Schedules 1A and 1B

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

NH Division Total Annual Demand Cost Allocation

Line		
1	**Resource**	**Costs**
2	Pipeline & Product Demand	$ 4,010,433
3	Storage	$ 14,466,973
4	Peaking	$ 1,213,889
5	Total Gross Demand Cost	$ 19,691,296
6		
7	Capacity Assignment Demand Revenue Estimate	$ 4,618,096
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 19,691,296
9	Capacity Assignment as % of Total Gross Demand Cost	23.45%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 940,546
14	Storage	$ 3,392,863
15	Peaking	$ 284,687
16	Total Capacity Assignment Credit	$ 4,618,096
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 3,069,887
21	Storage	$ 11,074,110
22	Peaking	$ 929,202
23	Total Net Demand Cost (Less Capacity Assignment)	$ 15,073,200
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,201
28	Less 23.45% NH Transp. Capacity Assignment	(2,627)
29	Net Pipeline MDQ	8,574
30		
31	Net Pipeline MDQ	8,574
32	Less: Firm Sales Base Use	3,517
33	Remaining Pipeline MDQ	5,057
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$358.03
37		
38		**Costs**
39	Pipeline & Product Demand	$ 3,069,887
40	Less: Base Pipeline Use	$ 1,259,223
41	Remaining Pipeline Use	$ 1,810,664

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

NH Division Total Annual Demand Cost Allocation

1	**Resource**	
2	Pipeline & Product Demand	Schedule 21, LN 84 + Schedule 21, LN 87
3	Storage	Schedule 21, LN 85
4	Peaking	Schedule 21, LN 86
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Schedule 5B, Page 1
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		
13	Pipeline & Product Demand	LN 2 * LN 9
14	Storage	LN 3 * LN 9
15	Peaking	LN 4 * LN 9
16	Total Capacity Assignment Credit	Sum (LN 13 : LN 15)
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		
20	Pipeline & Product Demand	LN 2 - LN 13
21	Storage	LN 3 - LN 14
22	Peaking	LN 4 - LN 15
23	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 16
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 23.45% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

All Months	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for All Months	2,477,390	4,103,796	4,877,822	4,218,975	3,457,242	1,974,053
Rank	5	3	1	2	4	6
% Max Month	50.79%	84.13%	100.00%	86.49%	70.88%	40.47%
PR	2.06%	4.42%	13.51%	1.18%	5.02%	4.40%
CumPR	8.30%	17.74%	32.43%	18.92%	13.32%	6.24%

Peak Months Only	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for Peak Months Only	2,477,390	4,103,796	4,877,822	4,218,975	3,457,242	1,974,053
Rank	5	3	1	2	4	6
% Max Month	50.79%	84.13%	100.00%	86.49%	70.88%	40.47%
PR	2.06%	4.42%	13.51%	1.18%	5.02%	6.74%
CumPR	8.81%	18.25%	32.94%	19.43%	13.83%	6.74%

DEMAND COST PR ALLOCATORS

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

DEMAND COSTS ALLOCATED TO MONTHS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Pipeline - Base	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 104,935
Pipeline - Remaining	$ 150,315	$ 321,247	$ 587,190	$ 342,624	$ 241,246	$ 112,947
Total Pipeline	$ 255,250	$ 426,182	$ 692,126	$ 447,559	$ 346,181	$ 217,882
Storage & Peaking	$ 996,471	$ 2,129,620	$ 3,892,621	$ 2,271,335	$ 1,599,274	$ 748,749
Less Credits to Demand Cost						
Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ 192,098	$ 397,968	$ 718,270	$ 423,715	$ 301,615	$ 147,092
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
Total Direct Demand Costs	$ 1,059,623	$ 2,157,834	$ 3,866,477	$ 2,295,180	$ 1,643,840	$ 819,539

