

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

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Summary

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

Anticipated Cost of Gas

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

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

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

Summary

Anticipated Cost of Gas

New Hampshire Division

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

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

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

65	Column A	Column B	Column C
67			
68	Total Anticipated Direct Cost of Gas	\$ 27,814,277	
69	Projected Prorated Sales (11/01/10 - 04/30/11)	28,028,950	
70	Direct Cost of Gas Rate		\$ 0.9923 per therm
71			
72	Demand Cost of Gas Rate	\$ 13,712,022	\$ 0.4892 per therm
73	Commodity Cost of Gas Rate	<u>\$ 14,102,256</u>	<u>\$ 0.5031 per therm</u>
74	Total Direct Cost of Gas Rate	\$ 27,814,277	\$ 0.9923 per therm
75			
76	Total Anticipated Indirect Cost of Gas	\$ 3,515,879	
77	Projected Prorated Sales (11/01/10 - 04/30/11)	28,028,950	
78	Indirect Cost of Gas		\$ 0.1254 per therm
79			
80			
81	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/2010		\$ 1.1177 per therm
82			
83	RESIDENTIAL COST OF GAS RATE - 11/01/10	COGwr	\$ 1.1177 per therm
84		Maximum (COG+25%)	\$ 1.3971
85			
86			
87	COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/10	COGwl	\$ 1.0019 per therm
88		Maximum (COG+25%)	\$ 1.2524
89			
90	C&I HLF Demand Costs Allocated per SMBA	\$ 712,743	
91	PLUS: Residential Demand Reallocation to C&I HLF	<u>\$ 12,540</u>	
92	C&I HLF Total Adjusted Demand Costs	\$ 725,283	
93	C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	2,402,246	
94	Demand Cost of Gas Rate	\$ 0.3019	
95			
96	C&I HLF Commodity Costs Allocated per SMBA	\$ 1,378,807	
97	PLUS: Residential Commodity Reallocation to C&I HLF	<u>\$ 1,419</u>	
98	C&I HLF Total Adjusted Commodity Costs	\$ 1,380,226	
99	C&I HLF Projected Prorated Sales (11/01/10 - 04/30/11)	2,402,246	
100	Commodity Cost of Gas Rate	\$ 0.5746	
101			
102	Indirect Cost of Gas	\$ 0.1254	
103			
104	Total C&I HLF Cost of Gas Rate	\$ 1.0019	
105			
106			
107	COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/10	COGwh	\$ 1.1398 per therm
108		Maximum (COG+25%)	\$ 1.4248
109			
110	C&I LLF Demand Costs Allocated per SMBA	\$ 6,495,498	
111	PLUS: Residential Demand Reallocation to C&I LLF	<u>\$ 114,281</u>	
112	C&I LLF Total Adjusted Demand Costs	\$ 6,609,778	
113	C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	12,591,463	
114	Demand Cost of Gas Rate	\$ 0.5249	
115			
116	C&I LLF Commodity Costs Allocated per SMBA	\$ 6,157,247	
117	PLUS: Residential Commodity Reallocation to C&I LLF	<u>\$ 6,338</u>	
118	C&I LLF Total Adjusted Commodity Costs	\$ 6,163,585	
119	C&I LLF Projected Prorated Sales (11/01/10 - 04/30/11)	12,591,463	
120	Commodity Cost of Gas Rate	\$ 0.4895	
121			
122	Indirect Cost of Gas	\$ 0.1254	
123			
124	Total C&I LLF Cost of Gas Rate	\$ 1.1398	

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

Schedule 1

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

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

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

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

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

42 NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)

43 (Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)

44

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

51

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

58

59 DEMAND COST PR ALLOCATORS

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

66

67 DEMAND COSTS ALLOCATED TO MONTHS

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

81

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**
43 (Based on NH Firm Sales Sendout for Remaining Temperature)
44

All Months	May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
Remaining Load for All Months	774,180	192,941	28,476	91,816	286,081	932,290	25,754,739	23,448,955	2,305,784
Rank	8	10	12	11	9	7			
% Max Month	13.75%	3.43%	0.51%	1.63%	5.08%	16.56%			
PR	1.08%	0.18%	0.04%	0.10%	0.18%	0.40%	34.53%		
CumPR	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%

Peak Months Only	Total	Winter	Summer
Remaining Load for Peak Months Only	23,448,955		
Rank			
% Max Month			
PR	35.30%		
CumPR	100.00%	100.00%	0.00%

58
59 **DEMAND COST PR ALLOCATORS**

	May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
Pipeline - Remaining	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%
Storage & Peaking	1.59%	0.32%	0.04%	0.14%	0.51%	1.99%	100.00%	95.40%	4.60%
Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

60
61 **DEMAND COSTS ALLOCATED TO MONTHS**

	May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer	Winter	Summer
Pipeline - Base	\$ 57,910	\$ 57,910	\$ 57,910	\$ 57,910	\$ 57,910	\$ 57,910	\$ 694,919	\$ 347,460	\$ 347,460	50.00%	50.00%
Pipeline - Remaining	\$ 26,645	\$ 5,425	\$ 706	\$ 2,418	\$ 8,502	\$ 33,361	\$ 1,673,893	\$ 1,596,836	\$ 77,057	95.40%	4.60%
Total Pipeline	\$ 84,555	\$ 63,335	\$ 58,616	\$ 60,328	\$ 66,412	\$ 91,271	\$ 2,368,813	\$ 1,944,296	\$ 424,516	82.08%	17.92%
Storage & Peaking	\$ 225,908	\$ 45,995	\$ 5,983	\$ 20,500	\$ 72,087	\$ 282,854	\$ 14,192,133	\$ 13,538,806	\$ 653,327	95.40%	4.60%
Less Credits to Demand Cost											
Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,771,080	\$ 1,771,080	\$ -	100.00%	0.00%
Interruptible Margins	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Re-Entry Fee Credits	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Total Direct Demand Costs	\$ 310,463	\$ 109,330	\$ 64,598	\$ 80,828	\$ 138,499	\$ 374,125	\$ 14,789,865	\$ 13,712,022	\$ 1,077,843	92.71%	7.29%
Indirect Demand Costs/(Credits)											
Miscellaneous Overhead							\$ 124,297	\$ 98,333	\$ 25,964	79.11%	20.89%
Local Production & Storage							\$ 686,673	\$ 686,673	\$ -	100.00%	0.00%
Subtotal							\$ 810,970	\$ 785,006	\$ 25,964	96.80%	3.20%

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

42 NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY

43 (Based on NH Firm Sales Sendout for Remaining Temperature)

44		
45	All Months	
46	Remaining Load for All Months	Schedule 10B, LN 80
47	Rank	Rank LN 46
48	% Max Month	LN 46 / MAX Month LN 46
49	PR	The difference between LN 48 for the month and LN 48 for next highest rank
50	CumPR	Cumulative Values, LN 49

51		
52	Peak Months Only	
53	Remaining Load for Peak Months Only	LN 46
54	Rank	Rank LN 53
55	% Max Month	LN 53 / MAX Month LN 53
56	PR	The difference between LN 55 for the month and LN 55 for next highest rank
57	CumPR	Cumulative Values, LN 56

58		
59	DEMAND COST PR ALLOCATORS	
60		
61	Pipeline - Base	1/12
62	Pipeline - Remaining	LN 50
63	Storage & Peaking	LN 50
64	Capacity Release	LN 57
65	Interr. Margins & Off Sys Sales	LN 57

66		
67	DEMAND COSTS ALLOCATED TO MONTHS	
68		
69	Pipeline - Base	LN 40 * LN 61
70	Pipeline - Remaining	LN 41 * LN 62
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & Peaking	LN 63 * (Sum LN 21 : LN 22)
74		
75	Less Credits to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	LN 64 * Sum (Schedule 25 LN 88, Schedule 25 LN 89)
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79		
80	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 78)

81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

P
COMMODITY COSTS

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

Northern Utilities - NEW HAMPSHIRE DIVISION COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Schedule 22, LN 9 * LN 60 * 10
2	New Hampshire Sales Storage	Schedule 22, LN 3 * LN 60 * 10
3	New Hampshire Sales Peaking	Schedule 22, LN 4 * LN 60 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Schedule 22, LN 7 * 10
7		
8	Total Firm Sendout	LN 4
9	Total Firm Sales	Schedule 10B, LN 11
10	Difference (LAUF & Company Use)	LN 8 - LN 9
11	Percent Difference	LN 10 / LN 8
12		
13	Variable Costs	
14	New Hampshire Sales Pipeline Commodity	Schedule 22, LN 74 * 10
15	New Hampshire Hedging (Gains) Losses	Schedule 22, LN 75 * 10
16	New Hampshire Total Storage	Schedule 22, LN 76 * 10
17	New Hampshire Total Peaking	Schedule 22, LN 77 * 10
18	New Hampshire Inventory Finance Charge	Schedule 22, LN 80 * 10
19	Total New Hampshire Sales Variable Costs	Sum LN 14 : LN 18
20	Total New Hampshire Sales Variable Costs Excl'd 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 Excl'd Hedges	LN 14 / LN 1
27	New Hampshire Hedging (Gains) Losses	LN 15 / LN 1
28	New Hampshire Storage Excl'd Inventory Finance Costs	LN 16 / LN 2
29	New Hampshire Peaking Excl'd 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 Excl'd 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 Excl'd Hedging	LN 20 - LN 37
40	Remaining Hedging Commodity	LN 15 - LN 38
41	Total Commodity Excl'd Hedging	LN 37 + LN 39
42	Total Hedging	LN 38 + LN 40
43	Total Commodity (Incl Hedging)	LN 41 + LN 42

Schedule 2

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes November 1, 2010 through April 30, 2011			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Peaking Supply 1	\$2,404,468	602,041	\$3.9939
Washington 10 Storage	\$11,577,747	2,559,895	\$4.5227
Tennessee Storage	\$707,503	147,681	\$4.7908
Chicago	\$1,667,801	301,862	\$5.5251
Niagara	\$1,035,386	184,693	\$5.6060
Tennessee Production	\$7,768,412	1,375,093	\$5.6494
LNG	\$111,223	18,872	\$5.8934
Pittsburgh, NH	\$1,240,066	199,100	\$6.2284
Peaking Supply 2	\$21,557	2,670	\$8.0723
Total System	\$26,534,162	5,391,907	\$4.9211

Schedule 3

Peak Period

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

Sales Revenues		Summer						Winter						Total
		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
Volumes	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	
Residential Heat & Non Heat								1,414,484	2,062,233	2,986,351	2,524,748	2,503,078	1,544,347	13,035,240
Sales HLF Classes								350,675	424,947	465,570	408,229	429,473	323,352	2,402,246
Sales LLF Classes								1,281,941	2,235,337	2,928,309	2,497,002	2,324,978	1,323,897	12,591,463
Total								3,047,100	4,722,517	6,380,229	5,429,979	5,257,529	3,191,596	28,028,950
Rates														
Residential Heat & Non Heat CGA								\$1.1177	\$1.1177	\$1.1177	\$1.1177	\$1.1177	\$1.1177	
Sales HLF Classes CGA								\$1.1177	\$1.1177	\$1.1177	\$1.1177	\$1.1177	\$1.1177	
Sales LLF Classes CGA								\$1.1177	\$1.1177	\$1.1177	\$1.1177	\$1.1177	\$1.1177	
Revenues														
Residential Heat & Non Heat								\$ (1,580,968)	\$ (2,304,958)	\$ (3,337,844)	\$ (2,821,911)	\$ (2,797,690)	\$ (1,726,117)	\$ (14,569,488)
Sales HLF Classes								\$ (391,950)	\$ (474,963)	\$ (520,367)	\$ (456,278)	\$ (480,022)	\$ (361,410)	\$ (2,684,990)
Sales LLF Classes								\$ (1,432,825)	\$ (2,498,436)	\$ (3,272,971)	\$ (2,790,899)	\$ (2,598,627)	\$ (1,479,720)	\$ (14,073,479)
Total Sales Revenues								\$ (3,405,743)	\$ (5,278,357)	\$ (7,131,182)	\$ (6,069,087)	\$ (5,876,340)	\$ (3,567,247)	\$ (31,327,957)
Gas Costs and Credits		Summer						Winter						Total
		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
Net Demand Costs (Net of Injection Fees & Cap. Assign.)		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	
Pipeline		\$ 165,006	\$ 165,006	\$ 165,006	\$ 165,006	\$ 165,006	\$ 165,006	\$ 144,690	\$ 149,541	\$ 165,006	\$ 165,006	\$ 165,006	\$ 165,006	\$ 1,944,296
Storage		\$ 513,332	\$ 513,332	\$ 513,332	\$ 513,332	\$ 513,332	\$ 513,332	\$ 1,212,196	\$ 1,537,673	\$ 1,564,703	\$ 1,564,703	\$ 1,564,703	\$ 513,332	\$ 11,037,302
Peaking		\$ 147,181	\$ 147,181	\$ 147,181	\$ 147,181	\$ 147,181	\$ 147,181	\$ 272,618	\$ 272,618	\$ 303,525	\$ 303,525	\$ 303,525	\$ 147,181	\$ 2,486,078
Total Demand Costs		\$ 825,520	\$ 825,520	\$ 825,520	\$ 825,520	\$ 825,520	\$ 825,520	\$ 1,629,504	\$ 1,959,832	\$ 2,033,234	\$ 2,033,234	\$ 2,033,234	\$ 825,520	\$ 15,467,675
NUI Commodity Costs														
NUI Total Pipeline Volumes								499,368	256,695	197,401	162,786	371,174	573,323	2,060,747
Pipeline Costs Modeled in Sendout™								\$ 2,759,757	\$ 1,490,684	\$ 1,187,524	\$ 978,909	\$ 2,173,072	\$ 3,121,720	\$ 11,711,666
NYMEX Price Used for Forecast								\$ 4.9050	\$ 5.1720	\$ 5.3370	\$ 5.3060	\$ 5.2100	\$ 5.0180	
NYMEX Price Used for Update								\$ 4.0250	\$ 4.3590	\$ 4.5430	\$ 4.5380	\$ 4.4720	\$ 4.3990	
Increase/(Decrease) NYMEX Price								\$ (1)	\$ (1)	\$ (1)	\$ (1)	\$ (1)	\$ (1)	
Increase/(Decrease) in Pipeline Costs								\$ (439,444)	\$ (208,693)	\$ (156,737)	\$ (125,020)	\$ (273,927)	\$ (354,887)	
Updated Pipeline Costs								\$ 2,320,313	\$ 1,281,991	\$ 1,030,787	\$ 853,889	\$ 1,899,146	\$ 2,766,833	
Interruptible Volumes - NH								0	0	0	0	0	0	
Average Supply Cost (\$/MMBtu)								\$ 4.65	\$ 4.99	\$ 5.22	\$ 5.25	\$ 5.12	\$ 4.83	
Interruptible Cost - NH								\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Total Updated Pipeline Costs								\$ 2,320,313	\$ 1,281,991	\$ 1,030,787	\$ 853,889	\$ 1,899,146	\$ 2,766,833	
New Hampshire Allocated Percentage								52.67%	50.65%	53.40%	54.23%	54.19%	54.01%	
NH Updated Pipeline Costs								\$ 1,222,161	\$ 649,388	\$ 550,433	\$ 463,086	\$ 1,029,074	\$ 1,494,396	\$ 5,408,538
Hedging (Gain)/Loss Estimate														
Time Triggered NYMEX Contracts (Allocated between ME and NH)														
NYMEX NG Futures Contracts								7	8	4	5	5	9	
Average Purchase Price								\$ 6.3850	\$ 6.6363	\$ 6.9913	\$ 6.9020	\$ 6.7130	\$ 6.1778	
NYMEX Price Used for Forecast								\$ 4.9050	\$ 5.1720	\$ 5.3370	\$ 5.3060	\$ 5.2100	\$ 5.0180	
NYMEX Price Used for Update								\$ 4.0250	\$ 4.3590	\$ 4.5430	\$ 4.5380	\$ 4.4720	\$ 4.3990	
Increase/(Decrease) NYMEX Price								(0.8800)	(0.8130)	(0.7940)	(0.7680)	(0.7380)	(0.6190)	
NUI Futures Hedging (Gain)/Loss - Allocate								\$ 165,200	\$ 182,180	\$ 97,930	\$ 118,200	\$ 112,050	\$ 160,090	\$ 835,650
New Hampshire Allocated Percentage								52.67%	50.65%	53.40%	54.23%	54.19%	54.01%	
NH Futures Hedging (Gain)/Loss, Time Triggered								\$ 87,015	\$ 92,283	\$ 52,294	\$ 64,103	\$ 60,716	\$ 86,466	\$ 442,876

Peak Period

Northern Utilities

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

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

Peak Period

Northern Utilities

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

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

Schedule 4

Reserved for Future Use

Schedule 5

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

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

Total Annual Demand Costs

\$ 31,558,769

Exchange Rate (CAD/USD) = 0.95

FXW-5A, Page 18

Note 1: Granite filed new rates under FERC docket RP10-896. New Granite rates projected to take effect on 1/1/2011.

Note 2: PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.

Note 3: Seasonal Recourse Rate. PNGTS filed new rates under FERC docket RP10-729. New PNGTS rates projected to take effect on 12/1/2010.

Note 4: The demand rate applied for Zone L to Zone 6 transportation capacity Zone 1 to Zone 6 demand rate.

Note 5: The rate is the Segment 3 demand rate of \$5.07 per Dth plus the Segment 4 demand rate of \$5.54 per Dth.

Note 6: For Contract ID 800384, Northern pays both the FT-1 Reservation Charge of \$5.148 (Page 10 of FXW-5A) and the FT-1/FTS Other Transportation Services charge of \$0.66 (Page 20 of FXW-5A).

Note 7: Rate is expressed in the tariff sheet as as a Delivery Zone of AAB ("Access Area Boundary"). The AAB is the border between the Access Areas (ETX, ELA, WLA, and STX) and the M1 Zone.

Note 8: Rate is the Delivery Pressure Toll for deliveries into Iroquois of \$CAD 0.78572 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to Iroquois of \$CAD 10.82669 (Page 12 of FXW-5A).

Note 9: Rate is the Delivery Pressure Toll for deliveries into E. Hereford of \$CAD 1.96558 (Page 11 of FXW-5A) plus the FT Toll for Union Dawn to E. Hereford of \$CAD 16.76744 (Page 12 of FXW-5A).

Note 10: Maximum tariff rate of \$7.7745 (Page 15 of FXW-5A) exceeds negotiated rate of \$8.0908 (Page 16 of FXW-5A). Therefore, Maximum tariff rate applies.

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

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

Annual Total Demand Costs

\$ 6,161,947	\$ 660,263	\$ 5,289,666	\$ 212,018	\$ 31,558,769	\$ 6,979,327	\$ 23,000,956	\$ 1,578,485
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Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2010 through October 31, 2011

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

Total Annual Fixed Charges

\$ 3,008,911

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

13.1103545

8.01319821

24.88671576

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

November 1, 2010 through October 31, 2011										
Resource	Contract Quantity	Maximum Daily Quantity	Contract Quantity Demand Rate	MDQ Demand Rate	Months Per Year	Support for Demand Rates	Annual CQ Demand Cost	Annual MDQ Demand Cost	Monthly Fixed Charges	Annual Fixed Charges
Peaking Supply 1	755,000	5,000	\$ -	\$ 44.09	12	FXW-5A, Page 22	\$ -	\$ 2,645,238	\$ 220,437	\$ 2,645,238
Peaking Supply 2	1,435,000	57,400	\$ 1.3500	\$ -	5	FXW-5A, Page 23	\$ 1,937,250	\$ -	\$ 387,450	\$ 1,937,250
Total Peaking Supply Contract Demand Costs										\$ 4,582,488

Northern Utilities, Inc.
Asset Management and Capacity Release Revenue Projections
November 1, 2010 through October 31, 2011

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

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

Total Asset Management and Capacity Release Revenue	\$ (2,931,530)
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ALCONQUIN GAS TRANSMISSION, LLC
DISCOUNTED RATE LETTER - SCHEDULE

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



ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2009

•RATE SCHEDULE AFT-1

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

•RATE SCHEDULE AFT-1S

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

•OTHER FIRM RATE SCHEDULES

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

•INTERRUPTIBLE SERVICE

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

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	\$5.3900	\$0.0000

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

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
--------	----------	-----

Rate Schedule FT-NN
 Firm Transportation Service

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

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

Rate Schedule FT-NN
Firm Transportation Service

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

Iroquois Gas Transmission System, L.P.

