Line 10 plus Line 12	$ 2.873	$ 3.139			$ 3.293	$ 3.227	$ 3.086
15	Total Purchase Cost	Line 11 plus Line 13	$ 156,806	$ 192,340	$ -	$ -	$ 1,024	$ 190,133	$ 540,304
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5265)								
20	Receipt Point: Tennessee FS-MA 300 Leg								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	54,579	61,274	-	-	311	58,920	175,084
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	53,924	60,539	-	-	307	58,212	172,983
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197
26	Variable Transportation Costs	Line 24 times Line 25	$ 6,455	$ 7,247	$ -	$ -	$ 37	$ 6,968	$ 20,706
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	53,924	60,539	-	-	307	58,212	172,983
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	53,736	60,327	-	-	306	58,009	172,378
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 97	$ 109	$ -	$ -	$ 1	$ 104	$ 310

Source of Supply: Tennessee Gas Pipeline Zone 6 Spot Supply
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	2,441	-	-	-	-	-	2,441
2	City Gate Delivered Volume	Line 24	2,432	-	-	-	-	-	2,432
3	Total Purchase Cost	Line 15	$ 8,707	$ -	$ -	$ -	$ -	$ -	$ 8,707
4	Variable Transportation Costs	Line 26	$ 4	$ -	$ -	$ -	$ -	$ -	$ 4
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 8,711	$ -	$ -	$ -	$ -	$ -	$ 8,711
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.581						$ 3.581
7									
8	<u>Tennessee Zone 6 Supply</u>								
9	Purchased Volumes	Sendout Optimization	2,441	-	-	-	-	-	2,441
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 2.811
11	NYMEX Cost	Line 9 times Line 10	$ 6,861	$ -	$ -	$ -	$ -	$ -	$ 6,861
12	NYMEX Basis Price	Att to Sch 5A, Line 17 of Page 1	$ 0.756						$ 0.756
13	NYMEX Basis Costs	Line 9 times Line 12	$ 1,845	$ -	$ -	$ -	$ -	$ -	$ 1,845
14	Total Purchase Price	Line 10 plus Line 12	$ 3.567						$ 3.567
15	Total Purchase Cost	Line 11 plus Line 13	$ 8,707	$ -	$ -	$ -	$ -	$ -	$ 8,707
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	2,441	-	-	-	-	-	2,441
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	2,432	-	-	-	-	-	2,432
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 4	$ -	$ -	$ -	$ -	$ -	$ 4

Source of Supply: W10 AMA Supplier
Delivered to Northern via PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 34	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 26 and 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 16 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	PNGTS (Contract 1997-004)								
19	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
20	Delivery Point: Granite (Westbrook, Newington, Eliot)								
21	Delivery Point: Granite (Westbrook)								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Gross Withdrawn Volume	Line 9	-	-	61,274	55,345	60,963	13,316	190,898
2	City Gate Delivered Volume	Line 36	-	-	60,327	54,489	60,021	13,110	187,947
3	Total Withdrawal Costs	Line 16	$ -	$ -	$ 173,492	$ 156,703	$ 172,612	$ 37,702	$ 540,508
4	Variable Transportation Costs	Sum Lines 27 and 37	$ -	$ -	$ 7,355	$ 6,643	$ 7,318	$ 1,598	$ 22,915
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ 180,847	$ 163,346	$ 179,929	$ 39,300	$ 563,423
6	Average Delivered Price	Line 5 divided by Line 2			$ 2.998	$ 2.998	$ 2.998	$ 2.998	$ 2.998
7									
8	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	61,274	55,345	60,963	13,316	190,898
10	Withdrawal Rate	Att to Sch 5A, Line 1 of Page 3			$ 0.0087	$ 0.0087	$ 0.0087	$ 0.0087	$ 0.0087
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ 533	$ 481	$ 530	$ 116	$ 1,661
12	Inventory Rate	FXW-8			$ 2.8227	$ 2.8227	$ 2.8227	$ 2.8227	$ 2.8227
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ 172,959	$ 156,221	$ 172,081	$ 37,586	$ 538,848
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 1 of Page 3 times Line	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	-	-	61,274	55,345	60,963	13,316	190,898
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ 173,492	$ 156,703	$ 172,612	$ 37,702	$ 540,508
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 2								
20	Tennessee Gas Pipeline (Contract 5265)								
21	Receipt Point: Tennessee FS-MA Withdrawal Meter								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 16	-	-	61,274	55,345	60,963	13,316	190,898
24	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2			1.20%	1.20%	1.20%	1.20%	1.20%
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	60,539	54,680	60,232	13,156	188,607
26	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2			$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ 7,247	$ 6,545	$ 7,210	$ 1,575	$ 22,576
28									
29	Transportation Segment 3								
30	Granite State Gas Transmission (Contract 10-010-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	-	-	60,539	54,680	60,232	13,156	188,607
34	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	-	-	60,327	54,489	60,021	13,110	187,947
36	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ 109	$ 98	$ 108	$ 24	$ 338

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

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Gross Withdrawn Volume	Line 9	-	214,240	598,676	523,266	314,219	-	1,650,400
2	City Gate Delivered Volume	Line 65	-	210,007	586,848	512,927	308,010	-	1,617,793
3	Total Withdrawal Costs	Line 16	$ -	$ 720,489	$ 2,013,346	$ 1,759,744	$ 1,056,717	$ -	$ 5,550,297
4	Variable Transportation Costs	Sum Lines 27, 37, 47, 57 and 67	$ -	$ 19,727	$ 55,126	$ 48,183	$ 28,933	$ -	$ 151,969
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ 740,217	$ 2,068,473	$ 1,807,926	$ 1,085,651	$ -	$ 5,702,266
6	Average Delivered Price	Line 5 divided by Line 2		$ 3.525	$ 3.525	$ 3.525	$ 3.525		$ 3.525
7									
8	Washington 10 Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	-	214,240	598,676	523,266	314,219	-	1,650,400
10	Withdrawal Rate	Att to Sch 5A, Line 3 of Page 3		$ -	$ -	$ -	$ -		$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8		$ 3.3630	$ 3.3630	$ 3.3630	$ 3.3630		$ 3.3630
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ 720,489	$ 2,013,346	$ 1,759,744	$ 1,056,717	$ -	$ 5,550,297
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 3 of Page 3 times Line	-	1,071	2,993	2,616	1,571	-	8,252
15	Net Withdrawn Volume	Line 9 minus Line 14	-	213,169	595,682	520,650	312,647	-	1,642,148
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ 720,489	$ 2,013,346	$ 1,759,744	$ 1,056,717	$ -	$ 5,550,297
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 2A								
20	Vector Pipeline (Contract CRL-NUI-0725)								
21	Receipt Point: Washington 10 Withdrawal Meter								
22	Delivery Point: Dawn (Interconnects with TransCanada)								
23	Received Volume	Line 15	-	83,228	285,477	268,195	179,358	-	816,258
24	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2		0.38%	0.38%	0.38%	0.38%		0.38%
25	Delivered Volume	Line 23 times (1 - Line 24)	-	82,912	284,392	267,176	178,677	-	813,156
26	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2		$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ 149	$ 512	$ 481	$ 322	$ -	$ 1,464
28									
29	Transportation Segment 2B								
30	Vector Pipeline (Contract CRL-NUI-0727)								
31	Receipt Point: Washington 10 Withdrawal Meter								
32	Delivery Point: Union Dawn (Interconnects with TransCanada)								
33	Received Volume	Line 25	-	129,941	310,205	252,455	133,289	-	825,890
34	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2		0.38%	0.38%	0.38%	0.38%		0.38%
35	Delivered Volume	Line 33 times (1 - Line 34)	-	129,447	309,027	251,496	132,783	-	822,752
36	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2		$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ 233	$ 556	$ 453	$ 239	$ -	$ 1,481
38									
39	Transportation Segment 3								
40	TransCanada Pipeline (Contract 33322)								
41	Receipt Point: Union Dawn								
42	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)								
43	Received Volume	Line 35	-	212,359	593,419	518,671	311,459	-	1,635,908
44	Fuel Loss Rate	Att to Sch 5A, Line 48 of Page 2		0.76%	0.76%	0.76%	0.76%		0.76%
45	Delivered Volume	Line 43 times (1 - Line 44)	-	210,745	588,909	514,729	309,092	-	1,623,475
46	Variable Transportation Rate	Att to Sch 5A, Line 31 of Page 2		$ 0.0882	$ 0.0882	$ 0.0882	$ 0.0882		$ 0.0882
47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ 18,588	$ 51,942	$ 45,399	$ 27,262	$ -	$ 143,191
48									
49	Transportation Segment 4								
50	PNGTS (Contract 1997-004)								
51	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
52	Delivery Point: Granite (Westbrook, Newington, Eliot)								
53	Received Volume	Line 45	-	210,745	588,909	514,729	309,092	-	1,623,475
54	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2		0.00%	0.00%	0.00%	0.00%		0.00%
55	Delivered Volume	Line 53 times (1 - Line 54)	-	210,745	588,909	514,729	309,092	-	1,623,475
56	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2		$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018		$ 0.0018
57	Variable Transportation Costs	Line 55 times Line 56	$ -	$ 379	$ 1,060	$ 927	$ 556	$ -	$ 2,922
58									
59	Transportation Segment 5								
60	Granite State Gas Transmission (Contract 10-010-FT-NN)								
61	Receipt Point: Westbrook, Newington, Eliot								
62	Delivery Point: Northern City Gates								
63	Received Volume	Line 55	-	210,745	588,909	514,729	309,092	-	1,623,475
64	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
65	City Gate Delivered Volume	Line 63 times (1 - Line 64)	-	210,007	586,848	512,927	308,010	-	1,617,793
66	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
67	Variable Transportation Costs	Line 65 times Line 66	$ -	$ 378	$ 1,056	$ 923	$ 554	$ -	$ 2,912

Source of Supply: Peaking Supply 1
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 1 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 10 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	2012-2013 Peak Nov-12	2012-2013 Peak Dec-12	2012-2013 Peak Jan-13	2012-2013 Peak Feb-13	2012-2013 Peak Mar-13	2012-2013 Peak Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 2 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 11 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Peaking Supply 3
Delivered to Northern via Granite Pipeline

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Peaking Supply 3 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 12 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Gross Withdrawn Volume	Line 9	1,350	1,395	1,395	1,260	1,395	1,350	8,145
2	City Gate Delivered Volume	Line 15	1,350	1,395	1,395	1,260	1,395	1,350	8,145
3	Total Withdrawal Costs	Line 16	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 38,997
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 38,997
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.515	$ 4.542	$ 4.785	$ 4.982	$ 4.986	$ 4.931	$ 4.788
7									
8	Northern LNG Withdrawn Inventory								
9	Gross Withdrawn Volume	Sendout Optimization	1,350	1,395	1,395	1,260	1,395	1,350	8,145
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8	$ 4.5150	$ 4.5419	$ 4.7852	$ 4.9822	$ 4.9858	$ 4.9314	$ 4.7878
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 38,997
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	1,350	1,395	1,395	1,260	1,395	1,350	8,145
16	Total Withdrawal Costs	Line 11 plus Line 13	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 38,997

Source of Supply: LNG Supply
Delivered to Northern via LNG Trucking Contract

Line	LNG Storage Deliveries	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	2012-2013 Peak
1	Purchased Volumes	Line 22	1,350	145	1,395	1,260	1,395	2,600	8,145
2	Storage Delivered Volume	Line 24	1,350	145	1,395	1,260	1,395	2,600	8,145
3	Total Purchase Price	Line 15	$ 3.567	$ 5.693	$ 5.577	$ 5.571	$ 3.845	$ 3.526	$ 4.294
4	Total Purchase Cost	Line 10 times Line 12	$ 4,815	$ 825	$ 7,780	$ 7,019	$ 5,364	$ 9,168	$ 34,972
5	Variable Transportation Costs	Line 26	$ 1,579	$ 170	$ 1,632	$ 1,474	$ 1,632	$ 3,042	$ 9,530
6	Total Storage Delivered Costs	Line 13 plus Line 14	$ 6,395	$ 995	$ 9,412	$ 8,494	$ 6,996	$ 12,210	$ 44,501
7	Average Delivered Price	Line 15 divided by Line 11	$ 4.737	$ 6.863	$ 6.747	$ 6.741	$ 5.015	$ 4.696	$ 5.464
8									
9	LNG Supply Costs								
10	Purchased Volumes	Sendout Optimization	1,350	145	1,395	1,260	1,395	2,600	8,145
11	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.157
12	LNG Supply Costs	Line 9 times Line 10	$ 3,795	$ 446	$ 4,493	$ 4,081	$ 4,507	$ 8,390	$ 25,713
13	NYMEX Basis Price	Att to Sch 5A, Line 13 of Page 1	$ 0.756	$ 2.616	$ 2.356	$ 2.332	$ 0.614	$ 0.299	$ 1.137
14	NYMEX Basis Costs	Line 9 times Line 12	$ 1,021	$ 379	$ 3,287	$ 2,938	$ 857	$ 777	$ 9,259
15	Total Purchase Price	Line 10 plus Line 12	$ 3.567	$ 5.693	$ 5.577	$ 5.571	$ 3.845	$ 3.526	$ 4.294
16	Total Purchase Cost	Line 11 plus Line 13	$ 4,815	$ 825	$ 7,780	$ 7,019	$ 5,364	$ 9,168	$ 34,972
17									
18	Transportation Segment 3								
19	Trucking Contract (TransGas)								
20	Receipt Point: Distrigas Terminal								
21	Delivery Point: Northern LNG Facility (Lewiston, ME)								
22	Received Volume	Line 19 minus Line 31	1,350	145	1,395	1,260	1,395	2,600	8,145
23	Fuel Loss Rate	N/A	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Storage Delivered Volume	Line 22 times (1 - Line 23)	1,350	145	1,395	1,260	1,395	2,600	8,145
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700
26	Variable Transportation Costs	Line 24 times Line 25	$ 1,579	$ 170	$ 1,632	$ 1,474	$ 1,632	$ 3,042	$ 9,530

Schedule 7

Northern Utilities, Inc.
Hedging Gains and Losses (Total Company)
November 2012 through October 2013
As of 8/28/2012

Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Oct-13	Winter	Summer
NYMEX Contracts	13	21	28	23	23	14	3	3	122	6
Average Purchase Price	$ 4.265	$ 4.442	$ 4.625	$ 4.562	$ 4.535	$ 4.354	$ 3.395	$ 3.557	$ 4.495	$ 3.476
Current NYMEX Price	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227	$ 3.267	$ 3.405	$ 3.158	$ 3.336
Hedging (Gains) and Losses	$ 189,020	$ 286,580	$ 393,120	$ 304,230	$ 300,020	$ 157,720	$ 3,840	$ 4,550	$ 1,630,690	$ 8,390

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Winter 2012-2013 vs. Winter 2011-2012

Line	Item		Rate	Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
2		Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
3	**Winter 2012- 2013**																	
4	Customer Charge	units @	$ 13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38								
5	First	50 units @	$0.4410	$22.05	$22.05	$22.05	$22.05	$22.05	$22.05	$132.30								
6	Over	50 units @	$0.3829	$22.59	$38.29	$52.46	$52.84	$44.42	$31.40	$241.99								
7		COG 1	$0.7892	$86.02						$86.02								
8		COG 2	$0.7892		$118.38					$118.38								
9		COG 3	$0.7892			$147.58				$147.58								
10		COG 4	$0.7892				$148.37			$148.37								
11		COG 5	$0.7892					$131.01		$131.01								
12		COG 6	$0.7892						$104.17	$104.17								
13		LDAC	$0.0708	$7.72	$10.62	$13.24	$13.31	$11.75	$9.35	$65.99								
14	**Summer 2012**																	
15	Customer Charge	units @	$ 13.73								$ 13.73	$13.73	$13.73	$13.73	$ 13.73	$13.73	$82.38	
16	First	50 units @	$0.4410								$22.05	$22.05	$13.23	$13.23	$18.52	$22.05	$111.13	
17	Over	50 units @	$0.4410								$17.64	$2.21	$0.00	$0.00	$0.00	$9.26	$29.11	
18		COG 1	$0.4264								$38.38						$38.38	
19		COG 2	$0.4006									$22.03					$22.03	
20		COG 3	$0.4006										$12.02				$12.02	
21		COG 4	$0.4297											$12.89			$12.89	
22		COG 5	$0.4014												$16.86		$16.86	
23		COG 6	$0.4014													$28.50	$28.50	
24	Summer Period 2012 Weighted Avg. COG		$0.4109															
25		LDAC	$ 0.0642								$5.78	$3.53	$1.93	$1.93	$2.70	$4.56	$20.42	
26			**TOTAL**	$152.11	$203.07	$249.06	$250.30	$222.96	$180.70	**$1,258.19**	$97.57	$63.55	$40.90	$41.78	$51.81	$78.10	$373.71	$1,631.90
27				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
28		Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
29	**Winter 2011 - 2012**																	
30	Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
31	First	50 units @	$0.4395	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$131.85								
32	Over	50 units @	$0.3283	$19.37	$32.83	$44.98	$45.31	$38.08	$26.92	$207.49								
33		COG 1	$1.0837	$118.12						$118.12								
34		COG 2	$1.0837		$162.56					$162.56								
35		COG 3	$1.1560			$216.17				$216.17								
36		COG 4	$1.1560				$217.33			$217.33								
37		COG 5	$1.2961					$215.15		$215.15								
38		COG 6	$1.0920						$144.14	$144.14								
39	Winter Period 11-12 Weighted Avg. COG		$1.1518															
40		LDAC	$ 0.0440	$4.80	$6.60	$8.23	$8.27	$7.30	$5.81	$41.01								
41	**Summer 2011**																	
42	Customer Charge	units @	$ 9.50								$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00	
43	First	50 units @	$0.4102								$20.51	$20.51	$12.31				$53.33	
44	Temp First	50 units @	$0.4395											$13.19	$18.46	$21.98	$53.62	
45	Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
46	Temp Over	50 units @	$0.3283															
47		COG 1	$0.6673								$60.06						$60.06	
48		COG 2	$0.6673									$36.70					$36.70	
49		COG 3	$0.5992										$17.98				$17.98	
50		COG 4	$0.6685											$20.06			$20.06	
51		COG 5	$0.5570												$23.39		$23.39	
52		COG 6	$0.5570													$39.55	$39.55	
53	Summer Period 2011 Wighted Avg. COG		$0.6218															
54		LDAC	$ 0.0456								$4.10	$2.51	$1.37	$1.37	$1.92	$3.24	$14.50	
55			**TOTAL**	$173.76	$233.46	$300.85	$302.38	$292.01	$208.35	**$1,510.82**	$106.13	$70.71	$41.15	$44.11	$53.27	$80.54	$395.91	$1,906.73
56			**Change**	($21.65)	($30.39)	($51.79)	($52.08)	($69.06)	($27.65)	**($252.63)**	($8.56)	($7.17)	($0.25)	($2.33)	($1.46)	($2.44)	**($22.20)**	($274.83)
57			**% Chg**	-12.46%	-13.02%	-17.22%	-17.22%	-23.65%	-13.27%	**-16.72%**	-8.06%	-10.13%	-0.60%	-5.28%	-2.74%	-3.03%	**-5.61%**	-14.41%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Winter 2012-2013 vs. Winter 2011-2012

1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
3	**Winter 2012 - 2013**																	
4	Customer Charge	units @	$ 31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
5	First	75 units @	$0.2701	$20.26	$20.26	$20.26	$20.26	$20.26	$20.26	$121.55								
6	Over	75 units @	$0.2226	$26.27	$43.18	$49.64	$41.63	$35.39	$21.37	$217.48								
7		COG 1	$0.8037	$155.11						$155.11								
8		COG 2	$0.8037		$216.20					$216.20								
9		COG 3	$0.8037			$239.50				$239.50								
10		COG 4	$0.8037				$210.57			$210.57								
11		COG 5	$0.8037					$188.07		$188.07								
12		COG 6	$0.8037						$137.43	$137.43								
13		LDAC	$0.0444	$8.57	$11.94	$13.23	$11.63	$10.39	$7.59	$63.36								
14	**Summer 2012**																	
15	Customer Charge	units @	$ 31.40								$ 31.40	$31.40	$31.40	$31.40	$ 31.40	$31.40	$188.40	
16	First	75 units @	$0.2701								$20.26	$20.26	$19.45	$19.45	$20.26	$20.26	$119.92	
17	Over	75 units @	$0.2226								$9.35	$1.34	$0.00	$0.00	$3.12	$14.91	$28.72	
18		COG 1	$0.4597								$53.78						$53.78	
19		COG 2	$0.4339									$35.15					$35.15	
20		COG 3	$0.4339										$31.24				$31.24	
21		COG 4	$0.4630											$33.34			$33.34	
22		COG 5	$0.4347												$38.69		$38.69	
23		COG 6	$0.4347													$61.73	$61.73	
24	Summer Period 2012 Weighted Avg. COG		$0.4431															
25		LDAC	$ 0.0435								$5.09	$3.52	$3.13	$3.13	$3.87	$6.18	$24.93	
26		TOTAL		$241.61	$322.98	$354.03	$315.49	$285.51	$218.05	**$1,737.66**	$119.88	$91.66	$85.22	$87.32	$97.33	$134.48	$615.89	$2,353.55
27				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
28		Typical Usage: therms		193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
29	**Winter 2011 - 2012**																	
30	Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
31	First	75 units @	$0.3370	$25.28	$25.28	$25.28	$25.28	$25.28	$25.28	$151.65								
32	Over	75 units @	$0.2300	$27.14	$44.62	$51.29	$43.01	$36.57	$22.08	$224.71								
33		COG 1	$1.1166	$215.50						$215.50								
34		COG 2	$1.1166		$300.37					$300.37								
35		COG 3	$1.1889			$354.29				$354.29								
36		COG 4	$1.1859				$310.71			$310.71								
37		COG 5	$1.3290					$310.99		$310.99								
38		COG 6	$1.1249						$192.36	$192.36								
39	Winter Period 11-12 Weighted Avg. COG		$1.1802															
40		LDAC	$ 0.0233	$4.50	$6.27	$6.94	$6.10	$5.45	$3.98	$33.25								
41	**Summer 2011**																	
42	Customer Charge	units @	$ 18.70								$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20	
43	First	75 units @	$0.3077								$23.08	$23.08	$22.15				$68.31	
44	First	75 units (Temp)	$0.3370											$24.26	$25.28	$25.28	$74.81	
45	Over	75 units @	$0.2007								$8.43	$1.20	$0.00				$9.63	
46	Over	75 units (Temp)	$0.2300											$0.00	$3.22	$15.41	$18.63	
47		COG 1	$0.7234								$84.64						$84.64	
48		COG 2	$0.7234									$58.60					$58.60	
49		COG 3	$0.6553										$47.18				$47.18	
50		COG 4	$0.7246											$52.17			$52.17	
51		COG 5	$0.6131												$54.57		$54.57	
52		COG 6	$0.6131													$87.06	$87.06	
53	Summer Period 2011 Wighted Avg. COG		$0.6705															
54		LDAC	$ 0.0297								$3.47	$2.41	$2.14	$2.14	$2.64	$4.22	$17.02	
55		TOTAL		$291.12	$395.23	$456.50	$403.80	$396.98	$262.40	**$2,206.02**	$138.32	$103.98	$90.17	$97.27	$104.40	$150.66	$684.82	$2,890.84
56		Change		($49.51)	($72.25)	($102.47)	($88.31)	($111.48)	($44.35)	**($468.36)**	($18.44)	($12.32)	($4.95)	($9.96)	($7.07)	($16.19)	**($68.93)**	($537.28)
57		% Chg		-17.01%	-18.28%	-22.45%	-21.87%	-28.08%	-16.90%	**-21.23%**	-13.33%	-11.85%	-5.49%	-10.24%	-6.77%	-10.74%	**-10.07%**	-18.59%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Winter 2012-2013 vs. Winter 2011-2012

1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
3	**Winter 2012 - 2013**																	
4	Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
5	All	units @	$0.2016	$313.08	$519.72	$658.22	$827.16	$685.84	$498.56	$3,502.60								
6		COG 1	$0.8037	$1,248.15						$1,248.15								
7		COG 2	$0.8037		$2,071.94					$2,071.94								
8		COG 3	$0.8037			$2,624.08				$2,624.08								
9		COG 4	$0.8037				$3,297.58			$3,297.58								
10		COG 5	$0.8037					$2,734.19		$2,734.19								
11		COG 6	$0.8037						$1,987.55	$1,987.55								
12		LDAC	$0.0444	$68.95	$114.46	$144.97	$182.17	$151.05	$109.80	$771.41								
13	**Summer 2012**																	
14	Customer Charge	units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
15	All	units @	$0.1557								$195.87	$109.15	$64.46	$33.16	$56.67	$108.83	$568.15	
16		COG 1	$0.4597								$578.30						$578.30	
17		COG 2	$0.4339									$304.16					$304.16	
18		COG 3	$0.4339										$179.63				$179.63	
19		COG 4	$0.4630											$98.62			$98.62	
20		COG 5	$0.4347												$158.23		$158.23	
21		COG 6	$0.4347													$303.86	$303.86	
22	Summer Period 2012 Weighted Avg. COG		$0.4447															
23		LDAC	$ 0.0435								$54.72	$30.49	$18.01	$9.27	$15.83	$30.41	$158.73	
24			**TOTAL**	$1,724.39	$2,800.34	$3,521.48	$4,401.13	$3,665.29	$2,690.12	**$18,802.75**	$923.11	$538.01	$356.31	$235.26	$324.95	$537.31	$2,914.95	$21,717.69
25				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
26		Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
27	**Winter 2011 - 2012**																	
28	Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
29	All	units @	$0.2235	$347.10	$576.18	$729.73	$917.02	$760.35	$552.72	$3,883.09								
30		COG 1	$1.1166	$1,734.08						$1,734.08								
31		COG 2	$1.1166		$2,878.59					$2,878.59								
32		COG 3	$1.1889			$3,881.76				$3,881.76								
33		COG 4	$1.1859				$4,865.75			$4,865.75								
34		COG 5	$1.3290					$4,521.26		$4,521.26								
35		COG 6	$1.1249						$2,781.88	$2,781.88								
36	Winter Period 11-12 Weighted Avg. COG		$1.1893															
37		LDAC	$ 0.0233	$36.18	$60.07	$76.07	$95.60	$79.27	$57.62	$404.81								
38	**Summer 2011**																	
39	Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
40	All	units @	$0.1124								$141.40	$78.79	$46.53				$266.73	
41	All	units (Temp)	$0.1417											$30.18	$51.58	$99.05	$180.81	
42		COG 1	$0.7234								$910.04						$910.04	
43		COG 2	$0.7234									$507.10					$507.10	
44		COG 3	$0.6553										$271.29				$271.29	
45		COG 4	$0.7246											$154.34			$154.34	
46		COG 5	$0.6131												$223.17		$223.17	
47		COG 6	$0.6131													$428.56	$428.56	
48	Summer Period 2011 Wighted Avg. COG		$0.6836															
49		LDAC	$ 0.0297								$37.36	$20.82	$12.30	$6.33	$10.81	$20.76	$108.38	
50			**TOTAL**	$2,177.66	$3,575.15	$4,747.86	$5,938.67	$5,421.17	$3,452.51	**$25,313.02**	$1,149.10	$667.02	$390.42	$251.15	$345.86	$608.67	$3,412.21	$28,725.23
51			**Change**	($453.27)	($774.81)	($1,226.38)	($1,537.54)	($1,755.88)	($762.40)	**($6,510.27)**	($225.99)	($129.00)	($34.11)	($15.89)	($20.91)	($71.36)	**($497.26)**	($7,007.53)
52			**% Chg**	-20.81%	-21.67%	-25.83%	-25.89%	-32.39%	-22.08%	**-25.72%**	-19.67%	-19.34%	-8.74%	-6.33%	-6.05%	-11.72%	**-14.57%**	-24.40%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 20,489 therms/year

Comparison of Winter 2012-2013 vs. Winter 2011-2012

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
3	**Winter 2012 - 2013**																	
4	Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
5	First	1,300 units @	$0.1849	$240.37	$240.37	$240.37	$240.37	$240.37	$240.37	$1,442.22								
6	Over	1,300 units @	$0.1482	$62.54	$116.49	$152.65	$153.09	$146.87	$84.77	$716.40								
7		COG 1	$0.7111	$1,224.51						$1,224.51								
8		COG 2	$0.7111		$1,483.35					$1,483.35								
9		COG 3	$0.7111			$1,656.86				$1,656.86								
10		COG 4	$0.7111				$1,659.00			$1,659.00								
11		COG 5	$0.7111					$1,629.13		$1,629.13								
12		COG 6	$0.7111						$1,331.18	$1,331.18								
13		LDAC	$0.0444	$76.46	$92.62	$103.45	$103.59	$101.72	$83.12	$560.95								
14	**Summer 2012**																	
15	Customer Charge	units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
16	First	1,000 units @	$0.1325								$132.50	$132.50	$132.50	$132.50	$132.50	$132.50	$795.00	
17	Over	1,000 units @	$0.1011								$51.56	$37.81	$24.97	$19.21	$21.23	$32.76	$187.54	
18		COG 1	$0.3835								$579.09						$579.09	
19		COG 2	$0.3577									$491.48					$491.48	
20		COG 3	$0.3577										$446.05				$446.05	
21		COG 4	$0.3868											$460.29			$460.29	
22		COG 5	$0.3868												$468.03		$468.03	
23		COG 6	$0.3585													$474.65	$474.65	
24	Summer Period 2012 Weighted Avg. COG		$0.3717															
25		LDAC	$ 0.0435								$65.69	$59.77	$54.24	$51.77	$52.64	$57.59	$341.69	
26		**TOTAL**		$1,698.09	$2,027.04	$2,247.54	$2,250.25	$2,212.30	$1,833.65	**$12,268.87**	$923.04	$815.77	$751.98	$757.98	$768.60	$791.71	$4,809.08	$17,077.95
27				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
28		Typical Usage: therms		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
29	**Winter 2011 - 2012**																	
30	Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
31	First	1,300 units @	$0.2155	$280.15	$280.15	$280.15	$280.15	$280.15	$280.15	$1,680.90								
32	Over	1,300 units @	$0.1760	$74.27	$138.34	$181.28	$181.81	$174.42	$100.67	$850.78								
33		COG 1	$0.9232	$1,589.75						$1,589.75								
34		COG 2	$0.9232		$1,925.80					$1,925.80								
35		COG 3	$0.9955			$2,319.52				$2,319.52								
36		COG 4	$0.9955				$2,322.50			$2,322.50								
37		COG 5	$1.1356					$2,601.66		$2,601.66								
38		COG 6	$0.9315						$1,743.77	$1,743.77								
39	Winter Period 11-12 Weighted Avg. COG		$0.9896															
40		LDAC	$ 0.0233	$40.12	$48.60	$54.29	$54.36	$53.38	$43.62	$294.37								
41	**Summer 2011**																	
42	Customer Charge	units @	$ 60.30								$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80	
43	First	1,000 units @	$0.1112								$111.20	$111.20	$111.20				$333.60	
44	First	1,000 Units (Temp)	$0.1405											$140.50	$140.50	$140.50	$421.50	
45	Over	1,000 units @	$0.0780								$39.78	$29.17	$19.27				$88.22	
46	Over	1,000 Units (Temp)	$0.1073											$20.39	$22.53	$34.77	$77.69	
47		COG 1	$0.5975								$902.23						$902.23	
48		COG 2	$0.5975									$820.97					$820.97	
49		COG 3	$0.5294										$660.16				$660.16	
50		COG 4	$0.5987											$712.45			$712.45	
51		COG 5	$0.4872												$589.51		$589.51	
52		COG 6	$0.4872													$645.05	$645.05	
53	Summer Period 2011 Wighted Avg. COG		$0.5513															
54		LDAC	$ 0.0297								$44.85	$40.81	$37.04	$35.34	$35.94	$39.32	$233.29	
55		**TOTAL**		$2,044.60	$2,453.19	$2,895.53	$2,899.12	$3,169.91	$2,228.51	**$15,690.85**	$1,158.35	$1,062.44	$887.96	$968.98	$848.78	$919.94	$5,846.47	$21,537.31
56		**Change**		($346.50)	($426.15)	($647.99)	($648.87)	($957.61)	($394.86)	**($3,421.98)**	($235.31)	($246.67)	($135.99)	($211.01)	($80.18)	($128.23)	**($1,037.38)**	($4,459.36)
57		**% Chg**		-16.95%	-17.37%	-22.38%	-22.38%	-30.21%	-17.72%	**-21.81%**	-20.31%	-23.22%	-15.31%	-21.78%	-9.45%	-13.94%	**-17.74%**	-20.71%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Winter 2012-2013 vs. Actual Winter 2011-2012

Residential Heating

	Winter 2011-2012	Winter 2012- 2013
Customer Charge	$9.50	$13.73
First 50 Therms	$0.4395	$0.4410
Over 50 therms	$0.3283	$0.3829
LDAC	$0.0440	$0.0708
CGA	$1.1518	$0.7892

	Usage (Therms)	Winter 2011-2012 Bill Amount	Winter 2012-2013 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$17.68	$20.24	$2.56	14.5%	$0.01	0.1%	($1.81)	-10.2%	$0.13	0.7%
	10	$25.85	$26.74	$0.89	3.4%	$0.02	0.1%	($3.63)	-14.0%	$0.27	1.0%
	20	$42.21	$39.75	($2.46)	-5.8%	$0.03	0.1%	($7.25)	-17.2%	$0.54	1.3%
	25	$50.38	$46.26	($4.13)	-8.2%	$0.04	0.1%	($9.06)	-18.0%	$0.67	1.3%
	30	$58.56	$52.76	($5.80)	-9.9%	$0.05	0.1%	($10.88)	-18.6%	$0.80	1.4%
	45	$83.09	$72.28	($10.81)	-13.0%	$0.07	0.1%	($16.32)	-19.6%	$1.21	1.5%
Average Monthly	50	$91.26	$78.78	($12.48)	-13.7%	$0.08	0.1%	($18.13)	-19.9%	$1.34	1.5%
	75	$129.37	$109.85	($19.51)	-15.1%	$0.12	0.1%	($27.19)	-21.0%	$2.01	1.6%
	125	$205.57	$172.00	($33.57)	-16.3%	$0.19	0.1%	($45.32)	-22.0%	$3.35	1.6%
	150	$243.67	$203.07	($40.60)	-16.7%	$0.23	0.1%	($54.39)	-22.3%	$4.02	1.6%
	200	$319.88	$265.22	($54.66)	-17.1%	$0.31	0.1%	($72.52)	-22.7%	$5.36	1.7%