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

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

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

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

51

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

58
59 **DEMAND COST PR ALLOCATORS**

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

66
67 **DEMAND COSTS ALLOCATED TO MONTHS**

		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer	Summer
68		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**	**Summer**
69	Pipeline - Base	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 1,259,223	$ 629,612	$ 629,612	50.00%
70	Pipeline - Remaining	$ 13,531	$ 2,229	$ -	$ 582	$ 5,558	$ 33,196	$ 1,810,664	$ 1,755,569	$ 55,095	3.04%
71	Total Pipeline	$ 118,466	$ 107,164	$ 104,935	$ 105,517	$ 110,493	$ 138,131	$ 3,069,887	$ 2,385,180	$ 684,707	22.30%
72											
73	Storage & Peaking	$ 89,700	$ 14,774	$ -	$ 3,857	$ 36,846	$ 220,065	$ 12,003,312	$ 11,638,072	$ 365,241	3.042832%
74											
75	Less Credits to Demand Cost										
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	$ -	$ -	$ -	$ -	$ -	$ -	$2,180,758	$ 2,180,758	$ -	$ 420,336
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
79											
80	Total Direct Demand Costs	$ 208,167	$ 121,937	$ 104,935	$ 109,374	$ 147,339	$ 358,196	$ 12,892,441	$ 11,842,494	$ 1,049,948	8.14%
81											
82	Indirect Demand Costs/(Credits)										
83	Miscellaneous Overhead							$ 411,600	$ 321,744	$ 89,856	21.83%
84	Local Production & Storage							$ 307,762	$ 307,762	$ -	0.00%
85	Subtotal							$ 719,362	$ 629,506	$ 89,856	12.49%

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**	
46	Remaining Load for All Months	Schedule 10B, LN 80
47	Rank	Rank LN 46
48	% Max Month	LN 46 / MAX Month LN 46
49	PR	The difference between LN 48 for the month and LN 48 for next highest rank
50	CumPR	Cumulative Values, LN 49
51		
52	**Peak Months Only**	
53	Remaining Load for Peak Months Only	LN 46
54	Rank	Rank LN 53
55	% Max Month	LN 53 / MAX Month LN 53
56	PR	The difference between LN 55 for the month and LN 55 for next highest rank
57	CumPR	Cumulative Values, LN 56
58		
59	**DEMAND COST PR ALLOCATORS**	
60		
61	Pipeline - Base	1/12
62	Pipeline - Remaining	LN 50
63	Storage & Peaking	LN 50
64	Capacity Release	LN 57
65	Interr. Margins & Off Sys Sales	LN 57
66		
67	**DEMAND COSTS ALLOCATED TO MONTHS**	
68		
69	Pipeline - Base	LN 40 * LN 61
70	Pipeline - Remaining	LN 41 * LN 62
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & Peaking	LN 63 * (Sum LN 21 : LN 22)
74		
75	Less Credits to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit net of PNGTS expense	Schedule 1A, Page 6, Line 6
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79		
80	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 78)
81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

New Hampshire PNGTS Refund, Litigation Costs and Asset Management

		Total	
1	Asset Management	($2,233,221)	Schedule 21, Line 89
2	Capacity Release Revenues	($99,458)	Schedule 21, Line 88
3	PNGTS Litigation	$151,922	Schedule 5A
4	PNGTS Refund	$0	
5	PNGTS litigation net of Refund	$151,922	
6	Total NH Cap Rel and Asset Management	($2,180,758)	Sum(D1 + D2 + D5)