Thirty First Revised Sheet No. 4

FERC Gas Tariff

Superseding

FIRST REVISED VOLUME NO. 1

Thirtieth Revised Sheet No. 4

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

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

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

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

(Footnotes continued on Sheet 4.01)

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

Issued on: Jan 26, 2009

Effective: Jan 27, 2009



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

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

Statement of Transportation Rates

(Rates per DTH)

Rate Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ Rate

FT Recourse Reservation Rate

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

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

Seasonal Recourse Reservation Rate

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

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

Recourse Usage Rate

-- Maximum \$00.0000 \$00.0019 \$00.0019

-- Minimum \$00.0000 \$00.0019 \$00.0019

FT-FLEX Recourse Reservation Rate

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

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

Recourse Usage Rate

--Maximum \$00.2962 \$00.0019 \$00.2981

--Minimum \$00.0000 \$00.0019 \$00.0019

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

Eighth Revised Sheet No. 100
 Superseding
 Seventh Revised Sheet No. 100

Statement of Transportation Rates
 (Rates per DTH)

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

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
 RATE SCHEDULE FOR FT-A

Base Reservation Rates

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

Surcharges

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
PCB Adjustment: 1/	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
L		\$0.00						
1	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
2	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
3	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
4	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
6	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

Maximum Reservation Rates 2 /

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

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

Notes:

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

RATES PER DEKATHERM

RATE SCHEDULE NET 284

=====

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

Notes:

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

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

CURRENTLY EFFECTIVE RATES 2/01/2010

•RESERVATION CHARGES

	CDS	FT-1	SCT	7(C) RATE	SCHEDULES
STX-AAB	6.8120	6.5890	2.7250	FTS	5.3500
WLA-AAB	2.8280	2.6050	1.1310	FTS-2	7.9590
ELA-AAB	2.3750	2.1520	0.9500	FTS-4	7.7210
ETX-AAB	2.1890	1.9660	0.8760	FTS-5	5.1790
STX-STX	5.7400	5.5170	2.2950	FTS-7	6.5760
STX-WLA	5.8990	5.6760	2.3580	FTS-8	6.8640
STX-ELA	6.8160	6.5930	2.7240	X-127	7.7060
STX-ETX	6.8170	6.5940	2.7250	X-129	7.5430
WLA-WLA	2.0570	1.8340	0.8220	X-130	7.5430
WLA-ELA	2.8310	2.6080	1.1310	X-135	1.6030
WLA-ETX	2.8300	2.6070	1.1300	X-137	4.0100
ELA-ELA	2.3790	2.1560	0.9500		
ETX-ETX	2.1930	1.9700	0.8760		
ETX-ELA	2.3780	2.1550	0.9500		
M1-M1	4.5870	4.3640	1.8320		
M1-M2	8.5650	8.3420	3.4230		
M1-M3	11.2800	11.0570	4.5080		
M2-M2	6.6330	6.4100	2.6510		
M2-M3	9.4860	9.2630	3.7910		
M3-M3	5.3710	5.1480	2.1460		
SCT DEMAND CHARGES					
Access Area	0.0020				
M1-M1	0.0030				
M1-M2	0.0030				
M1-M3	0.0040				

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0090	0.0098	0.0143	0.0143	0.0363	0.0726	0.0976
from WLA		0.0060	0.0105	0.0105	0.0325	0.0688	0.0938
from ELA			0.0089	0.0089	0.0309	0.0672	0.0922
from ETX				0.0089	0.0309	0.0672	0.0922
from M1					0.0220	0.0583	0.0833
from M2						0.0408	0.0655
from M3							0.0292
Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0088						
from WLA	0.0096	0.0059					
from ELA	0.0140	0.0103	0.0087				
from ETX	0.0140	0.0103	0.0087	0.0087			
from M1	0.0358	0.0321	0.0305	0.0305	0.0218		
from M2	0.0720	0.0683	0.0667	0.0667	0.0580	0.0405	
from M3	0.0968	0.0931	0.0915	0.0915	0.0828	0.0651	0.0290

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1903	0.1963	0.2309	0.2309	0.3962	0.5632	0.6774
from WLA		0.0662	0.0961	0.0961	0.2614	0.4284	0.5427
from ELA			0.0797	0.0797	0.2449	0.4119	0.5262
from ETX				0.0736	0.2388	0.4058	0.5201
from M1					0.1653	0.3323	0.4465
from M2						0.2513	0.3698
from M3							0.1983
Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1901						
from WLA	0.1961	0.0661					
from ELA	0.2306	0.0959	0.0795				
from ETX	0.2306	0.0959	0.0795	0.0734			
from M1	0.3957	0.2610	0.2445	0.2384	0.1651		
from M2	0.5626	0.4279	0.4114	0.4053	0.3320	0.2510	
from M3	0.6766	0.5420	0.5255	0.5194	0.4460	0.3694	0.1981

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1904	0.1964	0.2311	0.2311	0.3966	0.5636	0.6779
from WLA		0.0663	0.0962	0.0962	0.2618	0.4288	0.5431
from ELA			0.0798	0.0798	0.2453	0.4123	0.5266
from ETX				0.0736	0.2391	0.4061	0.5204
from M1					0.1655	0.3325	0.4468
from M2						0.2516	0.3701
from M3							0.1985
Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1902						
from WLA	0.1962	0.0662					
from ELA	0.2308	0.0960	0.0796				
from ETX	0.2308	0.0960	0.0796	0.0734			
from M1	0.3961	0.2614	0.2449	0.2387	0.1653		
from M2	0.5630	0.4283	0.4118	0.4056	0.3322	0.2513	
from M3	0.6771	0.5424	0.5259	0.5197	0.4463	0.3697	0.1983

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

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

Storage Transportation Service

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

Enhanced Capacity Release

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

Delivery Pressure

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

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

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

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

**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): Authorized Signature of Replacement
Shipper: DTE

Replacement shipper will receive
corresponding Vector-Canada capacity
from St. Clair (International Border)
to Dawn at no additional cost. Name: DON TULLY
Title: ANALYST
Telephone: (508) 836-7259
Fax: () 508-870-2294
- 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.

**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: \$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): Authorized Signature of Replacement
Shipper: [Signature]

Replacement shipper will receive
corresponding Vector-Canada capacity
from St. Clair (International Border)
to Dawn at no additional cost. Name: DON TULCHINSKY
Title: ANALYST

The Term of the FT1-DTE-0425 Telephone: () 508-836-7257
contract underlying this release Fax: () 508-870-2284
is subject to the June 30, 2005
Precedent Agreement between DTE
Energy Trading, Inc. and Vector
Pipeline L.P.

You are here: [Vector](#) > [Informational Postings](#) > [Informational Postings](#) > [Tariff](#) > Currently Effective Rates**INFORMATIONAL POSTINGS**[Capacity](#)[Gas Quality](#)[Index of Customers](#)[Notices](#)[Posted Imbalances](#)[Standards of Conduct](#)[Tariff](#)[Title Sheet](#)[Table of Contents](#)[Preliminary Statement](#)[Map](#)[Currently Effective Rates](#)[Rate Schedules](#)[General Terms and Conditions](#)[Form of Service Agreement](#)[Entire Tariff](#)[Sheet Index](#)[Vector - Canada Tariff](#)[Transactional Reporting](#)[Other](#)[Downloads](#)[Search](#)[Customer Activities](#)[Site Map](#)[Previous](#) [Next](#)

Vector Pipeline L.P.

FERC Gas Tariff

Eleventh Revised Sheet No. 20

Original Volume No. 1

Superseding

Tenth Revised Sheet No. 20

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. \$

Rate Schedule FT-1 1/

Recourse Rates:

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

Negotiated Rates:

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

Rate Schedule FT-L 1/

Recourse Rates:

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

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

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

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

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

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

Toll Election Negotiated:

The Reservation Charge applicable to this service is \$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.

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:

[10-Year Currency Converter](#)

Using rates for: 20 Jul 2010

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

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

Summary:

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

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

SEE ALSO:

[10-Year Currency Converter](#)

FREQUENTLY ASKED:

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

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

More comprehensive currency converters include [CanadianForex](#) and [OANDA.com](#).

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

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

RATES PER DEKATHERM

FIRM STORAGE SERVICE
 RATE SCHEDULE FS

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

1/ The quantity of gas associated with losses is 0.5%.

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

•OTHER TRANSPORTATION SERVICES

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

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

•STORAGE SERVICES

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

•SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31							
	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.12%	2.32%	3.38%	3.38%	5.35%	7.30%	8.59%
from WLA	1.40%	1.40%	2.48%	2.48%	4.45%	6.40%	7.69%
from ELA	2.08%	2.08%	2.08%	2.08%	4.05%	6.00%	7.29%
from ETX	2.12%	2.08%	2.08%	2.08%	4.05%	6.00%	7.29%
from M1					1.97%	3.92%	5.21%
from M2						2.99%	4.30%
from M3							2.36%
April 1 through November 30							
	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.06%	2.22%	3.02%	3.02%	4.97%	6.46%	7.46%
from WLA	1.52%	1.52%	2.34%	2.34%	4.29%	5.78%	6.78%
from ELA	2.03%	2.03%	2.03%	2.03%	3.98%	5.47%	6.47%
from ETX	2.06%	2.03%	2.03%	2.03%	3.98%	5.47%	6.47%
from M1					1.95%	3.44%	4.44%
from M2						2.72%	3.73%
from M3							2.25%

NON-ASA RATE SCHEDULES

FTS-4 LEIDY	FTS	1.29%
(Apr 1-Nov 14)	FTS-2	0.00%
(Nov 15-Mar 31)	X-127	0.00%
FTS-4 CHMSB6	X-129	0.00%
FTS-5	X-130	0.00%
FTS-7 M3	X-135	0.00%
FTS-7 M1 & M2	X-137	1.30%
FTS-8 M3		
FTS-8 M1 & M2		

ASA STORAGE RATE SCHEDULES

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

•SURCHARGES

ACA Surcharge
Commodity 0.0019

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

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

SHIPPER:

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

**INVOICES, STATEMENTS AND
NOMINATIONS**

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

ALL OTHER MATTERS

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

ARTICLE VIII: FURTHER AGREEMENT

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

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

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

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

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

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

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

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

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

Total NH Capacity Assignment Credits

\$ (2,094,795)

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

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

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

MSQ = Maximum Space Quantity

MDWQ = Maximum Daily Withdrawal Quantity

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2009 through October 2010

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

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

Total Asset Management and Capacity Release Revenue	\$ (2,931,530)				\$ 71,945
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Northern Utilities, Inc.
New Hampshire Division
Peaking Demand Capacity Assignment Revenues
November 2010 through April 2011

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

Total Division Peaking Demand Revenue \$ (392,804)

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

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

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

Estimate of PNGTS Transportation Costs Subject to Refund

Prior Rates			Filed Rates			Subject to Refund												
Prior Rate Volume	Annual Rate	Winter Rate		Annual Rate	Winter Rate		Annual Rate	Winter Rate		Annual Rate	Winter Rate		Annual Rate	Winter Rate				
	\$ 25,245	\$ 48,515		\$ 27,4017	\$ 52,063		\$ 2,157	\$ 3,549		\$ 1,100	\$ 33,000							
	1,100	33,000		1,100	33,000		1,100	33,000		1,100	33,000		1,100	33,000				
Month	FT-1997-003	FT-1997-004	Total Cost	FT-1997-003	FT-1997-004	Total Cost	FT-1997-003	FT-1997-004	Total Cost	ME Allocator	NH Allocator	ME Refund	NH Refund	Begin Month Balance	End Month Balance	Average Balance	Interest Rate	Interest
Sep-08	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.93%	50.07%	\$ 1,185	\$ 1,188	\$ -	\$ 2,372	\$ 1,186	5.30%	\$ 5
Oct-08	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.93%	50.07%	\$ 1,185	\$ 1,188	\$ 2,378	\$ 4,750	\$ 3,564	5.00%	\$ 15
Nov-08	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	49.91%	50.09%	\$ 59,629	\$ 59,844	\$ 4,765	\$ 124,238	\$ 64,502	5.00%	\$ 269
Dec-08	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	49.91%	50.09%	\$ 59,629	\$ 59,844	\$ 124,507	\$ 243,980	\$ 184,243	5.00%	\$ 793
Jan-09	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	49.91%	50.09%	\$ 59,629	\$ 59,844	\$ 244,773	\$ 364,246	\$ 304,510	4.52%	\$ 1,185
Feb-09	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	49.91%	50.09%	\$ 59,629	\$ 59,844	\$ 365,431	\$ 484,904	\$ 425,168	4.52%	\$ 1,495
Mar-09	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	49.91%	50.09%	\$ 59,629	\$ 59,844	\$ 486,399	\$ 605,872	\$ 546,135	4.52%	\$ 2,126
Apr-09	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.91%	50.09%	\$ 1,184	\$ 1,188	\$ 607,997	\$ 610,370	\$ 609,183	3.37%	\$ 1,711
May-09	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.91%	50.09%	\$ 1,184	\$ 1,188	\$ 612,080	\$ 614,453	\$ 613,267	3.37%	\$ 1,780
Jun-09	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.91%	50.09%	\$ 1,184	\$ 1,188	\$ 616,233	\$ 618,605	\$ 617,419	3.37%	\$ 1,734
Jul-09	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.91%	50.09%	\$ 1,184	\$ 1,188	\$ 620,339	\$ 622,711	\$ 621,525	3.25%	\$ 1,739
Aug-09	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.91%	50.09%	\$ 1,184	\$ 1,188	\$ 624,451	\$ 626,823	\$ 625,637	3.25%	\$ 1,751
Sep-09	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.91%	50.09%	\$ 1,184	\$ 1,188	\$ 628,574	\$ 630,946	\$ 629,760	3.25%	\$ 1,706
Oct-09	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	49.91%	50.09%	\$ 1,184	\$ 1,188	\$ 632,652	\$ 635,024	\$ 633,838	3.25%	\$ 1,774
Nov-09	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	52.54%	47.46%	\$ 62,771	\$ 56,702	\$ 636,798	\$ 756,271	\$ 696,534	3.25%	\$ 1,886
Dec-09	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	52.54%	47.46%	\$ 62,771	\$ 56,702	\$ 758,157	\$ 877,630	\$ 817,894	3.25%	\$ 2,289
Jan-10	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	52.54%	47.46%	\$ 62,771	\$ 56,702	\$ 879,919	\$ 999,392	\$ 939,656	3.25%	\$ 2,630
Feb-10	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	52.54%	47.46%	\$ 62,771	\$ 56,702	\$ 1,002,022	\$ 1,121,495	\$ 1,061,758	3.25%	\$ 2,684
Mar-10	\$ 27,770	\$ 1,600,985	\$ 1,628,755	\$ 30,142	\$ 1,718,086	\$ 1,748,227	\$ 2,372	\$ 117,101	\$ 119,473	52.54%	47.46%	\$ 62,771	\$ 56,702	\$ 1,124,179	\$ 1,243,651	\$ 1,183,915	3.25%	\$ 3,313
Apr-10	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	52.54%	47.46%	\$ 1,246	\$ 1,126	\$ 1,246,965	\$ 1,249,337	\$ 1,248,151	3.25%	\$ 3,380
May-10	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	52.54%	47.46%	\$ 1,246	\$ 1,126	\$ 1,252,718	\$ 1,255,090	\$ 1,253,904	3.25%	\$ 3,509
Jun-10	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	52.54%	47.46%	\$ 1,246	\$ 1,126	\$ 1,258,599	\$ 1,260,971	\$ 1,259,785	3.25%	\$ 3,412
Jul-10	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	52.54%	47.46%	\$ 1,246	\$ 1,126	\$ 1,264,383	\$ 1,266,756	\$ 1,265,570	3.25%	\$ 3,542
Aug-10	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	52.54%	47.46%	\$ 1,246	\$ 1,126	\$ 1,270,298	\$ 1,272,670	\$ 1,271,484	3.25%	\$ 3,558
Sep-10	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	52.54%	47.46%	\$ 1,246	\$ 1,126	\$ 1,276,228	\$ 1,278,601	\$ 1,277,415	3.25%	\$ 3,460
Oct-10	\$ 27,770		\$ 27,770	\$ 30,142		\$ 30,142	\$ 2,372		\$ 2,372	52.54%	47.46%	\$ 1,246	\$ 1,126	\$ 1,282,060	\$ 1,284,433	\$ 1,283,247	3.25%	\$ 3,591
Period Total	\$ 722,007	\$ 16,009,851	\$ 16,731,858	\$ 783,689	\$ 17,180,856	\$ 17,964,545	\$ 61,682	\$ 1,171,005	\$ 1,232,687	51.22%	48.78%	\$ 631,382	\$ 601,304	\$ 1,288,024				\$ 55,337
Period Total Including Interest													\$ 659,726	\$ 628,298			51.22% ME	\$ 28,344
																	48.78% NH	\$ 26,994

Schedule 6

Northern Utilities, Inc. Commodity Cost by Supply Source November 2010 through April 2011							
Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	\$ 411,430	\$ -	\$ 10,566	\$ 75,236	\$ 231,901	\$ 938,668	\$ 1,667,801
Pittsburgh, NH	\$ 201,993	\$ 217,831	\$ 223,457	\$ 200,878	\$ 219,127	\$ 176,781	\$ 1,240,066
Niagara	\$ 382,660	\$ -	\$ -	\$ 53,935	\$ 139,599	\$ 459,192	\$ 1,035,386
Tennessee Production	\$1,763,674	\$1,272,854	\$ 953,501	\$ 648,859	\$1,582,445	\$1,547,079	\$ 7,768,412
Storage							
Tennessee Storage	\$ -	\$ -	\$ 307,731	\$ 158,390	\$ 228,551	\$ 12,830	\$ 707,503
Washington 10 Storage	\$ -	\$2,582,738	\$3,763,469	\$3,230,332	\$2,001,207	\$ -	\$11,577,747
Peaking							
Peaking Supply 1	\$ 366,320	\$ 504,034	\$ 508,144	\$ 451,147	\$ 467,407	\$ 107,416	\$ 2,404,468
Peaking Supply 2	\$ -	\$ -	\$ -	\$ -	\$ 21,557	\$ -	\$ 21,557
LNG	\$ 9,402	\$ 9,375	\$ 9,290	\$ 7,955	\$ 65,264	\$ 9,937	\$ 111,223
Total Commodity Cost	\$3,135,479	\$4,586,832	\$5,776,158	\$4,826,734	\$4,957,057	\$3,251,903	\$26,534,162

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

Northern Utilities, Inc. Delivered Cost per Dth by Supply Source November 2010 through April 2011							
Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	\$ 5.5718		\$ 5.9576	\$ 5.9892	\$ 5.9192	\$ 5.3789	\$ 5.5251
Pittsburgh, NH	\$ 6.1210	\$ 6.3880	\$ 6.5530	\$ 6.5220	\$ 6.4260	\$ 5.3570	\$ 6.2284
Niagara	\$ 5.6122			\$ 6.0241	\$ 5.9244	\$ 5.4670	\$ 5.6060
Tennessee Production	\$ 5.4377	\$ 5.7183	\$ 5.9030	\$ 5.8736	\$ 5.7683	\$ 5.4896	\$ 5.6494
Storage							
Tennessee Storage			\$ 4.7861	\$ 4.7861	\$ 4.7861	\$ 5.0595	\$ 4.7908
Washington 10 Storage		\$ 4.5227	\$ 4.5227	\$ 4.5227	\$ 4.5227		\$ 4.5227
Peaking							
Peaking Supply 1	\$ 3.9939	\$ 3.9939	\$ 3.9939	\$ 3.9939	\$ 3.9939	\$ 3.9939	\$ 3.9939
Peaking Supply 2					\$ 8.0723		\$ 8.0723
LNG	\$ 6.9643	\$ 6.7203	\$ 6.6594	\$ 6.3138	\$ 5.6039	\$ 5.4412	\$ 5.8934
Total System	\$ 5.2925	\$ 4.8012	\$ 4.7251	\$ 4.7120	\$ 4.9932	\$ 5.3788	\$ 4.9211