Schedule 9

Northern Utilities New Hampshire Division
Period Covered: November 1, 2012 - April 30, 2013
Variance Analysis

		2011-2012 Winter (6 months actual)			Forecast Winter 2012-2013 (6 months proposed)			Variance		
1	Therm Sales	23,069,370			27,305,924			4,236,554		
2				EFFECT			EFFECT			EFFECT
3		THERM		ON COST	THERM		ON COST	THERM		ON COST
4		SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS
5										
6	Demand Charges		$ 16,502,810	$ 0.7154		$ 14,122,507	$ 0.5172		$ (2,380,303)	$ (0.1982)
7										
8	Purchased Gas		7,360,732	0.3191		8,117,009	0.2973		$ 756,277	$ (0.0218)
9										
10	Storage & Peaking Gas		2,249,838	0.0975		3,182,658	0.1166		$ 932,820	$ 0.0190
11										
12	Hedging (Gain)/Loss		1,195,000	0.0518		822,275	0.0301		(372,725)	(0.0217)
13										
14										
15	Total Volumes and Cost		$ 27,308,380	$ 1.1838	$ -	$ 26,244,448	$ 0.9611	$ -	$ (1,063,932)	$ (0.2226)
16										
17	Prior Period Balance		$973,628	$ 0.0422		$ (3,105,739)	$ (0.1137)		$ (4,079,367)	$ (0.1559)
18						$ -	$ -		$ -	$ -
19	Interest		$ 7,603	$ 0.0003		(10,976)	$ (0.0004)		(18,579)	$ (0.0007)
20	Refunds from Suppliers		-	$ -		(168,825)	$ (0.0062)		(168,825)	$ (0.0062)
21	Misc Credits & Costs									
22	Prior Period Adjustment									
23	Interruptible Sales Margin		-	$ -		-	$ -		-	$ -
24	Capacity Release		(2,496,446)	$ (0.0914)		$ (2,180,758)	$ (0.0799)		315,688	$ 0.0116
25	Working Capital Allowance		(9,592)	$ (0.0004)		10,231	$ 0.0004		19,823	$ 0.0008
26	Bad Debt Allowance		(142,934)	$ (0.0062)		$ 128,702	$ 0.0047		271,636	$ 0.0109
27	Fuel Inventory Financing		6,864			4,654			(2,210)	$ -
28	Local Production and Storage		307,762			307,762	$ 0.0113		-	$ -
29	Misc Overhead		382,438	$ 0.0166		321,744	$ 0.0118		(60,694)	$ (0.0048)
30										
31	Total Anticipated Indirect Cost of Gas		($970,677)	$ (0.0421)		(4,693,204)	$ (0.1719)		(3,722,527)	$ (0.1298)
32	Total Adjusted Cost		26,337,703	$ 1.1417		21,551,244	$ 0.7892		(4,786,459)	$ (0.3525)

Schedules 10A, 10B & Attachments, & 10C

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

Base Capacity Costs

LN	BASE SENDOUT BY CLASS	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
2	**Total Therms**									
3	Res Heat	460,839	476,200	476,200	430,116	476,200	460,839	5,599,341	2,780,395	Schedule 10B, LN 52
4	Res General	16,934	17,498	17,498	15,805	17,498	16,934	205,753	102,168	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	97,212	100,452	100,452	90,731	100,452	97,212	1,181,152	586,510	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	153,575	158,695	158,695	143,337	158,695	153,575	1,865,992	926,572	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	115,280	119,122	119,122	107,594	119,122	115,280	1,400,683	695,520	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	189,408	195,721	195,721	176,780	195,721	189,408	2,301,363	1,142,759	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	5,739	5,930	5,930	5,356	5,930	5,739	69,735	34,625	Schedule 10B, LN 58
10	G42 High Annual-High Winter	16,143	16,681	16,681	15,067	16,681	16,143	196,140	97,395	Schedule 10B, LN 59
11	Total Firm Sales	1,055,129	1,090,300	1,090,300	984,787	1,090,300	1,055,129	12,820,158	6,365,942	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	43.68%	43.68%	43.68%	43.68%	43.68%	43.68%			LN 3 / LN 11
15	Res General	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%			LN 5 / LN 11
17	G40 Low Annual-High Winter	14.56%	14.56%	14.56%	14.56%	14.56%	14.56%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	10.93%	10.93%	10.93%	10.93%	10.93%	10.93%			LN 7 / LN 11
19	G41 Med Annual-High Winter	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%			LN 8 / LN 11
20	G52 High Annual-Low Winter	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%			LN 9 / LN 11
21	G42 High Annual-High Winter	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%			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-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 88,434	$ 1,061,211	$ 530,606	Schedule 1A, LN 69
26	Res Heat	$ 38,625	$ 38,625	$ 38,625	$ 38,625	$ 38,625	$ 38,625	$ 463,495	$ 231,748	LN 25 * LN 14
27	Res General	$ 1,419	$ 1,419	$ 1,419	$ 1,419	$ 1,419	$ 1,419	$ 17,032	$ 8,516	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 8,148	$ 8,148	$ 8,148	$ 8,148	$ 8,148	$ 8,148	$ 97,772	$ 48,886	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 12,872	$ 12,872	$ 12,872	$ 12,872	$ 12,872	$ 12,872	$ 154,461	$ 77,230	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 9,662	$ 9,662	$ 9,662	$ 9,662	$ 9,662	$ 9,662	$ 115,944	$ 57,972	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 15,875	$ 15,875	$ 15,875	$ 15,875	$ 15,875	$ 15,875	$ 190,499	$ 95,250	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 481	$ 481	$ 481	$ 481	$ 481	$ 481	$ 5,772	$ 2,886	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,353	$ 1,353	$ 1,353	$ 1,353	$ 1,353	$ 1,353	$ 16,236	$ 8,118	LN 25 * LN 21
34										
35	Residential	$ 40,044	$ 40,044	$ 40,044	$ 40,044	$ 40,044	$ 40,044	$ 480,527	$ 240,264	LN 26 + LN 27
36	SALES HLF CLASSES	$ 18,291	$ 18,291	$ 18,291	$ 18,291	$ 18,291	$ 18,291	$ 219,488	$ 109,744	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 30,100	$ 30,100	$ 30,100	$ 30,100	$ 30,100	$ 30,100	$ 361,196	$ 180,598	LN 29 + LN 31 + LN 33
38										

Remaining Capacity Costs

LN		Column A Design Day Demand (MMBtu)	Column B Avg Daily Base Use Load (MMBtu)	Column C Remaining Design Day Demand (MMBtu)	Column D % of Total Remaining Design Day Demand	
39						
40	Res Heat	21,167	1,536	19,631	49.41%	Company Analysis
41	Res General	383	56	326	0.82%	Company Analysis
42	G50 Low Annual-Low Winter	1,181	324	857	2.16%	Company Analysis
43	G40 Low Annual-High Winter	9,329	512	8,817	22.19%	Company Analysis
44	G51 Med Annual-Low Winter	1,579	384	1,195	3.01%	Company Analysis
45	G41 Med Annual-High Winter	8,368	631	7,737	19.47%	Company Analysis
46	G52 High Annual-Low Winter	59	19	40	0.10%	Company Analysis
47	G42 High Annual-High Winter	1,181	54	1,127	2.84%	Company Analysis
48	TOTAL	43,248	3,517	39,731	100.00%	Sum LN 40 : LN 47

49

50 **REMAINING PIPELINE DEMAND**

LN		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
51										
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 127,846	$ 273,227	$ 499,417	$ 291,409	$ 205,185	$ 96,063	$ 1,540,007	$ 1,493,147	Schedule 1A, LN 70
53										
54	Res Heat	$ 63,168	$ 135,001	$ 246,760	$ 143,984	$ 101,381	$ 47,465	$ 760,912	$ 737,759	LN 40 Col D * LN 52
55	Res General	$ 1,050	$ 2,244	$ 4,101	$ 2,393	$ 1,685	$ 789	$ 12,647	$ 12,262	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 2,758	$ 5,895	$ 10,775	$ 6,287	$ 4,427	$ 2,072	$ 33,224	$ 32,213	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 28,370	$ 60,632	$ 110,826	$ 64,667	$ 45,533	$ 21,317	$ 341,744	$ 331,345	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 3,845	$ 8,218	$ 15,022	$ 8,765	$ 6,172	$ 2,889	$ 46,322	$ 44,912	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 24,896	$ 53,208	$ 97,256	$ 56,748	$ 39,957	$ 18,707	$ 299,898	$ 290,773	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 130	$ 277	$ 506	$ 295	$ 208	$ 97	$ 1,561	$ 1,513	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 3,628	$ 7,753	$ 14,171	$ 8,269	$ 5,822	$ 2,726	$ 43,699	$ 42,369	LN 47 Col D * LN 52
62	TOTAL	$ 127,846	$ 273,227	$ 499,417	$ 291,409	$ 205,185	$ 96,063	$ 1,540,007	$ 1,493,147	Sum LN 54 : LN 61
63										
64	Residential	$ 64,218	$ 137,244	$ 250,862	$ 146,377	$ 103,066	$ 48,254	$ 773,559	$ 750,021	LN 54 + LN 55
65	SALES HLF CLASSES	$ 6,733	$ 14,390	$ 26,303	$ 15,348	$ 10,806	$ 5,059	$ 81,107	$ 78,639	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 56,895	$ 121,593	$ 222,253	$ 129,684	$ 91,312	$ 42,751	$ 685,341	$ 664,487	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

LN		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
69										
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 1,035,916	$ 2,213,919	$ 4,046,707	$ 2,361,244	$ 1,662,580	$ 778,388	$ 12,478,452	$ 12,098,754	Schedule 1A, LN 73
71										
72	Res Heat	$ 511,842	$ 1,093,890	$ 1,999,463	$ 1,166,682	$ 821,475	$ 384,599	$ 6,165,559	$ 5,977,951	LN 40 Col D * LN 70
73	Res General	$ 8,507	$ 18,182	$ 33,233	$ 19,392	$ 13,654	$ 6,392	$ 102,479	$ 99,361	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 22,349	$ 47,763	$ 87,304	$ 50,942	$ 35,869	$ 16,793	$ 269,212	$ 261,021	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 229,881	$ 491,292	$ 898,007	$ 523,985	$ 368,944	$ 172,733	$ 2,769,100	$ 2,684,841	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 31,159	$ 66,593	$ 121,721	$ 71,024	$ 50,009	$ 23,413	$ 375,340	$ 363,919	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 201,732	$ 431,135	$ 788,049	$ 459,825	$ 323,768	$ 151,582	$ 2,430,033	$ 2,356,091	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 1,050	$ 2,243	$ 4,101	$ 2,393	$ 1,685	$ 789	$ 12,645	$ 12,260	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 29,395	$ 62,821	$ 114,828	$ 67,002	$ 47,177	$ 22,087	$ 354,085	$ 343,310	LN 47 Col D * LN 70
80	TOTAL	$ 1,035,916	$ 2,213,919	$ 4,046,707	$ 2,361,244	$ 1,662,580	$ 778,388	$ 12,478,452	$ 12,098,754	Sum LN 72 : LN 79
81										
82	Residential	$ 520,350	$ 1,112,071	$ 2,032,697	$ 1,186,074	$ 835,129	$ 390,991	$ 6,268,037	$ 6,077,312	LN 72 + LN 73
83	SALES HLF CLASSES	$ 54,558	$ 116,599	$ 213,126	$ 124,359	$ 87,562	$ 40,995	$ 657,197	$ 637,200	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 461,008	$ 985,248	$ 1,800,884	$ 1,050,812	$ 739,889	$ 346,402	$ 5,553,218	$ 5,384,243	LN 75 + LN 77 + LN 79

85

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

87		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ (192,098)	$ (397,968)	$ (718,270)	$ (423,715)	$ (301,615)	$ (147,092)	$ (2,180,758)	$ (2,180,758)	Schedule 1A, LN 76
89										
90	Res Heat	$ (94,915)	$ (196,635)	$ (354,894)	$ (209,356)	$ (149,027)	$ (72,678)	$ (1,077,505)	$ (1,077,505)	LN 40 Col D * LN 88
91	Res General	$ (1,578)	$ (3,268)	$ (5,899)	$ (3,480)	$ (2,477)	$ (1,208)	$ (17,909)	$ (17,909)	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ (4,144)	$ (8,586)	$ (15,496)	$ (9,141)	$ (6,507)	$ (3,173)	$ (47,048)	$ (47,048)	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ (42,629)	$ (88,313)	$ (159,392)	$ (94,027)	$ (66,932)	$ (32,641)	$ (483,933)	$ (483,933)	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ (5,778)	$ (11,971)	$ (21,605)	$ (12,745)	$ (9,072)	$ (4,424)	$ (65,595)	$ (65,595)	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ (37,409)	$ (77,500)	$ (139,875)	$ (82,514)	$ (58,736)	$ (28,644)	$ (424,677)	$ (424,677)	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ (195)	$ (403)	$ (728)	$ (429)	$ (306)	$ (149)	$ (2,210)	$ (2,210)	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ (5,451)	$ (11,293)	$ (20,381)	$ (12,023)	$ (8,559)	$ (4,174)	$ (61,881)	$ (61,881)	LN 47 Col D * LN 88
98	TOTAL	$ (192,098)	$ (397,968)	$ (718,270)	$ (423,715)	$ (301,615)	$ (147,092)	$ (2,180,758)	$ (2,180,758)	Sum LN 90 : LN 97
99										
100	Residential	$ (96,493)	$ (199,903)	$ (360,793)	$ (212,836)	$ (151,504)	$ (73,886)	$ (1,095,414)	$ (1,095,414)	LN 90 + LN 91
101	SALES HLF CLASSES	$ (10,117)	$ (20,960)	$ (37,829)	$ (22,316)	$ (15,885)	$ (7,747)	$ (114,853)	$ (114,853)	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ (85,488)	$ (177,106)	$ (319,648)	$ (188,564)	$ (134,226)	$ (65,460)	$ (970,491)	$ (970,491)	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

105		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 77
107										
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117										
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115

121

122 **REMAINING RE-ENTRY FEE CREDIT**

LN		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
123										
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-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
141										
142	Res Heat	$ 480,095	$ 1,032,255	$ 1,891,329	$ 1,101,310	$ 773,829	$ 359,386	$ 5,848,966	$ 5,638,205	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 7,980	$ 17,157	$ 31,436	$ 18,305	$ 12,862	$ 5,973	$ 97,217	$ 93,714	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 20,963	$ 45,072	$ 82,583	$ 48,087	$ 33,788	$ 15,692	$ 255,389	$ 246,186	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 215,622	$ 463,611	$ 849,441	$ 494,625	$ 347,545	$ 161,409	$ 2,626,911	$ 2,532,253	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 29,227	$ 62,840	$ 115,138	$ 67,044	$ 47,108	$ 21,878	$ 356,067	$ 343,236	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 189,220	$ 406,843	$ 745,430	$ 434,060	$ 304,989	$ 141,645	$ 2,305,254	$ 2,222,187	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 985	$ 2,117	$ 3,879	$ 2,259	$ 1,587	$ 737	$ 11,995	$ 11,563	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 27,572	$ 59,282	$ 108,618	$ 63,248	$ 44,441	$ 20,639	$ 335,903	$ 323,799	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 971,663	$ 2,089,178	$ 3,827,855	$ 2,228,938	$ 1,566,150	$ 727,359	$ 11,837,701	$ 11,411,143	Sum LN 142 : LN 149
151										
152	Residential	$ 488,075	$ 1,049,413	$ 1,922,765	$ 1,119,615	$ 786,691	$ 365,359	$ 5,946,182	$ 5,731,919	LN 142 + LN 143
153	SALES HLF CLASSES	$ 51,174	$ 110,030	$ 201,600	$ 117,390	$ 82,484	$ 38,308	$ 623,451	$ 600,985	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 432,414	$ 929,736	$ 1,703,489	$ 991,932	$ 696,975	$ 323,693	$ 5,268,068	$ 5,078,239	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER	
157										
158	Res Heat	$ 518,720	$ 1,070,880	$ 1,929,954	$ 1,139,935	$ 812,454	$ 398,010	$ 6,312,461	$ 5,869,953	LN 142 + LN 26
159	Res General	$ 9,399	$ 18,577	$ 32,855	$ 19,724	$ 14,281	$ 7,393	$ 114,248	$ 102,229	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 29,111	$ 53,220	$ 90,730	$ 56,235	$ 41,936	$ 23,840	$ 353,161	$ 295,072	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 228,494	$ 476,482	$ 862,313	$ 507,497	$ 360,417	$ 174,280	$ 2,781,372	$ 2,609,484	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 38,889	$ 72,502	$ 124,800	$ 76,706	$ 56,770	$ 31,540	$ 472,011	$ 401,208	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 205,095	$ 422,718	$ 761,305	$ 449,935	$ 320,864	$ 157,520	$ 2,495,753	$ 2,317,436	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,466	$ 2,598	$ 4,360	$ 2,740	$ 2,068	$ 1,218	$ 17,768	$ 14,449	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 28,925	$ 60,635	$ 109,971	$ 64,601	$ 45,794	$ 21,992	$ 352,139	$ 331,917	LN 149 + LN 33
166	TOTAL	$ 1,060,098	$ 2,177,612	$ 3,916,289	$ 2,317,372	$ 1,654,584	$ 815,794	$ 12,898,912	$ 11,941,749	Sum LN 158 : LN 165
167										
168	Residential	$ 528,119	$ 1,089,457	$ 1,962,809	$ 1,159,659	$ 826,735	$ 405,403	$ 6,426,710	$ 5,972,182	LN 158 + LN 159
169	SALES HLF CLASSES	$ 69,465	$ 128,320	$ 219,891	$ 135,681	$ 100,774	$ 56,598	$ 842,939	$ 710,730	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 462,514	$ 959,835	$ 1,733,589	$ 1,022,032	$ 727,075	$ 353,792	$ 5,629,264	$ 5,258,837	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								11.91%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								88.09%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2012 - 2013 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Normal Winter	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	Winter
1	Res Heat	1,682,465	2,475,904	2,845,549	2,480,965	2,167,331	1,442,636	16,426,972	13,094,849
2	Res General	31,759	46,737	53,714	46,832	40,912	27,232	369,628	247,186
3	**Total Residential**	**1,714,224**	**2,522,640**	**2,899,263**	**2,527,797**	**2,208,243**	**1,469,868**	**16,796,599**	**13,342,035**
4	G50 Low Annual-Low Winter	123,461	181,684	208,809	182,056	159,041	105,862	1,663,807	960,913
5	G40 Low Annual-High Winter	863,142	1,270,194	1,459,831	1,272,791	1,111,890	740,105	7,828,389	6,717,952
6	G51 Med Annual-Low Winter	146,011	214,869	246,948	215,308	188,090	125,198	1,969,961	1,136,425
7	G41 Med Annual-High Winter	592,183	871,453	1,001,558	873,234	762,844	507,770	5,978,565	4,609,043
8	G52 High Annual-Low Winter	12,959	14,762	15,536	13,847	13,705	11,319	120,363	82,128
9	G42 High Annual-High Winter	58,772	86,488	99,400	86,665	75,709	50,394	574,149	457,428
10	**Total C&I**	**1,796,529**	**2,639,451**	**3,032,084**	**2,643,900**	**2,311,278**	**1,540,648**	**18,135,234**	**13,963,889**
11	**Total Sales**	**3,510,752**	**5,162,091**	**5,931,347**	**5,171,697**	**4,519,520**	**3,010,516**	**34,931,833**	**27,305,924**
12									
13	Residential Heat & Non Heat	1,714,224	2,522,640	2,899,263	2,527,797	2,208,243	1,469,868	16,796,599	13,342,035
14	SALES HLF CLASSES	282,431	411,315	471,294	411,211	360,836	242,379	3,754,131	2,179,467
15	SALES LLF CLASSES	1,514,097	2,228,135	2,560,789	2,232,690	1,950,442	1,298,269	14,381,103	11,784,423
16	**Total Firm Sales**	**3,510,752**	**5,162,091**	**5,931,347**	**5,171,697**	**4,519,520**	**3,010,516**	**34,931,833**	**27,305,924**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)								
20	Normal Winter	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**Winter**
21	Res Heat	1,692,896	2,491,254	2,863,191	2,496,347	2,180,768	1,451,580	16,529,408	13,176,037
22	Res General	31,956	47,026	54,047	47,122	41,165	27,401	371,941	248,718
23	G50 Low Annual-Low Winter	124,226	182,811	210,104	183,184	160,027	106,518	1,674,247	966,871
24	G40 Low Annual-High Winter	868,494	1,278,070	1,468,882	1,280,682	1,118,783	744,693	7,877,121	6,759,603
25	G51 Med Annual-Low Winter	146,917	216,201	248,480	216,643	189,256	125,974	1,982,322	1,143,471
26	G41 Med Annual-High Winter	595,855	876,856	1,007,768	878,648	767,573	510,918	6,015,875	4,637,619
27	G52 High Annual-Low Winter	13,039	14,853	15,633	13,932	13,790	11,390	121,116	82,637
28	G42 High Annual-High Winter	59,136	87,024	100,017	87,202	76,178	50,706	577,729	460,264
29	**Subtotal**								
30	Residential	1,724,852	2,538,281	2,917,238	2,543,469	2,221,934	1,478,981	16,901,349	13,424,755
31	SALES HLF CLASSES	284,182	413,865	474,216	413,760	363,073	243,882	3,777,685	2,192,979
32	SALES LLF CLASSES	1,523,485	2,241,950	2,576,666	2,246,532	1,962,535	1,306,318	14,470,725	11,857,486
33	**Total Firm Sales**	3,532,519	5,194,096	5,968,121	5,203,762	4,547,541	3,029,182	35,149,759	27,475,221

Northern Utilities - NEW HAMPSHIRE DIVISION
2012 - 2013 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	15,361
37	Res General	564
38	G50 Low Annual-Low Winter	3,240
39	G40 Low Annual-High Winter	5,119
40	G51 Med Annual-Low Winter	3,843
41	G41 Med Annual-High Winter	6,314
42	G52 High Annual-Low Winter	191
43	G42 High Annual-High Winter	538
44	**Subtotal**	
45	Residential	15,926
46	SALES HLF CLASSES	7,274
47	SALES LLF CLASSES	11,971
48	**Total Firm Sales**	**35,171**

49	**BASE SENDOUT BY CLASS - Therms**								
50	Days per Month	30	31	31	28	31	30		
51		**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**
52	Res Heat	460,839	476,200	476,200	430,116	476,200	460,839	5,599,341	2,780,395
53	Res General	16,934	17,498	17,498	15,805	17,498	16,934	205,753	102,168
54	G50 Low Annual-Low Winter	97,212	100,452	100,452	90,731	100,452	97,212	1,181,152	586,510
55	G40 Low Annual-High Winter	153,575	158,695	158,695	143,337	158,695	153,575	1,865,992	926,572
56	G51 Med Annual-Low Winter	115,280	119,122	119,122	107,594	119,122	115,280	1,400,683	695,520
57	G41 Med Annual-High Winter	189,408	195,721	195,721	176,780	195,721	189,408	2,301,363	1,142,759
58	G52 High Annual-Low Winter	5,739	5,930	5,930	5,356	5,930	5,739	69,735	34,625
59	G42 High Annual-High Winter	16,143	16,681	16,681	15,067	16,681	16,143	196,140	97,395
60	**Subtotal**								
61	Residential	477,773	493,699	493,699	445,921	493,699	477,773	5,805,094	2,882,563
62	SALES HLF CLASSES	218,230	225,504	225,504	203,681	225,504	218,230	2,651,570	1,316,654
63	SALES LLF CLASSES	359,126	371,097	371,097	335,184	371,097	359,126	4,363,494	2,166,725
64	**Total Firm Sales**	1,055,129	1,090,300	1,090,300	984,787	1,090,300	1,055,129	12,820,158	6,365,942

65

66	**REMAINING SENDOUT BY CLASS - Therms**								
67		**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**
68	Res Heat	1,232,057	2,015,054	2,386,991	2,066,230	1,704,568	990,742	10,930,067	10,395,642
69	Res General	15,022	29,528	36,549	31,317	23,667	10,467	166,188	146,550
70	G50 Low Annual-Low Winter	27,015	82,359	109,652	92,454	59,575	9,307	493,095	380,361
71	G40 Low Annual-High Winter	714,918	1,119,375	1,310,187	1,137,345	960,089	591,118	6,011,129	5,833,031
72	G51 Med Annual-Low Winter	31,637	97,079	129,357	109,049	70,134	10,695	581,638	447,951
73	G41 Med Annual-High Winter	406,447	681,135	812,047	701,868	571,852	321,511	3,714,512	3,494,860
74	G52 High Annual-Low Winter	7,301	8,923	9,703	8,576	7,859	5,651	51,381	48,013
75	G42 High Annual-High Winter	42,993	70,343	83,336	72,135	59,497	34,564	381,589	362,869
76	**Subtotal**								
77	Residential	1,247,079	2,044,582	2,423,540	2,097,548	1,728,235	1,001,209	11,096,255	10,542,192
78	SALES HLF CLASSES	65,952	188,361	248,712	210,079	137,568	25,652	1,126,115	876,325
79	SALES LLF CLASSES	1,164,359	1,870,853	2,205,570	1,911,348	1,591,438	947,192	10,107,231	9,690,761
80	**Total Firm Sales**	2,477,390	4,103,796	4,877,822	4,218,975	3,457,242	1,974,053	22,329,601	21,109,278

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

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

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

	Total Division Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	563,246	546,018	17,228	3.2%	6,688	10,540	516,450	46,796	9.1%	14,434	32,362
Dec	808,129	779,702	28,427	3.6%	9,518	18,908	759,990	48,139	6.3%	21,085	27,054
Jan	992,955	989,691	3,264	0.3%	12,049	-8,785	1,065,429	-72,474	-6.8%	30,053	-102,528
Feb	1,030,069	1,011,643	18,426	1.8%	12,305	6,121	1,035,123	-5,054	-0.5%	28,686	-33,740
Mar	917,243	902,981	14,262	1.6%	10,981	3,281	936,166	-18,923	-2.0%	24,490	-43,414
Apr	708,200	697,251	10,949	1.6%	8,463	2,486	689,189	19,011	2.8%	17,377	1,634
May	484,431	475,441	8,990	1.9%	5,783	3,207	455,158	29,273	6.4%	11,161	18,113
Jun	354,205	347,817	6,388	1.8%	4,248	2,140	340,672	13,533	4.0%	8,399	5,134
Jul	286,323	281,316	5,007	1.8%	3,451	1,556	277,859	8,465	3.0%	6,901	1,564
Aug	297,936	292,438	5,498	1.9%	3,595	1,903	277,161	20,775	7.5%	6,899	13,876
Sep	314,137	307,848	6,289	2.0%	3,773	2,516	305,657	8,480	2.8%	7,585	895
Oct	424,265	415,494	8,770	2.1%	5,060	3,711	399,490	24,775	6.2%	9,836	14,940
Peak	5,019,842	4,927,286	92,556	1.9%	60,024	32,532	5,002,348	17,494	0.3%	135,868	-118,374
Off-Peak	2,161,298	2,120,355	40,943	1.9%	25,928	15,015	2,055,996	105,302	5.1%	50,830	54,472
Annual	7,181,139	7,047,641	133,498	1.9%	86,016	47,482	7,058,343	122,796	1.7%	183,112	-60,316

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	29,097	28,745	352	1.2%	28,306	791	2.8%
Dec	29,195	28,843	352	1.2%	28,407	788	2.8%
Jan	29,274	28,922	352	1.2%	28,471	803	2.8%
Feb	29,301	28,949	352	1.2%	28,511	790	2.8%
Mar	29,306	28,954	352	1.2%	28,559	747	2.6%
Apr	29,362	29,010	352	1.2%	28,640	722	2.5%
May	29,298	28,946	352	1.2%	28,597	701	2.5%
Jun	29,184	28,832	352	1.2%	28,482	702	2.5%
Jul	29,058	28,706	352	1.2%	28,354	704	2.5%
Aug	28,995	28,643	352	1.2%	28,291	704	2.5%
Sep	29,081	28,729	352	1.2%	28,377	704	2.5%
Oct	29,265	28,913	352	1.2%	28,562	703	2.5%
Peak	29,256	28,904	352	1.2%	28,482	774	2.7%
Off-Peak	29,147	28,795	352	1.2%	28,444	703	2.5%
Annual	29,201	28,849	352	1.2%	28,463	738	2.6%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	19.36	19.00	0.36	1.9%	18.25	1.11	6.1%
Dec	27.68	27.03	0.65	2.4%	26.75	0.93	3.5%
Jan	33.92	34.22	-0.30	-0.9%	37.42	-3.50	-9.4%
Feb	35.15	34.95	0.21	0.6%	36.31	-1.15	-3.2%
Mar	31.30	31.19	0.11	0.4%	32.78	-1.48	-4.5%
Apr	24.12	24.03	0.08	0.4%	24.06	0.06	0.2%
May	16.53	16.43	0.11	0.7%	15.92	0.62	3.9%
Jun	12.14	12.06	0.07	0.6%	11.96	0.18	1.5%
Jul	9.85	9.80	0.05	0.5%	9.80	0.05	0.5%
Aug	10.28	10.21	0.07	0.6%	9.80	0.48	4.9%
Sep	10.80	10.72	0.09	0.8%	10.77	0.03	0.3%
Oct	14.50	14.37	0.13	0.9%	13.99	0.51	3.6%
Peak	171.58	170.47	1.11	0.7%	175.63	-4.04	-2.3%
Off-Peak	74.15	73.64	0.52	0.7%	72.28	1.87	2.6%
Annual	245.92	244.29	1.63	0.7%	247.98	-2.17	-0.9%

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

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

	Residential Non-Heat Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	2,845	2,892	-46	-1.6%	-58	11	2,604	241	9.3%	-104	345
Dec	3,718	3,747	-29	-0.8%	-76	46	3,635	82	2.3%	-149	231
Jan	4,944	5,145	-201	-3.9%	-104	-97	4,976	-32	-0.6%	-201	169
Feb	5,097	5,204	-107	-2.1%	-106	-1	5,131	-34	-0.7%	-220	186
Mar	4,562	4,676	-114	-2.4%	-95	-19	4,482	80	1.8%	-190	270
Apr	3,552	3,639	-87	-2.4%	-73	-14	3,792	-239	-6.3%	-193	-47
May	2,680	2,732	-53	-1.9%	-53	1	2,690	-10	-0.4%	-103	93
Jun	2,150	2,192	-42	-1.9%	-43	0	2,265	-115	-5.1%	-86	-29
Jul	1,954	1,993	-39	-2.0%	-39	0	2,121	-167	-7.9%	-81	-86
Aug	1,704	1,738	-34	-2.0%	-34	0	1,684	20	1.2%	-64	85
Sep	1,742	1,777	-35	-2.0%	-35	0	1,901	-159	-8.4%	-74	-85
Oct	2,014	2,055	-41	-2.0%	-41	0	2,059	-45	-2.2%	-81	37
Peak	24,719	25,303	-584	-2.3%	-511	-73	24,621	98	0.4%	-1,057	1,154
Off-Peak	12,244	12,488	-244	-2.0%	-245	1	12,720	-476	-3.7%	-490	14
Annual	36,963	37,791	-828	-2.2%	-752	-75	37,341	-378	-1.0%	-1,520	1,142

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1,558	1,590	-32	-2.0%	1,623	-65	-4.0%
Dec	1,540	1,572	-32	-2.0%	1,606	-66	-4.1%
Jan	1,535	1,567	-32	-2.0%	1,600	-65	-4.0%
Feb	1,531	1,563	-32	-2.0%	1,600	-69	-4.3%
Mar	1,530	1,562	-32	-2.0%	1,598	-68	-4.2%
Apr	1,545	1,577	-32	-2.0%	1,628	-83	-5.1%
May	1,593	1,624	-32	-2.0%	1,656	-63	-3.8%
Jun	1,600	1,631	-32	-1.9%	1,663	-63	-3.8%
Jul	1,597	1,628	-32	-1.9%	1,660	-63	-3.8%
Aug	1,593	1,624	-32	-2.0%	1,656	-63	-3.8%
Sep	1,576	1,607	-32	-2.0%	1,639	-63	-3.9%
Oct	1,541	1,572	-32	-2.0%	1,604	-63	-4.0%
Peak	1,540	1,572	-32	-2.0%	1,609	-69	-4.3%
Off-Peak	1,583	1,615	-32	-2.0%	1,646	-63	-3.9%
Annual	1,562	1,593	-32	-2.0%	1,628	-66	-4.1%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1.83	1.82	0.01	0.4%	1.60	0.22	13.8%
Dec	2.41	2.38	0.03	1.3%	2.26	0.15	6.6%
Jan	3.22	3.28	-0.06	-1.9%	3.11	0.11	3.5%
Feb	3.33	3.33	0.00	0.0%	3.21	0.12	3.8%
Mar	2.98	2.99	-0.01	-0.4%	2.80	0.18	6.3%
Apr	2.30	2.31	-0.01	-0.4%	2.33	-0.03	-1.3%
May	1.68	1.68	0.00	0.0%	1.62	0.06	3.6%
Jun	1.34	1.34	0.00	0.0%	1.36	-0.02	-1.3%
Jul	1.22	1.22	0.00	0.0%	1.28	-0.05	-4.2%
Aug	1.07	1.07	0.00	0.0%	1.02	0.05	5.2%
Sep	1.11	1.11	0.00	0.0%	1.16	-0.05	-4.7%
Oct	1.31	1.31	0.00	0.0%	1.28	0.02	1.9%
Peak	16.05	16.10	-0.05	-0.3%	15.30	0.75	4.9%
Off-Peak	7.74	7.73	0.00	0.0%	7.73	0.01	0.1%
Annual	23.67	23.72	-0.05	-0.2%	22.94	0.76	3.3%