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

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	1,397,318	1,109,824	1,065,826	1,100,273	1,190,350	1,768,019	25,950,506	7,631,609
2	New Hampshire Sales Storage	0	0	0	0	0	0	9,115,351	0
3	New Hampshire Sales Peaking	7,141	6,928	7,249	7,288	7,119	7,320	84,069	43,045
4	Total New Hampshire Firm Sales Sendout	1,404,459	1,116,751	1,073,076	1,107,560	1,197,469	1,775,339	35,149,926	7,674,654
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	1,404,459	1,116,751	1,073,076	1,107,560	1,197,469	1,775,339	35,149,926	7,674,654
9	Total Firm Sales	1,395,526	1,109,630	1,066,236	1,100,496	1,189,842	1,764,179	34,931,833	7,625,909
10	Difference (LAUF & Company Use)	8,933	7,121	6,839	7,065	7,627	11,160	218,093	48,745
11	Percent Difference	0.64%	0.64%	0.64%	0.64%	0.64%	0.63%	0.62%	0.64%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 520,728	$ 417,167	$ 406,397	$ 422,692	$ 458,539	$ 695,133	$ 11,037,664	$ 2,920,655
15	New Hampshire Hedging (Gains) Losses	$ (394)	$ -	$ -	$ -	$ -	$ (1,270)	$ 653,291	$ (1,664)
16	New Hampshire Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,163,020	$ -
17	New Hampshire Total Peaking	$ 3,600	$ 3,499	$ 3,674	$ 3,696	$ 3,624	$ 3,740	$ 41,470	$ 21,832
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,581	$ -
19	Total New Hampshire Sales Variable Costs	$ 523,934	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 697,603	$ 14,900,025	$ 2,940,823
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 524,328	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 698,872	$ 14,246,735	$ 2,942,487
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 523,934	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 697,603	$ 14,900,025	$ 2,940,823
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.3727	$ 0.3759	$ 0.3813	$ 0.3842	$ 0.3852	$ 0.3932	$ 0.4253	$ 0.3827
27	New Hampshire Hedging (Gains) Losses	$ (0.0003)	$ -	$ -	$ -	$ -	$ (0.0007)	$ 0.0252	$ (0.0002)
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.3470	$ -
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.5041	$ 0.5050	$ 0.5068	$ 0.5071	$ 0.5090	$ 0.5109	$ 0.4933	$ 0.5072
30	New Hampshire Inventory Finance Costs per Dth Stor and F	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0005	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.3731	$ 0.3767	$ 0.3821	$ 0.3850	$ 0.3859	$ 0.3929	$ 0.4239	$ 0.3832
32									
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	1,090,300	1,055,129	1,073,060	1,090,300	1,055,129	1,090,300	12,820,158	6,454,216
37	Base Commodity Cost Excld Hedging	$ 406,314	$ 396,608	$ 409,155	$ 418,860	$ 406,450	$ 428,674	$ 5,316,990	$ 2,466,061
38	Base Hedging Commodity Cost	$ (308)	$ -	$ -	$ -	$ -	$ (783)	$ 247,233	$ (1,091)
39	Remaining Commodity Excld Hedging	$ 118,014	$ 24,058	$ 916	$ 7,527	$ 55,713	$ 270,199	$ 8,929,745	$ 476,427
40	Remaining Hedging Commodity	$ (87)	$ -	$ -	$ -	$ -	$ (487)	$ 406,058	$ (573)
41	Total Commodity Excld Hedging	$ 524,328	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 698,872	$ 14,246,735	$ 2,942,487
42	Total Hedging	$ (394)	$ -	$ -	$ -	$ -	$ (1,270)	$ 653,291	$ (1,664)
43	Total Commodity (Incl Hedging)	$ 523,934	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 697,603	$ 14,900,025	$ 2,940,823

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

Schedule 2

Estimated Delivered City-Gate Commodity Costs and Volumes May 2013 through October 2013			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tenn Zone 4 Spot	$1,542,326	405,092	$3.807
Tennessee Production	$3,374,038	886,129	$3.808
Algonquin Receipts	$259,521	67,000	$3.873
Chicago	$426,425	106,159	$4.017
PNGTS	$10,563	2,572	$4.107
TGP Zone 6	$2,707	656	$4.126
LNG	$41,993	8,280	$5.072
Total Delivered Commodity Cost	$5,657,572	1,475,889	$3.833