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

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 9	77,054	-	1,837	13,113	41,026	182,644	315,674
2	City Gate Delivered Volume	Sum Lines 54, 74 and 94	73,841	-	1,773	12,562	39,178	174,508	301,862
3	Total Purchase Cost	Line 14	\$ 408,155	\$ -	\$ 10,524	\$ 74,717	\$ 229,828	\$ 925,641	\$ 1,648,866
4	Variable Transportation Costs	Sum Lines 26, 36, 46, 56, 66, 76, 86 and 96	\$ 3,274	\$ -	\$ 41	\$ 519	\$ 2,074	\$ 13,027	\$ 18,935
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	\$ 411,430	\$ -	\$ 10,566	\$ 75,236	\$ 231,901	\$ 938,668	\$ 1,667,801
6	Average Delivered Price	Line 5 divided by Line 2	\$ 5.572	#DIV/0!	\$ 5.958	\$ 5.989	\$ 5.919	\$ 5.379	\$ 5.525
7									
8	<u>Chicago Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	77,054	-	1,837	13,113	41,026	182,644	315,674
10	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	\$ 4,905	#DIV/0!	\$ 5,337	\$ 5,306	\$ 5,210	\$ 5,018	\$ 5,029
11	NYMEX Cost	Line 9 times Line 10	\$ 377,950	\$ -	\$ 9,804	\$ 69,577	\$ 213,745	\$ 916,509	\$ 1,587,586
12	NYMEX Basis Price	FXW-7A, Line 6 of Page 1	\$ 0.392	#DIV/0!	\$ 0.392	\$ 0.392	\$ 0.392	\$ 0.050	\$ 0.194
13	NYMEX Basis Costs	Line 9 times Line 12	\$ 30,205	\$ -	\$ 720	\$ 5,140	\$ 16,082	\$ 9,132	\$ 61,280
14	Total Purchase Price	Line 10 plus Line 12	\$ 5,297	#DIV/0!	\$ 5,729	\$ 5,698	\$ 5,602	\$ 5,068	\$ 5,223
15	Total Purchase Cost	Line 11 plus Line 13	\$ 408,155	\$ -	\$ 10,524	\$ 74,717	\$ 229,828	\$ 925,641	\$ 1,648,866
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with TransCanada)								
22	Received Volume	Line 9	77,054	-	1,837	13,113	41,026	182,644	315,674
23	Fuel Loss Rate	FXW 7A, Line 17 of Page 2	0.99%	#DIV/0!	0.99%	0.99%	0.99%	0.99%	0.99%
24	Delivered Volume	Line 22 times (1 - Line 23)	76,291	-	1,819	12,983	40,620	180,836	312,549
25	Variable Transportation Rate	FXW 7A, Line 17 of Page 2	\$ 0.0019	#DIV/0!	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	\$ 145	\$ -	\$ 3	\$ 25	\$ 77	\$ 344	\$ 594
27									
28	Transportation Segment 3								
29	TransCanada Pipeline (Contract 29594)								
30	Receipt Point: Dawn								
31	Delivery Point: Parkway (Interconnects with Iroquois)								
32	Received Volume	Line 24	76,291	-	1,819	12,983	40,620	180,836	312,549
33	Fuel Loss Rate	FXW 7A, Line 14 of Page 2	1.45%	#DIV/0!	1.45%	1.45%	1.45%	1.25%	1.33%
34	Delivered Volume	Line 32 times (1 - Line 33)	75,185	-	1,792	12,795	40,031	178,576	308,379
35	Variable Transportation Rate	FXW 7A, Line 14 of Page 2	\$ 0.0141	#DIV/0!	\$ 0.0141	\$ 0.0141	\$ 0.0141	\$ 0.0141	\$ 0.0141
36	Variable Transportation Costs	Line 34 times Line 35	\$ 1,060	\$ -	\$ 25	\$ 180	\$ 564	\$ 2,518	\$ 4,348
37									
38	Transportation Segment 4								
39	Iroquois Pipeline (Contract R181001)								
40	Receipt Point: Parkway								
41	Delivery Point: Wright (Interconnection with Tennessee)								
42	Received Volume	Line 34	75,185	-	1,792	12,795	40,031	178,576	308,379
43	Fuel Loss Rate	FXW 7A, Line 4 of Page 2	0.10%	#DIV/0!	0.10%	0.10%	0.10%	0.10%	0.10%
44	Delivered Volume	Line 42 times (1 - Line 43)	75,110	-	1,791	12,782	39,991	178,397	308,070
45	Variable Transportation Rate	FXW 7A, Line 4 of Page 2	\$ 0.0052	#DIV/0!	\$ 0.0052	\$ 0.0052	\$ 0.0052	\$ 0.0052	\$ 0.0052
46	Variable Transportation Costs	Line 44 times Line 45	\$ 391	\$ -	\$ 9	\$ 66	\$ 208	\$ 928	\$ 1,602
47									
48	Transportation Segment 5A								
49	Tennessee Gas Pipeline (Contract 31861)								
50	Receipt Point: Mendon								
51	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
52	Received Volume	Line 44	34,578	-	1,791	6,426	16,747	39,208	98,750
53	Fuel Loss Rate	FXW 7A, Line 12 of Page 2	0.96%	#DIV/0!	0.96%	0.96%	0.96%	0.96%	0.96%
54	City Gate Delivered Volume	Line 52 times (1 - Line 53)	34,246	-	1,773	6,365	16,587	38,831	97,802
55	Variable Transportation Rate	FXW 7A, Line 12 of Page 2	\$ 0.0019	#DIV/0!	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
56	Variable Transportation Costs	Line 54 times Line 55	\$ 65	\$ -	\$ 3	\$ 12	\$ 32	\$ 74	\$ 186
57									
58	Transportation Segment 5B								
59	Tennessee Gas Pipeline (Contract 31861)								
60	Receipt Point: Mendon								
61	Delivery Point: Pleasant St. (Interconnection with Granite)								
62	Received Volume	Line 44	21,006	-	-	3,530	8,474	24,017	57,027
63	Fuel Loss Rate	FXW 7A, Line 13 of Page 2	1.26%	#DIV/0!	#DIV/0!	1.26%	1.26%	1.26%	1.26%
64	Delivered Volume	Line 62 times (1 - Line 63)	20,742	-	-	3,486	8,367	23,715	56,309
65	Variable Transportation Rate	FXW 7A, Line 13 of Page 2	\$ 0.0019	#DIV/0!	#DIV/0!	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
66	Variable Transportation Costs	Line 64 times Line 65	\$ 39	\$ -	\$ -	\$ 7	\$ 16	\$ 45	\$ 107
67									
68	Transportation Segment 6B								
69	Granite State Gas Transmission (Contract 10-010-FT-NN)								
70	Receipt Point: Pleasant St.								
71	Delivery Point: Northern City Gates								
72	Received Volume	Line 64	20,742	-	-	3,486	8,367	23,715	56,309
73	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
74	City Gate Delivered Volume	Line 72 times (1 - Line 73)	20,638	-	-	3,468	8,325	23,596	56,027
75	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
76	Variable Transportation Costs	Line 74 times Line 75	\$ 39	\$ -	\$ -	\$ 7	\$ 16	\$ 45	\$ 106
77									
78	Transportation Segment 5C								
79	Tennessee Gas Pipeline (Contract 41099)								
80	Receipt Point: Wright								
81	Delivery Point: Mendon (Interconnection with Algonquin)								
82	Received Volume	Line 44	19,526	-	-	2,826	14,770	115,172	152,293
83	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	2.09%	#DIV/0!	#DIV/0!	2.09%	2.09%	1.86%	1.92%
84	Delivered Volume	Line 82 times (1 - Line 83)	19,118	-	-	2,767	14,461	113,030	149,375
85	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	\$ 0.0784	#DIV/0!	#DIV/0!	\$ 0.0784	\$ 0.0784	\$ 0.0784	\$ 0.0784
86	Variable Transportation Costs	Line 84 times Line 85	\$ 1,499	\$ -	\$ -	\$ 217	\$ 1,134	\$ 8,862	\$ 11,711
87									
88	Transportation Segment 6C								
89	Algonquin Gas Transmission (Contract 93200F)								
90	Receipt Point: Mendon								
91	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
92	Received Volume	Line 84	19,118	-	-	2,767	14,461	113,030	149,375
93	Fuel Loss Rate	FXW 7A, Line 1 of Page 2	0.84%	#DIV/0!	#DIV/0!	1.35%	1.35%	0.84%	0.90%
94	City Gate Delivered Volume	Line 92 times (1 - Line 93)	18,957	-	-	2,729	14,266	112,080	148,032
95	Variable Transportation Rate	FXW 7A, Line 1 of Page 2	\$ 0.0019	#DIV/0!	#DIV/0!	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
96	Variable Transportation Costs	Line 94 times Line 95	\$ 36	\$ -	\$ -	\$ 5	\$ 27	\$ 213	\$ 281

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

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

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

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

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

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

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

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 32	124,999	5,247	27,104	33,301	80,025	80,628	351,304
2	City Gate Delivered Volume	Line 44	113,541	4,766	24,620	30,248	72,689	74,272	320,137
3	Total Purchase Price	Line 24	\$ 4,808	\$ 5,075	\$ 5,240	\$ 5,209	\$ 5,113	\$ 4,921	\$ 4,976
4	Total Purchase Cost	Line 2 times Line 3	\$ 600,997	\$ 26,628	\$ 142,027	\$ 173,462	\$ 409,165	\$ 396,770	\$ 1,749,050
5	Variable Transportation Costs	Sum Lines 36 and 46	\$ 18,782	\$ 788	\$ 4,073	\$ 5,004	\$ 12,024	\$ 12,286	\$ 52,956
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	\$ 619,779	\$ 27,417	\$ 146,100	\$ 178,466	\$ 421,189	\$ 409,056	\$ 1,802,007
7	Average Delivered Price	Line 6 divided by Line 2	\$ 5.459	\$ 5.753	\$ 5.934	\$ 5.900	\$ 5.794	\$ 5.508	\$ 5.629
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	17,827	17,827
11	Storage Delivered Volume	Line 54	-	-	-	-	-	16,793	16,793
12	Total Purchase Price	Line 24	\$ 4,808	\$ 5,075	\$ 5,240	\$ 5,209	\$ 5,113	\$ 4,921	\$ 4,976
13	Total Purchase Cost	Line 10 times Line 12	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 87,725	\$ 87,725
14	Variable Transportation Costs	Line 56	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,909	\$ 1,909
15	Total Storage Delivered Costs	Line 13 plus Line 14	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 89,635	\$ 89,635
16	Average Delivered Price	Line 15 divided by Line 11	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 5.338	\$ 5.338
17									
18	Tennessee Zone 0 Supply Costs								
19	Purchased Volumes	Sendout Optimization	124,999	5,247	27,104	33,301	80,025	98,455	369,130
20	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	\$ 4.905	\$ 5.172	\$ 5.337	\$ 5.306	\$ 5.210	\$ 5.018	\$ 5.073
21	NYMEX Cost	Line 25 times Line 26	\$ 613,122	\$ 27,137	\$ 144,656	\$ 176,693	\$ 416,928	\$ 494,046	\$ 1,872,581
22	NYMEX Basis Price	FXW-7A, Line 4 of Page 1	\$ (0.097)	\$ (0.097)	\$ (0.097)	\$ (0.097)	\$ (0.097)	\$ (0.097)	\$ (0.097)
23	NYMEX Basis Costs	Line 25 times Line 28	\$ (12,125)	\$ (509)	\$ (2,629)	\$ (3,230)	\$ (7,762)	\$ (9,550)	\$ (35,806)
24	Total Purchase Price	Line 26 plus Line 28	\$ 4,808	\$ 5,075	\$ 5,240	\$ 5,209	\$ 5,113	\$ 4,921	\$ 4,976
25	Total Purchase Cost	Line 27 plus Line 29	\$ 600,997	\$ 26,628	\$ 142,027	\$ 173,462	\$ 409,165	\$ 484,496	\$ 1,836,776
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1A								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone 0								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	124,999	5,247	27,104	33,301	80,025	80,628	351,304
33	Fuel Loss Rate	FXW 7A, Line 7 of Page 2	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	8.41%
34	Delivered Volume	Line 32 times (1 - Line 33)	114,112	4,790	24,744	30,400	73,054	74,645	321,745
35	Variable Transportation Rate	FXW 7A, Line 7 of Page 2	\$ 0.1627	\$ 0.1627	\$ 0.1627	\$ 0.1627	\$ 0.1627	\$ 0.1627	\$ 0.1627
36	Variable Transportation Costs	Line 34 times Line 35	\$ 18,566	\$ 779	\$ 4,026	\$ 4,946	\$ 11,886	\$ 12,145	\$ 52,348
37									
38	Transportation Segment 2A								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	114,112	4,790	24,744	30,400	73,054	74,645	321,745
43	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	113,541	4,766	24,620	30,248	72,689	74,272	320,137
45	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	\$ 216	\$ 9	\$ 47	\$ 57	\$ 138	\$ 141	\$ 608
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	17,827	17,827
53	Fuel Loss Rate	FXW 7A, Line 6 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	5.80%	5.80%
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	16,793	16,793
55	Variable Transportation Rate	FXW 7A, Line 6 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 0.1137	\$ 0.1137
56	Variable Transportation Costs	Line 54 times Line 55	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,909	\$ 1,909

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

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
2	Purchased Volumes	Line 33	229,835	237,496	149,269	87,466	219,850	223,500	1,147,415
3	City Gate Delivered Volume	Line 45	210,802	217,829	136,908	80,223	201,644	207,550	1,054,956
4	Total Purchase Price	Line 25	\$ 4,835	\$ 5,102	\$ 5,267	\$ 5,236	\$ 5,140	\$ 4,948	\$ 5,056
5	Total Purchase Cost	Line 2 times Line 3	\$ 1,111,250	\$ 1,211,703	\$ 786,199	\$ 457,970	\$ 1,130,028	\$ 1,105,880	\$ 5,803,030
6	Variable Transportation Costs	Sum Lines 37 and 47	\$ 32,646	\$ 33,734	\$ 21,202	\$ 12,424	\$ 31,228	\$ 32,142	\$ 163,376
7	Total City Gate Delivered Costs	Sum Lines 4 and 5	\$ 1,143,896	\$ 1,245,437	\$ 807,401	\$ 470,393	\$ 1,161,256	\$ 1,138,022	\$ 5,966,405
8	Average Delivered Price	Line 6 divided by Line 2	\$ 5.426	\$ 5.718	\$ 5.897	\$ 5.864	\$ 5.759	\$ 5.483	\$ 5.656
9									
10	Tennessee Northern Storage Injection Meter Deliveries								
11	Purchased Volumes	Line 53	-	-	-	-	-	14,805	14,805
12	Storage Delivered Volume	Line 55	-	-	-	-	-	14,055	14,055
13	Total Purchase Price	Line 25	\$ 4,835	\$ 5,102	\$ 5,267	\$ 5,236	\$ 5,140	\$ 4,948	\$ 5,056
14	Total Purchase Cost	Line 10 times Line 12	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 73,253	\$ 73,253
15	Variable Transportation Costs	Line 57	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,452	\$ 1,452
16	Total Storage Delivered Costs	Line 13 plus Line 14	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 74,705	\$ 74,705
17	Average Delivered Price	Line 15 divided by Line 11	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 5.315	\$ 5.315
18									
19	Tennessee Zone L Supply Costs								
20	Purchased Volumes	Sendout Optimization	229,835	237,496	149,269	87,466	219,850	238,305	1,162,219
21	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	\$ 4.905	\$ 5.172	\$ 5.337	\$ 5.306	\$ 5.210	\$ 5.018	\$ 5.126
22	NYMEX Cost	Line 25 times Line 26	\$ 1,127,338	\$ 1,228,328	\$ 796,648	\$ 464,092	\$ 1,145,418	\$ 1,195,814	\$ 5,957,638
23	NYMEX Basis Price	FXW-7A, Line 5 of Page 1	\$ (0.070)	\$ (0.070)	\$ (0.070)	\$ (0.070)	\$ (0.070)	\$ (0.070)	\$ (0.070)
24	NYMEX Basis Costs	Line 25 times Line 28	\$ (16,088)	\$ (16,625)	\$ (10,449)	\$ (6,123)	\$ (15,389)	\$ (16,681)	\$ (81,355)
25	Total Purchase Price	Line 26 plus Line 28	\$ 4,835	\$ 5,102	\$ 5,267	\$ 5,236	\$ 5,140	\$ 4,948	\$ 5,056
26	Total Purchase Cost	Line 27 plus Line 29	\$ 1,111,250	\$ 1,211,703	\$ 786,199	\$ 457,970	\$ 1,130,028	\$ 1,179,133	\$ 5,876,282
27									
28	Transportation Fuel Losses and Variable Charges								
29	Transportation Segment 1B								
30	Tennessee Gas Pipeline (Contract 5083)								
31	Receipt Point: Tennessee Zone L								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 20	229,835	237,496	149,269	87,466	219,850	223,500	1,147,415
34	Fuel Loss Rate	FXW 7A, Line 9 of Page 2	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	7.60%
35	Delivered Volume	Line 33 times (1 - Line 34)	211,861	218,923	137,596	80,626	202,658	208,593	1,060,257
36	Variable Transportation Rate	FXW 7A, Line 9 of Page 2	\$ 0.1522	\$ 0.1522	\$ 0.1522	\$ 0.1522	\$ 0.1522	\$ 0.1522	\$ 0.1522
37	Variable Transportation Costs	Line 35 times Line 36	\$ 32,245	\$ 33,320	\$ 20,942	\$ 12,271	\$ 30,844	\$ 31,748	\$ 161,371
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 10-010-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	211,861	218,923	137,596	80,626	202,658	208,593	1,060,257
44	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	210,802	217,829	136,908	80,223	201,644	207,550	1,054,956
46	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
47	Variable Transportation Costs	Line 45 times Line 46	\$ 401	\$ 414	\$ 260	\$ 152	\$ 383	\$ 394	\$ 2,004
48									
49	Transportation Segment 3								
50	Tennessee Gas Pipeline (Contract 5083)								
51	Receipt Point: Tennessee Zone L								
52	Delivery Point: Tennessee Market Area Storage								
53	Received Volume	Line 25 minus Line 38	-	-	-	-	-	14,805	14,805
54	Fuel Loss Rate	FXW 7A, Line 8 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	5.06%	5.06%
55	Storage Delivered Volume	Line 53 times (1 - Line 54)	-	-	-	-	-	14,055	14,055
56	Variable Transportation Rate	FXW 7A, Line 8 of Page 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 0.1033	\$ 0.1033
57	Variable Transportation Costs	Line 55 times Line 56	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,452	\$ 1,452

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

[illegible]

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

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

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

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 10	92,182	126,837	127,871	113,528	117,619	27,030	605,066
2	City Gate Delivered Volume	Line 33	91,721	126,202	127,231	112,960	117,031	26,895	602,041
3	Total Purchase Price	Line 24	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972
4	Total Purchase Cost	Line 1 times Line 3	\$ 366,145	\$ 503,795	\$ 507,902	\$ 450,933	\$ 467,184	\$ 107,365	\$ 2,403,324
5	Variable Transportation Costs	Line 35	\$ 174	\$ 240	\$ 242	\$ 215	\$ 222	\$ 51	\$ 1,144
6	Total City Gate Delivered Costs	Line 4 plus Line 5	\$ 366,320	\$ 504,034	\$ 508,144	\$ 451,147	\$ 467,407	\$ 107,416	\$ 2,404,468
7	Average Delivered Price	Line 6 divided by Line 2	\$ 3.994	\$ 3.994	\$ 3.994	\$ 3.994	\$ 3.994	\$ 3.994	\$ 3.994
8									
9	LNG Storage Deliveries								
10	Purchased Volumes	Line 41	2,023	1,395	361	2,294	10,612	2,860	19,545
11	Storage Delivered Volume	Line 43	2,023	1,395	361	2,294	10,612	2,860	19,545
12	Total Purchase Price	Line 24	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972
13	Total Purchase Cost	Line 10 times Line 12	\$ 8,034	\$ 5,541	\$ 1,433	\$ 9,112	\$ 42,151	\$ 11,361	\$ 77,633
14	Variable Transportation Costs	Line 45	\$ 1,901	\$ 1,311	\$ 339	\$ 2,156	\$ 9,975	\$ 2,689	\$ 18,372
15	Total Storage Delivered Costs	Line 13 plus Line 14	\$ 9,935	\$ 6,852	\$ 1,773	\$ 11,269	\$ 52,127	\$ 14,050	\$ 96,005
16	Average Delivered Price	Line 15 divided by Line 11	\$ 4.912	\$ 4.912	\$ 4.912	\$ 4.912	\$ 4.912	\$ 4.912	\$ 4.912
17									
18	Peaking Supply 1 Costs (Segment 1)								
19	Purchased Volumes	Sendout Optimization	94,204	128,232	128,232	115,822	128,232	29,891	624,612
20	Peaking Supply 1 Prices	FXW 7A, Line 2 of Page 1	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972
21	Peaking Supply 1 Costs	Line 19 times Line 20	\$ 374,179	\$ 509,336	\$ 509,336	\$ 460,045	\$ 509,336	\$ 118,726	\$ 2,480,957
22	NYMEX Basis Price	N/A	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
23	NYMEX Basis Costs	Line 19 times Line 22	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
24	Total Purchase Price	Line 20 plus Line 22	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972	\$ 3,972
25	Total Purchase Cost	Line 23 times (1 - Line 24)	\$ 374,179	\$ 509,336	\$ 509,336	\$ 460,045	\$ 509,336	\$ 118,726	\$ 2,480,957
26									
27	Transportation Segment 2								
28	Granite State Gas Transmission (Contract 10-010-FT-NN)								
29	Receipt Point: Pleasant St.								
30	Delivery Point: Northern City Gates								
31	Received Volume	Sendout Optimization	92,182	126,837	127,871	113,528	117,619	27,030	605,066
32	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
33	City Gate Delivered Volume	Line 31 times (1 - Line 32)	91,721	126,202	127,231	112,960	117,031	26,895	602,041
34	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
35	Variable Transportation Costs	Line 33 times Line 34	\$ 174	\$ 240	\$ 242	\$ 215	\$ 222	\$ 51	\$ 1,144
36									
37	Transportation Segment 3								
38	Trucking Contract (TransGas)								
39	Receipt Point: Distrigas Terminal								
40	Delivery Point: Northern LNG Facility (Lewiston, ME)								
41	Received Volume	Line 19 minus Line 31	2,023	1,395	361	2,294	10,612	2,860	19,545
42	Fuel Loss Rate	Company Forecast	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Storage Delivered Volume	Line 41 times (1 - Line 42)	2,023	1,395	361	2,294	10,612	2,860	19,545
44	Variable Transportation Rate	Company Forecast	\$ 0.9400	\$ 0.9400	\$ 0.9400	\$ 0.9400	\$ 0.9400	\$ 0.9400	\$ 0.9400
45	Variable Transportation Costs	Line 43 times Line 44	\$ 1,901	\$ 1,311	\$ 339	\$ 2,156	\$ 9,975	\$ 2,689	\$ 18,372

Source of Supply: Northern LNG Inventory
On-System Storage

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

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

Line	City Gate Delivered Costs	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	2010-2011 Peak
1	Purchased Volumes	Line 9	-	-	-	-	2,684	-	2,684
2	City Gate Delivered Volume	Line 24	-	-	-	-	2,670	-	2,670
3	Total Purchase Cost	Line 14	\$ -	\$ -	\$ -	\$ -	\$ 21,552	\$ -	\$ 21,552
4	Variable Transportation Costs	Line 26	\$ -	\$ -	\$ -	\$ -	\$ 5	\$ -	\$ 5
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	\$ -	\$ -	\$ -	\$ -	\$ 21,557	\$ -	\$ 21,557
6	Average Delivered Price	Line 5 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 8.072	#DIV/0!	\$ 8.072
7									
8	<u>Peaking Supply 2 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	2,684	-	2,684
10	Monthly NYMEX Price	FXW 7A, Line 1 of Page 1	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 5.210	#DIV/0!	\$ 5.210
11	NYMEX Cost	Line 9 times Line 10	\$ -	\$ -	\$ -	\$ -	\$ 13,983	\$ -	\$ 13,983
12	NYMEX Basis Price	FXW 7A, Line 9 of Page 1	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 2.820	#DIV/0!	\$ 2.820
13	NYMEX Basis Costs	Line 9 times Line 12	\$ -	\$ -	\$ -	\$ -	\$ 7,569	\$ -	\$ 7,569
14	Total Purchase Price	Line 10 plus Line 12	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 8.030	#DIV/0!	\$ 8.030
15	Total Purchase Cost	Line 11 plus Line 13	\$ -	\$ -	\$ -	\$ -	\$ 21,552	\$ -	\$ 21,552
16									
17	<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	-	-	-	-	2,684	-	2,684
23	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	2,670	-	2,670
25	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019	\$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	\$ -	\$ -	\$ -	\$ -	\$ 5	\$ -	\$ 5

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

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

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

Note 1: Iroquois Commodity Rates are equal to the RTS Commodity rate on Page 7 plus the ACA Adjustment and Deferred Asset Surcharge on Page 8.

Note 2: For Receipts from Zone L, the rates for Receipts from Zone 1 apply.