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

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

	Residential Heat Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	116,566	114,375	2,192	1.9%	1,804	388	102,734	13,832	13.5%	3,347	10,486
Dec	195,020	189,703	5,318	2.8%	2,980	2,338	183,054	11,966	6.5%	6,021	5,946
Jan	270,035	271,176	-1,141	-0.4%	4,247	-5,388	284,107	-14,072	-5.0%	9,559	-23,631
Feb	293,355	288,932	4,423	1.5%	4,520	-97	298,913	-5,558	-1.9%	9,985	-15,544
Mar	252,876	249,927	2,950	1.2%	3,905	-956	252,799	77	0.0%	8,333	-8,256
Apr	181,632	179,474	2,158	1.2%	2,798	-640	181,520	112	0.1%	5,798	-5,686
May	104,940	103,238	1,701	1.6%	1,613	88	98,069	6,871	7.0%	3,113	3,757
Jun	58,957	58,059	898	1.5%	911	-13	57,942	1,015	1.8%	1,848	-832
Jul	37,651	36,963	688	1.9%	583	105	37,861	-210	-0.6%	1,213	-1,423
Aug	32,980	32,476	505	1.6%	513	-8	30,381	2,600	8.6%	975	1,624
Sep	33,234	32,726	508	1.6%	515	-7	33,803	-569	-1.7%	1,082	-1,650
Oct	65,449	64,450	999	1.5%	1,007	-8	62,321	3,129	5.0%	1,979	1,150
Peak	1,309,485	1,293,586	15,899	1.2%	20,267	-4,368	1,303,127	6,358	0.5%	42,877	-36,520
Off-Peak	333,212	327,913	5,299	1.6%	5,152	147	320,377	12,835	4.0%	10,227	2,608
Annual	1,642,697	1,621,499	21,198	1.3%	25,439	-4,241	1,623,504	19,193	1.2%	52,623	-33,430

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	21,101	20,773	328	1.6%	20,435	666	3.3%
Dec	21,187	20,859	328	1.6%	20,512	675	3.3%
Jan	21,250	20,922	328	1.6%	20,558	692	3.4%
Feb	21,273	20,945	328	1.6%	20,585	688	3.3%
Mar	21,298	20,970	328	1.6%	20,618	680	3.3%
Apr	21,343	21,015	328	1.6%	20,682	661	3.2%
May	21,297	20,970	328	1.6%	20,642	655	3.2%
Jun	21,207	20,880	328	1.6%	20,552	655	3.2%
Jul	21,103	20,776	328	1.6%	20,448	655	3.2%
Aug	21,068	20,741	328	1.6%	20,413	655	3.2%
Sep	21,133	20,806	328	1.6%	20,478	655	3.2%
Oct	21,292	20,965	328	1.6%	20,637	655	3.2%
Peak	21,242	20,914	328	1.6%	20,565	677	3.3%
Off-Peak	21,184	20,856	328	1.6%	20,528	655	3.2%
Annual	21,213	20,885	328	1.6%	20,547	666	3.2%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	5.52	5.51	0.02	0.3%	5.03	0.50	9.9%
Dec	9.20	9.09	0.11	1.2%	8.92	0.28	3.1%
Jan	12.71	12.96	-0.25	-2.0%	13.82	-1.11	-8.0%
Feb	13.79	13.79	0.00	0.0%	14.52	-0.73	-5.0%
Mar	11.87	11.92	-0.04	-0.4%	12.26	-0.39	-3.2%
Apr	8.51	8.54	-0.03	-0.4%	8.78	-0.27	-3.0%
May	4.93	4.92	0.00	0.1%	4.75	0.18	3.7%
Jun	2.78	2.78	0.00	0.0%	2.82	-0.04	-1.4%
Jul	1.78	1.78	0.00	0.3%	1.85	-0.07	-3.6%
Aug	1.57	1.57	0.00	0.0%	1.49	0.08	5.2%
Sep	1.57	1.57	0.00	0.0%	1.65	-0.08	-4.7%
Oct	3.07	3.07	0.00	0.0%	3.02	0.05	1.8%
Peak	61.65	61.85	-0.21	-0.3%	63.37	-1.72	-2.7%
Off-Peak	15.73	15.72	0.01	0.0%	15.61	0.12	0.8%
Annual	77.44	77.64	-0.20	-0.3%	79.02	-1.60	-2.0%

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

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

	Total Division C&I Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	443,834	428,751	15,082	3.5%	3,773	11,309	411,111	32,723	8.0%	12,513	20,210
Dec	609,391	586,253	23,138	3.9%	5,135	18,003	573,301	36,090	6.3%	16,333	19,758
Jan	717,977	713,371	4,606	0.6%	6,229	-1,622	776,346	-58,369	-7.5%	21,664	-80,034
Feb	731,617	717,507	14,110	2.0%	6,257	7,853	731,078	538	0.1%	19,781	-19,243
Mar	659,804	648,378	11,426	1.8%	5,671	5,756	678,885	-19,081	-2.8%	14,467	-33,548
Apr	523,016	514,138	8,878	1.7%	4,500	4,378	503,878	19,138	3.8%	11,476	7,662
May	376,812	369,470	7,341	2.0%	3,267	4,074	354,399	22,413	6.3%	6,152	16,261
Jun	293,098	287,566	5,532	1.9%	2,555	2,977	280,465	12,634	4.5%	4,938	7,696
Jul	246,718	242,360	4,358	1.8%	2,160	2,198	237,876	8,842	3.7%	4,278	4,563
Aug	263,252	258,225	5,027	1.9%	2,310	2,717	245,096	18,156	7.4%	4,425	13,731
Sep	279,160	273,344	5,816	2.1%	2,431	3,386	269,953	9,207	3.4%	4,844	4,363
Oct	356,801	348,989	7,813	2.2%	3,074	4,738	335,110	21,692	6.5%	5,902	15,789
Peak	3,685,638	3,608,397	77,241	2.1%	31,579	45,661	3,674,600	11,039	0.3%	96,698	-85,660
Off-Peak	1,815,841	1,779,953	35,888	2.0%	15,808	20,079	1,722,898	92,943	5.4%	30,597	62,345
Annual	5,501,479	5,388,351	113,128	2.1%	47,503	65,625	5,397,498	103,981	1.9%	119,018	-15,036

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	6,438	6,382	56	0.9%	6,248	190	3.0%
Dec	6,468	6,412	56	0.9%	6,289	179	2.8%
Jan	6,489	6,433	56	0.9%	6,313	176	2.8%
Feb	6,497	6,441	56	0.9%	6,326	171	2.7%
Mar	6,478	6,422	56	0.9%	6,343	135	2.1%
Apr	6,474	6,418	56	0.9%	6,330	144	2.3%
May	6,408	6,352	56	0.9%	6,299	109	1.7%
Jun	6,377	6,321	56	0.9%	6,267	110	1.8%
Jul	6,358	6,302	56	0.9%	6,246	112	1.8%
Aug	6,334	6,278	56	0.9%	6,222	112	1.8%
Sep	6,372	6,316	56	0.9%	6,260	112	1.8%
Oct	6,432	6,376	56	0.9%	6,321	111	1.8%
Peak	6,474	6,418	56	0.9%	6,308	166	2.6%
Off-Peak	6,381	6,324	56	0.9%	6,269	111	1.8%
Annual	6,427	6,371	56	0.9%	6,289	139	2.2%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	68.94	67.18	1.76	2.6%	65.80	3.14	4.8%
Dec	94.21	91.43	2.78	3.0%	91.16	3.05	3.4%
Jan	110.64	110.89	-0.25	-0.2%	122.98	-12.33	-10.0%
Feb	112.61	111.40	1.21	1.1%	115.57	-2.96	-2.6%
Mar	101.85	100.96	0.89	0.9%	107.03	-5.18	-4.8%
Apr	80.78	80.11	0.68	0.8%	79.60	1.18	1.5%
May	58.80	58.16	0.64	1.1%	56.26	2.54	4.5%
Jun	45.96	45.49	0.47	1.0%	44.75	1.21	2.7%
Jul	38.80	38.46	0.35	0.9%	38.08	0.72	1.9%
Aug	41.56	41.13	0.43	1.0%	39.39	2.17	5.5%
Sep	43.81	43.28	0.53	1.2%	43.12	0.68	1.6%
Oct	55.47	54.73	0.74	1.3%	53.02	2.45	4.6%
Peak	569.28	562.23	7.05	1.3%	582.51	-13.10	-2.2%
Off-Peak	284.59	281.45	3.15	1.1%	274.82	9.77	3.6%
Annual	855.95	845.74	10.21	1.2%	858.29	-3.33	-0.4%

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

1 Northern Utilities, Inc.
2 New Hampshire Division
3 Sales Service Deliveries Forecast by Rate Class
4

5 Forecast Calendar Sales Service Usage (Dth)
6 (Forecast Billed Distribution Usage times Sales Service Percentage)

Line		Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
7											
8	Nov-12	3,176	168,246	86,314	12,346	59,218	14,601	5,877	1,296	0	351,075
9	Dec-12	4,674	247,590	127,019	18,168	87,145	21,487	8,649	1,476	0	516,209
10	Jan-13	5,371	284,555	145,983	20,881	100,156	24,695	9,940	1,554	0	593,135
11	Feb-13	4,683	248,096	127,279	18,206	87,323	21,531	8,666	1,385	0	517,170
12	Mar-13	4,091	216,733	111,189	15,904	76,284	18,809	7,571	1,370	0	451,952
13	Apr-13	2,723	144,264	74,010	10,586	50,777	12,520	5,039	1,132	0	301,052
14	May-13	2,241	60,983	20,323	12,864	25,064	15,255	2,136	686	0	139,553
15	Jun-13	1,781	48,464	16,151	10,223	19,919	12,123	1,698	605	0	110,963
16	Jul-13	1,711	46,569	15,519	9,823	19,140	11,649	1,631	580	0	106,624
17	Aug-13	1,766	48,066	16,018	10,139	19,755	12,024	1,684	598	0	110,050
18	Sep-13	1,910	51,978	17,322	10,965	21,363	13,002	1,821	623	0	118,984
19	Oct-13	2,835	77,152	25,711	16,275	31,710	19,300	2,703	732	0	176,418
20	Peak	24,719	1,309,485	671,795	96,091	460,904	113,643	45,743	8,213	0	2,730,592
21	Off-Peak	12,244	333,212	111,044	70,289	136,952	83,354	11,672	3,824	0	762,591
22	Total	36,963	1,642,697	782,839	166,381	597,857	196,996	57,415	12,036	0	3,493,183

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24 Forecast Calendar Distribution Service Usage (Dth)
25

Line		Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
26											
27	Nov-12	3,176	168,246	101,715	17,322	120,576	30,936	40,757	118,718	80,983	682,429
28	Dec-12	4,674	247,590	149,682	25,491	177,440	45,525	59,977	135,232	85,400	931,012
29	Jan-13	5,371	284,555	172,030	29,297	203,931	52,322	68,932	142,329	86,822	1,045,588
30	Feb-13	4,683	248,096	149,988	25,543	177,802	45,618	60,100	126,848	79,582	918,262
31	Mar-13	4,091	216,733	131,027	22,314	155,325	39,852	52,502	125,548	90,310	837,703
32	Apr-13	2,723	144,264	87,216	14,853	103,389	26,526	34,947	103,697	87,234	604,848
33	May-13	2,241	60,983	26,458	16,003	47,343	29,742	26,500	99,292	83,494	392,057
34	Jun-13	1,781	48,464	21,027	12,718	37,624	23,637	21,060	87,505	75,026	328,841
35	Jul-13	1,711	46,569	20,204	12,221	36,153	22,712	20,237	84,020	69,965	313,791
36	Aug-13	1,766	48,066	20,854	12,613	37,315	23,442	20,887	86,558	79,093	330,594
37	Sep-13	1,910	51,978	22,551	13,640	40,352	25,351	22,587	90,128	77,852	346,350
38	Oct-13	2,835	77,152	33,473	20,246	59,896	37,628	33,527	105,920	78,987	449,665
39	Peak	24,719	1,309,485	791,658	134,821	938,463	240,780	317,214	752,373	510,330	5,019,842
40	Off-Peak	12,244	333,212	144,568	87,441	258,682	162,513	144,798	553,422	464,417	2,161,298
41	Total	36,963	1,642,697	936,226	222,262	1,197,145	403,292	462,012	1,305,795	974,747	7,181,139

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43 Forecast Sales Service Percentage
43

Line		Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
44											
44	Nov-12	100%	100%	85%	71%	49%	47%	14%	1%	0%	51%
45	Dec-12	100%	100%	85%	71%	49%	47%	14%	1%	0%	55%
45	Jan-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	57%
46	Feb-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	56%
46	Mar-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	54%
47	Apr-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	50%
47	May-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	36%
48	Jun-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	34%
48	Jul-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	34%
49	Aug-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	33%
49	Sep-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	34%
50	Oct-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	39%
51	Peak	100%	100%	85%	71%	49%	47%	14%	1%	0%	54%
52	Off-Peak	100%	100%	77%	80%	53%	51%	8%	1%	0%	35%
53	Total	100%	100%	84%	75%	50%	49%	12%	1%	0%	49%

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

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

Month	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-12	2,845	116,566	53,363	12,415	43,692	14,958	6,226	1,296	0	251,361
Dec-12	3,718	195,020	100,142	14,717	71,541	18,927	9,277	1,476	0	414,818
Jan-13	4,944	270,035	142,479	18,385	93,201	20,664	8,880	1,554	0	560,141
Feb-13	5,097	293,355	156,882	18,834	102,007	21,487	8,748	1,385	0	607,795
Mar-13	4,562	252,876	129,272	17,132	86,249	19,869	7,190	1,370	0	518,521
Apr-13	3,552	181,632	89,658	14,608	64,215	17,738	5,422	1,132	0	377,957
May-13	2,680	104,940	37,240	13,137	40,676	15,691	1,756	686	0	216,804
Jun-13	2,150	58,957	17,249	11,906	24,910	14,225	1,492	605	0	131,494
Jul-13	1,954	37,651	10,073	11,087	14,382	13,019	1,070	580	0	89,817
Aug-13	1,704	32,980	9,341	11,510	12,717	13,184	1,725	598	0	83,759
Sep-13	1,742	33,234	10,446	11,391	14,814	12,864	2,446	623	0	87,562
Oct-13	2,014	65,449	26,694	11,258	29,454	14,370	3,183	732	0	153,155
Peak	24,719	1,309,485	671,795	96,091	460,904	113,643	45,743	8,213	0	2,730,592
Off-Peak	12,244	333,212	111,044	70,289	136,952	83,354	11,672	3,824	0	762,591
Total	36,963	1,642,697	782,839	166,381	597,857	196,996	57,415	12,036	0	3,493,183

Forecast Billed Distribution Service Usage (Dth)

Month	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-12	2,845	116,566	62,884	17,419	88,962	31,692	43,176	118,718	80,983	563,246
Dec-12	3,718	195,020	118,009	20,649	145,668	40,101	64,332	135,232	85,400	808,129
Jan-13	4,944	270,035	167,901	25,795	189,769	43,781	61,580	142,329	86,822	992,955
Feb-13	5,097	293,355	184,873	26,425	207,700	45,526	60,662	126,848	79,582	1,030,069
Mar-13	4,562	252,876	152,337	24,037	175,614	42,098	49,861	125,548	90,310	917,243
Apr-13	3,552	181,632	105,654	20,496	130,750	37,582	37,603	103,697	87,234	708,200
May-13	2,680	104,940	48,483	16,342	76,830	30,592	21,778	99,292	83,494	484,431
Jun-13	2,150	58,957	22,456	14,811	47,051	27,734	18,514	87,505	75,026	354,205
Jul-13	1,954	37,651	13,114	13,793	27,165	25,383	13,278	84,020	69,965	286,323
Aug-13	1,704	32,980	12,161	14,319	24,020	25,704	21,397	86,558	79,093	297,936
Sep-13	1,742	33,234	13,600	14,171	27,982	25,081	30,347	90,128	77,852	314,137
Oct-13	2,014	65,449	34,753	14,006	55,634	28,018	39,484	105,920	78,987	424,265
Peak	24,719	1,309,485	791,658	134,821	938,463	240,780	317,214	752,373	510,330	5,019,842
Off-Peak	12,244	333,212	144,568	87,441	258,682	162,513	144,798	553,422	464,417	2,161,298
Total	36,963	1,642,697	936,226	222,262	1,197,145	403,292	462,012	1,305,795	974,747	7,181,139

Forecast Sales Service Percentage

Month	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-12	100%	100%	85%	71%	49%	47%	14%	1%	0%	45%
Dec-12	100%	100%	85%	71%	49%	47%	14%	1%	0%	51%
Jan-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	56%
Feb-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	59%
Mar-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	57%
Apr-13	100%	100%	85%	71%	49%	47%	14%	1%	0%	53%
May-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	45%
Jun-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	37%
Jul-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	31%
Aug-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	28%
Sep-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	28%
Oct-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	36%
Peak	100%	100%	85%	71%	49%	47%	14%	1%	0%	54%
Off-Peak	100%	100%	77%	80%	53%	51%	8%	1%	0%	35%
Total	100%	100%	84%	75%	50%	49%	12%	1%	0%	49%

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

Month	Calendar Month Distribution Service Usage (Dth)	Estimated Company Use Factor	Estimated Company Use (Dth)	Billed Sales Service Deliveries (Dth)	Unbilled Sales Service Deliveries (Dth)	Calendar Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Lost and Unaccounted For (Percent)	Lost and Unaccounted For (Dth)	Estimated Division City-Gate Receipts (Dth)
Nov-12	682,429	0.02%	136	251,361	99,714	351,075	351,212	0.58%	2,049	353,261
Dec-12	931,012	0.02%	186	414,818	101,391	516,209	516,395	0.58%	3,013	519,408
Jan-13	1,045,588	0.02%	209	560,141	32,994	593,135	593,344	0.58%	3,461	596,805
Feb-13	918,262	0.02%	184	607,795	-90,625	517,170	517,353	0.58%	3,019	520,372
Mar-13	837,703	0.02%	168	518,521	-66,569	451,952	452,120	0.58%	2,637	454,757
Apr-13	604,848	0.02%	121	377,957	-76,905	301,052	301,173	0.58%	1,757	302,930
May-13	392,057	0.02%	78	216,804	-77,252	139,553	139,631	0.58%	815	140,446
Jun-13	328,841	0.02%	66	131,494	-20,531	110,963	111,029	0.58%	648	111,677
Jul-13	313,791	0.02%	63	89,817	16,806	106,624	106,686	0.58%	623	107,309
Aug-13	330,594	0.02%	66	83,759	26,291	110,050	110,116	0.58%	642	110,758
Sep-13	346,350	0.02%	69	87,562	31,423	118,984	119,053	0.58%	695	119,748
Oct-13	449,665	0.02%	90	153,155	23,263	176,418	176,508	0.58%	1,030	177,538
Peak	5,019,842	0.02%	1,004	2,730,592	0	2,730,592	2,731,596	0.58%	15,937	2,747,533
Off-Peak	2,161,298	0.02%	432	762,591	0	762,591	763,023	0.58%	4,453	767,476

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09
BTU Factor	1.043	1.046	1.033	1.031	1.037	1.035	1.058	1.043	1.046	1.029	1.05	1.042
GSG Meter Throughput (Mcf)	644,728	858,124	1,034,316	809,663	772,880	513,047	318,202	259,715	275,694	259,076	278,578	460,252
Salem Meter (Mcf)	36,383	55,135	71,820	50,982	42,498	23,072	13,740	10,711	11,098	10,145	11,353	21,545
Total Throughput IN (MCF)	681,112	913,260	1,106,137	860,646	815,379	536,120	331,943	270,427	286,793	269,222	289,932	481,798
GSG Meter Throughput (Dth)	672,451	897,598	1,068,448	834,763	801,477	531,004	336,658	270,883	288,376	266,589	292,507	479,583
Salem Meter (Dth)	37,947	57,671	74,190	52,562	44,070	23,880	14,537	11,172	11,609	10,439	11,921	22,450
Total Throughput IN (Dth)	710,399	955,269	1,142,638	887,325	845,547	554,883	351,195	282,054	299,984	277,028	304,428	502,032
Total Billed Units (MCF)	607,417	792,882	1,019,378	978,097	862,818	665,375	370,831	318,441	289,742	260,613	274,874	373,258
Company Use (MCF)	96	194	332	212	316	184	83	45	4	1	6	20
Current Month Unbilled Units (MCF)	252,349	269,633	407,062	308,944	266,368	140,325	93,046	83,561	78,024	65,978	134,517	197,180
Prior Month Unbilled Units (MCF)	-173,009	-252,349	-269,633	-407,062	-308,944	-266,368	-140,325	-93,046	-83,561	-78,024	-65,978	-134,517
Total Throughput OUT (MCF)	686,853	810,360	1,157,139	880,191	820,558	539,516	323,635	309,001	284,209	248,568	343,419	435,941
Total Billed Units (Dth)	633,536	829,354	1,053,018	1,008,419	894,743	688,664	392,339	332,134	303,069	268,171	288,617	388,935
Company Use (Dth)	100	203	343	219	328	190	88	47	5	1	7	21
Current Month Unbilled Units (Dth)	263,200	282,037	420,494	318,521	276,225	145,236	98,443	87,154	81,615	67,892	141,243	205,461
Prior Month Unbilled Units (Dth)	-182,179	-263,200	-282,037	-420,494	-318,521	-276,225	-145,236	-98,443	-87,154	-81,615	-67,892	-141,243
Total Throughput OUT (Dth)	714,657	848,394	1,191,818	906,665	852,774	557,866	345,633	320,892	297,534	254,449	361,975	453,174
Total Throughput IN (Dth)	710,399	955,269	1,142,638	887,325	845,547	554,883	351,195	282,054	299,984	277,028	304,428	502,032
Total Throughput OUT (Dth)	714,657	848,394	1,191,818	906,665	852,774	557,866	345,633	320,892	297,534	254,449	361,975	453,174
LAUF	-4,258	106,875	-49,180	-19,340	-7,227	-2,983	5,561	-38,838	2,450	22,579	-57,547	48,859
Company Use (Dth)	100	203	343	219	328	190	88	47	5	1	7	21
Company Gas Allowance	-4,158	107,078	-48,837	-19,121	-6,899	-2,793	5,649	-38,791	2,455	22,580	-57,541	48,879
LAUF %	-0.60%	11.19%	-4.30%	-2.18%	-0.85%	-0.54%	1.58%	-13.77%	0.82%	8.15%	-18.90%	9.73%
Company Use %	0.01%	0.02%	0.03%	0.02%	0.04%	0.03%	0.03%	0.02%	0.00%	0.00%	0.00%	0.00%
Company Gas Allowance %	-0.59%	11.21%	-4.27%	-2.15%	-0.82%	-0.50%	1.61%	-13.75%	0.82%	8.15%	-18.90%	9.74%

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
BTU Factor	1.037	1.041	1.042	1.044	1.039	1.03975	1.038	1.039	1.033	1.036	1.039	1.041
GSG Meter Throughput (Mcf)	528,094	880,611	977,063	812,599	665,946	416,782	312,869	265,598	249,025	269,606	273,645	427,825
Salem Meter (Mcf)	27,009	56,707	61,967	49,058	34,966	18,950	12,766	9,904	9,385	9,959	10,496	18,586
Total Throughput IN (MCF)	555,104	937,319	1,039,031	861,658	700,913	435,733	325,636	275,503	258,411	279,566	284,142	446,412
GSG Meter Throughput (Dth)	547,633	916,716	1,018,100	848,353	691,918	433,349	324,758	275,956	257,243	279,312	284,317	445,366
Salem Meter (Dth)	28,008	59,032	64,570	51,217	36,330	19,703	13,251	10,290	9,695	10,318	10,905	19,348
Total Throughput IN (Dth)	575,642	975,748	1,082,669	899,570	728,248	453,052	338,009	286,247	266,938	289,629	295,222	464,714
Total Billed Units (MCF)	504,178	700,447	1,065,387	908,747	764,228	568,184	385,888	293,685	263,021	273,467	283,785	341,331
Company Use (MCF)	36	78	131	113	73	47	24	6	2	2	5	16
Current Month Unbilled Units (MCF)	254,910	458,003	432,475	399,750	322,410	222,973	108,958	93,201	89,302	109,507	131,638	205,743
Prior Month Unbilled Units (MCF)	-197,180	-254,910	-458,003	-432,475	-399,750	-322,410	-222,973	-108,958	-93,201	-89,302	-109,507	-131,638
Total Throughput OUT (MCF)	561,944	903,618	1,039,990	876,135	686,961	468,794	271,897	277,934	259,124	293,674	305,921	415,452
Total Billed Units (Dth)	522,832	729,165	1,110,134	948,733	794,033	590,769	400,552	305,139	271,701	283,312	294,853	355,325
Company Use (Dth)	38	81	137	118	76	49	25	7	2	2	6	17
Current Month Unbilled Units (Dth)	264,341	476,781	450,639	417,339	334,984	231,836	113,098	96,836	92,248	113,449	136,772	214,178
Prior Month Unbilled Units (Dth)	-205,461	-264,341	-476,781	-450,639	-417,339	-334,984	-231,836	-113,098	-96,836	-92,248	-113,449	-136,772
Total Throughput OUT (Dth)	581,750	941,685	1,084,129	915,550	711,754	487,670	281,839	288,884	267,115	304,514	318,182	432,747
Total Throughput IN (Dth)	575,642	975,748	1,082,669	899,570	728,248	453,052	338,009	286,247	266,938	289,629	295,222	464,714
Total Throughput OUT (Dth)	581,750	941,685	1,084,129	915,550	711,754	487,670	281,839	288,884	267,115	304,514	318,182	432,747
LAUF	-6,108	34,063	-1,460	-15,980	16,494	-34,617	56,170	-2,637	-178	-14,885	-22,959	31,966
Company Use (Dth)	38	81	137	118	76	49	25	7	2	2	6	17
Company Gas Allowance	-6,070	34,143	-1,323	-15,863	16,570	-34,568	56,195	-2,631	-176	-14,883	-22,954	31,983
LAUF %	-1.06%	3.49%	-0.13%	-1.78%	2.26%	-7.64%	16.62%	-0.92%	-0.07%	-5.14%	-7.78%	6.88%
Company Use %	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
Company Gas Allowance %	-1.05%	3.50%	-0.12%	-1.76%	2.28%	-7.63%	16.63%	-0.92%	-0.07%	-5.14%	-7.78%	6.88%

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
BTU Factor	1.039	1.039	1.046	1.049	1.048	1.041	1.027	1.043	1.039	1.038	1.041	1.042
GSG Meter Throughput (Mcf)	569,708	849,169	1,045,428	914,419	780,093	493,361	356,512	270,436	244,612	266,618	284,943	411,448
Salem Meter (Mcf)	31,154	57,324	67,178	57,567	45,512	25,940	16,128	11,573	9,849	10,962	11,554	20,294
Total Throughput IN (MCF)	600,863	906,494	1,112,607	971,987	825,606	519,302	372,641	282,010	254,462	277,581	296,498	431,743
GSG Meter Throughput (Dth)	591,927	882,287	1,093,518	959,226	817,537	513,589	366,138	282,065	254,152	276,749	296,626	428,729
Salem Meter (Dth)	32,369	59,560	70,268	60,388	47,697	27,004	16,563	12,071	10,233	11,379	12,028	21,146
Total Throughput IN (Dth)	624,296	941,846	1,163,786	1,019,613	865,234	540,592	382,701	294,135	264,385	288,128	308,653	449,875
Total Billed Units (MCF)	501,994	754,087	1,025,592	1,045,825	886,534	679,479	438,668	326,626	267,428	267,015	293,619	328,407
Company Use (MCF)	36	82	139	135	99	73	30	28	21	20	27	98
Current Month Unbilled Units (MCF)	284,516	489,204	531,639	405,881	527,570	309,655	215,425	181,909	126,082	159,356	163,781	276,999
Prior Month Unbilled Units (MCF)	-205,743	-284,516	-489,204	-531,639	-405,881	-527,570	-309,655	-215,425	-181,909	-126,082	-159,356	-163,781
Total Throughput OUT (MCF)	580,803	958,857	1,068,166	920,202	1,008,322	461,637	344,468	293,138	211,622	300,309	298,071	441,723
Total Billed Units (Dth)	521,571	783,495	1,072,769	1,097,070	929,087	707,337	450,512	340,671	277,859	277,161	305,657	342,200
Company Use (Dth)	37	85	145	141	104	76	31	29	22	21	28	102
Current Month Unbilled Units (Dth)	295,613	508,283	556,095	425,769	552,893	322,351	221,241	189,731	130,999	165,412	170,496	288,633
Prior Month Unbilled Units (Dth)	-214,178	-295,613	-508,283	-556,095	-425,769	-552,893	-322,351	-221,241	-189,731	-130,999	-165,412	-170,496
Total Throughput OUT (Dth)	603,043	996,250	1,120,725	966,885	1,056,314	476,871	349,433	309,190	219,149	311,595	310,769	460,439
Total Throughput IN (Dth)	624,296	941,846	1,163,786	1,019,613	865,234	540,592	382,701	294,135	264,385	288,128	308,653	449,875
Total Throughput OUT (Dth)	603,043	996,250	1,120,725	966,885	1,056,314	476,871	349,433	309,190	219,149	311,595	310,769	460,439
LAUF	21,252	-54,404	43,060	52,728	-191,080	63,721	33,268	-15,055	45,236	-23,467	-2,116	-10,563
Company Use (Dth)	37	85	145	141	104	76	31	29	22	21	28	102
Company Gas Allowance	21,289	-54,319	43,205	52,869	-190,977	63,797	33,299	-15,026	45,258	-23,446	-2,088	-10,462
LAUF %	3.40%	-5.78%	3.70%	5.17%	-22.08%	11.79%	8.69%	-5.12%	17.11%	-8.14%	-0.69%	-2.35%
Company Use %	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.02%
Company Gas Allowance %	3.41%	-5.77%	3.71%	5.19%	-22.07%	11.80%	8.70%	-5.11%	17.12%	-8.14%	-0.68%	-2.33%

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	**43-Month**
BTU Factor	1.047	1.037	1.032	1.03	1.035	1.028	1.029	**1.039**
GSG Meter Throughput (Mcf)	528,465	774,469	924,402	771,024	625,991	456,655	353,621	**23,485,312**
Salem Meter (Mcf)	28,517	46,797	58,942	47,478	34,494	21,251	14,628	**1,295,377**
Total Throughput IN (MCF)	556,983	821,267	983,345	818,503	660,486	477,907	368,250	**24,780,734**
GSG Meter Throughput (Dth)	553,303	803,124	953,983	794,155	647,901	469,441	363,876	**24,411,681**
Salem Meter (Dth)	29,857	48,528	60,828	48,902	35,701	21,846	15,052	**1,346,535**
Total Throughput IN (Dth)	583,160	851,653	1,014,811	843,057	683,602	491,287	378,928	**25,758,215**
Total Billed Units (MCF)	504,624	638,201	916,302	878,240	773,119	555,475	417,161	**24,664,470**
Company Use (MCF)	111	160	266	301	240	173	87	**4,152**
Current Month Unbilled Units (MCF)	360,970	515,648	516,679	512,139	406,368	230,049	148,767	**11,488,494**
Prior Month Unbilled Units (MCF)	-276,999	-360,970	-515,648	-516,679	-512,139	-406,368	-230,049	**-11,512,736**
Total Throughput OUT (MCF)	588,706	793,039	917,599	874,001	667,588	379,329	335,966	**24,644,380**
Total Billed Units (Dth)	528,341	661,814	945,625	904,587	800,178	571,029	429,260	**25,633,769**
Company Use (Dth)	116	166	274	310	248	178	90	**4,307**
Current Month Unbilled Units (Dth)	377,937	534,727	533,212	527,504	420,590	236,491	153,081	**11,941,079**
Prior Month Unbilled Units (Dth)	-288,633	-377,937	-534,727	-533,212	-527,504	-420,590	-236,491	**-11,970,178**
Total Throughput OUT (Dth)	617,760	818,769	944,385	899,188	693,512	387,108	345,939	**25,608,978**
Total Throughput IN (Dth)	583,160	851,653	1,014,811	843,057	683,602	491,287	378,928	**25,758,215**
Total Throughput OUT (Dth)	617,760	818,769	944,385	899,188	693,512	387,108	345,939	**25,608,978**
LAUF	-34,600	32,884	70,426	-56,131	-9,910	104,179	32,989	**149,237**
Company Use (Dth)	116	166	274	310	248	178	90	**4,307**
Company Gas Allowance	-34,484	33,049	70,700	-55,821	-9,662	104,357	33,078	**153,544**
LAUF %	-5.93%	3.86%	6.94%	-6.66%	-1.45%	21.21%	8.71%	**0.58%**
Company Use %	0.02%	0.02%	0.03%	0.04%	0.04%	0.04%	0.02%	**0.02%**
Company Gas Allowance %	-5.91%	3.88%	6.97%	-6.62%	-1.41%	21.24%	8.73%	**0.60%**