Schedules 3A &3B

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

Line			Winter						Summer						
	Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total
2	Residential Heat & Non Heat								632,241	502,447	482,800	498,318	538,884	799,875	3,454,565
3	Sales HLF Classes								288,051	229,511	220,532	227,609	245,897	363,065	1,574,665
4	Sales LLF Classes								475,234	377,673	362,904	374,569	405,061	601,239	2,596,680
5	Total								1,395,526	1,109,630	1,066,236	1,100,496	1,189,842	1,764,179	7,625,909
6	Rates														
7	Residential Heat & Non Heat CGA								$0.5553	$0.5553	$0.5553	$0.5553	$0.5553	$0.5553	
8	Sales HLF Classes CGA								$0.5180	$0.5180	$0.5180	$0.5180	$0.5180	$0.5180	
9	Sales LLF Classes CGA								$0.5780	$0.5780	$0.5780	$0.5780	$0.5780	$0.5780	
10	Revenues														
11	Residential Heat & Non Heat								$ (351,083)	$ (279,009)	$ (268,099)	$ (276,716)	$ (299,242)	$ (444,171)	$ (1,918,320)
12	Sales HLF Classes								$ (149,211)	$ (118,887)	$ (114,235)	$ (117,901)	$ (127,375)	$ (188,068)	$ (815,676)
13	Sales LLF Classes								$ (274,685)	$ (218,295)	$ (209,759)	$ (216,501)	$ (234,125)	$ (347,516)	$ (1,500,881)
14	Total Sales								$ (774,979)	$ (616,190)	$ (592,093)	$ (611,118)	$ (660,742)	$ (979,754)	$ (4,234,877)
15															
16			Winter						Summer						
17	**Gas Costs and Credits**		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18		Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline								$ 114,118	$ 114,118	$ 114,118	$ 114,118	$ 114,118	$ 114,118	$ 684,707
21	Storage								$ 55,982	$ 55,982	$ 55,982	$ 55,982	$ 55,982	$ 55,982	$ 335,895
22	Peaking								$ 4,891	$ 4,891	$ 4,891	$ 4,891	$ 4,891	$ 4,891	$ 29,346
24	Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 174,991	$ 174,991	$ 174,991	$ 174,991	$ 174,991	$ 174,991	$ 1,049,948
25	NUI Commodity Costs														
26	NUI Total Pipeline Volumes								272,954	216,268	205,096	210,609	225,732	336,950	1,467,609
27	Pipeline Costs Modeled in Sendout™								$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 5,615,579
28	NYMEX Price Used for Forecast								$ 3.4710	$ 3.6960	$ 3.3540	$ 3.2260	$ 3.4270	$ 3.4860	
29	NYMEX Price Used for Update								$ 3.5310	$ 3.5790	$ 3.6340	$ 3.6620	$ 3.6670	$ 3.6990	
30	Increase/(Decrease) NYMEX Price														
31	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
32	Updated Pipeline Costs								$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 3.73	$ 3.76	$ 3.81	$ 3.84	$ 3.85	$ 3.93	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	
37	New Hampshire Allocated Percentage								51.19%	51.32%	51.97%	52.24%	52.73%	52.47%	
38	NH Updated Pipeline Costs								$ 520,728	$ 417,167	$ 406,397	$ 422,692	$ 458,539	$ 695,133	$ 2,920,655
39	Hedging (Gain)/Loss Estimate														
40	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
41	NYMEX NG Futures Contracts								11	0	0	0	0	11	
42	Average Purchase Price								$ 3.5240	$ -	$ -	$ -	$ -	$ 3.6770	
43	NYMEX Price Used for Forecast								$ 3.4710	$ 3.6960	$ 3.3540	$ 3.2260	$ 3.4270	$ 3.4860	
44	NYMEX Price Used for Update								$ 3.5310	$ 3.5790	$ 3.6340	$ 3.6620	$ 3.6670	$ 3.6990	
45	Increase/(Decrease) NYMEX Price								0.0600	(0.1170)	0.2800	0.4360	0.2400	0.2130	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ (770)	$ -	$ -	$ -	$ -	$ (2,420)	$ (3,190)
47	New Hampshire Allocated Percentage								51.19%	51.32%	51.97%	52.24%	52.73%	52.47%	
48	NH Futures Hedging (Gain)/Loss, Time Triggered								$ (394)	$ -	$ -	$ -	$ -	$ (1,270)	$ (1,664)
49	Price Triggered NYMEX Contracts (NH Only)														
50	NYMEX NG Futures Contracts								0	0	0	0	0	0	
51	Average Purchase Price								$ -	$ -	$ -	$ -	$ -	$ -	
52	NYMEX Price Used for Forecast								$ 3.4710	$ 3.6960	$ 3.3540	$ 3.2260	$ 3.4270	$ 3.4860	
53	NYMEX Price Used for Update								$ 3.5310	$ 3.5790	$ 3.6340	$ 3.6620	$ 3.6670	$ 3.6990	
54	Increase/(Decrease) NYMEX Price								0.0600	(0.1170)	0.2800	0.4360	0.2400	0.2130	
55	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	New Hampshire Allocated Percentage								100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
57	NH Futures Hedging (Gain)/Loss, Price Triggered								$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	NH Commodity Costs														
59	Pipeline Excl Hedging								$ 520,728	$ 417,167	$ 406,397	$ 422,692	$ 458,539	$ 695,133	$ 2,920,655
60	Hedging (Gain)/Loss Estimate								$ (394)	$ -	$ -	$ -	$ -	$ (1,270)	$ (1,664)
61	Storage								$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Peaking								$ 3,600	$ 3,499	$ 3,674	$ 3,696	$ 3,624	$ 3,740	$ 21,832
63	Total Commodity Costs								$ 523,934	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 697,603	$ 2,940,823