Northern Utilities, Inc.
Underground Storage Variable Rates

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

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2009

•RATE SCHEDULE AFT-1

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

•RATE SCHEDULE AFT-1S

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

•OTHER FIRM RATE SCHEDULES

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

•INTERRUPTIBLE SERVICE

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

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	\$5.3900	\$0.0000

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

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
--------	----------	-----

System Services

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

Incremental Ramapo Services

Winter	Dec 1 - Mar 31	2.36%
Spring, Summer and Fall	Apr 1 - Nov 30	1.18%

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

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

Rate Schedule FT-NN
 Firm Transportation Service

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

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

Iroquois Gas Transmission System, L.P.

Thirty First Revised Sheet No. 4

FERC Gas Tariff

Superseding

FIRST REVISED VOLUME NO. 1

Thirtieth Revised Sheet No. 4

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

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

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

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

(Footnotes continued on Sheet 4.01)

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

Issued on: Jan 26, 2009

Effective: Jan 27, 2009

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

Issued on: Sep 30, 2009 Effective: Nov 01, 2009



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

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

Statement of Transportation Rates

(Rates per DTH)

Rate Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ Rate

FT Recourse Reservation Rate

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

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

Seasonal Recourse Reservation Rate

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

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

Recourse Usage Rate

-- Maximum \$00.0000 \$00.0019 \$00.0019

-- Minimum \$00.0000 \$00.0019 \$00.0019

FT-FLEX Recourse Reservation Rate

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

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

Recourse Usage Rate

--Maximum \$00.2962 \$00.0019 \$00.2981

--Minimum \$00.0000 \$00.0019 \$00.0019

RATES PER DEKATHERM

COMMODITY RATES
 RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum
 Commodity Rates 2/

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

Maximum
 Commodity Rates 1/, 2/

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

Notes:

- 1/ The above maximum rates include a per Dth charge for:
 (ACA) Annual Charge Adjustment \$0.0019
- 2/ The applicable fuel retention percentages are listed on Sheet No. 32, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

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

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NOVEMBER - MARCH

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

APRIL - OCTOBER

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

- 1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.
- 2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.
- 3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

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

Notes:

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

NET-284 RATE SCHEDULE (continued)

5. FUEL AND USE (continued)

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

TransCanada Variable Transportation Rates

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

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

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

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

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

Storage Transportation Service

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

Enhanced Capacity Release

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

Delivery Pressure

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

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

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:

[10-Year Currency Converter](#)

Using rates for: 20 Jul 2010

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

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

Summary:

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

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

SEE ALSO:

[10-Year Currency Converter](#)

FREQUENTLY ASKED:

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

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

More comprehensive currency converters include [CanadianForex](#) and [OANDA.com](#).

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

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

Historic TransCanada Fuel Loss Percentages

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

You are here: [Vector](#) > [Informational Postings](#) > [Informational Postings](#) > [Tariff](#) > Currently Effective Rates**INFORMATIONAL POSTINGS**[Capacity](#)[Gas Quality](#)[Index of Customers](#)[Notices](#)[Posted Imbalances](#)[Standards of Conduct](#)[Tariff](#)[Title Sheet](#)[Table of Contents](#)[Preliminary Statement](#)[Map](#)[Currently Effective Rates](#)[Rate Schedules](#)[General Terms and Conditions](#)[Form of Service Agreement](#)[Entire Tariff](#)[Sheet Index](#)[Vector - Canada Tariff](#)[Transactional Reporting](#)[Other](#)[Downloads](#)[Search](#)[Customer Activities](#)[Site Map](#)[Previous](#) [Next](#)

Vector Pipeline L.P.

FERC Gas Tariff

Eleventh Revised Sheet No. 20

Original Volume No. 1

Superseding

Tenth Revised Sheet No. 20

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. \$

Rate Schedule FT-1 1/

Recourse Rates:

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

Negotiated Rates:

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

Rate Schedule FT-L 1/

Recourse Rates:

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

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

RATES PER DEKATHERM

FIRM STORAGE SERVICE
 RATE SCHEDULE FS

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

1/ The quantity of gas associated with losses is 0.5%.

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

EXHIBIT I**Rates:**

Monthly Deliverability Rate:	\$ <u>2.4754</u> per Dth
Monthly Capacity Rate:	\$ <u>0.0238</u> per Dth
Injection Rate:	\$ <u>0.00</u> per Dth
Withdrawal Rate:	\$ <u>0.00</u> per Dth
Authorized Overrun Rate:	\$ <u>0.05</u> per Dth
Interruptible Rate:	\$ <u>0.05</u> 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	34,000 Dth/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

- Our Services
- Notices
- Contact Us
- Forms
- Tariffs

DTE Gas Storage - Washington 10 Historic Fuel Rates

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



Schedule 7

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

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year Comparison of Winter 2010-2011 vs. Winter 2009-2010

Northern Utilities, Inc.
New Hampshire Division
Schedule 8
Page 1 of 5

Typical Usage: therms			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2010- 2011																	
Customer Charge	units @	\$ 9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$57.00								
First	50 units @	\$0.4102	\$20.51	\$20.51	\$20.51	\$20.51	\$20.51	\$20.51	\$123.06								
Over	50 units @	\$0.2990	\$17.64	\$29.90	\$40.96	\$41.26	\$34.68	\$24.52	\$188.97								
	CGA 1	\$1.1177	\$121.83						\$121.83								
	CGA 2	\$1.1177		\$167.66					\$167.66								
	CGA 3	\$1.1177			\$209.01				\$209.01								
	CGA 4	\$1.1177				\$210.13			\$210.13								
	CGA 5	\$1.1177					\$185.54		\$185.54								
	CGA 6	\$1.1177						\$147.54	\$147.54								
	LDAC	\$0.0454	\$4.95	\$6.81	\$8.49	\$8.54	\$7.54	\$5.99	\$42.31								
Summer 2010																	
Customer Charge	units @	\$ 9.50							\$ 9.50	\$9.50	\$9.50	\$9.50	\$ 9.50	\$9.50	\$9.50	\$57.00	
First	50 units @	\$0.4102							\$20.51	\$20.51	\$12.31	\$12.31	\$17.23	\$20.51	\$20.51	\$103.37	
Over	50 units @	\$0.2990							\$11.96	\$1.50	\$0.00	\$0.00	\$0.00	\$6.28	\$6.28	\$19.73	
	CGA 1	\$0.6545							\$58.91							\$58.91	
	CGA 2	\$0.5969								\$32.83						\$32.83	
	CGA 3	\$0.7280									\$21.84					\$21.84	
	CGA 4	\$0.7280										\$21.84				\$21.84	
	CGA 5	\$0.7280											\$30.58			\$30.58	
	CGA 6	\$0.7280												\$51.69		\$51.69	
	LDAC	\$ 0.0297							\$2.67	\$1.63	\$0.89	\$0.89	\$1.25	\$2.11	\$2.11	\$9.44	
TOTAL			\$174.43	\$234.38	\$288.47	\$289.93	\$257.77	\$208.06	\$1,453.04	\$103.55	\$65.97	\$44.54	\$44.54	\$58.55	\$90.09	\$407.23	\$1,860.26
Winter 2009 - 2010																	
Customer Charge	units @	\$ 9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$57.00								
First	50 units @	\$0.4102	\$20.51	\$20.51	\$20.51	\$20.51	\$20.51	\$20.51	\$123.06								
Over	50 units @	\$0.2990	\$17.64	\$29.90	\$40.96	\$41.26	\$34.68	\$24.52	\$188.97								
	CGA 1	\$1.0980	\$119.68						\$119.68								
	CGA 2	\$1.0980		\$164.70					\$164.70								
	CGA 3	\$1.0218			\$191.08				\$191.08								
	CGA 4	\$1.0758				\$202.25			\$202.25								
	CGA 5	\$1.0758					\$178.58		\$178.58								
	CGA 6	\$0.6693						\$88.35	\$88.35								
	LDAC	\$ 0.0297	\$3.24	\$4.46	\$5.55	\$5.58	\$4.93	\$3.92	\$27.68								
Summer 2009																	
Customer Charge	units @	\$ 9.50							\$9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$9.50	\$57.00	
First	50 units @	\$0.4102							\$20.51	\$20.51	\$12.31	\$12.31	\$17.23	\$20.51	\$20.51	\$103.37	
Over	50 units @	\$0.2990							\$11.96	\$1.50	\$0.00	\$0.00	\$0.00	\$6.28	\$6.28	\$19.73	
	CGA 1	\$0.7385							\$66.47							\$66.47	
	CGA 2	\$0.7385								\$40.62						\$40.62	
	CGA 3	\$0.7385									\$22.16					\$22.16	
	CGA 4	\$0.7385										\$22.16				\$22.16	
	CGA 5	\$0.7385											\$31.02			\$31.02	
	CGA 6	\$0.9231												\$65.54		\$65.54	
	LDAC	\$ 0.0255							\$2.30	\$1.40	\$0.77	\$0.77	\$1.07	\$1.81	\$1.81	\$8.11	
TOTAL			\$170.57	\$229.07	\$267.60	\$279.11	\$248.21	\$146.80	\$1,341.35	\$110.73	\$73.53	\$44.73	\$44.73	\$58.82	\$103.64	\$436.16	\$1,777.51
Change			\$3.86	\$5.31	\$20.87	\$10.83	\$9.56	\$61.26	\$111.69	(\$7.18)	(\$7.56)	(\$0.19)	(\$0.19)	(\$0.26)	(\$13.55)	(\$28.94)	\$82.75
% Chg			2.26%	2.32%	7.80%	3.88%	3.85%	41.73%	8.33%	-6.49%	-10.28%	-0.42%	-0.42%	-0.45%	-13.08%	-6.63%	4.66%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

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

Typical Usage: therms			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2010 - 2011																	
Customer Charge	units @	\$ 18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$112.20								
First	75 units @	\$0.3077	\$23.08	\$23.08	\$23.08	\$23.08	\$23.08	\$23.08	\$138.47								
Over	75 units @	\$0.2007	\$23.68	\$38.94	\$44.76	\$37.53	\$31.91	\$19.27	\$196.08								
	CGA 1	\$1.1398	\$219.98						\$219.98								
	CGA 2	\$1.1398		\$306.61					\$306.61								
	CGA 3	\$1.1398			\$339.66				\$339.66								
	CGA 4	\$1.1398				\$298.63			\$298.63								
	CGA 5	\$1.1398					\$266.71		\$266.71								
	CGA 6	\$1.1398						\$194.91	\$194.91								
	LDAC	\$0.0259	\$5.00	\$6.97	\$7.72	\$6.79	\$6.06	\$4.43	\$36.96								
Summer 2010																	
Customer Charge	units @	\$ 18.70								\$ 18.70	\$18.70	\$18.70	\$18.70	\$ 18.70	\$18.70	\$112.20	
First	75 units @	\$0.3077								\$23.08	\$23.08	\$22.15	\$22.15	\$23.08	\$23.08	\$136.62	
Over	75 units @	\$0.2007								\$8.43	\$1.20	\$0.00	\$0.00	\$2.81	\$13.45	\$25.89	
	CGA 1	\$0.6905								\$80.79						\$80.79	
	CGA 2	\$0.6329									\$51.26					\$51.26	
	CGA 3	\$0.7640										\$55.01				\$55.01	
	CGA 4	\$0.7640											\$55.01			\$55.01	
	CGA 5	\$0.7640												\$68.00		\$68.00	
	CGA 6	\$0.7640													\$108.49	\$108.49	
	LDAC	\$ 0.0166								\$1.94	\$1.34	\$1.20	\$1.20	\$1.48	\$2.36	\$9.51	
TOTAL			\$290.44	\$394.29	\$433.91	\$384.72	\$346.46	\$260.38	\$2,110.20	\$132.94	\$95.59	\$97.06	\$97.06	\$114.06	\$166.07	\$702.77	\$2,812.98
Winter 2009 - 2010																	
Customer Charge	units @	\$ 18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$112.20								
First	75 units @	\$0.3077	\$23.08	\$23.08	\$23.08	\$23.08	\$23.08	\$23.08	\$138.47								
Over	75 units @	\$0.2007	\$23.68	\$38.94	\$44.76	\$37.53	\$31.91	\$19.27	\$196.08								
	CGA 1	\$1.1058	\$213.42						\$213.42								
	CGA 2	\$1.1058		\$297.46					\$297.46								
	CGA 3	\$1.0296			\$306.82				\$306.82								
	CGA 4	\$1.0836				\$283.90			\$283.90								
	CGA 5	\$1.0836					\$253.56		\$253.56								
	CGA 6	\$0.6771						\$115.78	\$115.78								
	LDAC	\$ 0.0166	\$3.20	\$4.47	\$4.95	\$4.35	\$3.88	\$2.84	\$23.69								
Summer 2009																	
Customer Charge	units @	\$ 18.70								\$18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$18.70	\$112.20	
First	75 units @	\$0.3077								\$23.08	\$23.08	\$22.15	\$22.15	\$23.08	\$23.08	\$136.62	
Over	75 units @	\$0.2007								\$8.43	\$1.20	\$0.00	\$0.00	\$2.81	\$13.45	\$25.89	
	CGA 1	\$0.8355								\$97.75						\$97.75	
	CGA 2	\$0.8355									\$67.68					\$67.68	
	CGA 3	\$0.8355										\$60.16				\$60.16	
	CGA 4	\$0.8355											\$60.16			\$60.16	
	CGA 5	\$0.8355												\$74.36		\$74.36	
	CGA 6	\$1.0444													\$148.30	\$148.30	
	LDAC	\$ 0.0211								\$2.47	\$1.71	\$1.52	\$1.52	\$1.88	\$3.00	\$12.09	
TOTAL			\$282.08	\$382.64	\$398.30	\$367.56	\$331.14	\$179.67	\$1,941.39	\$150.43	\$112.37	\$102.53	\$102.53	\$120.82	\$206.53	\$795.20	\$2,736.59
Change			\$8.36	\$11.65	\$35.61	\$17.16	\$15.33	\$80.71	\$168.82	(\$17.49)	(\$16.78)	(\$5.47)	(\$5.47)	(\$6.76)	(\$40.46)	(\$92.43)	\$76.39
% Chg			2.96%	3.04%	8.94%	4.67%	4.63%	44.92%	8.70%	-11.63%	-14.93%	-5.34%	-5.34%	-5.60%	-19.59%	-11.62%	2.79%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

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

Typical Usage: therms			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2010 - 2011																	
Customer Charge	units @	\$ 60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$361.80								
All	units @	\$0.1942	\$301.59	\$500.65	\$634.06	\$796.80	\$660.67	\$480.26	\$3,374.03								
			\$1,770.11						\$1,770.11								
CGA 1		\$1.1398		\$2,938.40					\$2,938.40								
CGA 2		\$1.1398			\$3,721.45				\$3,721.45								
CGA 3		\$1.1398				\$4,676.60			\$4,676.60								
CGA 4		\$1.1398					\$3,877.60		\$3,877.60								
CGA 5		\$1.1398						\$2,818.73	\$2,818.73								
CGA 6		\$1.1398															
LDAC		\$0.0259	\$40.22	\$66.77	\$84.56	\$106.27	\$88.11	\$64.05	\$449.99								
Summer 2010																	
Customer Charge	units @	\$ 60.30							\$ 60.30	\$60.30	\$60.30	\$60.30	\$ 60.30	\$60.30		\$361.80	
All	units @	\$0.1124							\$141.40	\$78.79	\$46.53	\$23.94	\$40.91	\$78.57		\$410.15	
									\$868.65							\$868.65	
CGA 1		\$0.6905								\$443.66						\$443.66	
CGA 2		\$0.6329									\$316.30					\$316.30	
CGA 3		\$0.7640										\$162.73				\$162.73	
CGA 4		\$0.7640											\$278.10			\$278.10	
CGA 5		\$0.7640												\$534.04		\$534.04	
CGA 6		\$0.7640													\$11.60	\$60.57	
LDAC		\$ 0.0166							\$20.88	\$11.64	\$6.87	\$3.54	\$6.04				
TOTAL			\$2,172.22	\$3,566.12	\$4,500.37	\$5,639.97	\$4,686.68	\$3,423.33	\$23,988.70	\$1,091.23	\$594.39	\$430.00	\$250.51	\$385.35	\$684.51	\$3,435.99	\$27,424.70
Winter 2009 - 2010																	
Customer Charge	units @	\$ 60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$361.80								
All	units @	\$0.1942	\$301.59	\$500.65	\$634.06	\$796.80	\$660.67	\$480.26	\$3,374.03								
			\$1,717.31						\$1,717.31								
CGA 1		\$1.1058		\$2,850.75					\$2,850.75								
CGA 2		\$1.1058			\$3,361.64				\$3,361.64								
CGA 3		\$1.0296				\$4,446.01			\$4,446.01								
CGA 4		\$1.0836					\$3,686.41		\$3,686.41								
CGA 5		\$1.0836						\$1,674.47	\$1,674.47								
CGA 6		\$0.6771															
LDAC		\$ 0.0166	\$25.78	\$42.79	\$54.20	\$68.11	\$56.47	\$41.05	\$288.41								
Summer 2009																	
Customer Charge	units @	\$ 60.30							\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30		\$361.80	
All	units @	\$0.1124							\$141.40	\$78.79	\$46.53	\$23.94	\$40.91	\$78.57		\$410.15	
									\$1,051.06							\$1,051.06	
CGA 1		\$0.8355								\$585.69						\$585.69	
CGA 2		\$0.8355									\$345.90					\$345.90	
CGA 3		\$0.8355										\$177.96				\$177.96	
CGA 4		\$0.8355											\$304.12			\$304.12	
CGA 5		\$0.8355												\$730.04		\$730.04	
CGA 6		\$1.0444													\$14.75	\$76.99	
LDAC		\$ 0.0211							\$26.54	\$14.79	\$8.74	\$4.49	\$7.68				
TOTAL			\$2,104.98	\$3,454.49	\$4,110.21	\$5,371.22	\$4,463.85	\$2,256.08	\$21,760.83	\$1,279.30	\$739.57	\$461.47	\$266.70	\$413.02	\$883.65	\$4,043.70	\$25,804.53
Change			\$67.24	\$111.63	\$390.17	\$268.75	\$222.83	\$1,167.26	\$2,227.87	(\$188.07)	(\$145.18)	(\$31.46)	(\$16.19)	(\$27.66)	(\$199.15)	(\$607.71)	\$1,620.16
% Chg			3.19%	3.23%	9.49%	5.00%	4.99%	51.74%	10.24%	-14.70%	-19.63%	-6.82%	-6.07%	-6.70%	-22.54%	-15.03%	6.28%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

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

Typical Usage: therms		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2010 - 2011																
Customer Charge	units @ \$ 60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$361.80								
First	1,300 units @ \$0.1862	\$242.06	\$242.06	\$242.06	\$242.06	\$242.06	\$242.06	\$1,452.36								
Over	1,300 units @ \$0.1467	\$61.91	\$115.31	\$151.10	\$151.54	\$145.38	\$83.91	\$709.15								
CGA 1	\$1.0019	\$1,725.27						\$1,725.27								
CGA 2	\$1.0019		\$2,089.96					\$2,089.96								
CGA 3	\$1.0019			\$2,334.43				\$2,334.43								
CGA 4	\$1.0019				\$2,337.43			\$2,337.43								
CGA 5	\$1.0019					\$2,295.35		\$2,295.35								
CGA 6	\$1.0019						\$1,875.56	\$1,875.56								
LDAC	\$0.0259	\$44.60	\$54.03	\$60.35	\$60.42	\$59.34	\$48.48	\$327.22								
Summer 2010																
Customer Charge	units @ \$ 60.30							\$ 60.30	\$60.30	\$60.30	\$60.30	\$ 60.30	\$60.30	\$60.30	\$361.80	
First	1,000 units @ \$0.1112							\$111.20	\$111.20	\$111.20	\$111.20	\$111.20	\$111.20	\$111.20	\$667.20	
Over	1,000 units @ \$0.0780							\$39.78	\$29.17	\$19.27	\$14.82	\$16.38	\$25.27		\$144.69	
CGA 1	\$0.6075							\$917.33							\$917.33	
CGA 2	\$0.5499								\$755.56						\$755.56	
CGA 3	\$0.6810									\$849.21					\$849.21	
CGA 4	\$0.6810										\$810.39				\$810.39	
CGA 5	\$0.6810											\$824.01			\$824.01	
CGA 6	\$0.6810												\$901.64		\$901.64	
LDAC	\$ 0.0166							\$25.07	\$22.81	\$20.70	\$19.75	\$20.09	\$21.98		\$130.39	
TOTAL		\$2,134.14	\$2,561.66	\$2,848.24	\$2,851.76	\$2,802.43	\$2,310.31	\$15,508.53	\$1,153.67	\$979.04	\$1,060.67	\$1,016.46	\$1,031.98	\$1,120.39	\$6,362.22	\$21,870.75
Typical Usage: therms		1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2009 - 2010																
Customer Charge	units @ \$ 60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$361.80								
First	1,300 units @ \$0.1862	\$242.06	\$242.06	\$242.06	\$242.06	\$242.06	\$242.06	\$1,452.36								
Over	1,300 units @ \$0.1467	\$61.91	\$115.31	\$151.10	\$151.54	\$145.38	\$83.91	\$709.15								
CGA 1	\$1.0630	\$1,830.49						\$1,830.49								
CGA 2	\$1.0630		\$2,217.42					\$2,217.42								
CGA 3	\$0.9868			\$2,299.24				\$2,299.24								
CGA 4	\$1.0408				\$2,428.19			\$2,428.19								
CGA 5	\$1.0408					\$2,384.47		\$2,384.47								
CGA 6	\$0.6343						\$1,187.41	\$1,187.41								
LDAC	\$ 0.0166	\$28.59	\$34.63	\$38.68	\$38.73	\$38.03	\$31.08	\$209.72								
Summer 2009																
Customer Charge	units @ \$ 60.30							\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$60.30	\$361.80	
First	1,000 units @ \$0.1112							\$111.20	\$111.20	\$111.20	\$111.20	\$111.20	\$111.20	\$111.20	\$667.20	
Over	1,000 units @ \$0.0780							\$39.78	\$29.17	\$19.27	\$14.82	\$16.38	\$25.27		\$144.69	
CGA 1	\$0.6785							\$1,024.54							\$1,024.54	
CGA 2	\$0.6785								\$932.26						\$932.26	
CGA 3	\$0.6785									\$846.09					\$846.09	
CGA 4	\$0.6785										\$807.42				\$807.42	
CGA 5	\$0.6785											\$820.99			\$820.99	
CGA 6	\$0.8481												\$1,122.88		\$1,122.88	
LDAC	\$ 0.0211							\$31.86	\$28.99	\$26.31	\$25.11	\$25.53	\$27.94		\$165.74	
TOTAL		\$2,223.34	\$2,669.71	\$2,791.38	\$2,920.82	\$2,870.24	\$1,604.76	\$15,080.25	\$1,267.68	\$1,161.92	\$1,063.17	\$1,018.84	\$1,034.40	\$1,347.59	\$6,893.60	\$21,973.85
Change		(\$89.20)	(\$108.05)	\$56.85	(\$69.06)	(\$67.81)	\$705.56	\$428.28	(\$114.01)	(\$182.88)	(\$2.49)	(\$2.38)	(\$2.42)	(\$227.20)	(\$531.38)	(\$103.09)
% Chg		-4.01%	-4.05%	2.04%	-2.36%	-2.36%	43.97%	2.84%	-8.99%	-15.74%	-0.23%	-0.23%	-0.23%	-16.86%	-7.71%	-0.47%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