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

Base Commodity Costs

		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER
1	**BASE SENDOUT BY CLASS**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**
2	**Total Therms**								
3	Res Heat	460,839	476,200	476,200	430,116	476,200	460,839	5,599,341	2,780,395
4	Res General	16,934	17,498	17,498	15,805	17,498	16,934	205,753	102,168
5	G50 Low Annual-Low Winter	97,212	100,452	100,452	90,731	100,452	97,212	1,181,152	586,510
6	G40 Low Annual-High Winter	153,575	158,695	158,695	143,337	158,695	153,575	1,865,992	926,572
7	G51 Med Annual-Low Winter	115,280	119,122	119,122	107,594	119,122	115,280	1,400,683	695,520
8	G41 Med Annual-High Winter	189,408	195,721	195,721	176,780	195,721	189,408	2,301,363	1,142,759
9	G52 High Annual-Low Winter	5,739	5,930	5,930	5,356	5,930	5,739	69,735	34,625
10	G42 High Annual-High Winter	16,143	16,681	16,681	15,067	16,681	16,143	196,140	97,395
11	Total Firm Sales	1,055,129	1,090,300	1,090,300	984,787	1,090,300	1,055,129	12,820,158	6,365,942
12	**% of Total**								
13	Res Heat	43.68%	43.68%	43.68%	43.68%	43.68%	43.68%		
14	Res General	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%		
15	G50 Low Annual-Low Winter	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%		
16	G40 Low Annual-High Winter	14.56%	14.56%	14.56%	14.56%	14.56%	14.56%		
17	G51 Med Annual-Low Winter	10.93%	10.93%	10.93%	10.93%	10.93%	10.93%		
18	G41 Med Annual-High Winter	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%		
19	G52 High Annual-Low Winter	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%		
20	G42 High Annual-High Winter	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	WINTER
22	**BASE COMMODITY COSTS Excld Hedging**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**
23	TOTAL BASE COMMODITY Excld Hedging	$ 440,719	$ 473,804	$ 537,936	$ 492,928	$ 537,867	$ 367,674	$ 2,971,869	$ 2,850,929
24	Res Heat	$ 192,489	$ 206,939	$ 234,950	$ 215,292	$ 234,919	$ 160,586	$ 1,297,996	$ 1,245,174
25	Res General	$ 7,073	$ 7,604	$ 8,633	$ 7,911	$ 8,632	$ 5,901	$ 47,696	$ 45,755
26	G50 Low Annual-Low Winter	$ 40,605	$ 43,653	$ 49,561	$ 45,415	$ 49,555	$ 33,875	$ 273,806	$ 262,663
27	G40 Low Annual-High Winter	$ 64,147	$ 68,963	$ 78,297	$ 71,746	$ 78,287	$ 53,516	$ 432,560	$ 414,957
28	G51 Med Annual-Low Winter	$ 48,151	$ 51,766	$ 58,773	$ 53,856	$ 58,765	$ 40,171	$ 324,696	$ 311,482
29	G41 Med Annual-High Winter	$ 79,114	$ 85,053	$ 96,566	$ 88,486	$ 96,553	$ 66,002	$ 533,484	$ 511,774
30	G52 High Annual-Low Winter	$ 2,397	$ 2,577	$ 2,926	$ 2,681	$ 2,925	$ 2,000	$ 16,164	$ 15,506
31	G42 High Annual-High Winter	$ 6,743	$ 7,249	$ 8,230	$ 7,541	$ 8,229	$ 5,625	$ 45,468	$ 43,617
32									
33	Residential	$ 199,562	$ 214,543	$ 243,583	$ 223,203	$ 243,552	$ 166,487	$ 1,345,692	$ 1,290,930
34	SALES HLF CLASSES	$ 91,153	$ 97,996	$ 111,260	$ 101,951	$ 111,246	$ 76,045	$ 614,665	$ 589,652
35	SALES LLF CLASSES	$ 150,004	$ 161,265	$ 183,093	$ 167,774	$ 183,070	$ 125,142	$ 1,011,511	$ 970,348

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**							**TOTAL**	**WINTER**
37	TOTAL BASE HEDGING COMMODITY	$ 28,525	$ 38,557	$ 80,246	$ 64,835	$ 61,251	$ 27,937	$ 304,357	$ 301,351
38	Res Heat	$ 12,458	$ 16,840	$ 35,048	$ 28,317	$ 26,752	$ 12,202	$ 132,931	$ 131,618
39	Res General	$ 458	$ 619	$ 1,288	$ 1,041	$ 983	$ 448	$ 4,885	$ 4,836
40	G50 Low Annual-Low Winter	$ 2,628	$ 3,552	$ 7,393	$ 5,973	$ 5,643	$ 2,574	$ 28,041	$ 27,764
41	G40 Low Annual-High Winter	$ 4,152	$ 5,612	$ 11,680	$ 9,437	$ 8,915	$ 4,066	$ 44,300	$ 43,862
42	G51 Med Annual-Low Winter	$ 3,117	$ 4,213	$ 8,767	$ 7,084	$ 6,692	$ 3,052	$ 33,253	$ 32,925
43	G41 Med Annual-High Winter	$ 5,121	$ 6,921	$ 14,405	$ 11,639	$ 10,995	$ 5,015	$ 54,636	$ 54,096
44	G52 High Annual-Low Winter	$ 155	$ 210	$ 436	$ 353	$ 333	$ 152	$ 1,655	$ 1,639
45	G42 High Annual-High Winter	$ 436	$ 590	$ 1,228	$ 992	$ 937	$ 427	$ 4,656	$ 4,610
46									
47	Residential	$ 12,916	$ 17,459	$ 36,336	$ 29,358	$ 27,735	$ 12,650	$ 137,816	$ 136,455
48	SALES HLF CLASSES	$ 5,900	$ 7,975	$ 16,597	$ 13,410	$ 12,668	$ 5,778	$ 62,950	$ 62,328
49	SALES LLF CLASSES	$ 9,709	$ 13,123	$ 27,313	$ 22,067	$ 20,848	$ 9,509	$ 103,592	$ 102,569

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	Sum LN 13 : LN 20

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 37 * LN 13
39	Res General	LN 37 * LN 14
40	G50 Low Annual-Low Winter	LN 37 * LN 15
41	G40 Low Annual-High Winter	LN 37 * LN 16
42	G51 Med Annual-Low Winter	LN 37 * LN 17
43	G41 Med Annual-High Winter	LN 37 * LN 18
44	G52 High Annual-Low Winter	LN 37 * LN 19
45	G42 High Annual-High Winter	LN 37 * LN 20
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

50	**REMAINING SENDOUT BY CLASS**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**
51	**Total Therms**								
52	Res Heat	1,232,057	2,015,054	2,386,991	2,066,230	1,704,568	990,742	10,930,067	10,395,642
53	Res General	15,022	29,528	36,549	31,317	23,667	10,467	166,188	146,550
54	G50 Low Annual-Low Winter	27,015	82,359	109,652	92,454	59,575	9,307	493,095	380,361
55	G40 Low Annual-High Winter	714,918	1,119,375	1,310,187	1,137,345	960,089	591,118	6,011,129	5,833,031
56	G51 Med Annual-Low Winter	31,637	97,079	129,357	109,049	70,134	10,695	581,638	447,951
57	G41 Med Annual-High Winter	406,447	681,135	812,047	701,868	571,852	321,511	3,714,512	3,494,860
58	G52 High Annual-Low Winter	7,301	8,923	9,703	8,576	7,859	5,651	51,381	48,013
59	G42 High Annual-High Winter	42,993	70,343	83,336	72,135	59,497	34,564	381,589	362,869
60	Total Firm Sales	2,477,390	4,103,796	4,877,822	4,218,975	3,457,242	1,974,053	22,329,601	21,109,278
61	**% of Total**								
62	Res Heat	49.73%	49.10%	48.94%	48.97%	49.30%	50.19%		
63	Res General	0.61%	0.72%	0.75%	0.74%	0.68%	0.53%		
64	G50 Low Annual-Low Winter	1.09%	2.01%	2.25%	2.19%	1.72%	0.47%		
65	G40 Low Annual-High Winter	28.86%	27.28%	26.86%	26.96%	27.77%	29.94%		
66	G51 Med Annual-Low Winter	1.28%	2.37%	2.65%	2.58%	2.03%	0.54%		
67	G41 Med Annual-High Winter	16.41%	16.60%	16.65%	16.64%	16.54%	16.29%		
68	G52 High Annual-Low Winter	0.29%	0.22%	0.20%	0.20%	0.23%	0.29%		
69	G42 High Annual-High Winter	1.74%	1.71%	1.71%	1.71%	1.72%	1.75%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**
72	REMAINING COMMODITY Excld Hedging	$ 1,035,582	$ 1,696,764	$ 1,931,368	$ 1,674,034	$ 1,429,500	$ 686,143	$ 8,499,191	$ 8,453,391
73	Res Heat	$ 515,016	$ 833,149	$ 945,126	$ 819,853	$ 704,805	$ 344,363	$ 4,182,358	$ 4,162,312
74	Res General	$ 6,279	$ 12,209	$ 14,471	$ 12,426	$ 9,786	$ 3,638	$ 59,546	$ 58,810
75	G50 Low Annual-Low Winter	$ 11,293	$ 34,052	$ 43,417	$ 36,684	$ 24,633	$ 3,235	$ 157,542	$ 153,314
76	G40 Low Annual-High Winter	$ 298,845	$ 462,819	$ 518,767	$ 451,284	$ 396,977	$ 205,461	$ 2,340,834	$ 2,334,153
77	G51 Med Annual-Low Winter	$ 13,225	$ 40,139	$ 51,219	$ 43,269	$ 28,999	$ 3,717	$ 185,582	$ 180,568
78	G41 Med Annual-High Winter	$ 169,900	$ 281,624	$ 321,529	$ 278,492	$ 236,449	$ 111,751	$ 1,407,985	$ 1,399,745
79	G52 High Annual-Low Winter	$ 3,052	$ 3,689	$ 3,842	$ 3,403	$ 3,250	$ 1,964	$ 19,351	$ 19,200
80	G42 High Annual-High Winter	$ 17,972	$ 29,084	$ 32,997	$ 28,622	$ 24,601	$ 12,014	$ 145,992	$ 145,290
81									
82	Residential	$ 521,296	$ 845,357	$ 959,598	$ 832,279	$ 714,590	$ 348,001	$ 4,241,904	$ 4,221,121
83	SALES HLF CLASSES	$ 27,569	$ 77,880	$ 98,477	$ 83,357	$ 56,882	$ 8,916	$ 362,476	$ 353,081
84	SALES LLF CLASSES	$ 486,718	$ 773,527	$ 873,293	$ 758,398	$ 658,028	$ 329,226	$ 3,894,811	$ 3,879,189

85	**REMAINING COMMODITY HEDGING COSTS**							**TOTAL**	**WINTER**
86	TOTAL REMAINING COMMODITY HEDGING	$ 66,792	$ 107,122	$ 118,128	$ 88,752	$ 89,761	$ 50,369	$ 522,271	$ 520,924
87	Res Heat	$ 33,217	$ 52,599	$ 57,807	$ 43,466	$ 44,256	$ 25,279	$ 257,214	$ 256,624
88	Res General	$ 405	$ 771	$ 885	$ 659	$ 614	$ 267	$ 3,623	$ 3,601
89	G50 Low Annual-Low Winter	$ 728	$ 2,150	$ 2,655	$ 1,945	$ 1,547	$ 237	$ 9,387	$ 9,263
90	G40 Low Annual-High Winter	$ 19,275	$ 29,219	$ 31,729	$ 23,926	$ 24,927	$ 15,083	$ 144,355	$ 144,158
91	G51 Med Annual-Low Winter	$ 853	$ 2,534	$ 3,133	$ 2,294	$ 1,821	$ 273	$ 11,055	$ 10,907
92	G41 Med Annual-High Winter	$ 10,958	$ 17,780	$ 19,666	$ 14,765	$ 14,847	$ 8,204	$ 86,461	$ 86,219
93	G52 High Annual-Low Winter	$ 197	$ 233	$ 235	$ 180	$ 204	$ 144	$ 1,197	$ 1,193
94	G42 High Annual-High Winter	$ 1,159	$ 1,836	$ 2,018	$ 1,517	$ 1,545	$ 882	$ 8,978	$ 8,958
95								$ -	$ -
96	Residential	$ 33,622	$ 53,370	$ 58,692	$ 44,125	$ 44,870	$ 25,546	$ 260,837	$ 260,225
97	SALES HLF CLASSES	$ 1,778	$ 4,917	$ 6,023	$ 4,419	$ 3,572	$ 655	$ 21,639	$ 21,364
98	SALES LLF CLASSES	$ 31,392	$ 48,835	$ 53,413	$ 40,208	$ 41,319	$ 24,168	$ 239,795	$ 239,335

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	Sum LN 62 : LN 69

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 86 * LN 62
88	Res General	LN 86 * LN 63
89	G50 Low Annual-Low Winter	LN 86 * LN 64
90	G40 Low Annual-High Winter	LN 86 * LN 65
91	G51 Med Annual-Low Winter	LN 86 * LN 66
92	G41 Med Annual-High Winter	LN 86 * LN 67
93	G52 High Annual-Low Winter	LN 86 * LN 68
94	G42 High Annual-High Winter	LN 86 * LN 69
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**							**TOTAL**	**WINTER**
100	TOTAL COMMODITY Excld Hedging	$ 1,476,301	$ 2,170,569	$ 2,469,304	$ 2,166,963	$ 1,967,367	$ 1,053,817	$ 11,471,060	$ 11,304,321
101	Res Heat	$ 707,505	$ 1,040,088	$ 1,180,076	$ 1,035,145	$ 939,724	$ 504,948	$ 5,480,354	$ 5,407,486
102	Res General	$ 13,353	$ 19,813	$ 23,105	$ 20,337	$ 18,418	$ 9,539	$ 107,242	$ 104,565
103	G50 Low Annual-Low Winter	$ 51,897	$ 77,705	$ 92,978	$ 82,099	$ 74,188	$ 37,110	$ 431,348	$ 415,977
104	G40 Low Annual-High Winter	$ 362,993	$ 531,782	$ 597,064	$ 523,030	$ 475,265	$ 258,977	$ 2,773,394	$ 2,749,110
105	G51 Med Annual-Low Winter	$ 61,376	$ 91,905	$ 109,992	$ 97,125	$ 87,764	$ 43,888	$ 510,278	$ 492,050
106	G41 Med Annual-High Winter	$ 249,014	$ 366,677	$ 418,095	$ 366,978	$ 333,003	$ 177,753	$ 1,941,469	$ 1,911,519
107	G52 High Annual-Low Winter	$ 5,449	$ 6,266	$ 6,768	$ 6,084	$ 6,175	$ 3,964	$ 35,516	$ 34,706
108	G42 High Annual-High Winter	$ 24,714	$ 36,333	$ 41,227	$ 36,164	$ 32,830	$ 17,639	$ 191,460	$ 188,907
109									
110	Residential	$ 720,858	$ 1,059,901	$ 1,203,181	$ 1,055,482	$ 958,142	$ 514,487	$ 5,587,596	$ 5,512,051
111	SALES HLF CLASSES	$ 118,722	$ 175,876	$ 209,737	$ 185,308	$ 168,128	$ 84,961	$ 977,142	$ 942,733
112	SALES LLF CLASSES	$ 636,722	$ 934,792	$ 1,056,386	$ 926,172	$ 841,097	$ 454,368	$ 4,906,322	$ 4,849,537
113	**TOTAL HEDGING COMMODITY COSTS**							**TOTAL**	**WINTER**
114	TOTAL HEDGING COMMODITY	$ 95,316	$ 145,679	$ 198,374	$ 153,587	$ 151,012	$ 78,307	$ 826,628	$ 822,275
115	Res Heat	$ 45,675	$ 69,439	$ 92,855	$ 71,783	$ 71,008	$ 37,481	$ 390,146	$ 388,243
116	Res General	$ 863	$ 1,390	$ 2,173	$ 1,699	$ 1,598	$ 715	$ 8,508	$ 8,438
117	G50 Low Annual-Low Winter	$ 3,356	$ 5,702	$ 10,049	$ 7,918	$ 7,190	$ 2,811	$ 37,428	$ 37,027
118	G40 Low Annual-High Winter	$ 23,426	$ 34,831	$ 43,409	$ 33,362	$ 33,842	$ 19,149	$ 188,655	$ 188,020
119	G51 Med Annual-Low Winter	$ 3,969	$ 6,747	$ 11,900	$ 9,378	$ 8,513	$ 3,325	$ 44,308	$ 43,832
120	G41 Med Annual-High Winter	$ 16,079	$ 24,701	$ 34,071	$ 26,403	$ 25,842	$ 13,219	$ 141,097	$ 140,315
121	G52 High Annual-Low Winter	$ 352	$ 443	$ 671	$ 533	$ 537	$ 296	$ 2,852	$ 2,832
122	G42 High Annual-High Winter	$ 1,596	$ 2,426	$ 3,246	$ 2,509	$ 2,482	$ 1,309	$ 13,635	$ 13,568
123									
124	Residential	$ 46,538	$ 70,829	$ 95,028	$ 73,483	$ 72,606	$ 38,197	$ 398,653	$ 396,680
125	SALES HLF CLASSES	$ 7,678	$ 12,891	$ 22,620	$ 17,829	$ 16,240	$ 6,433	$ 84,589	$ 83,691
126	SALES LLF CLASSES	$ 41,100	$ 61,958	$ 80,726	$ 62,275	$ 62,166	$ 33,677	$ 343,386	$ 341,903
127	TOTAL COMMODITY	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	**WINTER**
128	Res Heat	$ 753,180	$ 1,109,527	$ 1,272,931	$ 1,106,928	$ 1,010,732	$ 542,430	$ 5,870,499	$ 5,795,729
129	Res General	$ 14,215	$ 21,202	$ 25,278	$ 22,037	$ 20,016	$ 10,254	$ 115,750	$ 113,003
130	G50 Low Annual-Low Winter	$ 55,253	$ 83,407	$ 103,027	$ 90,017	$ 81,378	$ 39,921	$ 468,776	$ 453,004
131	G40 Low Annual-High Winter	$ 386,419	$ 566,613	$ 640,474	$ 556,392	$ 509,107	$ 278,126	$ 2,962,048	$ 2,937,131
132	G51 Med Annual-Low Winter	$ 65,345	$ 98,651	$ 121,892	$ 106,502	$ 96,277	$ 47,213	$ 554,586	$ 535,882
133	G41 Med Annual-High Winter	$ 265,093	$ 391,378	$ 452,166	$ 393,382	$ 358,845	$ 190,971	$ 2,082,566	$ 2,051,834
134	G52 High Annual-Low Winter	$ 5,801	$ 6,709	$ 7,439	$ 6,617	$ 6,712	$ 4,260	$ 38,368	$ 37,538
135	G42 High Annual-High Winter	$ 26,310	$ 38,759	$ 44,473	$ 38,673	$ 35,312	$ 18,948	$ 205,094	$ 202,475
136	Total Firm Sales	$ 1,571,618	$ 2,316,248	$ 2,667,679	$ 2,320,549	$ 2,118,379	$ 1,132,124	$ 12,297,688	$ 12,126,595
137									
138	Residential	$ 767,396	$ 1,130,730	$ 1,298,209	$ 1,128,965	$ 1,030,748	$ 552,684	$ 5,986,250	$ 5,908,731
139	SALES HLF CLASSES	$ 126,400	$ 188,768	$ 232,358	$ 203,137	$ 184,368	$ 91,394	$ 1,061,730	$ 1,026,424
140	SALES LLF CLASSES	$ 677,822	$ 996,750	$ 1,137,112	$ 988,447	$ 903,263	$ 488,045	$ 5,249,708	$ 5,191,440
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								16.51%
144	SALES LLF CLASSES								83.49%

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)

Schedules 11A, 11B, 11C, 11D and 11E

Northern Utilities, Inc. Normal Weather - Sales Service Only Commodity Volumes by Supply Source (Dth) November 2012 through April 2013							
Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Season
Pipeline Supplies							
Chicago	85,197	123,455	21,755	1,958	0	6,572	238,936
Lewiston Baseload	165,000	170,500	170,500	154,000	170,500	0	830,500
TGP Zone 6	151,907	154,458	154,458	139,510	154,458	349,972	1,102,330
PNGTS	26,965	27,864	27,864	25,168	27,864	0	135,725
Niagara	3,987	0	0	0	0	0	3,987
Tennessee Production	189,843	273,778	159,553	139,510	154,457	149,475	1,066,617
AGT Receipts	22,551	0	0	1,954	26,464	31,642	82,610
Subtotal Pipeline	645,449	750,055	534,130	462,099	533,743	537,660	3,460,705
Underground Storage							
Tenn Zone 4 Spot	53,736	60,327	0	0	306	58,009	172,378
Tennessee Storage	0	0	60,327	54,489	60,021	13,110	187,947
Tennesse Storage Path	53,736	60,327	60,327	54,489	60,327	71,119	360,325
W10 AMA Spot	0	0	0	0	0	0	0
Washington 10 Storage	0	210,007	586,848	512,927	308,010	0	1,617,793
W10 Storage Path	0	210,007	586,848	512,927	308,010	0	1,617,793
Subtotal Storage	53,736	270,335	647,175	567,416	368,338	71,119	1,978,118
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
Peaking Supply 4	0	0	0	0	0	0	0
LNG	1,350	1,395	1,395	1,260	1,395	1,350	8,145
Subtotal Peaking	1,350	1,395	1,395	1,260	1,395	1,350	8,145
Total Delivered (Dth)	700,535	1,021,784	1,182,700	1,030,775	903,476	610,129	5,449,399

Northern Utilities, Inc.
Design Weather - All Capacity Assigned Loads
Commodity Volumes by Supply Source (Dth)
November 2012 through April 2013

Description	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Season
Pipeline Supplies							
Chicago	155,263	180,912	99,185	78,075	33,699	175,153	722,287
Lewiston Baseload	165,000	170,500	170,500	154,000	170,500	0	830,500
TGP Zone 6	149,475	154,458	154,458	139,510	154,458	0	752,358
PNGTS	26,965	28,456	29,640	26,351	27,864	32,885	172,161
Niagara	50,221	9,317	23,392	21,995	9,049	62,892	176,866
Tennessee Production	389,579	406,373	406,373	367,047	406,373	380,759	2,356,503
AGT Receipts	37,530	4,579	11,259	20,016	38,781	37,530	149,695
Subtotal Pipeline	974,033	954,595	894,806	806,994	840,723	689,218	5,160,370
Underground Storage							
Tenn Zone 4 Spot	79,309	81,953	0	0	416	61,500	223,177
Tennessee Storage	0	0	81,953	74,022	81,537	17,809	255,321
Tennesse Storage Path	79,309	81,953	81,953	74,022	81,953	79,309	478,498
W10 AMA Spot	147,270	0	0	0	10,162	0	157,432
Washington 10 Storage	0	633,108	918,297	836,745	581,421	282,234	3,251,805
W10 Storage Path	147,270	633,108	918,297	836,745	591,583	282,234	3,409,237
Subtotal Storage	226,580	715,061	1,000,249	910,767	673,536	361,542	3,887,735
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	393	5,976	0	0	0	6,368
Peaking Supply 4	0	0	0	0	0	0	0
LNG	1,350	20,549	46,078	18,307	1,395	21,414	109,093
Subtotal Peaking	1,350	20,942	52,053	18,307	1,395	21,414	115,461
Total Delivered (Dth)	1,201,962	1,690,598	1,947,109	1,736,069	1,515,654	1,072,174	9,163,566

Northern Utilities, Inc.
Normal Weather - Sales Service Only
Capacity Utilization by Supply Source
November 2012 through April 2013

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Chicago	238,936	825,710	29%
Lewiston Baseload	830,500	995,500	83%
TGP Zone 6	1,102,330	1,200,903	92%
PNGTS	135,725	140,656	96%
Niagara	3,987	299,150	1%
Tennessee Production	1,066,617	1,682,349	63%
AGT Receipts	82,610	160,548	51%
Subtotal Pipeline	3,460,705	5,144,267	67%
Underground Storage			
Tenn Zone 4 Spot	172,378		
Tennessee Storage	187,947		
Tennesse Storage Path	360,325	364,970	99%
W10 AMA Spot	0		
Washington 10 Storage	1,617,793		
W10 Storage Path	1,617,793	4,539,843	36%
Subtotal Storage	1,978,118	4,904,814	40%
Peaking Supplies			
Peaking Supply 1	0	51,432	0%
Peaking Supply 2	0	22,080	0%
Peaking Supply 3	0	22,005	0%
Peaking Supply 4	0	1,056,131	0%
LNG	8,145	1,380,370	1%
Subtotal Peaking	8,145	2,532,018	0%
Total Delivered (Dth)	5,449,399	12,581,099	43%

Northern Utilities, Inc.
Design Weather - All Capacity Assigned Loads
Capacity Utilization by Supply Source
November 2012 through April 2013

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Chicago	722,287	1,164,554	62%
Lewiston Baseload	830,500	995,500	83%
TGP Zone 6	752,358	1,200,903	63%
PNGTS	172,161	198,376	87%
Niagara	176,866	421,911	42%
Tennessee Production	2,356,503	2,372,729	99%
AGT Receipts	149,695	226,431	66%
Subtotal Pipeline	5,160,370	6,353,973	81%
Underground Storage			
Tenn Zone 4 Spot	223,177		
Tennessee Storage	255,321		
Tennesse Storage Path	478,498	478,512	100%
W10 AMA Spot	157,432		
Washington 10 Storage	3,251,805		
W10 Storage Path	3,409,237	5,952,185	57%
Subtotal Storage	3,887,735	6,430,697	60%
Peaking Supplies			
Peaking Supply 1	0	69,881	0%
Peaking Supply 2	0	30,000	0%
Peaking Supply 3	6,368	29,898	21%
Peaking Supply 4	0	1,434,960	0%
LNG	109,093	1,810,000	6%
Subtotal Peaking	115,461	3,374,739	3%
Total Delivered (Dth)	9,163,566	16,159,409	57%

Northern Utilities Inc.
Forecast of Upcoming Winter Period Design Day Report
2012 / 2013 Winter Period
(Therms)

Demand	
NH Firm Sales	432,479
NH Non-Capacity Exempt Transportation	117,536
NH Capacity Exempt Transportation	109,347
NH Interruptible Sales	0
NH Interruptible Transportation	0
NH Design Day Demand	659,361
ME Firm Sales	380,073
ME Non-Capacity Exempt Transportation	163,262
ME Capacity Exempt Transportation	223,688
ME Interruptible Sales	0
ME Interruptible Transportation	0
ME Design Day Demand	767,024
Total Firm Sales	812,552
Total Non-Capacity Exempt Transportation	280,798
Total Capacity Exempt Transportation	333,035
Total Interruptible Sales	0
Total Interruptible Transportation	0
Total Design Day Demand	1,426,385
Supplies	
Capacity Exempt Transportation	333,035
Pipeline	347,040
Storage	355,290
On-System LNG	100,000
Off-System Peaking	359,100
On-System Propane	0
Total	1,494,465
Effective Degree Day	
New Hampshire	81
Maine	79
Probability	1 in 30

Northern Utilities Inc.
New Hampshire 7 Day Cold Snap Analysis
Winter 2012-2013

Coldest 7 Consecutive Days
Based on historic Portsmouth weather data

Date	EDD
February 11, 1979	68
February 12, 1979	60
February 13, 1979	73
February 14, 1979	73
February 15, 1979	64
February 16, 1979	69
February 17, 1979	72
Total	479

Maximum Projected Design Week Demand (Dth)

Daily Baseload	5,329
Weekly Baseload	37,301
Heating Increment*	559
Effective Degree Days	479
Total Heat Load	267,732
Projected Cold Snap Demand	305,033

** Based on forecasted maximum heating increment in the latest IRP filing.*

New Hampshire Allocation **46.40%**
Based on the latest demand cost allocator in the Winter COG filing.

Maximum Supply Capability (Dth)

Amount to be Supplied by Natural Gas Pipelines	
Chicago Path	6,434
Lewiston Baseload	5,500
Tennessee Zone 6 Delivered Baseload	4,983
PNGTS Year-Round	1,096
Tennessee Niagara	2,331
Tennessee Long-Haul	13,109
Algonquin Receipt Points	1,251
Tennessee FS-MA & 5265	2,644
Washington 10 Path	32,885
Peaking Supply 1	9,983
Peaking Supply 2	5,000
Peaking Supply 3	4,983
Peaking Supply 4	15,944
Total Daily Pipeline	106,143
Pipeline for 7 days	743,001
New Hampshire Allocation	344,752

Available LNG Storage

Facility	Gallons	Dth
Lewiston LNG	145,134	12,140
Total	145,134	12,140
New Hampshire Allocation - 7 Days		5,633

LNG Delivery Contract

Northern Utilities plans to secure a contract for LNG Delivery for up to five loads of LNG per day.