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

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

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

Schedule 9

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

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

Schedule 10

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

Base Capacity Costs

1	BASE SENDOUT BY CLASS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
2	Total Therms								
3	Res Heat	390,983	404,016	404,016	364,917	404,016	390,983	2,358,930	Schedule 10B, LN 52
4	Res General	15,639	16,160	16,160	14,597	16,160	15,639	94,356	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	111,303	115,013	115,013	103,882	115,013	111,303	671,525	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	65,573	67,759	67,759	61,201	67,759	65,573	395,622	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	143,292	148,068	148,068	133,739	148,068	143,292	864,526	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	119,756	123,747	123,747	111,772	123,747	119,756	722,525	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	8,488	11,047	11,968	10,859	10,482	9,159	62,003	Schedule 10B, LN 58
10	G42 High Annual-High Winter	11,459	11,841	11,841	10,695	11,841	11,459	69,136	Schedule 10B, LN 59
11	Total Firm Sales	866,491	897,651	898,572	811,662	897,086	867,162	5,238,625	Sum LN 3 : LN 10
12									
13	% of Total								
14	Res Heat	45.12%	45.01%	44.96%	44.96%	45.04%	45.09%		LN 3 / LN 11
15	Res General	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%		LN 4 / LN 11
16	G50 Low Annual-Low Winter	12.85%	12.81%	12.80%	12.80%	12.82%	12.84%		LN 5 / LN 11
17	G40 Low Annual-High Winter	7.57%	7.55%	7.54%	7.54%	7.55%	7.56%		LN 6 / LN 11
18	G51 Med Annual-Low Winter	16.54%	16.50%	16.48%	16.48%	16.51%	16.52%		LN 7 / LN 11
19	G41 Med Annual-High Winter	13.82%	13.79%	13.77%	13.77%	13.79%	13.81%		LN 8 / LN 11
20	G52 High Annual-Low Winter	0.98%	1.23%	1.33%	1.34%	1.17%	1.06%		LN 9 / LN 11
21	G42 High Annual-High Winter	1.32%	1.32%	1.32%	1.32%	1.32%	1.32%		LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		LN 11 / LN 11
23									
24	PIPELINE BASE DEMAND COSTS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
25	TOTAL PIPELINE BASE DEMAND COST	\$ 57,910	\$ 57,910	\$ 57,910	\$ 57,910	\$ 57,910	\$ 57,910	\$ 347,460	Schedule 1A, LN 69
26	Res Heat	\$ 26,130	\$ 26,064	\$ 26,037	\$ 26,036	\$ 26,081	\$ 26,110	\$ 156,459	LN 25 * LN 14
27	Res General	\$ 1,045	\$ 1,043	\$ 1,041	\$ 1,041	\$ 1,043	\$ 1,044	\$ 6,258	LN 25 * LN 15
28	G50 Low Annual-Low Winter	\$ 7,439	\$ 7,420	\$ 7,412	\$ 7,412	\$ 7,424	\$ 7,433	\$ 44,540	LN 25 * LN 16
29	G40 Low Annual-High Winter	\$ 4,382	\$ 4,371	\$ 4,367	\$ 4,367	\$ 4,374	\$ 4,379	\$ 26,240	LN 25 * LN 17
30	G51 Med Annual-Low Winter	\$ 9,577	\$ 9,552	\$ 9,542	\$ 9,542	\$ 9,558	\$ 9,569	\$ 57,341	LN 25 * LN 18
31	G41 Med Annual-High Winter	\$ 8,004	\$ 7,983	\$ 7,975	\$ 7,975	\$ 7,988	\$ 7,997	\$ 47,922	LN 25 * LN 19
32	G52 High Annual-Low Winter	\$ 567	\$ 713	\$ 771	\$ 775	\$ 677	\$ 612	\$ 4,114	LN 25 * LN 20
33	G42 High Annual-High Winter	\$ 766	\$ 764	\$ 763	\$ 763	\$ 764	\$ 765	\$ 4,586	LN 25 * LN 21
34									
35	Residential	\$ 27,176	\$ 27,107	\$ 27,079	\$ 27,077	\$ 27,124	\$ 27,155	\$ 162,717	LN 26 + LN 27
36	SALES HLF CLASSES	\$ 17,582	\$ 17,685	\$ 17,726	\$ 17,728	\$ 17,659	\$ 17,614	\$ 105,995	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	\$ 13,152	\$ 13,118	\$ 13,105	\$ 13,104	\$ 13,127	\$ 13,142	\$ 78,748	LN 29 + LN 31 + LN 33

38

49
50 **REMAINING PIPELINE DEMAND**

67
68 **PEAKING AND STORAGE DEMAND**

85

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

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

103
104 **INTERRUPTIBLE MARGINS BY CLASS**

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
105 NH DIVISION - MONTHLY INTERR MARGINS	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Schedule 1A, LN 77
107 Res Heat	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 40 Col D * LN 106
108 Res General	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 41 Col D * LN 106
109 G50 Low Annual-Low Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 42 Col D * LN 106
110 G40 Low Annual-High Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 43 Col D * LN 106
111 G51 Med Annual-Low Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 44 Col D * LN 106
112 G41 Med Annual-High Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 45 Col D * LN 106
113 G52 High Annual-Low Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 46 Col D * LN 106
114 G42 High Annual-High Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 47 Col D * LN 106
115 TOTAL	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Sum LN 108 : LN 115
117 Residential	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 108 + LN 109
118 SALES HLF CLASSES	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 110 + LN 112 + LN 114
119 SALES LLF CLASSES	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	LN 111 + LN 113 + LN 115

121

122 **REMAINING RE-ENTRY FEE CREDIT**

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
124 NH DIVISION - RE-ENTRY FEE CREDITS	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Schedule 1A, LN 78
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
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

140 **TOTAL NON-BASE CAPACITY COSTS**

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
142 Res Heat	\$ 384,481	\$ 871,990	\$ 2,278,569	\$ 1,237,465	\$ 1,083,842	\$ 418,390	\$ 6,274,737	Sum of Ln 54, 72, 90, 108, 126
143 Res General	\$ 4,064	\$ 9,217	\$ 24,086	\$ 13,081	\$ 11,457	\$ 4,423	\$ 66,327	Sum of Ln 55, 73, 91, 109, 127
144 G50 Low Annual-Low Winter	\$ 13,714	\$ 31,102	\$ 81,272	\$ 44,138	\$ 38,658	\$ 14,923	\$ 223,808	Sum of Ln 56, 74, 92, 110, 128
145 G40 Low Annual-High Winter	\$ 190,806	\$ 432,741	\$ 1,130,782	\$ 614,115	\$ 537,876	\$ 207,634	\$ 3,113,954	Sum of Ln 57, 75, 93, 111, 129
146 G51 Med Annual-Low Winter	\$ 23,016	\$ 52,199	\$ 136,400	\$ 74,077	\$ 64,881	\$ 25,046	\$ 375,620	Sum of Ln 58, 76, 94, 112, 130
147 G41 Med Annual-High Winter	\$ 183,040	\$ 415,128	\$ 1,084,758	\$ 589,120	\$ 515,984	\$ 199,183	\$ 2,987,213	Sum of Ln 59, 77, 95, 113, 131
148 G52 High Annual-Low Winter	\$ 449	\$ 1,017	\$ 2,659	\$ 1,444	\$ 1,265	\$ 488	\$ 7,321	Sum of Ln 60, 78, 96, 114, 132
149 G42 High Annual-High Winter	\$ 19,337	\$ 43,856	\$ 114,599	\$ 62,237	\$ 54,511	\$ 21,043	\$ 315,582	Sum of Ln 61, 79, 97, 115, 133
150 TOTAL	\$ 818,907	\$ 1,857,251	\$ 4,853,125	\$ 2,635,676	\$ 2,308,474	\$ 891,129	\$ 13,364,562	Sum LN 142 : LN 149
152 Residential	\$ 388,546	\$ 881,207	\$ 2,302,655	\$ 1,250,545	\$ 1,095,298	\$ 422,813	\$ 6,341,064	LN 142 + LN 143
153 SALES HLF CLASSES	\$ 37,178	\$ 84,319	\$ 220,331	\$ 119,659	\$ 104,804	\$ 40,457	\$ 606,748	LN 144 + LN 146 + LN 148
154 SALES LLF CLASSES	\$ 393,183	\$ 891,725	\$ 2,330,139	\$ 1,265,471	\$ 1,108,372	\$ 427,859	\$ 6,416,750	LN 145 + LN 147 + LN 149

156 **TOTAL CAPACITY COSTS**

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	WINTER	
158 Res Heat	\$ 410,612	\$ 898,054	\$ 2,304,607	\$ 1,263,501	\$ 1,109,922	\$ 444,500	\$ 6,431,196	LN 142 + LN 26
159 Res General	\$ 5,109	\$ 10,260	\$ 25,127	\$ 14,122	\$ 12,500	\$ 5,467	\$ 72,585	LN 143 + LN 27
160 G50 Low Annual-Low Winter	\$ 21,152	\$ 38,522	\$ 88,684	\$ 51,550	\$ 46,083	\$ 22,356	\$ 268,347	LN 144 + LN 28
161 G40 Low Annual-High Winter	\$ 195,188	\$ 437,112	\$ 1,135,149	\$ 618,481	\$ 542,250	\$ 212,013	\$ 3,140,194	LN 145 + LN 29
162 G51 Med Annual-Low Winter	\$ 32,592	\$ 61,752	\$ 145,943	\$ 83,619	\$ 74,439	\$ 34,615	\$ 432,961	LN 146 + LN 30
163 G41 Med Annual-High Winter	\$ 191,044	\$ 423,111	\$ 1,092,733	\$ 597,094	\$ 523,973	\$ 207,180	\$ 3,035,136	LN 147 + LN 31
164 G52 High Annual-Low Winter	\$ 1,016	\$ 1,730	\$ 3,430	\$ 2,219	\$ 1,941	\$ 1,100	\$ 11,435	LN 148 + LN 32
165 G42 High Annual-High Winter	\$ 20,103	\$ 44,620	\$ 115,362	\$ 63,000	\$ 55,275	\$ 21,808	\$ 320,168	LN 149 + LN 33
166 TOTAL	\$ 876,817	\$ 1,915,161	\$ 4,911,035	\$ 2,693,586	\$ 2,366,384	\$ 949,039	\$ 13,712,022	Sum LN 158 : LN 165
168 Residential	\$ 415,721	\$ 908,314	\$ 2,329,734	\$ 1,277,623	\$ 1,122,422	\$ 449,967	\$ 6,503,781	LN 158 + LN 159
169 SALES HLF CLASSES	\$ 54,761	\$ 102,004	\$ 238,057	\$ 137,388	\$ 122,464	\$ 58,071	\$ 712,743	LN 160 + LN 162 + LN 164
170 SALES LLF CLASSES	\$ 406,335	\$ 904,844	\$ 2,343,244	\$ 1,278,576	\$ 1,121,498	\$ 441,001	\$ 6,495,498	LN 161 + LN 163 + LN 165
172 % ALLOCATION BETWEEN SALES HLF AND LLF								
173 SALES HLF CLASSES							9.89%	LN 169 / (LN169 + LN 170)
174 SALES LLF CLASSES							90.11%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2010 - 2011 Period

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

Northern Utilities - NEW HAMPSHIRE DIVISION
2010 - 2011 Period

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

Northern Utilities - NEW HAMPSHIRE DIVISION

Sendout by Class - Allocation between Base & Remaining Sendout

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

49	BASE SENDOUT BY CLASS - Therms									
50	Days per Month	30	31	31	28	31	30			
51		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER	
52	Res Heat	390,983	404,016	404,016	364,917	404,016	390,983	4,728,740	2,358,930	
53	Res General	15,639	16,160	16,160	14,597	16,160	15,639	187,959	94,356	
54	G50 Low Annual-Low Winter	111,303	115,013	115,013	103,882	115,013	111,303	1,335,873	671,525	
55	G40 Low Annual-High Winter	65,573	67,759	67,759	61,201	67,759	65,573	776,363	395,622	
56	G51 Med Annual-Low Winter	143,292	148,068	148,068	133,739	148,068	143,292	1,726,857	864,526	
57	G41 Med Annual-High Winter	119,756	123,747	123,747	111,772	123,747	119,756	1,423,799	722,525	
58	G52 High Annual-Low Winter	8,488	11,047	11,968	10,859	10,482	9,159	194,639	62,003	
59	G42 High Annual-High Winter	11,459	11,841	11,841	10,695	11,841	11,459	139,220	69,136	
60	Subtotal									
61	Residential	406,622	420,176	420,176	379,514	420,176	406,622	4,916,699	2,453,287	
62	SALES HLF CLASSES	263,082	274,128	275,049	248,480	273,563	263,753	3,257,369	1,598,055	
63	SALES LLF CLASSES	196,787	203,347	203,347	183,668	203,347	196,787	2,339,383	1,187,283	
64	Total Firm Sales	866,491	897,651	898,572	811,662	897,086	867,162	10,513,451	5,238,625	

65	REMAINING SENDOUT BY CLASS - Therms									
66		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER	
67										
68	Res Heat	1,028,528	1,674,678	2,604,787	2,176,245	2,115,513	1,157,671	11,625,830	10,757,423	
69	Res General	13,411	18,367	30,451	27,245	25,383	15,766	152,971	130,621	
70	G50 Low Annual-Low Winter	17,744	49,177	74,615	68,018	58,880	21,589	369,413	290,022	
71	G40 Low Annual-High Winter	497,305	910,077	1,523,378	1,308,102	1,146,689	619,942	6,519,560	6,005,493	
72	G51 Med Annual-Low Winter	78,298	112,149	126,673	101,151	106,981	45,487	698,478	570,738	
73	G41 Med Annual-High Winter	524,653	1,031,950	1,126,258	942,709	936,073	488,797	5,691,344	5,050,441	
74	G52 High Annual-Low Winter	-	-	-	-	-	-	12,460	-	
75	G42 High Annual-High Winter	94,079	145,231	143,047	120,139	92,735	48,985	684,682	644,217	
76	Subtotal									
77	Residential	1,041,939	1,693,045	2,635,238	2,203,490	2,140,896	1,173,437	11,778,801	10,888,044	
78	SALES HLF CLASSES	96,042	161,326	201,287	169,169	165,860	67,076	1,080,352	860,760	
79	SALES LLF CLASSES	1,116,038	2,087,258	2,792,683	2,370,949	2,175,498	1,157,724	12,895,586	11,700,151	
80	Total Firm Sales	2,254,019	3,941,629	5,629,208	4,743,608	4,482,254	2,398,238	25,754,739	23,448,955	

Northern Utilities - NEW HAMPSHIRE DIVISION

Sendout by Class - Allocation between Base & Remaining Sendout

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

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

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

Note 1 Company Forecast

Note 2 Pages 2 - 4; Sum of Column 2 of Billed Deliveries table. Actual Data is weather normalized.

Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.

Note 4 Pages 2 - 4; Sum of Column 7 of Billed Deliveries Table. Actual Data provided is weather normalized.

Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

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

Note 1 Company Forecast

Note 2 Actual Data. Page 2 - 4; Sum of Column 2 of Meter Counts table.

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

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

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.

Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.

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

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

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

Note 1 Company Forecast

Note 2 Actual, weather normalized data.

Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.

Note 4 Actual, weather normalized data.

Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

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

Note 1 Company Forecast

Note 2 Actual Data.

Note 3 Actual Data.

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

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.

Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.

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

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

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

Note 1 Company Forecast

Note 2 Actual, weather normalized data.

Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.

Note 4 Actual, weather normalized data.

Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

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

Note 1 Company Forecast

Note 2 Actual Data.

Note 3 Actual Data.

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

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.

Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.

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

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

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

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

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

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

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

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

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

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

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

Forecast Calendar Month Distribution Service Usage (Dth)

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

Forecast Sales Service Percentage

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

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

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

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

Forecast Billed Distribution Service Usage (Dth)

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

Forecast Sales Service Percentage

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

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

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

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

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

Base Commodity Costs

BASE SENDOUT BY CLASS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
Total Therms								
Res Heat	390,983	404,016	404,016	364,917	404,016	390,983	4,728,740	2,358,930
Res General	15,639	16,160	16,160	14,597	16,160	15,639	187,959	94,356
G50 Low Annual-Low Winter	111,303	115,013	115,013	103,882	115,013	111,303	1,335,873	671,525
G40 Low Annual-High Winter	65,573	67,759	67,759	61,201	67,759	65,573	776,363	395,622
G51 Med Annual-Low Winter	143,292	148,068	148,068	133,739	148,068	143,292	1,726,857	864,526
G41 Med Annual-High Winter	119,756	123,747	123,747	111,772	123,747	119,756	1,423,799	722,525
G52 High Annual-Low Winter	8,488	11,047	11,968	10,859	10,482	9,159	194,639	62,003
G42 High Annual-High Winter	11,459	11,841	11,841	10,695	11,841	11,459	139,220	69,136
Total Firm Sales	866,491	897,651	898,572	811,662	897,086	867,162	10,513,451	5,238,625
% of Total								
Res Heat	45.12%	45.01%	44.96%	44.96%	45.04%	45.09%		
Res General	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%		
G50 Low Annual-Low Winter	12.85%	12.81%	12.80%	12.80%	12.82%	12.84%		
G40 Low Annual-High Winter	7.57%	7.55%	7.54%	7.54%	7.55%	7.56%		
G51 Med Annual-Low Winter	16.54%	16.50%	16.48%	16.48%	16.51%	16.52%		
G41 Med Annual-High Winter	13.82%	13.79%	13.77%	13.77%	13.79%	13.81%		
G52 High Annual-Low Winter	0.98%	1.23%	1.33%	1.34%	1.17%	1.06%		
G42 High Annual-High Winter	1.32%	1.32%	1.32%	1.32%	1.32%	1.32%		
Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

BASE COMMODITY COSTS Excl'd Hedging	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
TOTAL BASE COMMODITY Excl'd Hedging	\$ 402,615	\$ 448,307	\$ 469,215	\$ 425,755	\$ 459,002	\$ 418,489	\$ 5,226,141	\$ 2,623,383
Res Heat	\$ 181,670	\$ 201,774	\$ 210,968	\$ 191,416	\$ 206,718	\$ 188,687	\$ 2,350,316	\$ 1,181,234
Res General	\$ 7,267	\$ 8,071	\$ 8,439	\$ 7,657	\$ 8,269	\$ 7,547	\$ 93,440	\$ 47,249
G50 Low Annual-Low Winter	\$ 51,717	\$ 57,440	\$ 60,057	\$ 54,491	\$ 58,847	\$ 53,714	\$ 664,119	\$ 336,266
G40 Low Annual-High Winter	\$ 30,468	\$ 33,840	\$ 35,382	\$ 32,103	\$ 34,669	\$ 31,645	\$ 386,060	\$ 198,108
G51 Med Annual-Low Winter	\$ 66,580	\$ 73,948	\$ 77,318	\$ 70,152	\$ 75,760	\$ 69,152	\$ 858,430	\$ 432,911
G41 Med Annual-High Winter	\$ 55,644	\$ 61,802	\$ 64,618	\$ 58,630	\$ 63,316	\$ 57,794	\$ 707,954	\$ 361,804
G52 High Annual-Low Winter	\$ 3,944	\$ 5,517	\$ 6,250	\$ 5,696	\$ 5,363	\$ 4,420	\$ 96,626	\$ 31,190
G42 High Annual-High Winter	\$ 5,324	\$ 5,914	\$ 6,183	\$ 5,610	\$ 6,059	\$ 5,530	\$ 69,196	\$ 34,620
Residential	\$ 188,937	\$ 209,845	\$ 219,407	\$ 199,073	\$ 214,987	\$ 196,234	\$ 2,443,757	\$ 1,228,483
SALES HLF CLASSES	\$ 122,241	\$ 136,906	\$ 143,625	\$ 130,339	\$ 139,971	\$ 127,286	\$ 1,619,175	\$ 800,368
SALES LLF CLASSES	\$ 91,437	\$ 101,556	\$ 106,183	\$ 96,343	\$ 104,044	\$ 94,969	\$ 1,163,209	\$ 594,532

NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS								
TOTAL BASE HEDGING COMMODITY	\$ 72,841	\$ 142,684	\$ 106,985	\$ 143,041	\$ 67,367	\$ 54,475	\$ 605,987	\$ 587,394
Res Heat	\$ 32,868	\$ 64,219	\$ 48,103	\$ 64,310	\$ 30,340	\$ 24,561	\$ 272,666	\$ 264,401
Res General	\$ 1,315	\$ 2,569	\$ 1,924	\$ 2,572	\$ 1,214	\$ 982	\$ 10,907	\$ 10,576
G50 Low Annual-Low Winter	\$ 9,357	\$ 18,282	\$ 13,694	\$ 18,307	\$ 8,637	\$ 6,992	\$ 77,621	\$ 75,268
G40 Low Annual-High Winter	\$ 5,512	\$ 10,770	\$ 8,067	\$ 10,786	\$ 5,088	\$ 4,119	\$ 45,729	\$ 44,343
G51 Med Annual-Low Winter	\$ 12,046	\$ 23,536	\$ 17,629	\$ 23,569	\$ 11,119	\$ 9,002	\$ 99,929	\$ 96,901
G41 Med Annual-High Winter	\$ 10,067	\$ 19,670	\$ 14,734	\$ 19,698	\$ 9,293	\$ 7,523	\$ 83,516	\$ 80,984
G52 High Annual-Low Winter	\$ 714	\$ 1,756	\$ 1,425	\$ 1,914	\$ 787	\$ 575	\$ 7,628	\$ 7,171
G42 High Annual-High Winter	\$ 963	\$ 1,882	\$ 1,410	\$ 1,885	\$ 889	\$ 720	\$ 7,991	\$ 7,749
Residential	\$ 34,183	\$ 66,788	\$ 50,027	\$ 66,882	\$ 31,553	\$ 25,544	\$ 283,572	\$ 274,977
SALES HLF CLASSES	\$ 22,116	\$ 43,573	\$ 32,748	\$ 43,790	\$ 20,543	\$ 16,569	\$ 185,178	\$ 179,339
SALES LLF CLASSES	\$ 16,543	\$ 32,323	\$ 24,211	\$ 32,368	\$ 15,270	\$ 12,362	\$ 137,237	\$ 133,077

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

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

Base Commodity Costs

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

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

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

Northern Utilities - MAINE DIVISION

Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

REMAINING SENDOUT BY CLASS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
Total Therms								
Res Heat	1,028,528	1,674,678	2,604,787	2,176,245	2,115,513	1,157,671	11,625,830	10,757,423
Res General	13,411	18,367	30,451	27,245	25,383	15,766	152,971	130,621
G50 Low Annual-Low Winter	17,744	49,177	74,615	68,018	58,880	21,589	369,413	290,022
G40 Low Annual-High Winter	497,305	910,077	1,523,378	1,308,102	1,146,689	619,942	6,519,560	6,005,493
G51 Med Annual-Low Winter	78,298	112,149	126,673	101,151	106,981	45,487	698,478	570,738
G41 Med Annual-High Winter	524,653	1,031,950	1,126,258	942,709	936,073	488,797	5,691,344	5,050,441
G52 High Annual-Low Winter	-	-	-	-	-	-	12,460	-
G42 High Annual-High Winter	94,079	145,231	143,047	120,139	92,735	48,985	684,682	644,217
Total Firm Sales	2,254,019	3,941,629	5,629,208	4,743,608	4,482,254	2,398,238	25,754,739	23,448,955
% of Total								
Res Heat	45.63%	42.49%	46.27%	45.88%	47.20%	48.27%		
Res General	0.59%	0.47%	0.54%	0.57%	0.57%	0.66%		
G50 Low Annual-Low Winter	0.79%	1.25%	1.33%	1.43%	1.31%	0.90%		
G40 Low Annual-High Winter	22.06%	23.09%	27.06%	27.58%	25.58%	25.85%		
G51 Med Annual-Low Winter	3.47%	2.85%	2.25%	2.13%	2.39%	1.90%		
G41 Med Annual-High Winter	23.28%	26.18%	20.01%	19.87%	20.88%	20.38%		
G52 High Annual-Low Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
G42 High Annual-High Winter	4.17%	3.68%	2.54%	2.53%	2.07%	2.04%		
Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

REMAINING COMMODITY COSTS EXCLD HEDGING	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
REMAINING COMMODITY Excl'd Hedging	\$ 1,018,400	\$ 1,721,760	\$ 2,449,559	\$ 2,055,564	\$ 2,032,520	\$ 1,146,625	\$ 11,571,544	\$ 10,424,427
Res Heat	\$ 464,705	\$ 731,523	\$ 1,133,477	\$ 943,040	\$ 959,299	\$ 553,496	\$ 5,216,126	\$ 4,785,540
Res General	\$ 6,059	\$ 8,023	\$ 13,251	\$ 11,806	\$ 11,510	\$ 7,538	\$ 69,224	\$ 58,187
G50 Low Annual-Low Winter	\$ 8,017	\$ 21,481	\$ 32,469	\$ 29,475	\$ 26,700	\$ 10,322	\$ 167,947	\$ 128,463
G40 Low Annual-High Winter	\$ 224,690	\$ 397,535	\$ 662,900	\$ 566,844	\$ 519,977	\$ 296,401	\$ 2,922,863	\$ 2,668,347
G51 Med Annual-Low Winter	\$ 35,376	\$ 48,988	\$ 55,122	\$ 43,832	\$ 48,511	\$ 21,748	\$ 317,673	\$ 253,577
G41 Med Annual-High Winter	\$ 237,046	\$ 450,770	\$ 490,093	\$ 408,507	\$ 424,471	\$ 233,700	\$ 2,565,325	\$ 2,244,588
G52 High Annual-Low Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,213	\$ -
G42 High Annual-High Winter	\$ 42,506	\$ 63,439	\$ 62,247	\$ 52,060	\$ 42,052	\$ 23,420	\$ 306,173	\$ 285,725
Residential	\$ 470,764	\$ 739,546	\$ 1,146,728	\$ 954,846	\$ 970,809	\$ 561,034	\$ 5,285,350	\$ 4,843,727
SALES HLF CLASSES	\$ 43,393	\$ 70,469	\$ 87,591	\$ 73,307	\$ 75,211	\$ 32,070	\$ 491,833	\$ 382,040
SALES LLF CLASSES	\$ 504,243	\$ 911,744	\$ 1,215,241	\$ 1,027,412	\$ 986,500	\$ 553,521	\$ 5,794,361	\$ 5,198,660

REMAINING COMMODITY HEDGING COSTS	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
TOTAL REMAINING COMMODITY HEDGING	\$ 148,273	\$ 63,999	\$ 18,519	\$ 12,542	\$ 83,669	\$ 140,051	\$ 483,848	\$ 467,052
Res Heat	\$ 67,658	\$ 27,191	\$ 8,569	\$ 5,754	\$ 39,489	\$ 67,605	\$ 223,637	\$ 216,267
Res General	\$ 882	\$ 298	\$ 100	\$ 72	\$ 474	\$ 921	\$ 2,893	\$ 2,747
G50 Low Annual-Low Winter	\$ 1,167	\$ 798	\$ 245	\$ 180	\$ 1,099	\$ 1,261	\$ 5,139	\$ 4,751
G40 Low Annual-High Winter	\$ 32,714	\$ 14,777	\$ 5,012	\$ 3,459	\$ 21,405	\$ 36,203	\$ 117,504	\$ 113,568
G51 Med Annual-Low Winter	\$ 5,151	\$ 1,821	\$ 417	\$ 267	\$ 1,997	\$ 2,656	\$ 13,032	\$ 12,309
G41 Med Annual-High Winter	\$ 34,513	\$ 16,755	\$ 3,705	\$ 2,493	\$ 17,473	\$ 28,545	\$ 107,430	\$ 103,483
G52 High Annual-Low Winter	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 80	\$ -
G42 High Annual-High Winter	\$ 6,189	\$ 2,358	\$ 471	\$ 318	\$ 1,731	\$ 2,861	\$ 14,134	\$ 13,927
Residential	\$ 68,540	\$ 27,489	\$ 8,669	\$ 5,826	\$ 39,963	\$ 68,526	\$ 226,530	\$ 219,014
SALES HLF CLASSES	\$ 6,318	\$ 2,619	\$ 662	\$ 447	\$ 3,096	\$ 3,917	\$ 18,251	\$ 17,060
SALES LLF CLASSES	\$ 73,415	\$ 33,890	\$ 9,187	\$ 6,269	\$ 40,609	\$ 67,608	\$ 239,067	\$ 230,978

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

Remaining Commodity Costs

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

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

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

N 99	TOTAL COMMODITY COSTS Excluding Hedging									
N 100	TOTAL COMMODITY Excl'd Hedging	\$ 1,421,015	\$ 2,170,067	\$ 2,918,774	\$ 2,481,319	\$ 2,491,522	\$ 1,565,114	\$ 16,797,685	\$ 13,047,810	
N 101	Res Heat	\$ 646,375	\$ 933,298	\$ 1,344,446	\$ 1,134,456	\$ 1,166,017	\$ 742,183	\$ 7,566,442	\$ 5,966,774	
N 102	Res General	\$ 13,326	\$ 16,094	\$ 21,689	\$ 19,463	\$ 19,779	\$ 15,085	\$ 162,664	\$ 105,435	
N 103	G50 Low Annual-Low Winter	\$ 59,734	\$ 78,921	\$ 92,526	\$ 83,966	\$ 85,547	\$ 64,036	\$ 832,067	\$ 464,729	
N 104	G40 Low Annual-High Winter	\$ 255,158	\$ 431,375	\$ 698,282	\$ 598,947	\$ 554,646	\$ 328,046	\$ 3,308,923	\$ 2,866,455	
N 105	G51 Med Annual-Low Winter	\$ 101,957	\$ 122,937	\$ 132,440	\$ 113,984	\$ 124,272	\$ 90,900	\$ 1,176,103	\$ 686,489	
N 106	G41 Med Annual-High Winter	\$ 292,691	\$ 512,572	\$ 554,711	\$ 467,137	\$ 487,788	\$ 291,493	\$ 3,273,279	\$ 2,606,392	
N 107	G52 High Annual-Low Winter	\$ 3,944	\$ 5,517	\$ 6,250	\$ 5,696	\$ 5,363	\$ 4,420	\$ 102,839	\$ 31,190	
N 108	G42 High Annual-High Winter	\$ 47,831	\$ 69,353	\$ 68,430	\$ 57,670	\$ 48,110	\$ 28,951	\$ 375,369	\$ 320,345	
N 109										
N 110	Residential	\$ 659,701	\$ 949,391	\$ 1,366,135	\$ 1,153,919	\$ 1,185,796	\$ 757,268	\$ 7,729,106	\$ 6,072,210	
N 111	SALES HLF CLASSES	\$ 165,634	\$ 207,375	\$ 231,215	\$ 203,646	\$ 215,182	\$ 159,356	\$ 2,111,009	\$ 1,182,408	
N 112	SALES LLF CLASSES	\$ 595,680	\$ 1,013,300	\$ 1,321,424	\$ 1,123,754	\$ 1,090,544	\$ 648,490	\$ 6,957,570	\$ 5,793,192	

N 113	TOTAL HEDGING COMMODITY COSTS									
N 114	TOTAL HEDGING COMMODITY	\$ 221,115	\$ 206,683	\$ 125,504	\$ 155,583	\$ 151,036	\$ 194,526	\$ 1,089,835	\$ 1,054,446	
N 115	Res Heat	\$ 100,526	\$ 91,410	\$ 56,672	\$ 70,064	\$ 69,829	\$ 92,167	\$ 496,303	\$ 480,668	
N 116	Res General	\$ 2,197	\$ 2,867	\$ 2,024	\$ 2,644	\$ 1,687	\$ 1,903	\$ 13,799	\$ 13,323	
N 117	G50 Low Annual-Low Winter	\$ 10,524	\$ 19,080	\$ 13,939	\$ 18,487	\$ 9,736	\$ 8,253	\$ 82,760	\$ 80,019	
N 118	G40 Low Annual-High Winter	\$ 38,226	\$ 25,547	\$ 13,079	\$ 14,244	\$ 26,493	\$ 40,322	\$ 163,233	\$ 157,912	
N 119	G51 Med Annual-Low Winter	\$ 17,196	\$ 25,357	\$ 18,046	\$ 23,837	\$ 13,116	\$ 11,658	\$ 112,961	\$ 109,210	
N 120	G41 Med Annual-High Winter	\$ 44,580	\$ 36,425	\$ 18,439	\$ 22,190	\$ 26,766	\$ 36,068	\$ 190,945	\$ 184,468	
N 121	G52 High Annual-Low Winter	\$ 714	\$ 1,756	\$ 1,425	\$ 1,914	\$ 787	\$ 575	\$ 7,708	\$ 7,171	
N 122	G42 High Annual-High Winter	\$ 7,152	\$ 4,240	\$ 1,880	\$ 2,202	\$ 2,620	\$ 3,580	\$ 22,125	\$ 21,676	
N 123										
N 124	Residential	\$ 102,723	\$ 94,277	\$ 58,696	\$ 72,709	\$ 71,517	\$ 94,070	\$ 510,102	\$ 493,991	
N 125	SALES HLF CLASSES	\$ 28,434	\$ 46,193	\$ 33,410	\$ 44,237	\$ 23,639	\$ 20,486	\$ 203,429	\$ 196,399	
N 126	SALES LLF CLASSES	\$ 89,958	\$ 66,212	\$ 33,398	\$ 38,637	\$ 55,880	\$ 79,970	\$ 376,304	\$ 364,055	

N 127	TOTAL COMMODITY	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
N 128	Res Heat	\$ 746,901	\$ 1,024,708	\$ 1,401,117	\$ 1,204,520	\$ 1,235,846	\$ 834,350	\$ 8,062,745	\$ 6,447,443
N 129	Res General	\$ 15,523	\$ 18,961	\$ 23,714	\$ 22,107	\$ 21,466	\$ 16,988	\$ 176,463	\$ 118,759
N 130	G50 Low Annual-Low Winter	\$ 70,257	\$ 98,001	\$ 106,465	\$ 102,453	\$ 95,283	\$ 72,289	\$ 914,827	\$ 544,748
N 131	G40 Low Annual-High Winter	\$ 293,384	\$ 456,922	\$ 711,361	\$ 613,191	\$ 581,139	\$ 368,369	\$ 3,472,156	\$ 3,024,367
N 132	G51 Med Annual-Low Winter	\$ 119,153	\$ 148,293	\$ 150,486	\$ 137,821	\$ 137,388	\$ 102,558	\$ 1,289,065	\$ 795,698
N 133	G41 Med Annual-High Winter	\$ 337,271	\$ 548,998	\$ 573,150	\$ 489,327	\$ 514,554	\$ 327,561	\$ 3,464,224	\$ 2,790,860
N 134	G52 High Annual-Low Winter	\$ 4,657	\$ 7,273	\$ 7,675	\$ 7,609	\$ 6,151	\$ 4,995	\$ 110,546	\$ 38,361
N 135	G42 High Annual-High Winter	\$ 54,983	\$ 73,593	\$ 70,311	\$ 59,873	\$ 50,731	\$ 32,531	\$ 397,494	\$ 342,021
N 136	Total Firm Sales	\$ 1,642,129	\$ 2,376,749	\$ 3,044,278	\$ 2,636,902	\$ 2,642,557	\$ 1,759,640	\$ 17,887,520	\$ 14,102,256
N 137									
N 138	Residential	\$ 762,424	\$ 1,043,669	\$ 1,424,831	\$ 1,226,627	\$ 1,257,312	\$ 851,338	\$ 8,239,208	\$ 6,566,201
N 139	SALES HLF CLASSES	\$ 194,068	\$ 253,568	\$ 264,625	\$ 247,883	\$ 238,821	\$ 179,842	\$ 2,314,438	\$ 1,378,807
N 140	SALES LLF CLASSES	\$ 685,638	\$ 1,079,513	\$ 1,354,822	\$ 1,162,391	\$ 1,146,424	\$ 728,461	\$ 7,333,874	\$ 6,157,247
N 141									
N 142	% ALLOCATION BETWEEN SALES HLF AND LLF								
N 143	SALES HLF CLASSES								18.30%
N 144	SALES LLF CLASSES								81.70%

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

Total Commodity Costs

99	TOTAL COMMODITY COSTS Excluding Hedging	
100	TOTAL COMMODITY Excl'd 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)

Schedule 11

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) November 2010 through April 2011							
Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	73,841	0	1,773	12,562	39,178	174,508	301,862
Pittsburgh, NH	33,000	34,100	34,100	30,800	34,100	33,000	199,100
Niagara	68,184	0	0	8,953	23,563	83,993	184,693
Tennessee Production	324,343	222,595	161,528	110,471	274,333	281,822	1,375,093
Subtotal Pipeline Volumes	499,368	256,695	197,401	162,786	371,174	573,323	2,060,747
Storage							
Tennessee Storage	0	0	64,297	33,094	47,753	2,536	147,681
Washington 10 Storage	0	571,056	832,121	714,242	442,476	0	2,559,895
Subtotal Storage Volumes	0	571,056	896,418	747,336	490,230	2,536	2,707,576
Peaking							
Peaking Supply 1	91,721	126,202	127,231	112,960	117,031	26,895	602,041
Peaking Supply 2	0	0	0	0	2,670	0	2,670
LNG	1,350	1,395	1,395	1,260	11,646	1,826	18,872
Subtotal Peaking Volumes	93,071	127,597	128,626	114,220	131,348	28,722	623,584
Total Delivered (Dth)	592,439	955,348	1,222,446	1,024,342	992,752	604,580	5,391,907

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) November 2010 through April 2011							
Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Season
Pipeline							
Chicago	175,173	180,435	180,435	162,974	174,615	175,782	1,049,415
PNGTS - Delivered	33,000	34,100	34,100	30,800	34,100	33,000	199,100
Niagara	98,411	101,691	101,691	91,850	98,411	96,562	588,615
Tennessee Production	392,668	405,757	405,757	366,490	404,093	374,722	2,349,486
Subtotal Pipeline Volumes	699,251	721,983	721,983	652,114	711,219	680,066	4,186,616
Storage							
Tennessee Storage	1,147	23,758	56,487	34,317	57,300	67,929	240,938
Washington 10 Storage	134,434	663,155	960,392	694,251	576,676	122,937	3,151,846
Subtotal Storage Volumes	135,581	686,913	1,016,879	728,568	633,976	190,867	3,392,784
Peaking							
Peaking Supply 1	132,990	124,141	141,421	113,574	78,712	119,882	710,722
Peaking Supply 2	0	2,706	56,522	48,071	31,774	0	139,073
LNG	1,350	1,395	1,395	1,260	1,395	20,029	26,824
Subtotal Peaking Volumes	134,340	128,242	199,339	162,905	111,881	139,911	876,619
Total Delivered (Dth)	969,173	1,537,138	1,938,201	1,543,587	1,457,076	1,010,844	8,456,019

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

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

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

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

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

Demand	
Firm Sales	645,003
Interruptible Sales	0
Capacity Exempt Transportation	260,631
Non-Capacity Exempt Transportation	248,920
Interruptible Transportation	0

Total	1,154,554
-------	-----------

Supplies	
Capacity Exempt Transportation	260,631
Pipeline	238,970
Storage	354,750
On-System LNG	100,000
Off-System Peaking	620,880
On-System Propane	0

Total	1,575,231
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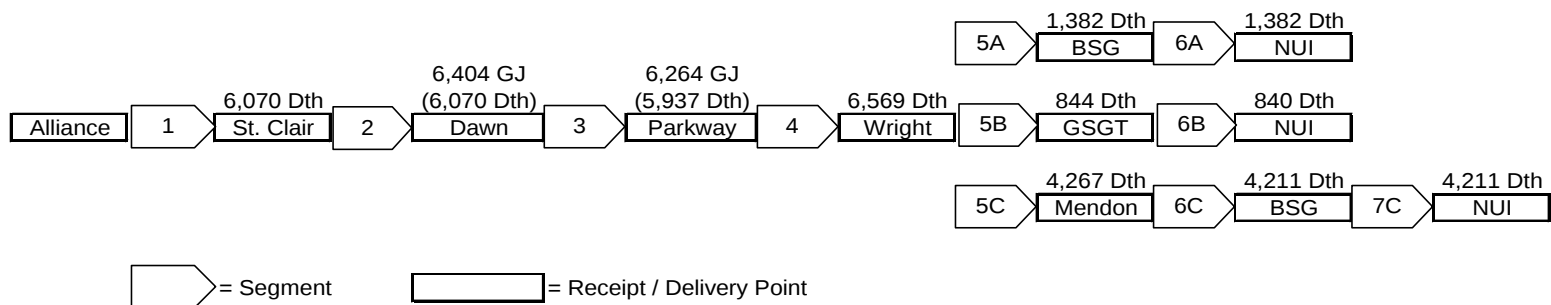
Effective Degree Day	
New Hampshire	80
Maine	81
Probability	1 in 30

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

Schedule 12

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

Capacity Path Diagram

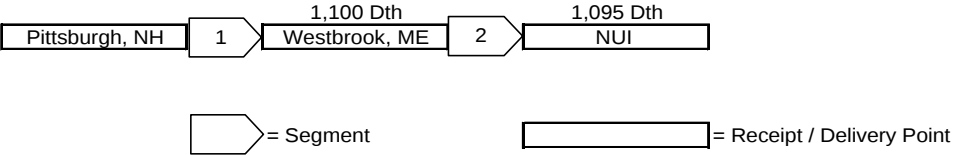


Capacity Path Detail

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	TransCanada
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	
3	Transportation	TransCanada	29594	FT	10/31/2016	6,264	GJ	Year-Round	Dawn	Parkway	
4	Transportation	Iroquois	R181001	RTS-1	10/31/2013	6,569	Dth	Year-Round	Parkway	Wright	
5A	Transportation	Tennessee	31861	NET-284	10/31/2012	1,382	Dth	Year-Round	Wright	Bay State City Gate	Tennessee
6A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
5B	Transportation	Tennessee	31861	NET-284	10/31/2012	844	Dth	Year-Round	Wright	Pleasant St.	
6B	Transportation	Granite	10-010-FT-NN	FT-NN	Renewal Clause	840	Dth	Year-Round	Pleasant St.	Northern City Gates	
5C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
6C	Transportation	Algonquin	93200F	AFT-1	10/31/2012	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
7C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,433	Dth				