The storage credit for LNG is calculated as follows:

Number of Days	5
Number of Loads	5
Delivery Reliability	70%
Assumed Number of LNG Deliveries	18
Dth Per Load	900
Total Storage Credit	15,750
NH Storage Credit - 7 Days	7,308

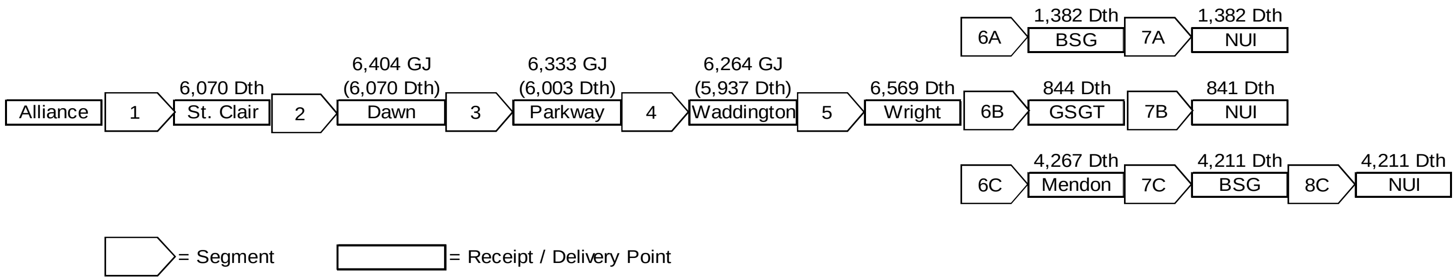
Summary	
Maximum projected design week demand	305,033
Amount to be furnished by natural gas pipeline	344,752
Remaining Balance	-39,720
Storage available	5,633
Credit from LNG delivery supply contract	7,308
Total available storage and propane deliveries	12,941
Net Surplus/(Deficiency)	**52,661**

Schedule 12

Northern Capacity by Supply Source (Dth per Day)		
Supply Source	2012-2013 Winter	2013 Summer
Chicago Path	6,434	6,434
Lewiston Baseload	5,500	0
Tennessee Zone 6 Delivered Baseload	4,983	0
PNGTS Year-Round	1,096	1,096
Tennessee Niagara	2,331	2,331
Tennessee Long-Haul	13,109	13,109
Algonquin Receipt Points	1,251	1,251
Tennessee FS-MA & 5265	2,644	2,644
Washington 10 Path	32,885	0
Peaking Supply 1	9,983	0
Peaking Supply 2	5,000	0
Peaking Supply 3	4,983	0
Peaking Supply 4	15,944	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**116,143**	**36,865**

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

Capacity Path Diagram

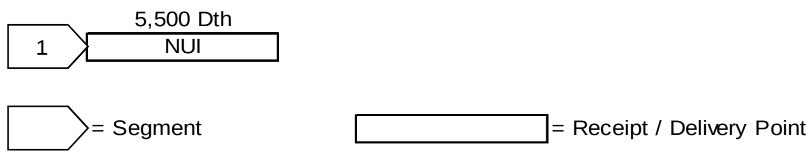


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	Union
3	Transportation	Union	M12205	M12	10/31/2017	6,333	GJ	Year-Round	Dawn	Parkway	TransCanada
4	Transportation	TransCanada	41235	FT	10/31/2017	6,264	GJ	Year-Round	Parkway	Waddington	Iroquois
5	Transportation	Iroquois	R181001	RTS-1	10/31/2017	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
6A	Transportation	Tennessee	95196	FT-A	10/31/2017	1,382	Dth	Year-Round	Wright	Bay State City Gate	
7A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
6B	Transportation	Tennessee	95196	FT-A	10/31/2017	844	Dth	Year-Round	Wright	Pleasant St.	Granite
7B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	841	Dth	Year-Round	Granite	Northern City Gates	
6C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
7C	Transportation	Algonquin	93200F	AFT-1	10/31/2013	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
8C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,434	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Lewiston Delivered Supply

Capacity Path Diagram

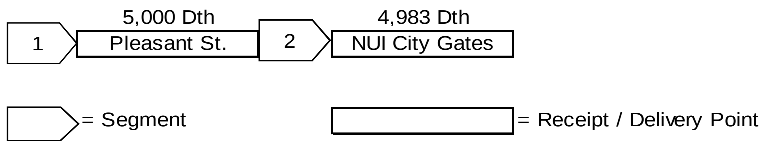


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Delivered Supply	Confidential	NA	NA	3/31/2013	5,500	Dth	NA	NA	Northern City Gate (Lewiston)	NA
Total Path Deliverable						5,500	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Zone 6 Baseload Supply

Capacity Path Diagram

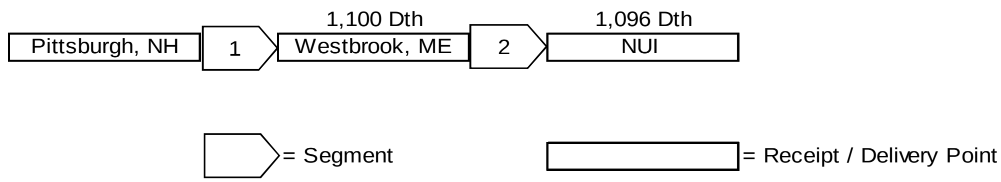


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Peaking Supply	Confidential	NA	NA	3/31/2012	5,000	Dth	Winter Only (Nov - Mar)	NA	Pleasant St.	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	4,983	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						4,983	Dth				

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

Capacity Path Diagram

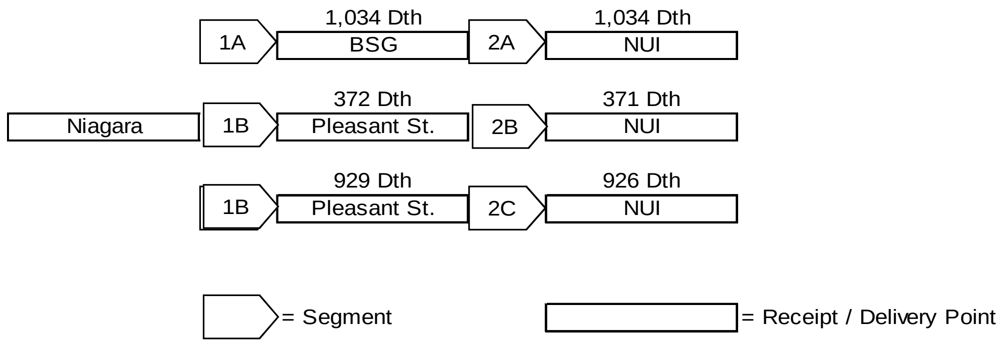


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	1,096	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						1,096	Dth				

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

Capacity Path Diagram

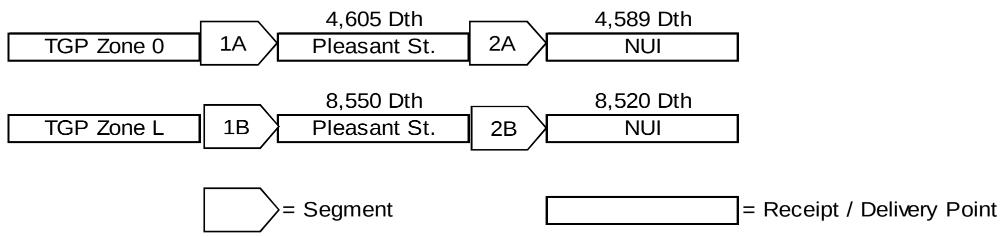


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2015	1,034	Dth	Year-Round	Niagara	Bay State City Gate	
2A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,034	Dth	Year-Round	Bay State City Gate	Northern City Gates	
1B	Transportation	Tennessee	5292	FT-A	3/31/2015	372	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	371	Dth	Year-Round	Granite	Northern City Gates	
1C	Transportation	Tennessee	39735	FT-A	3/31/2015	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2C	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	926	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						2,331	Dth				

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

Capacity Path Diagram



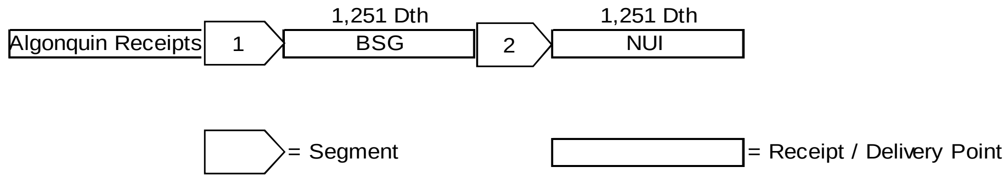
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	Dth				

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

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Algonquin Receipt Points

Capacity Path Diagram

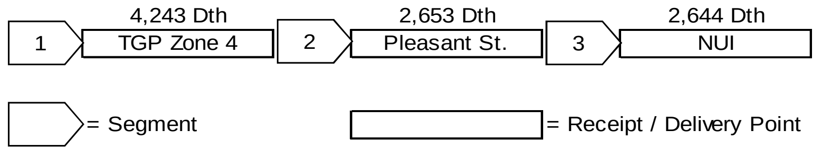


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2013	1,251	Dth	Year-Round	Algonquin Receipt Points	Bay State City Gate	
2	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,251	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						1,251	Dth				

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

Capacity Path Diagram



Capacity Path Detail

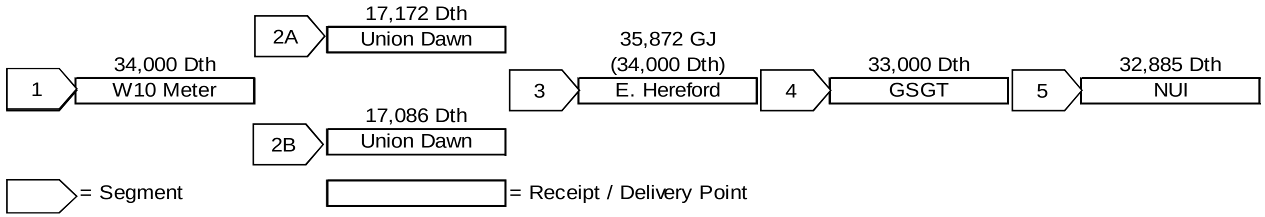
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	3/31/2015	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2015	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

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

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

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

Capacity Path Diagram



Capacity Path Detail

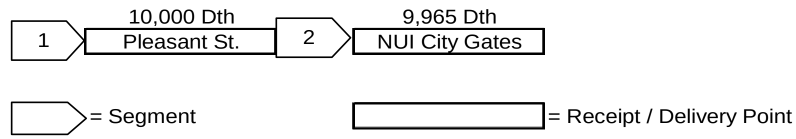
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-0725	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-0727	FT	3/31/2017	17,086	Dth	Winter Only (Nov - Mar)	W10 Withdrawal Meter	Union Dawn	TransCanada
3	Transportation	TransCanada	33322	FT	3/31/2018	35,872	GJ	Year-Round	Union Dawn	East Hereford	PNGTS
4	Transportation	PNGTS	1997-004	FT	3/9/2019	33,000	Dth	Winter Only (Nov - Mar)	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	32,885	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,885	Dth				

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

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

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

Capacity Path Diagram



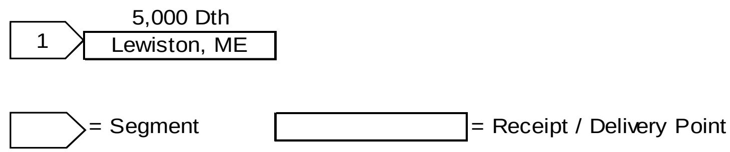
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2013	5,000	Dth	Winter Only (Nov - Mar)	NA	Northern City Gates	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	4,983	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						9,983	Dth				

Note 1: Peaking Supply 1 Contract allows Northern to nominate up to 10,000 Dth per Day and up to 70,000 Dth from November 2012 through March 2013.

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

Capacity Path Diagram



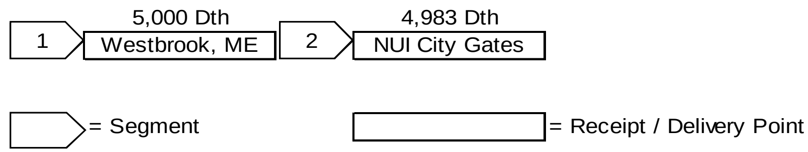
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2013	5,000	Dth	Winter Only (Nov-Mar)	NA	Northern City Gates	Granite
Total Path Deliverable						5,000	Dth				

Note 1: Peaking Supply 2 Contract allows Northern to nominate up to 5,000 Dth per Day and up to 30,000 Dth from November 2012 through March 2013.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Supply 3

Capacity Path Diagram



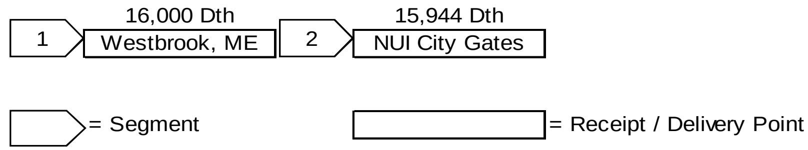
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2013	5,000	Dth	Winter Only (Dec-Feb)	NA	Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	4,983	Dth	Year-Round	Westbrook, ME	Northern City Gates	
Total Path Deliverable						4,983	Dth				

Note 1: Peaking Supply 3 Contract allows Northern to nominate up to 5,000 Dth per Day and up to 30,000 Dth from November 2012 through March 2013.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Supply 3

Capacity Path Diagram



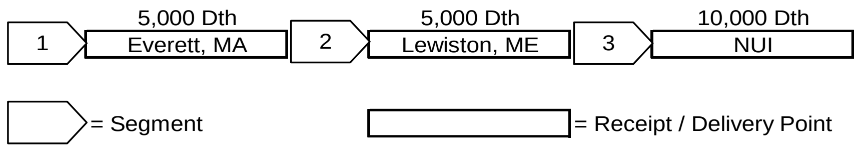
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	2/28/2013	16,000	Dth	Winter Only (Dec-Feb)	NA	Westbrook, ME	Granite
2	Transportation	Granite	10-010-FT-NN	FT-NN	10/31/2012	15,944	Dth	Year-Round	Westbrook, ME	Northern City Gates	
Total Path Deliverable						15,944	Dth				

Note 1: Peaking Supply 4 Contract allows Northern to nominate up to 16,000 Dth per Day from December 2012 through February 2013.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Lewiston LNG Plant

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	LNG Contract	Confidential	NA	NA	10/31/2012	5,000	Dth	Year-Round	NA	Everett, MA	NA
2	LNG Trucking Contract	Confidential			10/31/2012	5,000	Dth	Year-Round	Everett, MA	Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	10,000	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						10,000	Dth				

Note 1: The LNG Contract allows Northern to nominate up to 5,000 Dth per day with an annual maximum take is 125,000 Dth.

Schedule 13

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2012 through October 2013

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	782,839	43%	84%
G50	166,381	9%	75%
G41	597,857	33%	50%
G51	196,996	11%	49%
G42	57,415	3%	12%
G52	12,036	1%	1%
Special Contracts	-	0%	0%
Total C&I	1,813,523	100%	33%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
T40	153,387	4%	16%
T50	55,881	2%	25%
T41	599,289	16%	50%
T51	206,296	6%	51%
T42	404,597	11%	88%
T52	1,293,759	35%	99%
Special Contracts	974,747	26%	100%
Total C&I	3,687,956	100%	67%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G/T40	936,226	17%
G/T50	222,262	4%
G/T41	1,197,145	22%
G/T51	403,292	7%
G/T42	462,012	8%
G/T52	1,305,795	24%
Special Contracts	974,747	18%
Total C&I	5,501,479	100%

Schedule 14

Northern Utilities, Inc.
Storage Inventory and Activity Costs

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-12	190,898	-	-	190,898	$ 538,848	$ 2.82	NA	$ -	$ 2.82	$ -	$ 538,848	2.19%	$ 982	$ 538,848	$ -
Dec-12	190,898	-	-	190,898	$ 538,848	$ 2.82	NA	$ -	$ 2.82	$ -	$ 538,848	2.19%	$ 982	$ 538,848	$ -
Jan-13	190,898	-	61,274	129,624	$ 538,848	$ 2.82	NA	$ -	$ 2.82	$ 172,959	$ 365,889	2.19%	$ 824	$ 365,889	$ 172,959
Feb-13	129,624	-	55,345	74,279	$ 365,889	$ 2.82	NA	$ -	$ 2.82	$ 156,221	$ 209,667	2.19%	$ 524	$ 209,667	$ 156,221
Mar-13	74,279	-	60,963	13,316	$ 209,667	$ 2.82	NA	$ -	$ 2.82	$ 172,081	$ 37,586	2.19%	$ 225	$ 37,586	$ 172,081
Apr-13	13,316	-	13,316	-	$ 37,586	$ 2.82	NA	$ -	$ 2.82	$ 37,586	$ -	2.19%	$ 34	$ -	$ 37,586
May-13	-	39,454	-	39,454	-	NA	$ 3.36	$ 132,515	$ 3.36	$ -	$ 132,515	2.19%	$ 121	$ 132,515	$ -
Jun-13	39,454	38,182	-	77,636	$ 132,515	$ 3.36	$ 3.41	$ 130,025	$ 3.38	$ -	$ 262,540	2.19%	$ 360	$ 262,540	$ -
Jul-13	77,636	39,454	-	117,090	$ 262,540	$ 3.38	$ 3.45	$ 135,973	$ 3.40	$ -	$ 398,513	2.19%	$ 602	$ 398,513	$ -
Aug-13	117,090	39,454	-	156,544	$ 398,513	$ 3.40	$ 3.47	$ 136,818	$ 3.42	$ -	$ 535,331	2.19%	$ 851	$ 535,330	$ -
Sep-13	156,544	34,354	-	190,898	$ 535,331	$ 3.42	$ 3.47	$ 119,236	$ 3.43	$ -	$ 654,566	2.19%	$ 1,084	$ 654,565	$ -
Oct-13	190,898	-	-	190,898	$ 654,566	$ 3.43	NA	$ -	$ 3.43	$ -	$ 654,566	2.19%	$ 1,193	$ 654,565	$ -

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-12	2,502,740	-	-	2,502,740	$ 8,416,715	$ 3.36	NA	$ -	$ 3.36	$ -	$ 8,416,715	2.19%		$ 8,416,715	$ -
Dec-12	2,502,740	-	214,240	2,288,500	$ 8,416,715	$ 3.36	NA	$ -	$ 3.36	$ 720,489	$ 7,696,225	2.19%		$ 7,696,225	$ 720,489
Jan-13	2,288,500	-	598,676	1,689,824	$ 7,696,225	$ 3.36	NA	$ -	$ 3.36	$2,013,346	$ 5,682,879	2.19%		$ 5,682,879	$2,013,346
Feb-13	1,689,824	-	523,266	1,166,558	$ 5,682,879	$ 3.36	NA	$ -	$ 3.36	$1,759,744	$ 3,923,135	2.19%		$ 3,923,135	$1,759,744
Mar-13	1,166,558	-	314,219	852,340	$ 3,923,135	$ 3.36	NA	$ -	$ 3.36	$1,056,717	$ 2,866,418	2.19%		$ 2,866,418	$1,056,717
Apr-13	852,339	371,281	-	1,223,621	$ 2,866,418	$ 3.36	$ 3.39	$1,259,957	$ 3.37	$ -	$ 4,126,375	2.19%		$ 4,126,375	$ -
May-13	1,223,621	383,658	-	1,607,279	$ 4,126,375	$ 3.37	$ 3.43	$1,317,531	$ 3.39	$ -	$ 5,443,906	2.19%		$ 5,443,906	$ -
Jun-13	1,607,278	371,281	-	1,978,560	$ 5,443,906	$ 3.39	$ 3.48	$1,292,432	$ 3.40	$ -	$ 6,736,338	2.19%		$ 6,736,338	$ -
Jul-13	1,978,560	383,658	-	2,362,217	$ 6,736,338	$ 3.40	$ 3.52	$1,351,263	$ 3.42	$ -	$ 8,087,600	2.19%		$ 8,087,600	$ -
Aug-13	2,362,218	140,523	-	2,502,740	$ 8,087,600	$ 3.42	$ 3.54	$ 497,946	$ 3.43	$ -	$ 8,585,547	2.19%		$ 8,585,547	$ -
Sep-13	2,502,740	-	-	2,502,740	$ 8,585,547	$ 3.43	NA	$ -	$ 3.43	$ -	$ 8,585,547	2.19%		$ 8,585,547	$ -
Oct-13	2,502,740	-	-	2,502,740	$ 8,585,547	$ 3.43	NA	$ -	$ 3.43	$ -	$ 8,585,547	2.19%		$ 8,585,547	$ -

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-12	12,500	1,350	1,350	12,500	$ 56,138	$ 4.49	$ 4.74	$ 6,395	$ 4.51	$ 6,095	$ 56,437	2.19%	$ 103	$ 56,437	$ 6,095
Dec-12	12,500	145	1,395	11,250	$ 56,437	$ 4.51	$ 6.86	$ 995	$ 4.54	$ 6,336	$ 51,096	2.19%	$ 98	$ 51,096	$ 6,336
Jan-13	11,250	1,395	1,395	11,250	$ 51,096	$ 4.54	$ 6.75	$ 9,412	$ 4.79	$ 6,675	$ 53,833	2.19%	$ 96	$ 53,833	$ 6,675
Feb-13	11,250	1,260	1,260	11,250	$ 53,833	$ 4.79	$ 6.74	$ 8,494	$ 4.98	$ 6,278	$ 56,049	2.19%	$ 100	$ 56,049	$ 6,278
Mar-13	11,250	1,395	1,395	11,250	$ 56,049	$ 4.98	$ 5.02	$ 6,996	$ 4.99	$ 6,955	$ 56,090	2.19%	$ 102	$ 56,090	$ 6,955
Apr-13	11,250	2,600	1,350	12,500	$ 56,090	$ 4.99	$ 4.70	$ 12,210	$ 4.93	$ 6,657	$ 61,642	2.19%	$ 107	$ 61,642	$ 6,657
May-13	12,500	1,395	1,395	12,500	$ 61,642	$ 4.93	$ 4.72	$ 6,586	$ 4.91	$ 6,850	$ 61,378	2.19%	$ 112	$ 61,378	$ 6,850
Jun-13	12,500	1,350	1,350	12,500	$ 61,378	$ 4.91	$ 4.87	$ 6,580	$ 4.91	$ 6,624	$ 61,334	2.19%	$ 112	$ 61,334	$ 6,624
Jul-13	12,500	1,395	1,395	12,500	$ 61,334	$ 4.91	$ 4.95	$ 6,900	$ 4.91	$ 6,850	$ 61,383	2.19%	$ 112	$ 61,383	$ 6,850
Aug-13	12,500	145	1,395	11,250	$ 61,383	$ 4.91	$ 5.06	$ 734	$ 4.91	$ 6,853	$ 55,265	2.19%	$ 106	$ 55,265	$ 6,853
Sep-13	11,250	2,600	1,350	12,500	$ 55,265	$ 4.91	$ 4.88	$ 12,688	$ 4.91	$ 6,624	$ 61,329	2.19%	$ 106	$ 61,329	$ 6,624
Oct-13	12,500	1,395	1,395	12,500	$ 61,329	$ 4.91	$ 4.99	$ 6,955	$ 4.91	$ 6,856	$ 61,429	2.19%	$ 112	$ 61,429	$ 6,856

Schedule 15

FORM III
Schedule 1 - Revised

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011-2012 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
May 2011 - April 2012

	AMOUNT	
Winter Period Beg. Balance	($3,107,451)	SCHEDULE 2
Less: Reported Collections	($25,514,890)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$25,508,999	SCHEDULE 4
Add: Interest	$7,603	SCHEDULE 2
Winter Period Ending Balance	($3,105,739)	

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2011-2012 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED WINTER PERIOD ACCOUNTS
May 2011 - April 2012
Acct 191.20

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
WINTER PERIOD													
Winter Period Account Beginning Balance	$ 973,628												
Reconciliation Adjustment (1)	$ (4,081,078)												
Winter Period Account Beginning Balance	$ (3,107,451)	$ (1,880,938)	$ (981,331)	$ (205,517)	$ 608,603	$ 1,459,375	$ 2,225,607	$ 3,369,075	$ 2,864,984	$ 1,107,722	$ (726,336)	$ (1,923,594)	$ (3,107,451)
Plus: Cost of Firm Gas (Schedule 4)	$ 636,208	$ 948,618	$ 778,189	$ 813,387	$ 847,959	$ 761,195	$ 3,510,672	$ 3,832,084	$ 4,751,878	$ 3,940,510	$ 3,362,115	$ 1,326,182	$ 25,508,999
Less: Reported Collections (Schedule 3)	$ 597,051	$ (45,141)	$ (771)	$ 189	$ 16	$ 53	$ (2,374,769)	$ (4,344,606)	$ (6,514,512)	$ (5,775,084)	$ (4,555,790)	$ (2,501,526)	$ (25,514,890)
Less: Billing Adjustment													
Winter Period Account Ending Balance	$ (1,874,192)	$ (977,460)	$ (203,912)	$ 608,058	$ 1,456,578	$ 2,220,623	$ 3,361,509	$ 2,856,554	$ 1,102,350	$ (726,851)	$ (1,920,011)	$ (3,098,938)	$ (3,113,342)
Month's Average Balance	$ (2,490,821)	$ (1,429,199)	$ (592,622)	$ 201,270	$ 1,032,591	$ 1,839,999	$ 2,793,558	$ 3,112,814	$ 1,983,667	$ 190,435	$ (1,323,173)	$ (2,511,266)	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (6,746)	$ (3,871)	$ (1,605)	$ 545	$ 2,797	$ 4,983	$ 7,566	$ 8,431	$ 5,372	$ 516	$ (3,584)	$ (6,801)	$ 7,603
Winter Period Account Ending Balance w/int	**$ (1,880,938)**	**$ (981,331)**	**$ (205,517)**	**$ 608,603**	**$ 1,459,375**	**$ 2,225,607**	**$ 3,369,075**	**$ 2,864,984**	**$ 1,107,722**	**$ (726,336)**	**$ (1,923,594)**	**$ (3,105,739)**	**$ (3,105,739)**

(1) Prior Period Adjustment Provided in New Hampshire Docket No. DG 12-131	Prinicipal	($3,953,636)	Schedule 1, Page 2, Column D, Line 60
	Interest	($127,442)	Schedule 1, Page 2, Column D, Line 62
	Total	($4,081,078)	

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011-2012 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2011 - April 2012

FORM III
Schedule 3

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
Accrued Revenue	$ (2,240,351)	$ -	$ -	$ -	$ -	$ -	$1,369,829	$ 979,795	$ 609,827	$ (151,122)	$ (552,507)	$ (804,085)	$ (788,615)
Billed Revenue	$ 1,643,301	$ 45,141	$ 771	$ (189)	$ (16)	$ (53)	$1,004,941	$ 3,364,811	$ 5,904,685	$ 5,926,205	$ 5,108,297	$ 3,305,611	$ 26,303,506
Calendarized Revenue	**$ (597,051)**	**$ 45,141**	**$ 771**	**$ (189)**	**$ (16)**	**$ (53)**	**$ 2,374,769**	**$ 4,344,606**	**$ 6,514,512**	**$ 5,775,084**	**$ 4,555,790**	**$ 2,501,526**	**$ 25,514,890**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011-2012 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2011 - April 2012

Commodity Costs:	May-11 (Actual)	Jun-11 (Actual)	Jul-11 (Actual)	Aug-11 (Actual)	Sep-11 (Actual)	Oct-11 (Actual)	Nov-11 (Actual)	Dec-11 (Actual)	Jan-12 (Actual)	Feb-12 (Actual)	Mar-12 (Actual)	Apr-12 (Actual)	Total Winter
Chesapeake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 200,404	$ -	$ 310,808	$ -	$ -	**$ 511,212**
Distrigas	$ 50,391	$ 33,682	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 84,073**
DTE	$ 389,347		$ -	$ -	$ -	$ -	$ -	$ 120	$ 20,295	$ 244,732	$ 20,973	$ 51,076	**$ 726,543**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 622,426	$ 575,979	$ 579,304	$ 483,200	$ 295,025	**$ 2,555,934**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 198	$ 563	$ 813	$ 629	$ 252	$ 180	**$ 2,635**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,826	$ -	**$ 71,826**
Portland	$ 30	$ 117	$ 66	$ -	$ -	$ -	$ -	$ 546	$ 27	$ 4,826	$ 3,021	$ 27	**$ 8,661**
Repsol	$ 268,857	$ -	$ -	$ -	$ -	$ -	$ -	$ 759,850	$ 512,514	$ 484,519	$ 432,145	$ 460,129	**$ 2,918,015**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,402)	$ -	**$ (11,402)**
Spark Energy Gas, LP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Tennessee	$ 9,251	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,503	$ 12,104	$ 7,468	$ 6,583	$ 8,844	**$ 55,751**
Virginia Power	$ 492,014	$ -	$ -	$ -	$ -	$ -	$ -	$ 138,203	$ -	$ 237,055	$ 75,098	$ 22,946	**$ 965,316**
Allocation Adjustment	$ 4,371	$ 129	$ 3	$ 3	$ 4	$ 4	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4,513**
Subtotal	$ 1,214,261	$ 33,927	$ 69	$ 3	$ 4	$ 4	$ 198	$ 1,733,615	$ 1,121,731	$ 1,869,341	$ 1,081,697	$ 838,227	**$ 7,893,076**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,843,954	$ 1,435,228	$ 1,884,619	$ 1,094,583	$ 1,071,786	$ 677,517	**$ 8,007,687**
Commodity Cost Reversals	$ (1,209,861)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,843,954)	$ (1,435,228)	$ (1,884,619)	$ (1,094,583)	$ (1,071,786)	**$ (8,540,031)**
Subtotal	$ 4,400	$ 33,927	$ 69	$ 3	$ 4	$ 4	$ 1,844,152	$ 1,324,889	$ 1,571,122	$ 1,079,305	$ 1,058,900	$ 443,958	**$ 7,360,732**
Withdrawal Charges	$ -	$ -	$ (62,534)	$ -	$ -	$ -	$ 201,259	$ 1,135,357	$ 2,185,675	$ 1,165,304	$ 247,601	$ 1,411	**$ 4,874,074**
ATV Reconciliation	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,226	$ 45,242	$ 97,490	$ 90,513	$ 55,026	$ 10,964	**$ 342,462**
Non Traditional Sales	$ (83,131)	$ 406	$ -	$ -	$ -	$ -	$ -	$ (382,078)	$ (415,221)	$ (783,865)	$ (493,165)	$ (66,381)	**$ (2,223,434)**
Net OBA Adjustment (Granite State Gas)	$ -	$ -	$ 62,534	$ -	$ -	$ -	$ 23,553	$ (2,646)	$ 7,308	$ (4,898)	$ 649	$ (17,482)	**$ 69,017**
Company Managed	$ (2,864)	$ -	$ -	$ -	$ -	$ -	$ -	$ (115,599)	$ (217,827)	$ (356,553)	$ (147,551)	$ (104,397)	**$ (944,791)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,390	$ 4,300	$ 3,081	$ 4,394	$ 6,206	$ 4,644	**$ 26,015**
Transportation Charges	$ 23,790	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,936	$ 9,687	$ 39,484	$ 30,910	**$ 128,806**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 73,468	$ 156,663	$ 238,823	$ 301,797	$ 265,323	$ 158,926	**$ 1,195,000**
Inventory Finance Charges	$ 158	$ 396	$ 635	$ 849	$ 957	$ 956	$ 969	$ 823	$ 563	$ 279	$ 159	$ 121	**$ 6,864**
Other	$ -	$ -	$ (973)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (973)**
Subtotal	$ (62,046)	$ 802	$ (339)	$ 849	$ 957	$ 956	$ 345,864	$ 842,062	$ 1,924,828	$ 426,657	$ (26,267)	$ 18,716	**$ 3,473,040**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (487,378)	$ (670,459)	$ (1,140,418)	$ (646,727)	$ (170,778)	$ (115,281)	**$ (3,231,041)**
Sales for Resale Reversals	$ 93,943	$ -	$ -	$ -	$ -	$ -	$ -	$ 487,378	$ 670,459	$ 1,140,418	$ 646,727	$ 170,778	**$ 3,209,704**
Subtotal	$ 93,943	$ -	$ -	$ -	$ -	$ -	$ (487,378)	$ (183,082)	$ (469,959)	$ 493,691	$ 475,949	$ 55,497	**$ (21,338)**
Total Commodity Costs	**$ 36,297**	**$ 34,729**	**$ (270)**	**$ 852**	**$ 960**	**$ 960**	**$ 1,702,639**	**$ 1,983,870**	**$ 3,025,991**	**$ 1,999,653**	**$ 1,508,582**	**$ 518,171**	**$ 10,812,435**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011-2012 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2011 - April 2012

FORM III
Schedule 4 - Revised
Page 2 of 2

Demand Costs

	May-11 (Actual)	Jun-11 (Actual)	Jul-11 (Actual)	Aug-11 (Actual)	Sep-11 (Actual)	Oct-11 (Actual)	Nov-11 (Actual)	Dec-11 (Actual)	Jan-12 (Actual)	Feb-12 (Actual)	Mar-12 (Actual)	Apr-12 (Actual)	Total Winter
Pipeline Reservation													
Algonquin Gas Transmission	$ 16,159	$ 16,159	$ 16,159	$ 16,159	$ 16,159	$ 16,159	$ 16,159	$ 15,741	$ 15,741	$ 15,741	$ 15,741	$ 15,741	**$ 191,820**
BG Energy Merchants, LLC	$ 491,230	$ 489,712	$ 505,061	$ 486,505	$ 484,225	$ 478,859	$ 459,866	$ 461,995	$ 468,958	$ 468,152	$ 486,657	$ 473,272	**$ 5,754,493**
Emera Energy Services, Inc.	$ 35,586	$ 35,168	$ 36,251	$ 34,828	$ 34,778	$ 34,043	$ 33,730	$ 34,196	$ 33,227	$ 33,719	$ 33,808	$ 33,865	**$ 413,199**
Granite State Gas Transmission, Inc.	$ 134,633	$ 134,633	$ 134,633	$ 138,202	$ 143,630	$ 143,630	$ 146,878	$ 146,878	$ 146,878	$ 146,878	$ 146,878	$ 146,878	**$ 1,710,628**
Iroquois Gas Transmision System	$ 21,079	$ 21,079	$ 21,079	$ 21,079	$ 21,079	$ 21,079	$ 21,079	$ 20,533	$ 20,533	$ 20,533	$ 20,533	$ 20,533	**$ 250,215**
Portland Natural Gas Transmission	$ 21,533	$ 21,533	$ 21,533	$ 21,533	$ 21,533	$ 21,533	$ 21,533	$ 1,216,561	$ 1,216,561	$ 1,216,561	$ 1,216,561	$ 1,216,561	**$ 6,233,536**
Tennessee Gas Pipeline Co	$ 133,638	$ 133,638	$ 206,238	$ 263,692	$ 263,692	$ 206,238	$ 263,692	$ 188,276	$ 128,912	$ 186,366	$ 186,366	$ 128,912	**$ 2,289,659**
Texas Eastern Transmission	$ 3,304	$ 3,304	$ 3,304	$ 3,304	$ 3,289	$ 3,289	$ 3,289	$ 3,204	$ 3,204	$ 3,204	$ 3,231	$ 3,231	**$ 39,156**
Union Gas Transmission	$ 7,497	$ 7,421	$ 7,354	$ 7,520	$ 7,320	$ 7,151	$ 7,045	$ 6,825	$ 6,835	$ 6,880	$ 6,880	$ 7,128	**$ 85,854**
Vector Pipeline LP	$ 87,970	$ 87,951	$ 87,983	$ 87,952	$ 87,895	$ 87,897	$ 87,898	$ 122,532	$ 122,553	$ 122,581	$ 122,592	$ 122,588	**$ 1,228,391**
Total Pipeline Reservation	$ 952,629	$ 950,598	$ 1,039,595	$ 1,080,774	$ 1,083,600	$ 1,019,877	$ 1,061,169	$ 2,216,739	$ 2,163,402	$ 2,220,616	$ 2,239,246	$ 2,168,709	**$ 18,196,953**
Product Demand													
Alberta Northeast	$ 2,068	$ 1,103	$ -	$ 2,741	$ -	$ 2,333	$ 1,356	$ -	$ 19,462	$ 9,283	$ 8,665	$ 10,281	**$ 57,292**
Distrigas	$ 107,849	$ 107,849	$ 107,849	$ 107,849	$ 107,849	$ 107,849	$ 107,849	$ 35,417	$ 35,417	$ 35,417	$ 35,417	$ 35,417	**$ 932,022**
DTE Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,952	$ 18,952	$ 18,952	$ -	**$ 56,856**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,264	$ 1,421	$ 1,421	
Total Product Demand	$ 109,917	$ 108,951	$ 107,849	$ 110,589	$ 107,849	$ 110,182	$ 109,205	$ 35,417	$ 73,830	$ 67,916	$ 64,455	$ 47,119	**$ 1,046,170**
Storage Pipeline Transportation and Demand Reservation													
Adj for PNTGS Rate Case Billings to Marketers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,921	$ 22,610	$ 22,936	$ 23,232	$ 23,719	**$ 114,417**
DTE Energy	$ 117,141	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 117,141**
Tennessee	$ 4,707	$ 4,707	$ 6,889	$ 6,889	$ 6,889	$ 6,889	$ 6,889	$ 5,705	$ 5,689	$ 5,689	$ 5,689	$ 5,689	**$ 72,318**
Texas Eastern	$ 85	$ 84	$ 83	$ 83	$ 83	$ 83	$ 83	$ 81	$ 81	$ 81	$ 82	$ 82	**$ 989**
Wash 10	$ -	$ 117,141	$ 117,141	$ 117,141	$ 117,141	$ 117,141	$ 117,141	$ 114,107	$ 114,107	$ 114,107	$ 114,107	$ 114,107	**$ 1,273,382**
Company Managed	$ (201,732)	$ (108,786)	$ (110,391)	$ (107,389)	$ (107,984)	$ (110,579)	$ (111,915)	$ (422,104)	$ (441,163)	$ (452,192)	$ (462,652)	$ (470,580)	**$ (3,107,468)**
Total Storage and Demand Reservation	$ (79,799)	$ 13,146	$ 13,723	$ 16,724	$ 16,129	$ 13,534	$ 12,198	$ (280,290)	$ (298,677)	$ (309,380)	$ (319,544)	$ (326,984)	**$ 1,578,248**
Demand Cost Estimates	$ 841,183	$ 1,074,499	$ 1,083,651	$ 1,061,311	$ 1,075,120	$ 1,057,308	$ 1,794,427	$ 1,794,320	$ 1,814,333	$ 1,772,830	$ 1,756,079	$ 764,457	**$ 15,889,517**
Demand Cost Reversals	$ (854,320)	$ (841,183)	$ (1,074,499)	$ (1,083,651)	$ (1,061,311)	$ (1,075,120)	$ (1,057,308)	$ (1,794,427)	$ (1,794,320)	$ (1,814,333)	$ (1,772,830)	$ (1,756,079)	**$ (15,979,380)**
Total Fixed Demand	$ 969,609	$ 1,306,012	$ 1,170,317	$ 1,185,748	$ 1,221,386	$ 1,125,781	$ 1,919,691	$ 1,971,758	$ 1,958,568	$ 1,937,649	$ 1,967,407	$ 897,221	**$ 20,731,508**
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,478	$ 63,478	$ 63,478	$ 63,478	$ 63,478	$ 63,478	**$ 380,866**
Capacity Release	$ (148,146)	$ (158,427)	$ (169,830)	$ (170,085)	$ (170,088)	$ (167,974)	$ (171,454)	$ (268,407)	$ (144,594)	$ (388,743)	$ (267,484)	$ (271,214)	**$ (2,496,446)**
Capacity Mitigation	$ (12,294)	$ (11,752)	$ (22,280)	$ (22,284)	$ (22,287)	$ (25,979)	$ (26,230)	$ (16,223)	$ (16,223)	$ (15,393)	$ (15,393)	$ (16,630)	**$ (222,966)**
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	$ 51,294	**$ 307,762**
Miscellaneous Overhead	$ -	$ -	$ -	$ 18,940	$ 18,940	$ 18,940	$ 54,269	$ 54,269	$ 54,269	$ 54,269	$ 54,269	$ 54,270	**$ 382,438**
Demand Cost Estimates - Capacity Release	$ (178,303)	$ (200,501)	$ (200,505)	$ (200,544)	$ (201,751)	$ (192,539)	$ (275,553)	$ (283,509)	$ (524,415)	$ (286,112)	$ (286,149)	$ (256,556)	**$ (3,086,438)**
Demand Cost Reversals - Capacity Release	$ 168,788	$ 178,303	$ 200,501	$ 200,505	$ 200,544	$ 201,751	$ 192,539	$ 275,553	$ 283,509	$ 524,415	$ 286,112	$ 286,149	**$ 2,998,670**
Total Demand Costs	**$ 799,655**	**$ 1,113,635**	**$ 978,204**	**$ 1,012,280**	**$ 1,046,744**	**$ 959,980**	**$ 1,808,034**	**$ 1,848,214**	**$ 1,725,886**	**$ 1,940,857**	**$ 1,853,533**	**$ 808,011**	$ 15,895,034
Demand Costs Transferred to Summer Perioc	$ (199,745)	$ (199,745)	$ (199,745)	$ (199,745)	$ (199,745)	$ (199,745)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,198,470)**
Net Demand Costs For Winter Period	**$ 599,910**	**$ 913,890**	**$ 778,459**	**$ 812,535**	**$ 846,999**	**$ 760,235**	**$ 1,808,034**	**$ 1,848,214**	**$ 1,725,886**	**$ 1,940,857**	**$ 1,853,533**	**$ 808,011**	**$ 14,696,564**
Total Gas Costs	**$ 636,208**	**$ 948,618**	**$ 778,189**	**$ 813,387**	**$ 847,959**	**$ 761,195**	**$ 3,510,672**	**$ 3,832,084**	**$ 4,751,878**	**$ 3,940,510**	**$ 3,362,115**	**$ 1,326,182**	**$ 25,508,999**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2011-2012 WINTER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
May 2011 - April 2012

New Hampshire	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
Throughput IN													
BTU Factor	1.027	1.043	1.039	1.038	1.041	1.042	1.047	1.037	1.032	1.030	1.035	1.028	
GST Meter Throughput (MCF)	356,512	270,436	244,612	266,618	284,943	411,448	528,465	774,469	924,402	771,024	625,991	456,655	5,915,575
Salem Meter (MCF)	16,128	11,573	9,849	10,962	11,554	20,294	28,517	46,797	58,942	47,478	34,494	21,251	317,839
GST Meter Throughpurt (DTH)	366,138	282,065	254,152	276,749	296,626	428,729	553,303	803,124	953,983	794,155	647,901	469,441	6,126,365
Salem Meter (DTH)	16,563	12,071	10,233	11,379	12,028	21,146	29,857	48,528	60,828	48,902	35,701	21,846	329,083
LNG/Propane													
Total Throughput	382,701	294,135	264,385	288,128	308,653	449,875	583,160	851,653	1,014,811	843,057	683,602	491,287	6,455,449
Throughput OUT													
Residential Gas													
Charged	99,021	60,207	39,982	32,065	35,704	42,794	110,616	149,104	259,735	253,799	215,755	135,293	1,434,075
Uncharged Current	54,059	36,548	23,711	26,200	30,507	67,389	95,865	147,129	160,385	159,951	120,325	62,968	985,036
Uncharged Prior	-93,513	-54,059	-36,548	-23,711	-26,200	-30,507	-67,389	-95,865	-147,129	-160,385	-159,951	-120,325	-1,015,582
Total Residential Gas	**59,567**	**42,695**	**27,145**	**34,555**	**40,010**	**79,677**	**139,091**	**200,368**	**272,991**	**253,365**	**176,129**	**77,936**	1,403,530
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	105,557	73,565	51,650	45,133	51,409	58,886	125,070	166,260	276,762	263,638	214,109	136,423	1,568,462
Uncharged Current	60,304	50,260	31,891	37,106	37,702	65,381	106,073	159,767	171,210	167,289	122,384	65,190	1,074,556
Uncharged Prior	-100,854	-60,304	-50,260	-31,891	-37,106	-37,702	-65,381	-106,073	-159,767	-171,210	-167,289	-122,384	-1,110,221
Total C/I Gas	**65,006**	**63,521**	**33,281**	**50,348**	**52,005**	**86,565**	**165,762**	**219,954**	**288,205**	**259,717**	**169,205**	**79,229**	1,532,797
Transportation													
Charged	245,934	206,899	186,227	199,963	218,544	240,520	292,655	346,450	409,128	387,150	370,314	299,313	3,403,097
Uncharged Current	106,878	102,924	75,397	102,105	102,288	155,863	175,999	227,831	201,618	200,264	177,881	108,333	1,737,380
Uncharged Prior	-127,983	-106,878	-102,924	-75,397	-102,105	-102,288	-155,863	-175,999	-227,831	-201,618	-200,264	-177,881	-1,757,031
Total Transportation	**224,829**	**202,945**	**158,700**	**226,671**	**218,726**	**294,095**	**312,791**	**398,282**	**382,915**	**385,796**	**347,931**	**229,765**	**3,383,447**
Company Use	**31**	**29**	**22**	**21**	**28**	**102**	**116**	**166**	**274**	**310**	**248**	**178**	**1,524**
Total Throughput OUT	**349,433**	**309,190**	**219,149**	**311,595**	**310,769**	**460,439**	**617,760**	**818,769**	**944,385**	**899,188**	**693,512**	**387,108**	**6,321,298**
Total Throughput IN	**382,701**	**294,135**	**264,385**	**288,128**	**308,653**	**449,875**	**583,160**	**851,653**	**1,014,811**	**843,057**	**683,602**	**491,287**	**6,455,449**
Difference IN/OUT	33,268	-15,055	45,236	-23,467	-2,116	-10,563	-34,600	32,884	70,426	-56,131	-9,910	104,179	134,151
%													2.08%

Attachment A- Revised

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2012

PEAK PERIOD - Acct 182.11

	BEGINNING BALANCE	RECONCILIATION ADJUSTMENT (1)	REVISED BALANCE	WORKING CAP ALLOWANCE	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E	F	G = D + F	H = C + G	I = (C + H) / 2	J	K = I * (J / 12)	L = H + K
May 2011 *(2)*	$ (35,228)	$ (2,375)	$ (37,603)	359	0.0564%	(568)	(209)	(37,812)	(37,707)	3.25%	(102)	(37,914)
June			$ (37,914)	535	0.0564%	44	579	(37,335)	(37,625)	3.25%	(102)	(37,437)
July			$ (37,437)	439	0.0564%	1	440	(36,998)	(37,217)	3.25%	(101)	(37,098)
August *(3)*			$ (37,098)	670	0.0824%	(0)	670	(36,428)	(36,763)	3.25%	(100)	(36,528)
September			$ (36,528)	699	0.0824%	(0)	699	(35,829)	(36,179)	3.25%	(98)	(35,927)
October			$ (35,927)	627	0.0824%	(0)	627	(35,300)	(35,614)	3.25%	(96)	(35,397)
November			$ (35,397)	2,893	0.0824%	883	3,776	(31,621)	(33,509)	3.25%	(91)	(31,712)
December			$ (31,712)	3,158	0.0824%	1,625	4,783	(26,929)	(29,320)	3.25%	(79)	(27,008)
January 2012			$ (27,008)	3,916	0.0824%	2,292	6,208	(20,800)	(23,904)	3.25%	(65)	(20,865)
February			$ (20,865)	3,247	0.0824%	2,018	5,265	(15,600)	(18,232)	3.25%	(49)	(15,649)
March			$ (15,649)	2,770	0.0824%	1,438	4,209	(11,440)	(13,545)	3.25%	(37)	(11,477)
April			$ (11,477)	1,093	0.0824%	820	1,913	(9,564)	(10,520)	3.25%	(28)	(9,592)
Totals				20,405		8,554					(948)	

(1) Prior Period Adjustment Provided in New Hampshire	Prinicipal	($2,243)	Schedule 1, Page 2, Column D, Line 63
Docket No. DG 12-131	Interest	($77)	Schedule 1, Page 2, Column D, Line 64
	Total	($2,320)	
		(55)	Interest Adjustment to beginning balance - Revise Sch 3 page 8 of 22
		(2,375)	

(2) Working Capital Allowance calculated by taking monthly Total Gas Costs from Sch 4, page 2 of 2, and multiplying by (6.33/365)*Interest Rate.
(3) Effective 8/1/2011, Working Capital Percentage changed in accordance with most recent rate case proceeding - Docket No. DG 11-69 .
Effective 8/1/2011, Working Capital Allowance = Total Gas Costs from Sch 4, page 2 of 2, multiplied by (9.25/365)*Interest Rate.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2012

PEAK PERIOD - Acct 182.16

	BEGINNING BALANCE	RECONCILIATION ADJUSTMENT(1)	REVISED BALANCE	BAD DEBT ALLOWANCE	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E	F	G = D + F	H = C + G	I = (C + H) / 2	J	K = I * (J / 12)	L = H + K
May 2011 (2)	1,935	(18,489)	(16,554)	2,865	0.45%	2,417	5,282	(11,272)	(13,913)	3.25%	(38)	(11,310)
June			(11,310)	4,271	0.45%	(187)	4,084	(7,226)	(9,268)	3.25%	(25)	(7,251)
July			(7,251)	3,504	0.45%	(3)	3,501	(3,750)	(5,501)	3.25%	(15)	(3,765)
August (3)			(3,765)	79,527		1	79,528	75,763	35,999	3.25%	97	75,860
September			75,860	29,438		0	29,438	105,299	90,579	3.25%	245	105,544
October			105,544	10,859		0	10,860	116,403	110,974	3.25%	301	116,704
November			116,704	4,172		(29,635)	(25,463)	91,241	103,973	3.25%	282	91,523
December			91,523	3,788		(53,981)	(50,193)	41,330	66,426	3.25%	180	41,510
January 2012			41,510	4,193		(76,543)	(72,349)	(30,839)	5,335	3.25%	14	(30,825)
February			(30,825)	1,957		(67,080)	(65,123)	(95,948)	(63,386)	3.25%	(172)	(96,120)
March			(96,120)	19,429		(47,960)	(28,530)	(124,650)	(110,385)	3.25%	(299)	(124,949)
April			(124,949)	10,222		(27,845)	(17,623)	(142,572)	(133,760)	3.25%	(362)	(142,934)
Totals				174,226		(300,815)					209	

(1) Prior Period Adjustment Provided in New Hampshire Docket No. DG 12-131	Prinicipal	($17,801)	Schedule 1, Page 2, Column D, Line 65
	Interest	($580)	Schedule 1, Page 2, Column D, Line 66
	Total	($18,381)	
		(108)	Interest Adjustment to beginning balance - Revise Sch 3 page 9 of 22
		(18,489)	

(2) Bad Debt Allowance calculated by multiplying % Allowed Bad Debt by monthly Total Gas Cost on Sch 4, page 2 of 2, and Working Capital Allowance on Attachment A
(3) Effective 8/1/2011, Bad Debt recovery method is changed in accordance with Northern's most recent rate case proceeding - Docket No. DG 11-69.
Bad Debt recovery is based on actual write-offs. Bad Debt Allowance is based on projected write-offs.

Attachment C

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Costs
June 2011 through October 2012

		Beginning Balance		Firm Sales and Transportation (therms)	ERC Recovery/Passback Rate		Current ERC Recoveries/ Passbacks	Ending Balance
June 2011	(act)	$ 22,192		2,685,591	$ 0.0054		$ 14,506	$ 7,686
July 2011	(act)	$ 7,686		2,106,104	$ 0.0054		$ 11,378	$ (3,692)
August 2011	(act)	$ (3,692)		2,011,395	$ 0.0054		$ 10,860	$ (14,553)
September 2011	(act)	$ (14,553)		2,308,283	$ 0.0054		$ 12,467	$ (27,020)
October 2011	(act)	$ (27,020)		2,662,803	$ 0.0054		$ 14,380	$ (41,400)
November 2011	(act)	$ 301,442	(1)	4,489,460	$ 0.0053	(2)	$ 23,464	$ 277,978
December 2011	(act)	$ 277,978		5,830,741	$ 0.0051		$ 29,740	$ 248,238
January 2012	(act)	$ 248,238		8,605,058	$ 0.0051		$ 43,634	$ 204,604
February 2012	(act)	$ 204,604		8,265,650	$ 0.0051		$ 42,157	$ 162,447
March 2012	(act)	$ 162,447		7,116,396	$ 0.0051		$ 36,296	$ 126,151
April 2012	(act)	$ 126,151		4,855,061	$ 0.0051		$ 24,764	$ 101,387
May 2012	(act)	$ 101,387		3,446,312	$ 0.0051		$ 17,579	$ 83,808
June 2012	(act)	$ 83,808		2,609,863	$ 0.0051		$ 13,320	$ 70,489
July 2012	(est)	$ 70,489		2,127,235	$ 0.0051		$ 10,849	$ 59,640
August 2012	(est)	$ 59,640		2,148,963	$ 0.0051		$ 10,960	$ 48,680
September 2012	(est)	$ 48,680		2,315,223	$ 0.0051		$ 11,808	$ 36,872
October 2012	(est)	$ 36,872		3,380,560	$ 0.0051		$ 17,241	$ 19,632

(1) November Beginning Balance includes $342,842 amortization from all prior years at 1/7 of annual costs. (See Section 4.7 of Tariff.)

(2) November Current ERC Recoveries/Passbacks reflect an Average ERC Rate based on actual Firm Sales and Transportation (therms) at $0.0054 and actual Firm Sales and Transportation (therms) at $0.0051.

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
RLIARA Reconciliation

		Beginning Balance	Program Costs	Regulatory Assessments	RLIARA Recoveries	Ending Balance	Average Monthly Balance	Interest Rate	Interest	Ending Balance w/Interest
		A	B	C	D	D = A + B +C - D	E = (A +D) / 2	F	G = E * (F / 12)	H = D + G
May 2011	Actual	$ (37,232)	$ 23,941		$ 15,922	$ (29,212)	$ (33,222)	3.25%	$ (92)	$ (29,303)
June 2011	Actual	$ (29,303)	$ 14,720		$ 11,548	$ (26,132)	$ (27,718)	3.25%	$ (75)	$ (26,207)
July 2011	Actual	$ (26,207)	$ 16,632		$ 9,053	$ (18,629)	$ (22,418)	3.25%	$ (62)	$ (18,691)
August 2011	Actual	$ (18,691)	$ 10,600		$ 8,642	$ (16,733)	$ (17,712)	3.25%	$ (48)	$ (16,781)
September 2011	Actual	$ (16,781)	$ 10,749		$ 9,925	$ (15,956)	$ (16,369)	3.25%	$ (44)	$ (16,000)
October 2011	Actual	$ (16,000)	$ 11,515		$ 11,419	$ (15,905)	$ (15,953)	3.25%	$ (43)	$ (15,948)
November 2011	Actual	$ (15,948)	$ 18,393		$ 22,735	$ (20,291)	$ (18,119)	3.25%	$ (49)	$ (20,340)
December 2011	Actual	$ (20,340)	$ 22,445		$ 32,653	$ (30,549)	$ (25,444)	3.25%	$ (69)	$ (30,618)
January 2012	Actual	$ (30,619)	$ 31,132		$ 47,910	$ (47,396)	$ (39,008)	3.25%	$ (108)	$ (47,504)
February 2012	Actual	$ (47,504)	$ 41,685		$ 46,289	$ (52,108)	$ (49,806)	3.25%	$ (129)	$ (52,237)
March 2012	Actual	$ (52,237)	$ 32,705		$ 39,852	$ (59,384)	$ (55,810)	3.25%	$ (151)	$ (59,535)
April 2012	Actual	$ (59,535)	$ 24,970		$ 27,191	$ (61,756)	$ (60,645)	3.25%	$ (164)	$ (61,920)
May 2012	Actual	$ (61,920)	$ 24,071	$ 137,625 (1)	$ 25,180	$ 74,597	$ 6,339	3.25%	$ 1,477 (2)	$ 76,074
June 2012	Actual	$ 76,074	$ 15,339	$ 15,861	$ 23,230	$ 84,044	$ 80,059	3.25%	$ 210	$ 84,254
July 2012	Est.	$ 84,254	$ 16,632	$ 15,861	$ 9,053	$ 107,694	$ 95,974	3.25%	$ 260	$ 107,954
August 2012	Est.	$ 107,954	$ 10,600	$ 15,861	$ 8,642	$ 125,772	$ 116,863	3.25%	$ 317	$ 126,089
September 2012	Est.	$ 126,089	$ 10,749	$ 15,861	$ 9,925	$ 142,775	$ 134,432	3.25%	$ 364	$ 143,139
October 2012	Est.	$ 143,139	$ 11,515	$ 15,861	$ 11,419	$ 159,096	$ 151,118	3.25%	$ 409	$ 159,505

(1) May 2012 Regulatory Assessment includes Assessments from August 1, 2011 to April 30, 2012.
(2) Includes interest true up from August 1, 2011 to April 30, 2012.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2011 - 2012

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	TOTAL
Forecast Calendar Month Sales	366,085	540,243	617,378	541,485	480,275	315,980	2,861,446
Actual Sales	304,854	425,306	561,195	513,083	345,334	157,165	2,306,937
Difference	(61,231)	(114,937)	(56,183)	(28,402)	(134,941)	(158,815)	(554,509)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	321,945	544,407	596,158	592,336	406,398	210,270	2,671,513
Actual Sales	304,854	425,306	561,195	513,083	345,334	157,165	2,306,937
Weather Variance	17,091	119,101	34,963	79,252	61,064	53,105	364,576
Total Variance Excluding Weather (excl weather effect)	(44,140)	4,164	(21,220)	50,851	(73,877)	(105,710)	(189,933)
Variance-difference due to meter count							(125,595)
-difference in load pattern							(428,913)
SALES							(554,509)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2011 - 2012

	NORMAL MMBtu			METERS		
	2011-12 Forecast	2011-12 Actual	Difference	2011-12 Forecast	2011-12 Actual	Difference
Res Heat	1,331,896	1,098,432	(233,464)	125,978	125,484	(494)
Res General	21,321	23,626	2,305	9,191	9,431	240
Total Res	1,353,217	1,122,059	(231,159)	135,169	134,915	(254)
G-40	636,387	558,540	(77,848)	26,049	25,792	(257)
G-50	107,036	93,427	(13,609)	5,474	5,087	(387)
G-41	538,218	381,000	(157,218)	2,373	2,106	(267)
G-51	143,120	106,593	(36,526)	979	873	(106)
G-42	78,088	37,332	(40,755)	103	60	(43)
G-52	5,380	7,986	2,606	23	30	7
Total C & I	1,508,228	1,184,878	(323,350)	35,001	33,948	(1,053) .
Total Company	2,861,446	2,306,937	(554,509)	170,170	168,863	(1,307)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2011-12 Forecast	2011-12 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.57	8.75	(1.82)	(5,223)	(228,241)	(233,464)	-17.53%
Res General	2.32	2.51	0.19	557	1,749	2,305	10.81%
Total Res	12.89	11.26	(1.63)	(4,666)	(226,493)	(231,159)	-17.08%
G-40	24.43	21.66	(2.77)	(6,279)	(71,569)	(77,848)	-12.23%
G-50	19.55	18.37	(1.19)	(7,563)	(6,046)	(13,609)	-12.71%
G-41	226.80	180.91	(45.89)	(60,582)	(96,636)	(157,218)	-29.21%
G-51	146.18	122.10	(24.08)	(15,509)	(21,018)	(36,526)	-25.52%
G-42	759.30	622.21	(137.09)	(32,530)	(8,225)	(40,755)	-52.19%
G-52	230.43	266.21	35.78	1,533	1,073	2,606	48.45%
Total C & I	43.09	34.90	(8.19)	(120,929)	(202,421)	(323,350)	-21.44%
Total Company	16.82	13.66	(3.15)	(125,595)	(428,913)	(554,509)	-19.38%

Schedule 16

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
Residential Low Income Assistance and Regulatory Assessment Costs (RLIARA)

		Customer Charge	First Block	Last Block	Total
1	**Peak Period**				
2	R-5 Base Rates	$13.73	$0.4410	$0.3829	
3	R-10 Rate at 40% of R5	$5.50	$0.1764	$0.1532	
4	Program Subsidy	$8.23	$0.2646	$0.2297	
5	Average Annual Therms		203	412	615
6					
7	Peak Period Subsidy	$49.37	$53.70	$94.66	$197.73
8					
9	**Off Peak Period**				
10	R-5 Base Rates	$13.73	$0.4410	$0.4410	
11	R10 Rate at 40% of R5	$3.80	$0.1764	$0.1764	
12	Program Subsidy	$9.93	$0.2646	$0.2646	
13	Average Annual Therms		142	35	177
14					
15	Off Peak Period Subsidy	$59.58	$37.47	$9.37	$106.41
16					
17	Estimated Annual Subsidy				$304.15
18					
19	Number of Estimated 2012/13 Participants				1,198
20					
21	Annual Subsidy times Number of Participants (Ln 17 *Ln 19)				$364,368
22	Prior Year Ending Balance - RLIARA Page 2				$146,417
23	Estimated Annual Administrative Costs				$0
24	Estimated 12 month Regulatory Assessment				$190,332
25	Total Program Costs				$701,117
26					
27	Estimated weather normalized firm therms billed for				
28	the twelve months ended 10/31/13 sales and transportation				62,063,926
29	(Attachment 2 to Schedule 10B, Revised Page 1 of 3, Line 41, "Total Division"				
30	subtract Line 41 "Special Contracts").				
31	**Total Residential Low Income Assistance and Regulatory Assessment Costs Charge**				**$0.0113**

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
NOVEMBER 2011 THROUGH OCTOBER 2012
RESIDENTIAL LOW INCOME ASSISTANCE AND REGULATORY ASSESSMENT COSTS (RLIARA) RECONCILIATION

											(Estimate)	(Estimate)	(Estimate)	(Estimate)
1	**FOR THE MONTH OF:**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total**
2	**DAYS IN MONTH**	30	31	31	28	31	30	31	30	31	31	30	31	365
3														**Average**
4	RLIA Participant Count	1,109	1,112	1,116	1,579	1,329	1,334	1,114	1,223	1,180	1,199	1,036	1,042	1,198
5														**Total**
6	Beginning Balance	($15,948)	($20,340)	($30,619)	($47,504)	($52,237)	($59,538)	($61,920)	$76,074	$84,254	$94,962	$113,068	$130,079	($15,948)
7														
8	Add: Actual Costs	$18,393	$22,445	$31,132	$41,685	$32,705	$24,970	$24,071	$15,339	$14,333	$10,600	$10,749	$11,515	$257,937
9														
10	Add: Regulatory Assessments							$137,625	$15,861	$15,861	$15,861	$15,861	$15,861	$216,932
11														
12	Less: Collected Revenue	$22,735	$32,653	$47,910	$46,289	$39,852	$27,191	$25,180	$23,230	$19,733	$8,642	$9,925	$11,419	($314,759)
13														
14	Add: Administrative and Start Up Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15														
16	Ending Balance Pre-Interest	($20,291)	($30,548)	($47,396)	($52,108)	($59,384)	($61,759)	$74,597	$84,044	$94,715	$112,782	$129,754	$146,036	
17														
18	Month's Average Balance	($18,120)	($25,444)	($39,008)	($49,806)	($55,810)	($60,648)	$6,339	$80,059	$89,485	$103,872	$121,411	$138,057	
19														
20	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%	
21														
22	Interest Applied	($48.40)	($70.23)	($107.67)	($128.61)	($154.05)	($161.56)	$1,477.24	$209.59	$247.00	$286.71	$324.32	$381.08	$2,255
23														
24	Ending Balance	($20,340)	($30,619)	($47,504)	($52,237)	($59,538)	($61,920)	$76,074	$84,254	$94,962	$113,068	$130,079	**$146,417**	$146,417

Note- Regulatory Assesement costs reflect an adjustment to include costs for the period August 2011 through April 2012 consistant with the Settlement Agreement approved in DG 11-069.
May and June 2012 Interest Applied line items includes true ups for Regulatory Assessment Costs.

Northern Utilities, Inc. -- New Hampshire Division

Energy Efficiency Budget

	Residential	Low-Income	Gen Service	Total
September-12	$30,261	$8,776	$46,855	$85,892
October-12	$30,261	$8,776	$23,428	$62,464
November-12	$30,261	$8,776	$31,237	$70,274
December-12	$145,254	$42,123	$31,237	$218,613
January-13	$25,375	$7,250	$29,400	$62,025
February-13	$30,450	$8,700	$39,200	$78,350
March-13	$35,525	$10,150	$30,810	$76,485
April-13	$35,525	$10,150	$49,000	$94,675
May-13	$25,375	$7,250	$29,400	$62,025
June-13	$88,154	$24,650	$70,010	$182,814
July-13	$20,300	$5,800	$19,600	$45,700
August-13	$50,750	$14,500	$58,800	$124,050
September-13	$27,254	$7,250	$60,210	$94,714
October-13	$25,375	$7,250	$29,400	$62,025
Total	$660,643	$173,558	$595,441	$1,429,642

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

	Residential	Low-Income	Gen Service	Total
September-12	$31,569	0	$54,323	$85,892
October-12	$31,988	0	$30,477	$62,464
November-12	$32,434	0	$37,840	$70,274
December-12	$156,837	0	$61,777	$218,613
January-13	$27,575	0	$34,450	$62,025
February-13	$33,182	0	$45,168	$78,350
March-13	$38,685	0	$37,800	$76,485
April-13	$38,552	0	$56,123	$94,675
May-13	$27,321	0	$34,704	$62,025
June-13	$93,550	0	$89,264	$182,814
July-13	$21,362	0	$24,338	$45,700
August-13	$53,048	0	$71,002	$124,050
September-13	$28,328	0	$66,386	$94,714
October-13	$26,792	0	$35,233	$62,025
Total	$702,087	$0	$727,555	$1,429,642

DSM Charge Factor Calculation

DSM Charge Factors for Residential Customers

DSM Reconciliation Adjustment	$17,540	Schedule 16 DSM B Nov '12 - Oct '13 Totals- November 2012 Beginning Balance
DSM Costs	$539,599	Schedule 16 DSM B Nov '12 - Oct '13 Totals- Column 2
DSM Share Holder Incentive	$40,246	Schedule 16 DSM B Nov '12 - Oct '13 Totals- Column 3
DSM Low-Income Costs	$38,066	Schedule 16 DSM B Nov '12 - Oct '13 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$2,703	Schedule 16 DSM B Nov '12 - Oct '13 Totals- Column 5
Total	$638,154	
Forecasted Annual Throughput Volumes for Residential Customers	16,796,601	Schedule 16 DSM B Nov '12 - Oct '13 Totals- Column 6
Conservation Charge Factor for Residential Customers	**$0.0380**	

DSM Charge Factors for Commercial and Industrial Customers (C&I)

DSM Reconciliation Adjustment	($115,205)	Schedule 16 DSM C Nov '12 - Oct '13 Totals- November 2011 Beginning Balance
DSM Costs	$478,303	Schedule 16 DSM C Nov '12 - Oct '13 Totals- Column 2
DSM Share Holder Incentive	$39,648	Schedule 16 DSM C Nov '12 - Oct '13 Totals- Column 3
DSM Low-Income Costs	$115,783	Schedule 16 DSM C Nov '12 - Oct '13 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$8,433	Schedule 16 DSM C Nov '12 - Oct '13 Totals- Column 5
Total	$526,961	
Forecasted Annual Throughput Volumes for C&I Customers	45,267,325	Schedule 16 DSM C Nov '12 - Oct '13 Totals- Column 6
Conservation Charge Factor for C&I Customers	**$0.0116**	

Northern Utilities, Inc.

New Hampshire Division

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

To Be Effective November 1, 2012 through October 31, 2013

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
August-11	Actual	$163,601	$0.0359	$11,272	$13,894	$1,724	$5,071	$267	$173,286	$168,443	3.25%	$465	$173,751	313,978	31
September-11	Actual	$173,751	$0.0359	$6,541	$30,378	$1,724	$2,713	$143	$202,168	$187,959	3.25%	$502	$202,670	353,426	30
October-11	Actual	$202,670	$0.0359	$16,260	($8,531)	$1,724	$560	$29	$180,192	$191,431	3.25%	$528	$180,720	452,865	31
November-11	Actual	$180,720	$0.0333	$24,885	$58,977	$1,724	$888	$47	$217,470	$199,095	3.25%	$532	$218,002	1,072,476	30
December-11	Actual	$218,002	$0.0333	$70,287	$30,186	$1,724	$581	$31	$180,237	$199,120	3.25%	$550	$180,787	1,957,958	31
January-12	Actual	$180,787	$0.0333	$104,751	$22,454	$2,973	$1,569	$83	$103,115	$141,951	3.25%	$392	$103,507	2,914,686	31
February-12	Actual	$103,507	$0.0333	$108,927	$17,659	$2,973	$1,245	$66	$16,522	$60,014	3.25%	$150	$16,672	3,271,023	28
March-12	Actual	$16,672	$0.0333	$84,802	$16,137	$2,973	$1,291	$68	($47,662)	($15,495)	3.25%	($43)	($47,704)	2,546,460	31
April-12	Actual	($47,704)	$0.0333	$68,916	$34,661	$2,973	$2,952	$155	($75,878)	($61,791)	3.25%	($165)	($76,043)	1,920,837	30
May-12	Actual	($76,043)	$0.0333	$32,974	$13,813	$2,973	$4,045	$213	($87,973)	($82,008)	3.25%	($226)	($88,199)	990,209	31
June-12	Actual	($88,199)	$0.0333	$21,606	$20,884	$2,973	$507	$27	($85,416)	($86,807)	3.25%	($232)	($85,647)	602,071	30
July-12	Actual	($85,647)	$0.0333	$13,314	$24,549	$2,973	$591	$31	($70,817)	($78,232)	3.25%	($216)	($71,033)	399,823	31
August-12	Actual	($71,033)	$0.0333	$11,393	$60,522	$2,973	$344	$117	($18,470)	($44,751)	3.25%	($124)	($18,593)	342,134	31
September-12	Forecast	($18,591)	$0.0333	$11,490	$30,261	$2,973	$1,308	$109	$4,570	($7,010)	3.25%	($19)	$4,552	345,038	30
October-12	Forecast	$4,552	$0.0333	$22,146	$30,261	$2,973	$1,726	$144	$17,510	$11,031	3.25%	$30	$17,540	665,059	31
November-12	Forecast	**$17,540**	$0.0380	$45,368	$30,261	$2,973	$2,173	$181	$7,761	$12,651	3.25%	$34	$7,795	1,194,118	30
December-12	Forecast	$7,795	$0.0380	$75,507	$145,254	$2,973	$11,583	$202	$92,299	$50,047	3.25%	$138	$92,437	1,987,378	31
January-13	Forecast	$92,437	$0.0380	$104,473	$25,375	$3,430	$2,200	$293	$19,263	$55,850	3.25%	$154	$19,417	2,749,786	31
February-13	Forecast	$19,417	$0.0380	$113,391	$30,450	$3,430	$2,732	$304	($57,059)	($18,821)	3.25%	($47)	($57,106)	2,984,525	28
March-13	Forecast	($57,106)	$0.0380	$97,809	$35,525	$3,430	$3,160	$301	($112,499)	($84,802)	3.25%	($234)	($112,733)	2,574,384	31
April-13	Forecast	($112,733)	$0.0380	$70,357	$35,525	$3,430	$3,027	$288	($140,819)	($126,776)	3.25%	($339)	($141,158)	1,851,842	30
May-13	Forecast	($141,158)	$0.0380	$40,888	$25,375	$3,430	$1,946	$260	($151,035)	($146,097)	3.25%	($403)	($151,439)	1,076,194	31
June-13	Forecast	($151,439)	$0.0380	$23,216	$88,154	$3,430	$5,395	$212	($77,463)	($114,451)	3.25%	($306)	($77,769)	611,070	30
July-13	Forecast	($77,769)	$0.0380	$15,047	$20,300	$3,430	$1,062	$177	($67,847)	($72,808)	3.25%	($201)	($68,048)	396,053	31
August-13	Forecast	($68,048)	$0.0380	$13,178	$50,750	$3,430	$2,298	$153	($24,595)	($46,322)	3.25%	($128)	($24,723)	346,842	31
September-13	Forecast	($24,723)	$0.0380	$13,289	$27,254	$3,430	$1,073	$143	($6,111)	($15,417)	3.25%	($41)	($6,152)	349,769	30
October-13	Forecast	($6,152)	$0.0380	$25,632	$25,375	$3,430	$1,417	$189	($1,374)	($3,763)	3.25%	($10)	($1,384)	674,638	31
Nov 12 thru Oct 13 Totals				$638,155	$539,599	$40,246	$38,066	$2,703						16,796,601	

Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 1 of 3, Lines 26 through 41 filed on September 14, 2012 in this Cost of Gas Docket.