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

Capacity Path Diagram

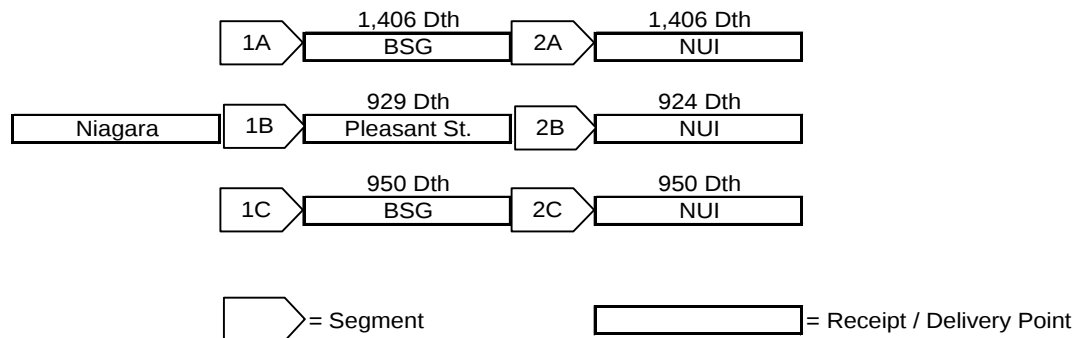


Capacity Path Detail

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

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

Capacity Path Diagram

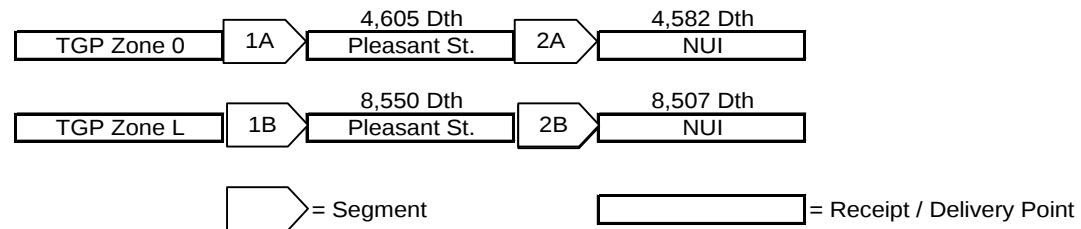


Capacity Path Detail

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

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

Capacity Path Diagram



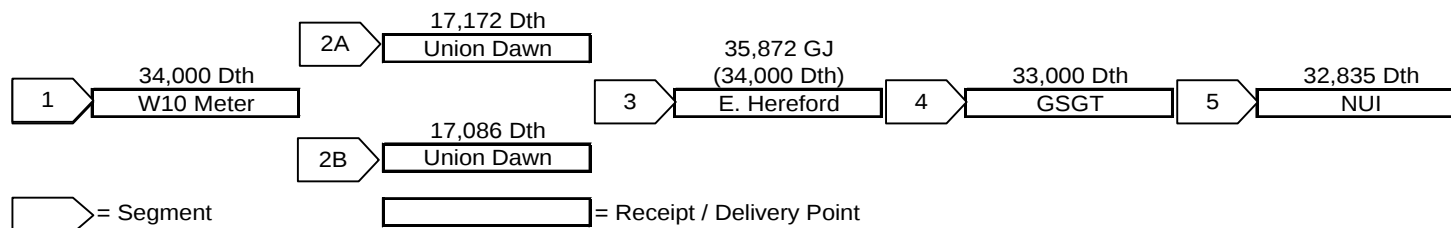
Capacity Path Detail

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

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

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

Capacity Path Diagram



Capacity Path Detail

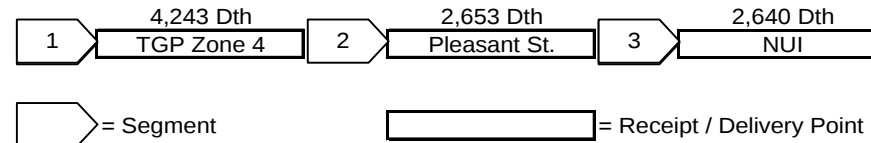
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1 ¹	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A ²	Transportation	Vector	CRL-NUI-0725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

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

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

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

Capacity Path Diagram



Capacity Path Detail

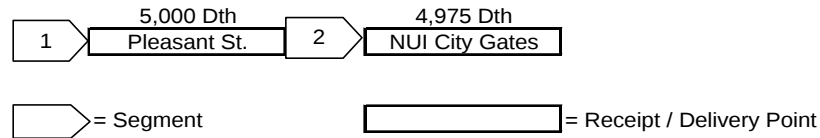
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1 ¹	Storage	Tennessee	5195	FS-MA	10/31/2013	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2 ²	Transportation	Tennessee	5265	FT-A	10/31/2013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

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

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

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

Capacity Path Diagram



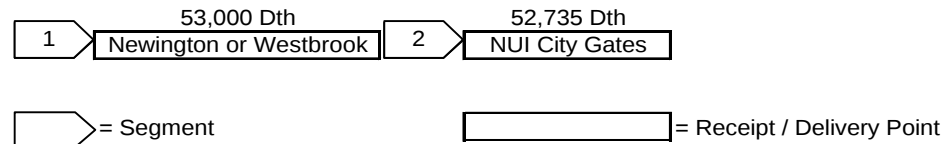
Capacity Path Detail

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

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

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

Capacity Path Diagram



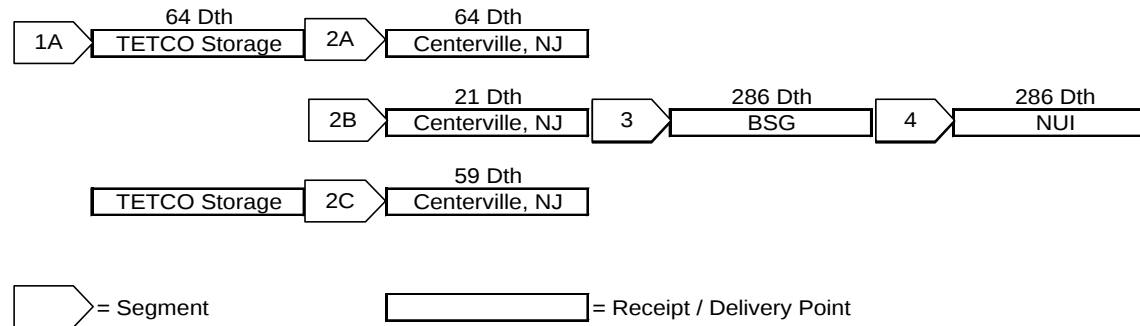
Capacity Path Detail

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

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

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

Capacity Path Diagram



Capacity Path Detail

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

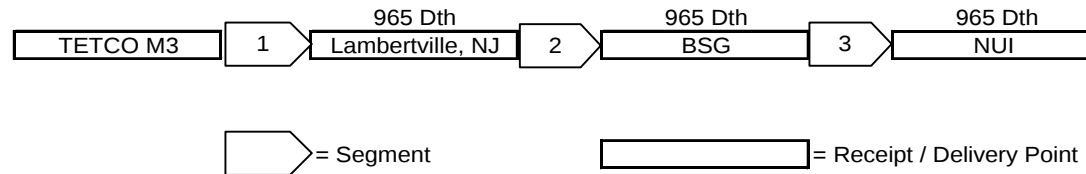
Note 1: Texas Eastern Contract No. 400513 has a maximum storage quantity of 3,840 Dth.

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

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

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

Capacity Path Diagram



Capacity Path Detail

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

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

Schedule 13

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

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

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

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

Schedule 14

**Northern Utilities, Inc.
Storage Analysis**

Northern Utilities, Inc.
New Hampshire Division
Schedule 14
Page 1 of 1

Tennessee Storage

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

Washington 10 Storage

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

LNG Storage

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

Schedule 15

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

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

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

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

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

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

FORM III
Schedule 3

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

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

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

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

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

FORM III
Schedule 4
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Demand Costs

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

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

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

OFF-PEAK PERIOD - Acct 182.21

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

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

(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate.

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

OFF-PEAK PERIOD - Acct 182.22

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

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

(2) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.

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

Attachment E
Page 2 of 2

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

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

Schedule 16

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

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

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

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

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

Northern Utilities, Inc. -- New Hampshire Division**Energy Efficiency Budget**

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

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

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

Northern Utilities, Inc. New Hampshire Division Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge To Be Effective November 1, 2010 through October 31, 2011 Residential Customers															
		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Costs	DSM SHI	Allocated Low Income Costs	Allocated Low Income SHI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
July-10	Actual	152,267	\$0.0185	6,949	10,388	1,724	5,607	128	163,165	157,716	3.25%	435	163,600	375,418	31
August-10	Forecast	163,600	\$0.0185	6,722	11,443	1,724	1,879	137	172,061	167,831	3.25%	463	172,524	363,367	31
September-10	Forecast	172,524	\$0.0185	7,814	5,722	1,724	860	126	173,141	172,833	3.25%	462	173,603	422,359	30
October-10	Forecast	173,603	\$0.0185	9,175	5,722	1,724	841	123	172,837	173,220	3.25%	478	173,315	495,952	31
November-10	Forecast	173,315	\$0.0355	40,000	5,722	1,724	1,163	170	142,094	157,704	3.25%	421	142,515	1,126,635	30
December-10	Forecast	142,515	\$0.0355	67,464	27,464	1,724	5,827	177	110,242	126,378	3.25%	349	110,591	1,900,203	31
January-11	Forecast	110,591	\$0.0355	99,555	22,231	2,964	1,733	231	38,195	74,393	3.25%	205	38,400	2,804,066	31
February-11	Forecast	38,400	\$0.0355	103,950	26,677	2,964	2,234	248	(33,427)	2,486	3.25%	6	(33,421)	2,927,871	28
March-11	Forecast	(33,421)	\$0.0355	86,768	31,123	2,964	2,519	240	(83,344)	(58,382)	3.25%	(161)	(83,505)	2,443,900	31
April-11	Forecast	(83,505)	\$0.0355	64,703	31,123	2,964	2,490	237	(111,393)	(97,449)	3.25%	(260)	(111,653)	1,822,428	30
May-11	Forecast	(111,653)	\$0.0355	39,264	22,231	2,964	1,794	239	(123,688)	(117,671)	3.25%	(325)	(124,013)	1,105,900	31
June-11	Forecast	(124,013)	\$0.0355	23,275	75,585	2,964	4,967	195	(63,578)	(93,796)	3.25%	(251)	(63,829)	655,568	30
July-11	Forecast	(63,829)	\$0.0355	14,915	17,785	2,964	983	164	(56,848)	(60,339)	3.25%	(167)	(57,015)	420,094	31
August-11	Forecast	(57,015)	\$0.0355	12,998	44,462	2,964	2,327	155	(20,106)	(38,560)	3.25%	(106)	(20,212)	366,114	31
September-11	Forecast	(20,212)	\$0.0355	15,105	22,231	2,964	1,059	141	(8,921)	(14,566)	3.25%	(39)	(8,960)	425,454	30
October-11	Forecast	(8,960)	\$0.0355	17,735	22,231	2,964	1,034	138	(329)	(4,644)	3.25%	(13)	(342)	499,521	31

Northern Utilities, Inc.
New Hampshire Division
Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge
To Be Effective November 1, 2010 through October 31, 2011
General Service Customers

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

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE

November 1, 2010 through October 31, 2011

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

Schedule 17

**NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDATION ADJUSTMENT CLAUSE COMPLIANCE FILING
2009-2010 ENVIORNMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES**

**SCHEDULE 1
PAGE 1 OF 1**

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

Schedule 18

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

November 2010 through October 2011

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

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

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

48.95%

0.02418093

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

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

Schedule 19

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

Basic assumptions:

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

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

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

7					
8					
9	LLF - C&I Allocation		Capacity Cost	MDQ, Dt	\$/Dt-Mo.
10	Pipeline - Base		213,759	1,168	15.25
11	Pipeline - Remaining		180,371	985	15.25
12	Storage		7,737,599	10,553	61.10
13	Peaking		2,250,126	18,563	10.10
14	Total	55.9%	10,381,856	31,270	27.67

15					
16					
17	HLF - C&I Allocation		Capacity Cost	MDQ, Dt	\$/Dt-Mo.
18	Pipeline - Base		1,025,678	5,603	15.25
19	Pipeline - Remaining		19,066	104	15.25
20	Storage		817,915	1,116	61.10
21	Peaking		237,853	1,962	10.10
22	Total	11.3%	2,100,512	8,785	19.93

23					
24					
25	Unit Cost		Residential	LLF C&I	HLF C&I
26					
27	Pipeline		\$ 15.25	\$ 15.25	\$ 15.25
28	Storage		\$ 61.10	\$ 61.10	\$ 61.10
29	Peaking		\$ 10.10	\$ 10.10	\$ 10.10
30	Total		\$ 25.97	\$ 27.67	\$ 19.93
31	Checktotal		\$ 25.97	\$ 27.67	\$ 19.93

32					
33					
34	Load Makeup	Residential	LLF C&I	HLF C&I	
35					
36	Pipeline	19.62%	6.89%	64.97%	
37	Storage	29.13%	33.75%	12.70%	
38	Peaking	51.24%	59.37%	22.34%	
39	Total	100.00%	100.00%	100.00%	

Storage and Peaking

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

40					
41					
42	Supply Makeup	Residential	LLF C&I	HLF C&I	Total
43					
44	Pipeline	32.80%	18.41%	48.79%	100.00%
45	Storage	32.80%	60.77%	6.42%	100.00%
46	Peaking	32.80%	60.77%	6.42%	100.00%

Schedule 20

Provided in Summer 2011 Cost-of Gas Filing

Schedule 21

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

1 Total Fixed Capacity Costs To Be Allocated

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

13 Proportional Responsibility (PR) Allocators

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

16		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
17	Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
18	Rank	4	2	1	6	3	5	8	9	12	11	10	7	
19	% Max Month	96.85%	100.00%	100.00%	90.32%	98.51%	94.19%	86.61%	60.01%	51.03%	54.37%	58.89%	89.57%	
20	PR	0.66%	0.75%	0.00%	0.13%	0.55%	0.77%	3.32%	0.12%	4.25%	0.30%	0.45%	0.42%	11.74%
21	CumPR	10.44%	11.74%	11.74%	9.01%	11.00%	9.78%	8.46%	5.13%	4.25%	4.56%	5.01%	8.88%	100.00%
22	Product and Pipeline Demand Costs	\$ 728,959	\$ 819,550	\$ 819,550	\$ 628,551	\$ 767,521	\$ 682,593	\$ 590,239	\$ 358,201	\$ 296,825	\$ 318,012	\$ 349,555	\$ 619,771	\$ 6,979,327

24 Allocation of Storage Injection Fees to Months

25		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
26	Storage Injection Volume	-	-	-	-	-	5,234	554,104	556,770	575,329	574,118	556,770	551,826	3,374,152
27	Design Year Pipeline Sendout	699,251	721,983	721,983	652,114	711,219	680,066	625,280	433,252	368,464	392,573	425,203	646,665	7,078,052
28	% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	47.0%	56.2%	61.0%	59.4%	56.7%	46.0%	
29	Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,214	\$ 277,309	\$ 201,445	\$ 180,942	\$ 188,867	\$ 198,195	\$ 285,364	\$ 1,337,337

31 Allocation of Storage Demand Costs to Months

32		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
33	Design Year Storage	135,581	686,913	1,016,879	728,568	633,976	190,867	24,831	-	-	-	-	17,189	3,434,803
34	Rank	6	3	1	2	4	5	7	9	9	9	9	8	
35	% Max Month	13.33%	67.55%	100.00%	71.65%	62.35%	18.77%	2.44%	0.00%	0.00%	0.00%	0.00%	1.69%	
36	PR	1.82%	1.74%	28.35%	2.05%	10.89%	1.09%	0.11%	0.00%	0.00%	0.00%	0.00%	0.21%	46.25%
37	CumPR	2.13%	15.85%	46.25%	17.90%	14.12%	3.22%	0.32%	0.00%	0.00%	0.00%	0.00%	0.21%	100.00%
38	Storage Demand Costs	\$ 555,014	\$ 4,122,650	\$ 12,029,843	\$ 4,655,382	\$ 3,671,308	\$ 837,833	\$ 82,881	\$ -	\$ -	\$ -	\$ -	\$ 54,956	\$ 26,009,867
39	Plus Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,214	\$ 277,309	\$ 201,445	\$ 180,942	\$ 188,867	\$ 198,195	\$ 285,364	\$ 1,337,337
40	TOTAL	\$ 555,014	\$ 4,122,650	\$ 12,029,843	\$ 4,655,382	\$ 3,671,308	\$ 843,047	\$ 360,190	\$ 201,445	\$ 180,942	\$ 188,867	\$ 198,195	\$ 340,320	\$ 27,347,204

42 Allocation of Peaking Demand Costs to Months

43		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
44	Design Year Peaking Volumes	134,340	128,242	199,339	162,905	111,881	139,911	16,142	1,350	1,395	1,395	1,350	3,873	902,124
45	Rank	4	5	1	2	6	3	7	12	10	9	11	8	
46	% Max Month	67.39%	64.33%	100.00%	81.72%	56.13%	70.19%	8.10%	0.68%	0.70%	0.70%	0.68%	1.94%	
47	PR	0.76%	1.64%	18.28%	5.77%	8.00%	0.93%	0.88%	0.06%	0.00%	0.00%	0.00%	0.16%	36.48%
48	CumPR	11.50%	10.74%	36.48%	18.20%	9.10%	12.44%	1.09%	0.06%	0.06%	0.06%	0.06%	0.21%	100.00%
49	Peaking Demand Costs	\$ 708,782	\$ 661,665	\$ 2,247,566	\$ 1,121,516	\$ 560,532	\$ 766,178	\$ 67,359	\$ 3,477	\$ 3,616	\$ 3,616	\$ 3,477	\$ 13,189	\$ 6,160,974

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

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

Proportional Responsibility (PR) Allocators

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		

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		

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		

Allocation of Peaking Demand Costs to Months

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

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

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

57
58 **Capacity Cost Allocator based on Design Year Firm Sendout**

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

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

68
69 **Allocation of Demand Costs by Division**

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

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

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	TOTAL	
74 Maine														
75 Pipeline & Product Demand	\$ 385,430	\$ 427,642	\$ 416,381	\$ 317,362	\$ 384,317	\$ 346,105	\$ 296,160	\$ 164,826	\$ 169,851	\$ 181,339	\$ 177,185	\$ 335,173	\$ 3,601,771	51.61%
76 Storage Incl'd Injection Fees	\$ 293,458	\$ 2,151,205	\$ 6,111,892	\$ 2,350,551	\$ 1,838,315	\$ 427,462	\$ 180,730	\$ 92,695	\$ 103,540	\$ 107,697	\$ 100,462	\$ 184,046	\$ 13,942,053	50.98%
77 Peaking	\$ 374,762	\$ 345,258	\$ 1,141,900	\$ 566,265	\$ 280,672	\$ 388,487	\$ 33,798	\$ 1,600	\$ 2,069	\$ 2,062	\$ 1,762	\$ 7,133	\$ 3,145,768	51.06%
78 Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (2,644)	\$ (139,143)	\$ (92,695)	\$ (103,540)	\$ (107,697)	\$ (100,462)	\$ (154,325)	\$ (700,506)	
79 Capacity Release (Credit)	\$ (44,893)	\$ (44,304)	\$ (43,137)	\$ (42,870)	\$ (42,515)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (217,719)	51.28%
80 Asset Management - PNGTS (Credit)	\$ (187,717)	\$ (185,253)	\$ (180,375)	\$ (179,257)	\$ (177,771)	\$ (180,014)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,090,387)	51.19%
81 Total Allocated Demand	\$ 821,040	\$ 2,694,548	\$ 7,446,661	\$ 3,012,051	\$ 2,283,019	\$ 979,396	\$ 371,544	\$ 166,426	\$ 171,920	\$ 183,401	\$ 178,947	\$ 372,026	\$ 18,680,979	51.05%
82														
83 New Hampshire														
84 Pipeline & Product Demand	\$ 343,529	\$ 391,908	\$ 403,169	\$ 311,189	\$ 383,204	\$ 336,488	\$ 294,080	\$ 193,375	\$ 126,974	\$ 136,673	\$ 172,370	\$ 284,598	\$ 3,377,556	48.39%
85 Storage Incl'd Injection Fees	\$ 261,555	\$ 1,971,445	\$ 5,917,951	\$ 2,304,832	\$ 1,832,993	\$ 415,584	\$ 179,461	\$ 108,750	\$ 77,402	\$ 81,170	\$ 97,732	\$ 156,275	\$ 13,405,151	49.02%
86 Peaking	\$ 334,020	\$ 316,407	\$ 1,105,666	\$ 555,251	\$ 279,860	\$ 377,692	\$ 33,561	\$ 1,877	\$ 1,547	\$ 1,554	\$ 1,715	\$ 6,057	\$ 3,015,206	48.94%
87 Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (2,570)	\$ (138,166)	\$ (108,750)	\$ (77,402)	\$ (81,170)	\$ (97,732)	\$ (131,039)	\$ (636,830)	
88 Capacity Release	\$ (40,013)	\$ (40,602)	\$ (41,769)	\$ (42,036)	\$ (42,391)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (206,811)	48.72%
89 Asset Management - PNGTS (Credit)	\$ (167,310)	\$ (169,773)	\$ (174,652)	\$ (175,770)	\$ (177,256)	\$ (175,012)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,039,773)	48.81%
90 Total Allocated Demand	\$ 731,782	\$ 2,469,384	\$ 7,210,366	\$ 2,953,466	\$ 2,276,410	\$ 952,182	\$ 368,935	\$ 195,252	\$ 128,521	\$ 138,227	\$ 174,085	\$ 315,891	\$ 17,914,499	48.95%