Northern Utilities, Inc.

New Hampshire Division

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

To Be Effective November 1, 2012 through October 31, 2013

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
August-11	Actual	($242,646)	$0.0152	$25,699	$36,527	$2,894	$25,930	$1,365	($201,630)	($123,822)	3.25%	($342)	($201,971)	1,690,750	31
September-11	Actual	($201,971)	$0.0152	$9,617	$35,276	$2,894	$13,685	$720	($159,012)	($76,871)	3.25%	($205)	($159,217)	1,951,241	30
October-11	Actual	($159,217)	$0.0152	$33,970	$24,447	$2,894	$2,803	$148	($162,896)	($33,641)	3.25%	($93)	($162,988)	2,234,860	31
November-11	Actual	($162,988)	$0.0126	$38,691	$106,272	$2,894	$2,749	$145	($89,620)	($18,729)	3.25%	($50)	($89,670)	3,383,296	30
December-11	Actual	($89,670)	$0.0126	$76,818	$18,219	$2,894	$1,500	$79	($143,797)	($11,016)	3.25%	($30)	($143,827)	4,339,703	31
January-12	Actual	($143,827)	$0.0126	$75,697	$34,019	$2,870	$3,726	$196	($178,713)	($36,635)	3.25%	($1,191)	($179,904)	6,007,712	31
February-12	Actual	($179,904)	$0.0126	$104,940	$38,388	$2,870	$2,628	$138	($240,819)	($116,496)	3.25%	($301)	($241,120)	5,727,655	29
March-12	Actual	($241,120)	$0.0126	$89,429	$29,333	$2,870	$2,980	$157	($295,208)	($169,762)	3.25%	$627	($294,582)	4,958,839	31
April-12	Actual	($294,582)	$0.0126	$44,127	$120,115	$2,870	$6,719	$354	($208,650)	($200,281)	3.25%	($535)	($209,185)	3,502,134	30
May-12	Actual	($209,185)	$0.0126	$41,219	$61,130	$2,870	$11,081	$583	($174,739)	($222,829)	3.25%	($615)	($175,354)	2,598,065	31
June-12	Actual	($175,354)	$0.0126	$26,375	$14,563	$2,870	$1,753	$92	($182,450)	($231,872)	3.25%	($619)	($183,070)	2,093,258	30
July-12	Actual	($183,070)	$0.0126	$23,149	$25,155	$2,870	$2,522	$133	($175,538)	($238,767)	3.25%	($659)	($176,197)	1,837,235	31
August-12	Actual	($176,197)	$0.0126	$22,766	$46,855	$2,870	$1,814	$616	($146,807)	($161,502)	3.25%	($446)	($147,253)	1,806,829	31
September-12	Forecast	($147,253)	$0.0126	$24,824	$46,855	$2,870	$7,468	$624	($114,260)	($130,756)	3.25%	($349)	($114,609)	1,970,185	30
October-12	Forecast	($114,609)	$0.0126	$34,215	$23,428	$2,870	$7,049	$589	($114,889)	($114,749)	3.25%	($317)	($115,205)	2,715,501	31
November-12	Forecast	**($115,205)**	$0.0116	$42,240	$31,237	$3,304	$6,603	$552	($115,750)	($115,478)	3.25%	($308)	($116,058)	3,628,507	30
December-12	Forecast	($116,058)	$0.0116	$60,998	$31,237	$3,304	$30,540	$531	($111,444)	($113,751)	3.25%	($314)	($111,758)	5,239,916	31
January-13	Forecast	($111,758)	$0.0116	$73,473	$29,400	$3,304	$5,050	$674	($146,804)	($129,281)	3.25%	($357)	($147,161)	6,311,549	31
February-13	Forecast	($147,161)	$0.0116	$75,904	$39,200	$3,304	$5,968	$663	($173,929)	($160,545)	3.25%	($400)	($174,329)	6,520,343	28
March-13	Forecast	($174,329)	$0.0116	$66,295	$30,810	$3,304	$6,990	$666	($198,854)	($186,592)	3.25%	($515)	($199,369)	5,694,947	31
April-13	Forecast	($199,369)	$0.0116	$50,730	$49,000	$3,304	$7,123	$679	($189,994)	($194,682)	3.25%	($520)	($190,514)	4,357,818	30
May-13	Forecast	($190,514)	$0.0116	$34,145	$29,400	$3,304	$5,304	$707	($185,943)	($188,228)	3.25%	($520)	($186,463)	2,933,176	31
June-13	Forecast	($186,463)	$0.0116	$25,386	$70,010	$3,304	$19,255	$755	($118,526)	($152,495)	3.25%	($407)	($118,933)	2,180,721	30
July-13	Forecast	($118,933)	$0.0116	$20,576	$19,600	$3,304	$4,738	$790	($111,076)	($115,005)	3.25%	($317)	($111,393)	1,767,530	31
August-13	Forecast	($111,393)	$0.0116	$21,438	$58,800	$3,304	$12,202	$814	($57,712)	($84,553)	3.25%	($233)	($57,945)	1,841,594	31
September-13	Forecast	($57,945)	$0.0116	$23,434	$60,210	$3,304	$6,177	$824	($10,865)	($34,405)	3.25%	($92)	($10,957)	2,013,083	30
October-13	Forecast	($10,957)	$0.0116	$32,341	$29,400	$3,304	$5,833	$778	($3,982)	($7,469)	3.25%	($21)	($4,003)	2,778,139	31
Nov 12 thru Oct 13 Totals				$526,960	$478,303	$39,648	$115,783	$8,433						45,267,324	

Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 1 of 3, Lines 26 through 41 filed on September 14, 2012 in this Cost of Gas Docket.

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE
November 1, 2012 through October 31, 2013

Total ERC Costs for the Period	$235,688	
Less Current Under Collection (Estimated)	$48,107	(See page 2 of 2)
Total ERC Cost to be Recovered	$283,795	
Forcasted Firm Sales & Firm Transportation Volumes (Attachment 2 to Schedule 10B, Revised Page 1 of 3, Line 41, "Total Division" subtract Line 41 "Special Contracts").	62,063,926	
ERC Recovery Rate	**$0.0046**	

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Cost 12 Month Reconciliation

Month	Actual or Forecast	Beginning Balance (Over)/Under	Monthly Amortization of ERC costs	New ERC Costs To be recovered	Ending Balance
August	Actual	($3,692)	$10,860		($14,553)
September	Actual	($14,553)	$12,467		($27,020)
October	Actual	($27,020)	$14,380		($41,400)
November-'11	Actual	($41,400)	$23,464	$342,842	$277,978
December	Actual	$277,978	$29,740		$248,238
January- '12	Actual	$248,238	$43,634		$204,604
February	Actual	$204,604	$42,157		$162,447
March	Actual	$162,447	$36,296		$126,151
April	Actual	$126,151	$24,764		$101,387
May	Actual	$101,387	$17,579		$83,808
June	Actual	$83,808	$13,320		$70,489
July	Actual	$70,489	$11,311		$59,177
August	Actual	$59,177	$11,070		**$48,107**

Schedule 17

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDIATION ADJUSTMENT CLAUSE COMPLIANE FILING
2011-2012 ENVIORMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES

Line	Description	Total	11/06 - 10/07	11/07 - 10/08	11/08 - 10/09	11/09 - 10/10	11/10 - 10/11	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14 10/15	11/15-10/16	11/16-10/17	11/17-10/18	11/18-10/19

	ENVIRONMENTAL RESPONSE COST (ERC)														
1	July 05 - June 06 Expenses Amortization (1/7)	$ 632,461	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352						
2	July 06 - June 07 Expenses Amortization (1/7)	$ 186,804		$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686					
3	July 07 - June 08 Expenses Amortization (1/7)	$ 232,960			$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280				
4	July 08 - June 09 Expenses Amortization (1/7)	$ 127,728				$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247			
5	July 09 - June 10 Expenses Amortization (1/7)	$ 189,634					$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091		
6	July 10 - June 11 Expenses Amortization (1/7)	$ 121,209						$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	
7	July 11 - June 12 Expenses Amortization (1/7)	$ 159,020							$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717
8	Subtotal (Line 1 through Line 7)	$ 2,558,915	$ 90,352	$ 117,038	$ 150,318	$ 168,565	$ 195,655	$ 212,971	$ 235,688	$ 145,336	$ 118,650	$ 85,370	$ 67,123	$ 40,033	$ 22,717
9	Add: Excess amortization from prior years (from schedule 5, Line 10)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Less: Excess amortization to be deferred (from schedule 5, Line 9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total Enviromental Response cost to be recovered (ERC)	$ 2,558,915	$ 90,352	$ 117,038	$ 150,319	$ 168,565	$ 195,655	$ 212,971	$ 235,688	$ 145,336	$ 118,650	$ 85,370	$ 67,123	$ 40,033	$ 22,717
12	July 2005 - June 2006 Unamortized beginning balance		$ 632,461	$ 542,109	$ 451,758	$ 361,406	$ 271,055	$ 180,703	$ 90,352	$ -					
13	July 2006 - June 2007 Unamortized beginning balance			$ 186,804	$ 160,118	$ 133,431	$ 106,745	$ 80,059	$ 53,373	$ 26,686	$ -				
14	July 2007 - June 2008 Unamortized beginning balance				$ 232,960	$ 199,680	$ 166,400	$ 133,120	$ 99,840	$ 66,560	$ 33,280	$ -			
15	July 2008 - June 2009 Unamortized beginning balance					$ 127,728	$ 109,481	$ 91,234	$ 72,987	$ 54,741	$ 36,494	$ 18,247	$ -		
16	July 2009 - June 2010 Unamortized beginning balance						$ 189,634	$ 162,544	$ 135,453	$ 108,362	$ 81,272	$ 54,181	$ 27,091	$ -	
17	July 2010 - June 2011 Unamortized beginning balance							$ 121,209	$ 103,893	$ 86,578	$ 69,262	$ 51,947	$ 34,631	$ 17,316	$ 0
18	July 2011 - June 2012 Unamortized beginning balance								$ 159,020	$ 136,303	$ 113,586	$ 90,869	$ 68,151	$ 45,434	$ 22,717
19	Total Unamortized beginning balance		$ 632,461	$ 728,913	$ 844,836	$ 822,246	$ 843,315	$ 768,869	$ 714,918	$ 479,230	$ 333,893	$ 215,243	$ 129,873	$ 62,750	$ 22,717
20	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)														
21	INSURANCE/3RD PARTY RECOVERIES (IR)														
22	UNDER/OVER Recovery from previous year														
23	**Total of Lines 15, 16, 17, 18**		$ 632,461	$ 728,913	$ 844,836	$ 822,246	$ 843,315	$ 768,869	$ 714,918	$ 479,230	$ 333,893	$ 215,243	$ 129,873	$ 62,750	$ 22,717

Schedule 18

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

November 2012 through October 2013

		MDQ	Max Swing	% MDQ
1	New Hampshire Underground	16,543	3,532	21.35%
2	LNG	0	0	0.00%
3	Propane	0	0	0.00%

		% MDQ	Costs	Balancing Costs	% Allocated	Allocated Costs
4	New Hampshire Underground					
5	Del., Res., and Transp.	21.35%	$13,233,527	$2,825,389	0.20%	$5,773
6	Capacity	21.35%	$1,371,428	$292,803	35.64%	$104,350
7	LNG	0.00%	$93,340	$0	0.00%	$0
8	Propane	0.00%	$117,438	$0	0.00%	$0
9	Total		$14,815,734	$3,118,192		$110,123
10	Annual Sum of Absolute Swings					142,624
11	Balancing Rate Per MMBtu Swing					**$0.77**

Note: LNG and LP MDQ allocated based on Maine's current PR-Allocator percentage. 46.40%

Northern Utilities, Inc.
Calculation of Balancing Charge
Costs of Balancing Resources
November 2012 through October 2013

Line			Northern Capacity	Division Allocated	Rate	Months	Costs
1	**New Hampshire**						
2	El Paso FS Storage						
3	Capacity	Cap	259,337	120,332	$0.0211	12	$30,468
4	Deliverability	Del	4,243	1,969	$1.5400	12	$36,383
5	Firm Transportation-Tenn	Trans	2,653	1,231	$8.4896	12	$125,408
6	Firm Transportation-GSGT	Trans	2,653	1,231	$3.3391	12	$49,325
7	Total						$241,583
8							
9	W-10 Storage						
10	W-10	Cap	34,000	15,776	$ 7.0833	12	$1,340,960
11	PNGTS	Trans	33,000	15,312	$ 76.4666	5	$5,854,283
12	Vector - In	Trans	17,172	7,968	$ 7.6042	12	$727,066
13	Vector -Out	Trans	17,086	7,928	$ 5.0650	5	$200,774
14	TCPL	Trans	34,000	15,776	$ 29.7221	12	$5,626,750
15	Firm Transportation-GSGT	Trans	33,000	15,312	$ 3.3391	12	$613,540
16	Total						$14,363,373
17	LNG						
18	NH		10,000	4,640			$93,340
18	ME		10,000	5,360			$201,164
19	Total						$201,164
20	Propane						
21	Capacity						
22	NH		4,000	1,856			$219,101
22	ME		4,000	2,144			$253,100
23	Total						$472,201
24							
25	New Hampshire Summary						
26		Del	4,243	1,969			$36,383
27		Res	0	0			$0
28		Trans	139,564	64,758			$13,197,145
29		Cap	293,337	136,108			$1,371,428
30		Total	437,144	202,835			$14,604,956
31	Gate Station Delivery		35,653	16,543			

Northern Utilities, Inc.
Calculation of Balancing Charge
Analysis of Swings

	Division	UGS Maximum Swings	UGS Sum Positive Swings	Northern UGS Withdrawals	Allocated UGS Withdrawals	Positive UGS Swings as a % of UGS Withdrawals
1	NH	3,532	3,811	4,019,426	1,865,014	0.20%
2	ME	7,580	1,635	4,019,426	2,154,412	0.08%

	Division	LP Max. Swing	LP Sum Positive Swings	LP Tank Capacity	LP Allocated Tank Capacity	LP Swings as a % of Tank Capacity
3	NH	0	0	25,733	11,940	0.00%
4	ME	0	0	25,733	13,793	0.00%

	Division	LNG Max. Swing	LNG Sum Positive Swings	LNG Tank Capacity	LNG Allocated Tank Capacity	LNG Swings as a % of Tank Capacity
5	NH	0	(9,481)	13,750	6,380	148.61%
6	ME	1,418	(26,271)	13,750	7,370	356.46%

	Division	UGS Absolute Value All Swings	UGS Total Absolute Value All Swings	Northern UGS Capacity	Allocated UGS Capacity	Positive UGS Swings as a % of UGS Withdrawals
7	NH	45,999	36,518	293,337	136,108	33.80%
8	ME	94,294	68,023	293,337	157,229	59.97%
9	Total	140,292	104,540		293,337	35.64%

	Division		UGS Max Abs Cum. All Swings		Allocated UGS Capacity	
10	NH		49,355		136,108	46.40%
11	ME		34,012		157,229	53.60%
12	Total		83,367		293,337	**28.42%**

Northern Utilities, Inc.
Calculation of Suppliler Balancing Charge

Derivation of Absolute Swings
May 2000 through April 2001
Summary

		Sum Positive Swings		Sum Negative Swings		Sum LP / LNG Swings		ABS all Swings		Total
		Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	ABS Swings
1	May	1,060	1,484	8,125	1,162	0	0	9,185	2,646	11,832
2	June	0	28	1,213	5,553	0	0	1,213	5,582	6,794
3	July	1,125	0	0	0	0	0	1,125	0	1,125
4	Aug	45	0	99	1,027	0	0	145	1,027	1,172
5	Sept	0	0	301	11,279	0	0	301	11,279	11,580
6	Oct	1,196	123	2,821	26,853	0	0	4,017	26,976	30,993
7	Nov	384	0	3,976	7,620	(2,382)	(2,539)	6,743	10,159	16,901
8	Dec	0	0	7,956	12,177	0	0	7,956	12,177	20,133
9	Jan	0	0	1,873	174	(423)	(13,355)	2,296	13,530	15,826
10	Feb	0	0	2,807	542	(4,431)	(4,339)	7,238	4,880	12,118
11	March	0	0	1,048	0	(2,245)	(6,038)	3,293	6,038	9,331
12	April	0	0	2,487	0	0	0	2,487	0	2,487
13	Total	3,811	1,635	32,707	66,387	(9,481)	(26,271)	45,999	94,294	140,292
14				add back 10% of the scheduled deliveries=				96,625	97,195	193,819
15						Total ABS Swings =		**142,624**	**191,488**	334,112

Schedule 19

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2012-2013
Derivation of Class Assignments and Weightings

Basic assumptions:

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

			Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total	Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	383	3,830	341	0.7%	56	285
2	RATE B-Resi Htg	21,167	211,670	18,868	38.5%	1,536	17,332
3	RATE G-40 (R)	9,329	93,290	8,316	17.0%	512	7,804
4	RATE G-50 (Q)	1,181	11,810	1,053	2.1%	324	729
5	RATE G-41 (T)	8,368	83,680	7,459	15.2%	631	6,828
6	RATE G-51 (S)	1,579	15,790	1,408	2.9%	384	1,024
7	RATE G-42 (V)	1,181	11,810	1,053	2.1%	54	999
8	RATE G-52a (U)	59	590	53	0.1%	19	34
9	Special Contract	724	7,240	645	1.3%	645	0
10	RATE T-40	1,421	14,205	1,266	2.6%	78	1,188
11	RATE T-50	329	3,293	294	0.6%	225	69
12	RATE T-41	6,361	63,613	5,670	11.6%	480	5,190
13	RATE T-51	1,103	11,029	983	2.0%	734	249
14	RATE T-42	1,489	14,889	1,327	2.7%	68	1,259
15	RATE T-52	326	3,262	291	0.6%	263	28
16	Total	55,000	550,001	49,027	100.0%	6,009	43,018
17			55,000				-
18	Residential Total		215,500	19,210	**39.2%**	1,592	17,618
19	LLF Total		281,487	25,092	51.2%	1,823	23,269
20	HLF Total		53,014	4,726	9.6%	2,594	2,132
21	Total		550,001	49,027	100.0%	6,009	43,018
22							
23							

		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
24		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
25	Pipeline	2,017,066	11,239	14.96	
26	Storage	14,583,468	16,485	73.72	
27	Peaking	1,417,435	21,302	5.54	
28	Total	18,017,969	49,027	**30.63**	**73.50**
29					
30					
31					

		Capacity Cost	MDQ, Dt	$/Dt-Mo.
32		Capacity Cost	MDQ, Dt	$/Dt-Mo.
33	Pipeline - Baseload	1,078,404	6,009	14.96
34	Pipeline - Remaining	938,662	5,230	14.96
35	Storage	14,583,468	16,485	73.72
36	Peaking	1,417,435	21,302	5.54
37	Total	18,017,969	49,027	30.63
38				
39				

			Capacity Cost	MDQ, Dt	$/Dt-Mo.
40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
41	Pipeline - Base	**39.2%**	422,538	2,354	14.96
42	Pipeline - Remaining	**39.2%**	367,785	2,049	14.96
43	Storage	**39.2%**	5,714,061	6,459	73.72
44	Peaking	**39.2%**	555,376	8,347	5.54
45	Total	**39.2%**	7,059,759	19,210	30.63

C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		655,866	3,654	14.96
Pipeline - Remaining		570,878	3,181	14.96
Storage		8,869,407	10,026	73.72
Peaking		862,059	12,956	5.54
Total	**60.8%**	10,958,209	29,817	30.63

LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		270,702	1,508	14.96
Pipeline - Remaining		522,965	2,914	14.96
Storage		8,125,013	9,185	73.72
Peaking		789,708	11,868	5.54
Total	**53.9%**	9,708,388	25,475	**31.76**

HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		385,164	2,146	14.96
Pipeline - Remaining		47,913	267	14.96
Storage		744,394	841	73.72
Peaking		72,351	1,087	5.54
Total	**6.9%**	1,249,821	4,342	**23.99**

Unit Cost	Residential	LLF C&I	HLF C&I
Pipeline	$ 14.96	$ 14.96	$ 14.96
Storage	$ 73.72	$ 73.72	$ 73.72
Peaking	$ 5.54	$ 5.54	$ 5.54
Total	$ 30.63	$ 31.76	$ 23.99
Checktotal	$ 30.63	$ 31.76	$ 23.99

Load Makeup	Residential	**LLF C&I**	**HLF C&I**
Pipeline	22.92%	**17.36%**	**55.58%**
Storage	33.63%	**36.05%**	**19.38%**
Peaking	43.45%	**46.59%**	**25.04%**
Total	100.00%	**100.00%**	**100.00%**

Storage and Peaking

LLF C&I	**HLF C&I**
NA	**NA**
43.63%	**43.63%**
56.37%	**56.37%**

Supply Makeup	Residential	LLF C&I	HLF C&I	Total
Pipeline	39.18%	39.35%	21.47%	100.00%
Storage	39.18%	55.71%	5.10%	100.00%
Peaking	39.18%	55.71%	5.10%	100.00%

Schedule 20

Provided in Summer 2013 Cost-of-Gas Filing

Schedule 21

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	$ 8,397,821
Storage Demand	$ 31,429,888
Peaking Demand	$ 2,391,536
Subtotal Demand	$ 42,219,244
Capacity Release (Credit)	$ (213,450)
Asset Management (Credit)	$ (4,810,000)
Total Net Demand Costs	$ 37,195,794

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	1,200,612	1,036,548	894,806	806,994	851,301	750,718	565,888	463,400	428,421	444,101	462,409	637,572	8,542,771
Rank	1	2	3	5	4	6	8	9	12	11	10	7	
% Max Month	100.00%	86.33%	74.53%	67.22%	70.91%	62.53%	47.13%	38.60%	35.68%	36.99%	38.51%	53.10%	
PR	13.67%	5.90%	1.21%	0.94%	0.92%	1.57%	1.07%	0.01%	2.97%	0.12%	0.15%	0.85%	29.38%
CumPR	29.38%	15.72%	9.81%	7.68%	8.60%	6.74%	4.32%	3.25%	2.97%	3.09%	3.24%	5.17%	100.00%
Product and Pipeline Demand Costs	$ 2,467,322	$ 1,319,758	$ 824,044	$ 645,132	$ 722,608	$ 566,406	$ 362,874	$ 273,267	$ 249,720	$ 259,690	$ 272,496	$ 434,504	$ 8,397,821

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	504,390	574,802	556,260	574,802	574,802	551,060	240,566	3,576,682
Design Year Pipeline Sendout	1,200,612	1,036,548	894,806	806,994	851,301	750,718	565,888	463,400	428,421	444,101	462,409	637,572	8,542,771
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	40.2%	50.4%	54.6%	57.3%	56.4%	54.4%	27.4%	29.5%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 227,621	$ 182,855	$ 149,076	$ 143,078	$ 146,501	$ 148,166	$ 119,032	$ 1,116,331

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	-	633,108	1,000,249	910,767	662,958	300,043	-	-	-	-	-	-	3,507,125
Rank	6	4	1	2	3	5	6	6	6	6	6	6	
% Max Month	0.00%	63.30%	100.00%	91.05%	66.28%	30.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	8.32%	8.95%	12.39%	0.99%	6.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.65%
CumPR	0.00%	14.32%	36.65%	27.71%	15.32%	6.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ -	$ 4,501,993	$ 11,519,694	$ 8,707,971	$ 4,814,639	$1,885,591	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,429,888
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 227,621	$ 182,855	$ 149,076	$ 143,078	$ 146,501	$ 148,166	$ 119,032	$ 1,116,331
TOTAL	$ -	$ 4,501,993	$ 11,519,694	$ 8,707,971	$ 4,814,639	$2,113,212	$ 182,855	$ 149,076	$ 143,078	$ 146,501	$ 148,166	$ 119,032	$ 32,546,219

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	1,350	20,942	52,053	18,307	1,395	21,414	1,395	1,350	1,395	1,395	1,350	4,325	126,671
Rank	12	3	1	4	9	2	8	11	7	6	10	5	
% Max Month	2.59%	40.23%	100.00%	35.17%	2.68%	41.14%	2.68%	2.59%	2.68%	2.68%	2.59%	8.31%	
PR	0.22%	1.69%	58.86%	6.72%	0.01%	0.45%	0.00%	0.00%	0.00%	0.00%	0.00%	1.13%	69.07%
CumPR	0.22%	9.75%	69.07%	8.07%	0.23%	10.21%	0.23%	0.22%	0.23%	0.23%	0.22%	1.35%	100.00%
Peaking Demand Costs	$ 5,169	$ 233,269	$ 1,651,819	$ 192,924	$ 5,398	$ 244,106	$ 5,398	$ 5,169	$ 5,398	$ 5,398	$ 5,169	$ 32,317	$ 2,391,536

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

LN		
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		
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-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL
Pipeline & Product Demand	$ 2,467,322	$ 1,319,758	$ 824,044	$ 645,132	$ 722,608	$ 566,406	$ 362,874	$ 273,267	$ 249,720	$ 259,690	$ 272,496	$ 434,504	$ 8,397,821
Storage Incld Inj Fees	$ -	$ 4,501,993	$ 11,519,694	$ 8,707,971	$ 4,814,639	$2,113,212	$ 182,855	$ 149,076	$ 143,078	$ 146,501	$ 148,166	$ 119,032	$ 32,546,219
Peaking	$ 5,169	$ 233,269	$ 1,651,819	$ 192,924	$ 5,398	$ 244,106	$ 5,398	$ 5,169	$ 5,398	$ 5,398	$ 5,169	$ 32,317	$ 2,391,536
Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (227,621)	$ (182,855)	$ (149,076)	$ (143,078)	$ (146,501)	$ (148,166)	$ (119,032)	$ (1,116,331)
Less: Capacity Release	$ (42,690)	$ (42,690)	$ (42,690)	$ (42,690)	$ (42,690)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (213,450)
Less: Asset Mgmt	$ (801,667)	$ (801,667)	$ (801,667)	$ (801,667)	$ (801,667)	$ (801,667)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,810,000)
Total Demand	$ 1,628,134	$ 5,210,663	$ 13,151,200	$ 8,701,670	$ 4,698,289	$1,894,436	$ 368,273	$ 278,435	$ 255,118	$ 265,089	$ 277,665	$ 466,821	$ 37,195,794

Capacity Cost Allocator based on Design Year Firm Sendout

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL
Therms													
Maine	641,270	892,614	1,037,642	941,523	808,574	583,326	311,865	254,226	238,272	246,185	253,792	352,200	6,561,489
New Hampshire	560,699	797,991	909,474	794,552	707,086	488,856	255,425	210,531	191,551	199,318	209,974	289,704	5,615,161
Total	1,201,969	1,690,605	1,947,116	1,736,075	1,515,660	1,072,182	567,290	464,757	429,823	445,503	463,766	641,904	12,176,650

Percentage of Total	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL
Maine	53.35%	52.80%	53.29%	54.23%	53.35%	54.41%	54.97%	54.70%	55.43%	55.26%	54.72%	54.87%	53.60%
New Hampshire	46.65%	47.20%	46.71%	45.77%	46.65%	45.59%	45.03%	45.30%	44.57%	44.74%	45.28%	45.13%	46.40%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Allocation of Demand Costs by Division

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL
Maine	$868,636	$2,751,152	$7,008,436	$4,719,164	$2,506,442	$1,030,678	$202,456	$152,306	$141,425	$146,488	$151,950	$256,135	$19,935,268
New Hampshire	$759,498	$2,459,511	$6,142,764	$3,982,506	$2,191,847	$863,759	$165,817	$126,129	$113,694	$118,601	$125,715	$210,686	$17,260,526
Total	$ 1,628,134	$ 5,210,663	$ 13,151,200	$ 8,701,670	$ 4,698,289	$ 1,894,436	$ 368,273	$ 278,435	$ 255,118	$ 265,089	$ 277,665	$ 466,821	$ 37,195,794

Detailed Allocation of Demand Costs by Division

Maine	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	
Pipeline & Product Demand	$ 1,316,357	$ 696,812	$ 439,143	$ 349,873	$ 385,497	$ 308,156	$ 199,488	$ 149,479	$ 138,432	$ 143,505	$ 149,121	$ 238,404	$ 4,514,267	53.76%
Storage Incld Injection Fees	$ -	$ 2,376,985	$ 6,138,986	$ 4,722,581	$ 2,568,513	$ 1,149,704	$ 100,524	$ 81,546	$ 79,315	$ 80,957	$ 81,083	$ 65,311	$ 17,445,503	53.60%
Peaking	$ 2,758	$ 123,162	$ 880,275	$ 104,628	$ 2,880	$ 132,807	$ 2,968	$ 2,827	$ 2,993	$ 2,983	$ 2,829	$ 17,732	$ 1,278,841	53.47%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (123,839)	$ (100,524)	$ (81,546)	$ (79,315)	$ (80,957)	$ (81,083)	$ (65,311)	$ (612,574)	
Capacity Release (Credit)	$ (22,776)	$ (22,540)	$ (22,750)	$ (23,152)	$ (22,774)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (113,992)	53.40%
Asset Management (Credit)	$ (427,702)	$ (423,268)	$ (427,218)	$ (434,767)	$ (427,673)	$ (436,151)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,576,779)	53.57%
Total Allocated Demand	$ 868,636	$ 2,751,152	$ 7,008,436	$ 4,719,164	$ 2,506,442	$ 1,030,678	$ 202,456	$ 152,306	$ 141,425	$ 146,488	$ 151,950	$ 256,135	$ 19,935,268	53.60%

New Hampshire	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	
Pipeline & Product Demand	$ 1,150,966	$ 622,946	$ 384,901	$ 295,258	$ 337,111	$ 258,250	$ 163,386	$ 123,787	$ 111,288	$ 116,185	$ 123,375	$ 196,100	$ 3,883,553	46.24%
Storage Incld Injection Fees	$ -	$ 2,125,008	$ 5,380,708	$ 3,985,390	$ 2,246,126	$ 963,509	$ 82,331	$ 67,530	$ 63,763	$ 65,545	$ 67,084	$ 53,722	$ 15,100,715	46.40%
Peaking	$ 2,411	$ 110,106	$ 771,544	$ 88,296	$ 2,518	$ 111,299	$ 2,431	$ 2,341	$ 2,406	$ 2,415	$ 2,340	$ 14,585	$ 1,112,694	46.53%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (103,783)	$ (82,331)	$ (67,530)	$ (63,763)	$ (65,545)	$ (67,084)	$ (53,722)	$ (503,757)	
Capacity Release	$ (19,914)	$ (20,150)	$ (19,940)	$ (19,538)	$ (19,916)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (99,458)	46.60%
Asset Management	$ (373,964)	$ (378,399)	$ (374,449)	$ (366,900)	$ (373,994)	$ (365,516)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,233,221)	46.43%
Total Allocated Demand	$ 759,498	$ 2,459,511	$ 6,142,764	$ 3,982,506	$ 2,191,847	$ 863,759	$ 165,817	$ 126,129	$ 113,694	$ 118,601	$ 125,715	$ 210,686	$ 17,260,526	46.40%

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 / 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)

Schedule 22

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	PEAK
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	699,185	810,382	534,130	462,099	534,049	595,669	5,103,124	3,635,515
3	Total Storage	0	210,007	647,175	567,416	368,031	13,110	1,805,740	1,805,740
4	Total Peaking	1,350	1,395	1,395	1,260	1,395	1,350	16,425	8,145
5	Subtotal	700,535	1,021,784	1,182,700	1,030,775	903,476	610,129	6,925,288	5,449,399
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	700,535	1,021,784	1,182,700	1,030,775	903,476	610,129	6,925,288	5,449,399
9	Total Firm Pipeline Sendout	699,185	810,382	534,130	462,099	534,049	595,669	5,103,124	3,635,515
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 21,296,681	$ 16,100,651
12	NYMEX Price Used for Forecast	$2.811	$3.077	$3.221	$3.239	$3.231	$3.227		
13	NYMEX Price Used for Update	$2.811	$3.077	$3.221	$3.239	$3.231	$3.227		
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	$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 16,380,551	$ 16,100,651
17									
18	Total Pipeline	$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 16,380,551	$ 16,100,651
19	Total Storage	$ -	$ 740,216	$ 2,249,319	$ 1,971,272	$ 1,265,580	$ 39,300	$ 6,265,688	$ 6,265,688
20	Total Peaking	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 79,653	$ 38,997
21	Subtotal	$ 2,926,537	$ 4,268,176	$ 4,891,308	$ 4,290,556	$ 3,907,110	$ 2,121,650	$ 22,725,892	$ 22,405,336
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	13	21	28	23	23	14	128	122
26	Average Purchase Price	$ 4.265	$ 4.442	$ 4.625	$ 4.562	$ 4.535	$ 4.354		
27	NYMEX Price Used for Forecast	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227		
28	NYMEX Price Used for Update								
29	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
30	Futures Hedging (Gain)/Loss - Allocate	$ 189,020	$ 286,580	$ 393,120	$ 304,230	$ 300,020	$ 157,720	$ 1,639,080	$ 1,630,690
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	-	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 2.811	$ 3.077	$ 3.221	$ 3.239	$ 3.231	$ 3.227		
35	NYMEX Price Used for Update	$ -	$ -	$ -	$ -	$ -	$ -		
36	Increase/(Decrease) NYMEX Price	$ (2.811)	$ (3.077)	$ (3.221)	$ (3.239)	$ (3.231)	$ (3.227)		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 16,380,551	$ 16,100,651
41	Average Supply Cost ($/MMBtu)	$ 4.177	$ 4.346	$ 4.934	$ 5.005	$ 4.933	$ 3.485		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 16,380,551	$ 16,100,651
46	Total Storage	$ -	$ 740,216	$ 2,249,319	$ 1,971,272	$ 1,265,580	$ 39,300	$ 6,265,688	$ 6,265,688
47	Total Peaking	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 79,653	$ 38,997
48	Firm Sales Variable Costs Excld Hedge	$ 2,926,537	$ 4,268,176	$ 4,891,308	$ 4,290,556	$ 3,907,110	$ 2,121,650	$ 22,725,892	$ 22,405,336
49	Plus Hedging (Gain)/Loss	$ 189,020	$ 286,580	$ 393,120	$ 304,230	$ 300,020	$ 157,720	$ 1,639,080	$ 1,630,690
50	Total Firm Sales Variable Costs	$ 3,115,557	$ 4,554,756	$ 5,284,428	$ 4,594,786	$ 4,207,130	$ 2,279,370	$ 24,364,972	$ 24,036,026