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

50	Pipeline & Product Demand	LN 22
51	Storage	LN 40
52	Peaking	LN 49
53	Less: Injection Fees	-(LN 29)
54	Less: Capacity Release	LN 8 / 5
55	Less: Asset Management	(LN 9 + LN 7) / 6
56	Total Demand	Sum (LN 50 : LN 55)
57		
58	Capacity Cost Allocator based on Design Year Firm Sendout	
59		
60	Therms	
61	Maine	Company Analysis
62	New Hampshire	Company Analysis
63	Total	LN 61 + LN 62
64	Percentage of Total	
65	Maine	LN 61 / LN 63
66	New Hampshire	LN 62 / LN 63
67	Total	LN 65 + LN 66
68		
69	Allocation of Demand Costs by Division	
70	Maine	LN 56 * LN 65
71	New Hampshire	LN 56 * LN 66
72	Total	LN 70 + LN 71
73	Detailed Allocation of Demand Costs by Division	
74	Maine	
75	Pipeline & Product Demand	LN 50 * LN 65
76	Storage	LN 51 * LN 65
77	Peaking	LN 52 * LN 65
78	Injection Fees	LN 53 * LN 65
79	Capacity Release (Credit)	LN 54 * LN 65
80	Asset Management (Credit)	LN 55 * LN 65
81	Total Allocated Demand	Sum (LN 75 : LN 80)
82		
83	New Hampshire	
84	Pipeline & Product Demand	LN 50 * LN 66
85	Storage	LN 51 * LN 66
86	Peaking	LN 52 * LN 66
87	Injection Fees	LN 53 * LN 66
88	Capacity Release	LN 54 * LN 66
89	Asset Management (Credit)	LN 55 * LN 66
90	Total Allocated Demand	Sum (LN 84 : LN 89)

Schedule 22

Northern Utilities

ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
Supply Volumes - MMBtu								
Total Pipeline	499,368	256,695	197,401	162,786	371,174	573,323	3,444,961	2,060,747
Total Storage	0	571,056	896,418	747,336	490,230	2,536	2,707,576	2,707,576
Total Peaking	93,071	127,597	128,626	114,220	131,348	28,722	631,864	623,584
Subtotal	592,439	955,348	1,222,446	1,024,342	992,752	604,580	6,784,401	5,391,907
Less Interruptible - Maine	0	0	0	0	0	0	0	0
Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
Total Firm Supply	592,439	955,348	1,222,446	1,024,342	992,752	604,580	6,784,401	5,391,907
Total Firm Pipeline Sendout	499,368	256,695	197,401	162,786	371,174	573,323	3,444,961	2,060,747
Variable Costs								
Pipeline Costs Modeled in Sendout™	\$ 2,759,757	\$ 1,490,684	\$ 1,187,524	\$ 978,909	\$ 2,173,072	\$ 3,121,720	\$ 19,355,513	\$ 11,711,666
NYMEX Price Used for Forecast	\$4.905	\$5.172	\$5.337	\$5.306	\$5.210	\$5.018		
NYMEX Price Used for Update	\$4.025	\$4.359	\$4.543	\$4.538	\$4.472	\$4.399		
Increase/(Decrease) NYMEX Price	-\$0.880	-\$0.813	-\$0.794	-\$0.768	-\$0.738	-\$0.619		
Increase/(Decrease) in Pipeline Costs	\$ (439,444)	\$ (208,693)	\$ (156,737)	\$ (125,020)	\$ (273,927)	\$ (354,887)		
Total Updated Pipeline Costs	\$ 2,320,313	\$ 1,281,991	\$ 1,030,787	\$ 853,889	\$ 1,899,146	\$ 2,766,833	\$ 17,001,598	\$ 10,152,959
Total Pipeline	\$ 2,320,313	\$ 1,281,991	\$ 1,030,787	\$ 853,889	\$ 1,899,146	\$ 2,766,833	\$ 17,001,598	\$ 10,152,959
Total Storage	\$ -	\$ 2,485,349	\$ 3,913,239	\$ 3,258,653	\$ 2,142,377	\$ 11,880	\$ 11,811,500	\$ 11,811,500
Total Peaking	\$ 375,688	\$ 513,353	\$ 517,373	\$ 459,022	\$ 552,995	\$ 117,142	\$ 2,579,670	\$ 2,535,574
Subtotal	\$ 2,696,001	\$ 4,280,694	\$ 5,461,399	\$ 4,571,564	\$ 4,594,518	\$ 2,895,855	\$ 31,392,767	\$ 24,500,032
Hedging (Gain)/Loss Estimate								
Time Triggered NYMEX Contracts (Allocated between ME and NH)								
NYMEX NG Futures Contracts	7	8	4	5	5	9	46	38
Average Purchase Price	\$ 6.385	\$ 6.636	\$ 6.991	\$ 6.902	\$ 6.713	\$ 6.178		
NYMEX Price Used for Forecast	\$ 4.905	\$ 5.172	\$ 5.337	\$ 5.306	\$ 5.210	\$ 5.018		
NYMEX Price Used for Update	\$ 4.025	\$ 4.359	\$ 4.543	\$ 4.538	\$ 4.472	\$ 4.399		
Increase/(Decrease) NYMEX Price	\$ (0.880)	\$ (0.813)	\$ (0.794)	\$ (0.768)	\$ (0.738)	\$ (0.619)		
Futures Hedging (Gain)/Loss - Allocate	\$ 165,200	\$ 182,180	\$ 97,930	\$ 118,200	\$ 112,050	\$ 160,090	\$ 901,540	\$ 835,650
Price Triggered NYMEX Contracts (NH Only)								
NYMEX NG Futures Contracts	6	5	3	4	4	6	28	28
Average Purchase Price	\$ 6.260	\$ 6.647	\$ 6.983	\$ 6.825	\$ 6.730	\$ 6.200		
NYMEX Price Used for Forecast	\$ 4.905	\$ 5.172	\$ 5.337	\$ 5.306	\$ 5.210	\$ 5.018		
NYMEX Price Used for Update	\$ 4.025	\$ 4.359	\$ 4.543	\$ 4.538	\$ 4.472	\$ 4.399		
Increase/(Decrease) NYMEX Price	\$ (0.880)	\$ (0.813)	\$ (0.794)	\$ (0.768)	\$ (0.738)	\$ (0.619)		
Futures Hedging (Gain)/Loss (NH ONLY)	\$ 134,100	\$ 114,400	\$ 73,210	\$ 91,480	\$ 90,320	\$ 108,060	\$ 611,570	\$ 611,570
Interruptible Cost Estimate								
Variable Pipeline Costs Excl'd Hedges	\$ 2,320,313	\$ 1,281,991	\$ 1,030,787	\$ 853,889	\$ 1,899,146	\$ 2,766,833	\$ 17,001,598	\$ 10,152,959
Average Supply Cost (\$/MMBtu)	\$ 4.646	\$ 4.994	\$ 5.222	\$ 5.245	\$ 5.117	\$ 4.826		
Interruptible Cost - Maine	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Interruptible Cost - New Hampshire	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Firm Sales Pipeline Commodity Excl'd Hedge	\$ 2,320,313	\$ 1,281,991	\$ 1,030,787	\$ 853,889	\$ 1,899,146	\$ 2,766,833	\$ 17,001,598	\$ 10,152,959
Total Storage	\$ -	\$ 2,485,349	\$ 3,913,239	\$ 3,258,653	\$ 2,142,377	\$ 11,880	\$ 11,811,500	\$ 11,811,500
Total Peaking	\$ 375,688	\$ 513,353	\$ 517,373	\$ 459,022	\$ 552,995	\$ 117,142	\$ 2,579,670	\$ 2,535,574
Firm Sales Variable Costs Excl'd Hedge	\$ 2,696,001	\$ 4,280,694	\$ 5,461,399	\$ 4,571,564	\$ 4,594,518	\$ 2,895,855	\$ 31,392,767	\$ 24,500,032
Plus Hedging (Gain)/Loss	\$ 165,200	\$ 182,180	\$ 97,930	\$ 118,200	\$ 112,050	\$ 160,090	\$ 901,540	\$ 835,650
Total Firm Sales Variable Costs	\$ 2,861,201	\$ 4,462,874	\$ 5,559,329	\$ 4,689,764	\$ 4,706,568	\$ 3,055,945	\$ 32,294,307	\$ 25,335,682

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Schedule 6A, page 2
3	Total Storage	Schedule 6A, page 2
4	Total Peaking	Schedule 6A, page 2
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Schedule 6A, page 2
7	Less Interruptible - New Hampshire	Schedule 6A, page 2
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Schedule 6A, Page 1
12	NYMEX Price Used for Forecast	Schedule 6A
13	NYMEX Price Used for Update	Schedule 6A
14	Increase/(Decrease) NYMEX Price	LN 13 - LN 12
15	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 14
16	Total Updated Pipeline Costs	LN 15 + LN 11
17		
18	Total Pipeline	LN 16
19	Total Storage	Schedule 6A, page 2
20	Total Peaking	Schedule 6A, page 2
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)	
25	NYMEX NG Futures Contracts	Schedule 6A, Page 2
26	Average Purchase Price	Schedule 6A, Page 2
27	NYMEX Price Used for Forecast	Schedule 6A
28	NYMEX Price Used for Update	Company Analysis
29	Increase/(Decrease) NYMEX Price	LN 28 - LN 27
30	Futures Hedging (Gain)/Loss - Allocate	(LN 26 - LN 27 - LN 29) * LN 25*10,000
31	Price Triggered NYMEX Contracts (NH Only)	
32	NYMEX NG Futures Contracts	Schedule 6A, Page 2
33	Average Purchase Price	Schedule 6A, Page 2
34	NYMEX Price Used for Forecast	Schedule 6A, Page 2
35	NYMEX Price Used for Update	Company Analysis
36	Increase/(Decrease) NYMEX Price	LN 35 - LN 34
37	Futures Hedging (Gain)/Loss (NH ONLY)	(LN 33 - LN 34 - LN 36) * LN 32*10,000
38		
39	Interruptible Cost Estimate	
40	Variable Pipeline Costs Excl'd 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 Excl'd Hedge	LN 40 - LN 42 - LN 43
46	Total Storage	LN 19
47	Total Peaking	LN 20
48	Firm Sales Variable Costs Excl'd Hedge	Sum LN 45 : LN 47
49	Plus Hedging (Gain)/Loss	LN 30
50	Total Firm Sales Variable Costs	LN 48 + LN 49

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51 **Commodity Allocation Factors**

52 Firm Sales Sendout for Normal Winter, MMBtu

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	WINTER
54 Maine	280,388	471,420	569,668	468,815	454,818	278,040	3,157,582	2,523,149
55 New Hampshire	312,051	483,928	652,778	555,527	537,934	326,540	3,626,819	2,868,758
56 Total	592,439	955,348	1,222,446	1,024,342	992,752	604,580	6,784,401	5,391,907

58 Percentage of Total								
59 Maine	47.33%	49.35%	46.60%	45.77%	45.81%	45.99%	46.54%	46.80%
60 New Hampshire	52.67%	50.65%	53.40%	54.23%	54.19%	54.01%	53.46%	53.20%
61 Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

63 **Commodity Allocation by Jurisdiction**

64 **Maine**

65 Firm Sales Pipeline Commodity Excl'd Hedge	\$ 1,098,152	\$ 632,603	\$ 480,354	\$ 390,803	\$ 870,072	\$ 1,272,437	\$ 7,867,440	\$ 4,744,421
66 Hedging (Gains) Losses	\$ 78,185	\$ 89,897	\$ 45,636	\$ 54,097	\$ 51,334	\$ 73,624	\$ 423,275	\$ 392,774
67 Storage	\$ -	\$ 1,226,405	\$ 1,823,596	\$ 1,491,402	\$ 981,506	\$ 5,464	\$ 5,528,372	\$ 5,528,372
68 Peaking	\$ 177,804	\$ 253,316	\$ 241,099	\$ 210,083	\$ 253,349	\$ 53,872	\$ 1,209,364	\$ 1,189,523
69 Maine Interruptible	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
70 Total Maine Commodity Costs	\$ 1,354,142	\$ 2,202,222	\$ 2,590,685	\$ 2,146,385	\$ 2,156,261	\$ 1,405,397	\$ 15,028,451	\$ 11,855,090
71 Maine Inventory Finance Costs	\$ 864	\$ 1,629	\$ 2,027	\$ 1,646	\$ 1,562	\$ 855	\$ 8,583	\$ 8,583
72 Total Maine Variable Costs	\$ 1,355,006	\$ 2,203,851	\$ 2,592,712	\$ 2,148,031	\$ 2,157,823	\$ 1,406,252	\$ 15,037,034	\$ 11,863,674

73 **New Hampshire**

74 Firm Sales Pipeline Commodity Excl'd Hedge	\$ 1,222,161	\$ 649,388	\$ 550,433	\$ 463,086	\$ 1,029,074	\$ 1,494,396	\$ 9,134,158	\$ 5,408,538
75 Hedging (Gains) Losses	\$ 221,115	\$ 206,683	\$ 125,504	\$ 155,583	\$ 151,036	\$ 194,526	\$ 1,089,835	\$ 1,054,446
76 Storage	\$ -	\$ 1,258,945	\$ 2,089,644	\$ 1,767,251	\$ 1,160,872	\$ 6,417	\$ 6,283,128	\$ 6,283,128
77 Peaking	\$ 197,883	\$ 260,037	\$ 276,274	\$ 248,940	\$ 299,647	\$ 63,270	\$ 1,370,306	\$ 1,346,050
78 New Hampshire Interruptible	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
79 Total New Hampshire Commodity Costs	\$ 1,641,159	\$ 2,375,052	\$ 3,041,855	\$ 2,634,860	\$ 2,640,628	\$ 1,758,608	\$ 17,877,426	\$ 14,092,162
80 New Hampshire Inventory Finance Costs	\$ 970	\$ 1,697	\$ 2,423	\$ 2,042	\$ 1,929	\$ 1,032	\$ 10,094	\$ 10,094
81 Total New Hampshire Variable Costs	\$ 1,642,129	\$ 2,376,749	\$ 3,044,278	\$ 2,636,902	\$ 2,642,557	\$ 1,759,640	\$ 17,887,520	\$ 14,102,256

82 **Northern Utilities**

83 Firm Sales Pipeline Commodity Excl'd Hedge	\$ 2,320,313	\$ 1,281,991	\$ 1,030,787	\$ 853,889	\$ 1,899,146	\$ 2,766,833	\$ 17,001,598	\$ 10,152,959
84 Hedging (Gains) Losses	\$ 299,300	\$ 296,580	\$ 171,140	\$ 209,680	\$ 202,370	\$ 268,150	\$ 1,513,110	\$ 1,447,220
85 Storage	\$ -	\$ 2,485,349	\$ 3,913,239	\$ 3,258,653	\$ 2,142,377	\$ 11,880	\$ 11,811,500	\$ 11,811,500
86 Peaking	\$ 375,688	\$ 513,353	\$ 517,373	\$ 459,022	\$ 552,995	\$ 117,142	\$ 2,579,670	\$ 2,535,574
87 Northern Interruptible	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
88 Total Northern Commodity Costs	\$ 2,995,301	\$ 4,577,274	\$ 5,632,539	\$ 4,781,244	\$ 4,796,888	\$ 3,164,005	\$ 32,905,877	\$ 25,947,252
89 Northern Inventory Finance Costs	\$ 1,834	\$ 3,326	\$ 4,451	\$ 3,688	\$ 3,491	\$ 1,887	\$ 18,677	\$ 18,677
90 Total Northern Variable Costs	\$ 2,997,135	\$ 4,580,600	\$ 5,636,990	\$ 4,784,932	\$ 4,800,380	\$ 3,165,892	\$ 32,924,554	\$ 25,965,929

91

Northern Utilities

ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51 Commodity Allocation Factors

52 Firm Sales Sendout for Normal Winter, MMBtu

53		
54	Maine	ME Attachment NUI-JDS-4, LN 33 / 10
55	New Hampshire	Company Analysis
56	Total	LN 54 + LN 55

57		
58	Percentage of Total	
59	Maine	LN 54 / LN 56
60	New Hampshire	LN 55 / LN 56
61	Total	LN 59 + LN 60

63 Commodity Allocation by Jurisdiction

64 Maine

65	Firm Sales Pipeline Commodity Excl'd 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 Excl'd Hedge	LN 45 * LN 60
75	Hedging (Gains) Losses	LN 30 * LN 60 + LN 37
76	Storage	LN 46 * LN 60
77	Peaking	LN 47 * LN 60
78	New Hampshire Interruptible	LN 43
79	Total New Hampshire Commodity Costs	Sum LN 74 : LN 78
80	New Hampshire Inventory Finance Costs	LN 117
81	Total New Hampshire Variable Costs	LN 79 + LN 80

82 Northern Utilities

83	Firm Sales Pipeline Commodity Excl'd 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

92 **Northern Utilities**
93 **Simplified Market Based Allocator (MBA) Calculations**
94 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**

	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
97									
98	Inventory Finance Charge								
99		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	TOTAL	
100	Storage	\$ 1,793	\$ 1,793	\$ 1,514	\$ 1,091	\$ 739	\$ 663	\$ 17,542	
101	Peaking	\$ 140	\$ 138	\$ 128	\$ 124	\$ 113	\$ 104	\$ 1,135	
102	Total	\$ 1,933	\$ 1,931	\$ 1,642	\$ 1,214	\$ 853	\$ 767	\$ 18,677	
103	Inventory Finance Charge Allocation by Jurisdiction								
104	Maine	\$ 915	\$ 953	\$ 765	\$ 556	\$ 391	\$ 353	\$ 8,583	
105	New Hampshire	\$ 1,018	\$ 978	\$ 877	\$ 658	\$ 462	\$ 414	\$ 10,094	
106	Total	\$ 1,933	\$ 1,931	\$ 1,642	\$ 1,214	\$ 853	\$ 767	\$ 18,677	
107									
108	Inventory Finance Charge Allocation by Month								
109	Maine								
110	Firm Sales Normal Remaining Sendout	213,227	402,021	500,269	406,132	385,419	210,879	2,117,945	2,117,945
111	Monthly % Sendout of Total Winter	10.07%	18.98%	23.62%	19.18%	18.20%	9.96%	100.00%	100.00%
112	ME Allocated Inventory Finance Charge	\$ 864	\$ 1,629	\$ 2,027	\$ 1,646	\$ 1,562	\$ 855	\$ 8,583	\$ 8,583
113									
114	New Hampshire								
115	Firm Sales Normal Remaining Sendout	225,402	394,163	562,921	474,361	448,225	239,824	2,344,895	2,344,895
116	Monthly % Sendout of Total Winter	9.61%	16.81%	24.01%	20.23%	19.11%	10.23%	100.00%	100.00%
117	NH Allocated Inventory Finance Charge	\$ 970	\$ 1,697	\$ 2,423	\$ 2,042	\$ 1,929	\$ 1,032	\$ 10,094	\$ 10,094

Northern Utilities

ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

92 **Northern Utilities**

93 **Simplified Market Based Allocator (MBA) Calculations**

94 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**

95

96

97

98	Inventory Finance Charge	
99	Storage	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
100	Peaking	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
101	Total	Sum LN 99 : LN 100

102

103	Inventory Finance Charge Allocation by Jurisdiction	
104	Maine	LN 101 * LN 59
105	New Hampshire	LN 101 * LN 60
106	Total	Sum LN 104 : LN 105

107

108 **Inventory Finance Charge Allocation by Month**

109 **Maine**

110	Firm Sales Remaining Sendout	ME Attachment NUI-JDS-4, LN 80 / 10
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 Col N
112	ME Allocated Inventory Finance Charge	LN 104 Col N * LN 111

113

114 **New Hampshire**

115	Firm Sales Remaining Sendout	Company Analysis
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Schedule 23

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

		Winter	Summer	Total	
1	Demand	\$ 13,712,022	\$ 1,077,843	\$ 14,789,865	Schedule 1A, LN 80
2	Commodity	\$ 14,102,256	\$ 3,785,265	\$ 17,887,520	Schedule 1B, LN 0
3	Total	\$ 27,814,277	\$ 4,863,108	\$ 32,677,385	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,028,950	7,400,642	35,429,591	Schedule 10B, LN 11 * 10
6	Forecasted Residential Sales (Therms)	13,035,240	3,274,690	16,309,931	Schedule 10B, LN 3 * 10
7	Average Residential Rate:	Winter	Summer	Total	
8	Average Demand Rate	\$0.4892	\$0.1456		LN 1 / LN 5
9	Average Commodity Rate	\$0.5031	\$0.5115		LN 2 / LN 5
10	Average Rate	\$0.9923	\$0.6571		LN 3 / LN 5
11					
12	Residential Reallocation:	Winter	Summer	Total	
13	Demand Costs Allocated To Residential per SMBA	\$ 6,503,781	\$ 509,014	\$ 7,012,796	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	\$ 6,376,960	\$ 476,795	\$ 6,853,755	LN 8 * LN 6
15	Demand Reallocation:	\$ 126,821	\$ 32,219	\$ 159,040	LN 13 - LN 14
16	HLF Allocation	\$ 12,540	\$ 8,067	\$ 20,607	LN 15 / LN 20
17	LLF Allocation	\$ 114,281	\$ 24,152	\$ 138,433	LN 15 / LN 21
18					
19	SMBA Capacity Cost Allocation (%)				
20	HLF	9.89%	25.04%		Schedule 10A, LN 173
21	LLF	90.11%	74.96%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	\$ 6,566,201	\$ 1,673,007	\$ 8,239,208	Schedule 10A, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	\$ 6,558,444	\$ 1,675,004	\$ 8,233,448	LN 18 * LN 16
25	Commodity Reallocation:	\$ 7,757	\$ (1,997)	\$ 5,760	LN 23 - LN 24
26	HLF Allocation	\$ 1,419	\$ (885)	\$ 535	LN 25 / LN 30
27	LLF Allocation	\$ 6,338	\$ (1,112)	\$ 5,226	LN 25 / LN 31
28					
29	SMBA Commodity Cost Allocation (%)				
30	HLF	18.30%	44.30%		Schedule 10C, LN 143
31	LLF	81.70%	55.70%		Schedule 10C, LN 144