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	Company Analysis
7	Less Interruptible - New Hampshire	Company Analysis
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	Attachment to Schedule 6B, page 1, Line 1
13	NYMEX Price Used for Update	Attachment to Schedule 6B, page 1, Line 1
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	Attachment NUI-FXW-6, Page 1
20	Total Peaking	Attachment NUI-FXW-6, Page 1
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 7
26	Average Purchase Price	Schedule 7
27	NYMEX Price Used for Forecast	Line 14
28	NYMEX Price Used for Update	
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 7
33	Average Purchase Price	Schedule 7
34	NYMEX Price Used for Forecast	Line 14
35	NYMEX Price Used for Update	
36	Increase/(Decrease) NYMEX Price	LN 35 - LN 34
37	Futures Hedging (Gain)/Loss (NH ONLY)	(LN 33 - LN 34 - LN 36) * LN 32*10,000
38		
39	Interruptible Cost Estimate	
40	Variable Pipeline Costs Excld Hedges	LN 16
41	Average Supply Cost ($/MMBtu)	LN 40 / LN 2
42	Interruptible Cost - Maine	LN 41 * LN 6
43	Interruptible Cost - New Hampshire	LN 41 * LN 7
44		
45	Firm Sales Pipeline Commodity Excld Hedge	LN 40 - LN 42 - LN 43
46	Total Storage	LN 19
47	Total Peaking	LN 20
48	Firm Sales Variable Costs Excld Hedge	Sum LN 45 : LN 47
49	Plus Hedging (Gain)/Loss	LN 30
50	Total Firm Sales Variable Costs	LN 48 + LN 49

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	PEAK
Maine	347,274	502,376	585,895	510,404	448,719	307,199	3,410,280	2,701,867
New Hampshire	353,252	519,410	596,812	520,376	454,754	302,918	3,514,976	2,747,522
Total	700,526	1,021,786	1,182,707	1,030,780	903,473	610,117	6,925,256	5,449,389
Percentage of Total								
Maine	49.57%	49.17%	49.54%	49.52%	49.67%	50.35%	49.24%	49.58%
New Hampshire	50.43%	50.83%	50.46%	50.48%	50.33%	49.65%	50.76%	50.42%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Commodity Allocation by Jurisdiction

Maine

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	PEAK
Firm Sales Pipeline Commodity Excld Hedge	$ 1,447,760	$ 1,731,458	$ 1,305,494	$ 1,145,315	$ 1,308,488	$ 1,045,128	$ 8,117,939	$ 7,983,643
Hedging (Gains) Losses	$ 93,704	$ 140,901	$ 194,746	$ 150,643	$ 149,008	$ 79,413	$ 812,452	$ 808,415
Storage	$ -	$ 363,938	$ 1,114,278	$ 976,101	$ 628,563	$ 19,788	$ 3,102,668	$ 3,102,668
Peaking	$ 3,022	$ 3,115	$ 3,307	$ 3,108	$ 3,454	$ 3,352	$ 38,879	$ 19,358
Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Maine Commodity Costs	$ 1,544,485	$ 2,239,413	$ 2,617,825	$ 2,275,167	$ 2,089,513	$ 1,147,681	$ 12,071,938	$ 11,914,085
Maine Inventory Finance Costs	$ 519	$ 835	$ 1,008	$ 871	$ 723	$ 436	$ 4,393	$ 4,393
Total Maine Variable Costs	$ 1,545,004	$ 2,240,248	$ 2,618,833	$ 2,276,039	$ 2,090,236	$ 1,148,118	$ 12,076,331	$ 11,918,477

New Hampshire

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	PEAK
Firm Sales Pipeline Commodity Excld Hedge	$ 1,472,681	$ 1,790,165	$ 1,329,819	$ 1,167,692	$ 1,326,087	$ 1,030,564	$ 8,262,612	$ 8,117,009
Hedging (Gains) Losses	$ 95,316	$ 145,679	$ 198,374	$ 153,587	$ 151,012	$ 78,307	$ 826,628	$ 822,275
Storage	$ -	$ 376,278	$ 1,135,041	$ 995,172	$ 637,017	$ 19,512	$ 3,163,020	$ 3,163,020
Peaking	$ 3,074	$ 3,221	$ 3,368	$ 3,169	$ 3,501	$ 3,305	$ 40,774	$ 19,638
New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 1,571,071	$ 2,315,343	$ 2,666,603	$ 2,319,619	$ 2,117,617	$ 1,131,688	$ 12,293,034	$ 12,121,941
New Hampshire Inventory Finance Costs	$ 546	$ 905	$ 1,075	$ 930	$ 762	$ 435	$ 4,654	$ 4,654
Total New Hampshire Variable Costs	$ 1,571,618	$ 2,316,248	$ 2,667,679	$ 2,320,549	$ 2,118,379	$ 1,132,124	$ 12,297,688	$ 12,126,595

Northern Utilities

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	TOTAL	PEAK
Firm Sales Pipeline Commodity Excld Hedge	$ 2,920,441	$ 3,521,623	$ 2,635,313	$ 2,313,006	$ 2,634,575	$ 2,075,692	$ 16,380,551	$ 16,100,651
Hedging (Gains) Losses	$ 189,020	$ 286,580	$ 393,120	$ 304,230	$ 300,020	$ 157,720	$ 1,639,080	$ 1,630,690
Storage	$ -	$ 740,216	$ 2,249,319	$ 1,971,272	$ 1,265,580	$ 39,300	$ 6,265,688	$ 6,265,688
Peaking	$ 6,095	$ 6,336	$ 6,675	$ 6,278	$ 6,955	$ 6,657	$ 79,653	$ 38,997
Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Northern Commodity Costs	$ 3,115,557	$ 4,554,756	$ 5,284,428	$ 4,594,786	$ 4,207,130	$ 2,279,370	$ 24,364,972	$ 24,036,026
Northern Inventory Finance Costs	$ 1,066	$ 1,739	$ 2,083	$ 1,802	$ 1,485	$ 871	$ 9,047	$ 9,047
Total Northern Variable Costs	$ 3,116,622	$ 4,556,495	$ 5,286,511	$ 4,596,588	$ 4,208,615	$ 2,280,241	$ 24,374,019	$ 24,045,073

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51	**Commodity Allocation Factors**	
52	Firm Sales Sendout for Normal Winter, MMBtu	
53		
54	Maine	Company Analysis
55	New Hampshire	NH Schedule 10B, LN 33 / 10
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
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

Line	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
92	**Northern Utilities**								
93	**Simplified Market Based Allocator (MBA) Calculations**								
94	**ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**								
95									
96	**Col A**	**Col B**	**Col C**	**Col D**	**Col E**	**Col F**	**Col G**	**Col N**	**Col O**
97									
98	**Inventory Finance Charge**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**TOTAL**	
99	Storage	$ 982	$ 982	$ 824	$ 524	$ 225	$ 34	$ 7,781	
100	Peaking	$ 103	$ 98	$ 96	$ 100	$ 102	$ 107	$ 1,266	
101	Total	$ 1,084	$ 1,080	$ 920	$ 624	$ 327	$ 141	$ 9,047	
102									
103	**Inventory Finance Charge Allocation by Jurisdiction**								
104	Maine	$ 538	$ 531	$ 456	$ 309	$ 163	$ 71	$ 4,393	
105	New Hampshire	$ 547	$ 549	$ 464	$ 315	$ 165	$ 70	$ 4,654	
106	Total	$ 1,084	$ 1,080	$ 920	$ 624	$ 327	$ 141	$ 9,047	
107									
108	**Inventory Finance Charge Allocation by Month**								
109	**Maine**								
110	Firm Sales Normal Remaining Sendout	250,293	402,162	485,681	419,888	348,505	210,218	2,116,747	2,116,747
111	Monthly % Sendout of Total Winter	11.82%	19.00%	22.94%	19.84%	16.46%	9.93%	100.00%	100.00%
112	ME Allocated Inventory Finance Charge	$ 519	$ 835	$ 1,008	$ 871	$ 723	$ 436	$ 4,393	$ 4,393
113									
114	**New Hampshire**								
115	Firm Sales Normal Remaining Sendout	247,739	410,380	487,782	421,897	345,724	197,405	2,110,928	2,110,928
116	Monthly % Sendout of Total Winter	11.74%	19.44%	23.11%	19.99%	16.38%	9.35%	100.00%	100.00%
117	NH Allocated Inventory Finance Charge	$ 546	$ 905	$ 1,075	$ 930	$ 762	$ 435	$ 4,654	$ 4,654

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	"Schedule 14 - Carrying Costs"
100	Peaking	"Schedule 14 - 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	Company Analysis
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	NH Schedule 10B, LN 80 / 10
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Schedule 23

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

		Winter	Summer	Total	
1	Demand	$ 11,941,749	$ 957,164	$ 12,898,912	Schedule 1A, LN 80
2	Commodity	$ 12,126,595	$ 171,092	$ 12,297,688	Schedule 1B, LN 43
3	Total	$ 24,068,344	$ 1,128,256	$ 25,196,600	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	27,305,924	7,625,909	34,931,833	Schedule 10B, LN 12
6	Forecasted Residential Sales (Therms)	13,342,035	3,454,565	16,796,599	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.4373	$0.1255		LN 1 / LN 5
9	Average Commodity Rate	$0.4441	$0.0224		LN 2 / LN 5
10	Average Rate	$0.8814	$0.1480		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 5,972,182	$ 454,527	$ 6,426,710	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 5,834,896	$ 433,548	$ 6,268,444	LN 8 * LN 6
15	**Demand Reallocation:**	$ 137,286	$ 20,980	$ 158,266	LN 13 - LN 14
16	**HLF Allocation**	$ 16,345	$ 5,518	$ 21,863	LN 15 / LN 20
17	**LLF Allocation**	$ 120,941	$ 15,461	$ 136,402	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	11.91%	26.30%		Schedule 10A, LN 173
21	LLF	88.09%	73.70%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 5,908,731	$ 77,518	$ 5,986,250	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 5,925,214	$ 77,382	$ 6,002,597	LN 9 * LN 6
25	**Commodity Reallocation:**	$ (16,483)	$ 136	$ (16,347)	LN 23 - LN 24
26	**HLF Allocation**	$ (2,721)	$ 51	$ (2,670)	LN 25 * LN 30
27	**LLF Allocation**	$ (13,762)	$ 85	$ (13,678)	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	16.51%	37.73%		Schedule 10C, LN 143
31	LLF	83.49%	62.27%		Schedule 10C, LN 144

Schedule 24

Northern Utilities, Inc.
Short-Term Debt Limit
($ in thousands)

NU Short-Term Debt Limit Calculation (11/1/12 - 10/31/2013)			
Fuel Financing Purposes			
NU ME winter gas costs		31,463	
NU NH winter gas costs		21,551	
	Total	53,015	
30% of total winter gas costs		15,904	(a)
Non-Fuel Financing Purposes			
Estimated net utility plant @ 12/31/12 before plant acquisition adjustment		224,044	
15% of Net Utility Plant		33,607	(b)
Short-Term Debt Limit			
Short Term Debt Limit		**49,511**	(a) + (b)

Schedule 25

Northern Utilities, Inc., New Hampshire Division
Determination of Tenneesee Gas Refund - Demand Cost Portion
Effective: June 2012 - April 2013

1	Tennessee Refund - Principle	$190,516	PG 5, LN 5
2	Tennessee Refund - Interest	$3,256	PG 5, LN 15
3	Estimated Interest Expense - Northern	$5,064	PG 2, LN 9
4	Total	$198,836	LN 1 + LN 2 + LN 3
5	Total Therms: (June 12 - April 13)	34,734,538	FORECAST
6	Demand Refund Rate ($/CCF)	$0.0057	LN 4/ LN 5

Northern Utilities, Inc. New Hampshire Division
Tennessee Gas Refund - Demand Portion
Effective: June 2012 - April 2013

		Mar-12	Apr-12	Estimate May-12	Estimate Jun-12	Estimate Jul-12	Estimate Aug-12	Estimate Sep-12	Estimate Oct-12	Estimate Nov-12	Estimate Dec-12	Estimate Jan-13	Estimate Feb-13	Estimate Mar-13	Estimate Apr-13	Total Mar-12 to Oct-12	Total Nov-12 to Apr-13	Total Mar-12 to Apr-13
1	Beginning Balance	$0	$194,039	$194,558	$195,095	$189,432	$183,921	$178,288	$172,110	$162,666	$142,206	$111,762	$76,831	$46,120	$18,833			
2	TGP Refund	$193,772	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0			
3	FS and FT (Therms)	$0	$0	0	1,083,360	1,057,284	1,075,722	1,165,799	1,737,916	3,660,851	5,402,430	6,173,777	5,414,848	4,802,750	3,159,801	6,120,081	28,614,458	34,734,538
4	Refund	$0	$0	$0.0000	$0.0057	$0.0057	$0.0057	$0.0057	$0.0057	$0.0057	$0.0057	$0.0057	$0.0057	$0.0057	$0.0057			
5	Estimated Refund Amount	$0	$0	$0	$6,175	$6,027	$6,132	$6,645	$9,906	$20,867	$30,794	$35,191	$30,865	$27,376	$18,011	$34,884	$163,102	$197,987
6	Ending Balance - excl. interest	$193,772	$194,039	$194,558	$188,920	$183,406	$177,789	$171,643	$162,204	$141,799	$111,412	$76,571	$45,966	$18,744	$823			
7	Average Monthly Balance	$96,886	$194,039	$194,558	$192,007	$186,419	$180,855	$174,966	$167,157	$152,232	$126,809	$94,166	$61,399	$32,432	$9,828			
8	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%	3.25%	3.25%			
9	Computed Interest	$267	$518	$537	$513	$515	$499	$467	$461	$407	$350	$260	$153	$90	$26	$3,778	$1,285	$5,064
10	Ending Balance	$194,039	$194,558	$195,095	$189,432	$183,921	$178,288	$172,110	$162,666	$142,206	$111,762	$76,831	$46,120	$18,833	$849			

Northern Utilities, Inc., New Hampshire Division
Determination of Tenneesee Gas Refund - Commodity Cost Portion
Effective: June 2012 - April 2013

1	Tennessee Refund - Principle	$6,247	PG 5, LN 5
2	Tennessee Refund - Interest	$124	PG 5, LN 15
3	Estimated Interest Expense - Northern	$162	PG 4, LN 9
4	Total	$6,533	LN 1 + LN 2 + LN 3
5	Total Therms: (June 12 - April 13)	34,734,538	FORECAST
6	Commodity Refund Rate ($/CCF)	$0.0002	LN 4/ LN 5

Northern Utilities, Inc. New Hampshire Division
Tennessee Gas Refund - Commodity Portion
Effective: June 2012 - April 2013

		Mar-12	Apr-12	Estimate May-12	Estimate Jun-12	Estimate Jul-12	Estimate Aug-12	Estimate Sep-12	Estimate Oct-12	Estimate Nov-12	Estimate Dec-12	Estimate Jan-13	Estimate Feb-13	Estimate Mar-13	Estimate Apr-13	Total Mar-12 to Oct-12	Total Nov-12 to Apr-13	Total Mar 12 to Apr-13
1	Beginning Balance	$0	$6,380	$6,397	$6,415	$6,215	$6,021	$5,822	$5,604	$5,271	$4,552	$3,483	$2,256	$1,177	$219			
2	TGP Refund	$ 6,372	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0			
3	FS and FT (Therms)	$0	$0		1,083,360	1,057,284	1,075,722	1,165,799	1,737,916	3,660,851	5,402,430	6,173,777	5,414,848	4,802,750	3,159,801	6,120,081	28,614,458	34,734,538
4	Refund	$0	$0		$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002			
5	Estimated Refund Amount	$0	$0	$0	$217	$211	$215	$233	$348	$732	$1,080	$1,235	$1,083	$961	$632	$1,224	$5,723	$6,947
6	Ending Balance - excl. interest	$6,372	$6,380	$6,397	$6,198	$6,004	$5,805	$5,589	$5,256	$4,539	$3,472	$2,248	$1,173	$217	($413)			
7	Average Monthly Balance	$3,186	$6,380	$6,397	$6,307	$6,109	$5,913	$5,705	$5,430	$4,905	$4,012	$2,865	$1,714	$697	($97)			
8	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%	3.25%	3.25%			
9	Computed Interest	$9	$17	$18	$17	$17	$16	$15	$15	$13	$11	$8	$4	$2	($0)	$124	$38	$162
10	Ending Balance	$6,380	$6,397	$6,415	$6,215	$6,021	$5,822	$5,604	$5,271	$4,552	$3,483	$2,256	$1,177	$219	($414)			

Northern Utilities, Inc.
Allocation of TGP Rate Case Refund

		NUI	NH	ME
1	Amount Wired from TGP to NUI	$ 494,770.14		
2	Demand Allocator		48.64%	51.36%
3	Total Demand Refund (Principal Amount)	$ 472,641.75	$ 229,892.95	$ 242,748.80
4	Demand Refunds Due to Retail Marketers	$ 39,376.86	$ 39,376.86	
5	**Credit to Fixed Demand Gas Expense**	**$ 433,264.89**	**$ 190,516.09**	**$ 242,748.80**
6				
7	Average Commodity Allocator		52.84%	47.16%
8	Total Commodity Refund (Principal Amount)	$ 13,821.24		
9	Credit to Inventory Cost	$ 1,999.01		
10	**Credit to Variable Commodity Gas Expense**	**$ 11,822.23**	**$ 6,247.19**	**$ 5,575.04**
11				
12	Total Interest	$ 8,307.15		
13	Demand Related Interest	$ 8,071.86	$ 3,926.15	$ 4,145.71
14	Interest Payments Due to Retail Marketers	$ 670.28	$ 670.28	
15	**Interest Credit to Cost of Gas (Demand Related)**	**$ 7,401.58**	**$ 3,255.87**	**$ 4,145.71**
16	**Interest Credit to Cost of Gas (Commodity Related)**	**$ 235.29**	**$ 124.33**	**$ 110.96**
17				
18	**Total Demand Costs from Sales Customers**	**$ 440,666.47**	**$ 193,771.96**	**$ 246,894.51**
19				
20	**Total Commodity Costs from Sales Customers**	**$ 12,057.52**	**$ 6,371.52**	**$ 5,686.00**
21				
22	**Total Amount From Sales Customers**	**$ 452,723.99**	**$ 200,143.49**	**$ 252,580.50**
23				
24	Amounts Due to Retail Marketers		**$ 40,047.14**	
25	Total State Allocated		$ 240,190.63	$ 252,580.50
26				
27	**Credit to Inventory Account**	**$ 1,999.01**		

Northern Utilities, Inc.
Demand Charges Refund
Tennessee Gas Pipeline Company, L.L.C.
Interest Calculation: RP11-1566 Rate Refund
Refund Payment Date 3/30/2012

Line No.	Month Col. 1	Days in Month Col. 2	Prior Month Interest Base (Col. 6) Col. 3	(1) Quarterly Interest Col. 4	(2) Current Month Principal Col. 5	Current Month Interest Base (Col. 3+4+5) Col. 6	Interest Rate Col. 7	(3) Monthly Interest Rate Col. 8	Prior Month Interest (Col. 3+4) x Col. 8 Col. 9	(4) Current Month Interest Col. 10	Total Monthly Interest (Col. 9+10) Col. 11	Days to end of Month Col. 12	Due Date Col. 13
1	Jul-11	31	$ -	$ -	$ 94,528.35	$ 94,528.35	3.25%	0.2760%	$ -	$ 67.34	$ 67.34	8	7/23/2011
2	Aug-11	31	$ 94,528.35		$ 94,528.35	$ 189,056.70	3.25%	0.2760%	$ 260.92	$ 92.59	$ 353.51	11	8/20/2011
3	Sep-11	30	$ 189,056.70		$ 94,528.35	$ 283,585.05	3.25%	0.2671%	$ 505.01	$ 58.92	$ 563.93	7	9/23/2011
4	Oct-11	31	$ 283,585.05	$ 984.78	$ 94,528.35	$ 379,098.18	3.25%	0.2760%	$ 785.49	$ 75.75	$ 861.24	9	10/22/2011
5	Nov-11	30	$ 379,098.18		$ 94,528.35	$ 473,626.53	3.25%	0.2671%	$ 1,012.66	$ 84.17	$ 1,096.83	10	11/20/2011
6	Dec-11	31	$ 473,626.53			$ 473,626.53	3.25%	0.2760%	$ 1,307.34	$ -	$ 1,307.34	9	12/22/2011
7	Jan-12	31	$ 473,626.53	$ 3,265.41		$ 476,891.94	3.25%	0.2760%	$ 1,316.35	$ -	$ 1,316.35	9	1/22/2012
8	Feb-12	29	$ 476,891.94			$ 476,891.94	3.25%	0.2582%	$ 1,231.43	$ -	$ 1,231.43	6	2/23/2012
9	Mar-12	30	$ 476,891.94			$ 476,891.94	3.25%	0.2671%	$ 1,273.89	$ -	$ 1,273.89	7	3/23/2012
10	Total				$ 472,641.75				$ 7,693.09	$ 378.77	$ 8,071.86		

(1) Quarterly interest based upon Col. 8.
(2) Refund Principal
(3) FERC prescribed interest rates pursuant to CFR 154.501. Rate factored by number of days in the month.
(4) Interest calculated assuming amount is due or received as shown above. Column 5 * Column 7 * (No. of days in the month - date due)/365.

Northern Utilities, Inc.
Demand & Commodity Charges Refund
Tennessee Gas Pipeline Company, L.L.C.
Interest Calculation: RP11-1566 Rate Refund
Refund Payment Date 3/30/2012

Line No.	Month Col. 1	Days in Month Col. 2	Prior Month Interest Base (Col. 6) Col. 3	(1) Quarterly Interest Col. 4	(2) Current Month Principal Col. 5	Current Month Interest Base (Col. 3+4+5) Col. 6	Interest Rate Col. 7	(3) Monthly Interest Rate Col. 8	Prior Month Interest (Col. 3+4) x Col. 8 Col. 9	(4) Current Month Interest Col. 10	Total Monthly Interest (Col. 9+10) Col. 11	Days to end of Month Col. 12	Due Date Col. 13
1	Jul-11	31	$ -	$ -	$ 97,343.80	$ 97,343.80	3.25%	0.2760%	$ -	$ 69.34	$ 69.34	8	7/23/2011
2	Aug-11	31	$ 97,343.80		$ 97,361.65	$ 194,705.45	3.25%	0.2760%	$ 268.70	$ 95.36	$ 364.06	11	8/20/2011
3	Sep-11	30	$ 194,705.45		$ 97,224.40	$ 291,929.85	3.25%	0.2671%	$ 520.10	$ 60.60	$ 580.70	7	9/23/2011
4	Oct-11	31	$ 291,929.85	$ 1,014.10	$ 97,050.07	$ 389,994.02	3.25%	0.2760%	$ 808.61	$ 77.77	$ 886.38	9	10/22/2011
5	Nov-11	30	$ 389,994.02		$ 97,483.06	$ 487,477.09	3.25%	0.2671%	$ 1,041.76	$ 86.80	$ 1,128.56	10	11/20/2011
6	Dec-11	31	$ 487,477.09			$ 487,477.09	3.25%	0.2760%	$ 1,345.57	$ -	$ 1,345.57	9	12/22/2011
7	Jan-12	31	$ 487,477.09	$ 3,360.51		$ 490,837.60	3.25%	0.2760%	$ 1,354.85	$ -	$ 1,354.85	9	1/22/2012
8	Feb-12	29	$ 490,837.60			$ 490,837.60	3.25%	0.2582%	$ 1,267.44	$ -	$ 1,267.44	6	2/23/2012
9	Mar-12	30	$ 490,837.60			$ 490,837.60	3.25%	0.2671%	$ 1,311.14	$ -	$ 1,311.14	7	3/23/2012
10	Total				$ 486,462.99				$ 7,918.17	$ 389.87	$ 8,308.04		

(1) Quarterly interest based upon Col. 8.
(2) Refund Principal
(3) FERC prescribed interest rates pursuant to CFR 154.501. Rate factored by number of days in the month.
(4) Interest calculated assuming amount is due or received as shown above. Column 5 * Column 7 * (No. of days in the month - date due)/365.

Amount Wired	$ 494,770.14
Accounted For	$ 494,771.03
Unaccounted For	$ (0.89)

Northern Utilities, Inc.
New Hamsphire Division Capacity Assignment
Tennessee Refund Calculations

Tennessee Commodity Nominations

Pipeline	Contract ID	Rate	Receipt Zone	Delivery Zone	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Tennessee	5083	FT-A	Zone 4	Zone 6	133,306	137,919	137,919	134,460	138,924	682,528
Tennessee	5540	IT	Zone 6	Zone 6					5,892	5,892
Tennessee	5292	FT-A								-
Tennessee	39735	FT-A								-
Tennessee	46314	FT-A								-
Tennessee	5195	FS-MA	Injection		50,190	45,186	33,573	23,610	18,290	170,849
Tennessee	5265	FT-A	Zone 4	Zone 4		15				15
Tennessee	5265	FT-A	Zone 4	Zone 6	121	78				199

Commodity Refund Amount

Pipeline	Contract ID	Rate	Receipt Zone	Delivery Zone	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Tennessee	5083	FT-A	Zone 4	Zone 6	$ (2,226.21)	$ (2,303.25)	$ (2,303.25)	$ (2,245.48)	$ (2,320.03)	$ (11,398.22)
Tennessee	5540	IT	Zone 6	Zone 6	$ -	$ -	$ -	$ -	$ (420.69)	$ (420.69)
Tennessee	5292	FT-A			$ -	$ -	$ -	$ -	$ -	$ -
Tennessee	39735	FT-A			$ -	$ -	$ -	$ -	$ -	$ -
Tennessee	46314	FT-A			$ -	$ -	$ -	$ -	$ -	$ -
Tennessee	5195	FS-MA	Injection		$ (587.22)	$ (528.68)	$ (392.80)	$ (276.24)	$ (213.99)	$ (1,998.93)
Tennessee	5265	FT-A	Zone 4	Zone 4	$ -	$ (0.07)	$ -	$ -	$ -	$ (0.07)
Tennessee	5265	FT-A	Zone 4	Zone 6	$ (2.02)	$ (1.30)	$ -	$ -	$ -	$ (3.32)
Monthly Total Demand Refund					$ (2,815.45)	$ (2,833.30)	$ (2,696.05)	$ (2,521.72)	$ (2,954.71)	$ (13,821.24)

Tennessee Billed Commodity Rates (June 2011 through October 2011

Pipeline	Contract ID	Rate	Receipt Zone	Delivery Zone	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Tennessee	5083	FT-A	Zone 4	Zone 6	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259
Tennessee	5540	IT	Zone 6	Zone 6					$ 0.2503	
Tennessee	5292	FT-A								
Tennessee	39735	FT-A								
Tennessee	46314	FT-A								
Tennessee	5195	FS-MA	Injection		$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204
Tennessee	5265	FT-A	Zone 4	Zone 4		$ 0.0077				
Tennessee	5265	FT-A	Zone 4	Zone 6	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259

Tennessee Settlement Commodity Rates (June 2011 through October 2011

Pipeline	Contract ID	Rate	Receipt Zone	Delivery Zone	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Tennessee	5083	FT-A	Zone 4	Zone 6	$ 0.0092	$ 0.0092	$ 0.0092	$ 0.0092	$ 0.0092	
Tennessee	5540	IT	Zone 6	Zone 6					$ 0.1789	
Tennessee	5292	FT-A								
Tennessee	39735	FT-A								
Tennessee	46314	FT-A								
Tennessee	5195	FS-MA	Injection		$ 0.0087	$ 0.0087	$ 0.0087	$ 0.0087	$ 0.0087	
Tennessee	5265	FT-A	Zone 4	Zone 4		$ 0.0028				
Tennessee	5265	FT-A	Zone 4	Zone 6	$ 0.0092	$ 0.0092				

Settlement Commodity Rate Minus Billed Commodity Rate (June 2011 through October 2011

Pipeline	Contract ID	Rate	Receipt Zone	Delivery Zone	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Tennessee	5083	FT-A	Zone 4	Zone 6	$ (0.0167)	$ (0.0167)	$ (0.0167)	$ (0.0167)	$ (0.0167)	$ (0.0259)
Tennessee	5540	IT	Zone 6	Zone 6	$ -	$ -	$ -	$ -	$ (0.0714)	$ -
Tennessee	5292	FT-A			$ -	$ -	$ -	$ -	$ -	$ -
Tennessee	39735	FT-A			$ -	$ -	$ -	$ -	$ -	$ -
Tennessee	46314	FT-A			$ -	$ -	$ -	$ -	$ -	$ -
Tennessee	5195	FS-MA	Injection		$ (0.0117)	$ (0.0117)	$ (0.0117)	$ (0.0117)	$ (0.0117)	$ (0.0204)
Tennessee	5265	FT-A	Zone 4	Zone 4	$ -	$ (0.00)	$ -	$ -	$ -	$ -
Tennessee	5265	FT-A	Zone 4	Zone 6	$ (0.0167)	$ (0.0167)	$ (0.0259)	$ (0.0259)	$ (0.0259)	$ (0.0259)

Item	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
Monthly Inventory Adjustment	$ (587.22)	$ (528.75)	$ (392.80)	$ (276.24)	$ (213.99)	$ (1,999.01)
Monthly Expense Adjustment	$ (2,228.23)	$ (2,304.55)	$ (2,303.25)	$ (2,245.48)	$ (2,740.72)	$ (11,822.23)
NH Expense Allocator	54.31%	52.70%	53.42%	53.52%	50.73%	52.84%
ME Expense Allocator	45.69%	47.30%	46.58%	46.48%	49.27%	47.16%
NH Expense Adjustment	$ (1,210.15)	$ (1,214.50)	$ (1,230.39)	$ (1,201.78)	$ (1,390.37)	$ (6,247.19)
ME Expense Adjustment	$ (1,018.08)	$ (1,090.05)	$ (1,072.86)	$ (1,043.70)	$ (1,350.35)	$ (5,575.04)

Northern Utilities, Inc.
New Hamsphire Division Capacity Assignment
Tennessee Demand Refund Calculations
June 2011 through October 2011

		NUI	SPRAGUE	BUCKLEY	HESS	METRO	GLOBAL	SHELL
Month	Payment Date	Monthly Demand Refund Amount	Monthly Demand Refund Amount	Monthly Demand Refund Amount	Monthly Demand Refund Amount	Monthly Demand Refund Amount	Monthly Demand Refund Amount	Monthly Demand Refund Amount
Jun-11	7/23/2011	$ (94,528.35)	$ (1,109.98)	$ (692.51)	$ (229.95)	$ (3,849.63)	$ -	$ (1,898.18)
Jul-11	8/20/2011	$ (94,528.35)	$ (1,109.98)	$ (692.51)	$ (229.95)	$ (3,849.63)	$ -	$ (1,898.18)
Aug-11	9/23/2011	$ (94,528.35)	$ (1,109.98)	$ (692.51)	$ (229.95)	$ (3,849.63)	$ -	$ (1,898.18)
Sep-11	10/22/2011	$ (94,528.35)	$ (1,109.98)	$ (599.81)	$ (229.95)	$ (3,573.81)	$ (523.45)	$ (1,898.18)
Oct-11	11/20/2011	$ (94,528.35)	$ (1,109.98)	$ (599.81)	$ (229.95)	$ (3,573.81)	$ (689.19)	$ (1,898.18)

Northern Utilities, Inc.
New Hamsphire Division Capacity Assignment
Credits Due to Retail Marketers from Tennessee Rate Case Refund

Item	Supplier A	Supplier B	Supplier C	Supplier D	Supplier E	Supplier F	TOTAL
Demand Refund	$ (5,549.90)	$ (3,277.14)	$ (1,149.75)	$ (18,696.51)	$ (1,212.64)	$ (9,490.92)	$ (39,376.86)
Interest	$ (94.78)	$ (56.71)	$ (19.62)	$ (321.56)	$ (15.54)	$ (162.07)	$ (670.28)
Total	$ (5,644.68)	$ (3,333.85)	$ (1,169.37)	$ (19,018.07)	$ (1,228.18)	$ (9,652.99)	$ (40,047.14)