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

64	Inventory Finance Charge														$ -
65	Asset Management and Capacity Release														
66	NUI AMA Revenue														$ -
67	PNGTS Litigation Cost														$ -
68	NUI Capacity Release														$ -
69	NUI AMA Rev & Cap. Release Subtotal														$ -
70	NH AMA Revenue														$ -
71	NH Capacity Release														$ -
72	NH Total Asset Management and Capacity Release		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73															
74	**Total Anticipated Direct Cost of Gas**		$ -	$ -	$ -	$ -	$ -	$ -	$ 698,925	$ 595,657	$ 585,062	$ 601,379	$ 637,154	$ 872,594	$ 3,990,771
75					Winter							Summer			
76			(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 698,925	$ 595,657	$ 585,062	$ 601,379	$ 637,154	$ 872,594	$ 3,990,771
80	Working Capital Percentage		0.0824%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
81	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -	$ -	$ 576	$ 491	$ 482	$ 495	$ 525	$ 719	$ 3,287
82	Beginning Period Working Capital Balance		$ 1,289	$ 1,291	$ 1,294	$ 1,296	$ 1,298	$ 1,301	$ 1,303	$ 1,882	$ 2,376	$ 2,863	$ 3,364	$ 3,895	
83	End of Period Working Capital Allowance		$ 1,289	$ 1,291	$ 1,294	$ 1,296	$ 1,298	$ 1,301	$ 1,879	$ 2,372	$ 2,858	$ 3,358	$ 3,889	$ 4,614	
84	Interest		$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 3	$ 4	$ 5	$ 6	$ 7	$ 8	$ 46
85	End of period with Interest	$ 1,289	$ 1,291	$ 1,294	$ 1,296	$ 1,298	$ 1,301	$ 1,303	$ 1,882	$ 2,376	$ 2,863	$ 3,364	$ 3,895	$ 4,622	
86	Bad Debt														
92	Projected Bad Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,110	$ 3,110	$ 3,110	$ 3,110	$ 3,110	$ 3,110	$ 18,660
93	Beginning Period Bad Debt Balance		$ (19,277)	$ (19,312)	$ (19,347)	$ (19,383)	$ (19,418)	$ (19,453)	$ (19,489)	$ (16,411)	$ (13,328)	$ (10,240)	$ (7,145)	$ (4,045)	
94	End of Period Bad Debt Balance		***$ (19,277)***	***$ (19,312)***	***$ (19,347)***	***$ (19,383)***	***$ (19,418)***	***$ (19,453)***	***$ (16,379)***	***$ (13,301)***	***$ (10,218)***	***$ (7,130)***	***$ (4,035)***	***$ (935)***	
95	Interest		$ (35)	$ (35)	$ (35)	$ (35)	$ (35)	$ (35)	$ (33)	$ (27)	$ (21)	$ (16)	$ (10)	$ (5)	$ (323)
96	End of Period Bad Debt Balance with Interest	$ (19,277)	$ (19,312)	$ (19,347)	$ (19,383)	$ (19,418)	$ (19,453)	$ (19,489)	$ (16,411)	$ (13,328)	$ (10,240)	$ (7,145)	$ (4,045)	$ (940)	
97	Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
99	Miscellaneous Overhead								$ 14,976	$ 14,976	$ 14,976	$ 14,976	$ 14,976	$ 14,976	$ 89,856
100	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
101	Beginning Balance Over/Under Collection		$ 147,647	$ 147,916	$ 148,185	$ 148,455	$ 148,726	$ 148,997	$ 149,268	$ 88,406	$ 83,005	$ 91,109	$ 96,516	$ 88,072	$ 1,486,304
102	Net Costs - Revenues		$ -	$ -	$ -	$ -	$ -	$ -	$ (61,078)	$ (5,557)	$ 7,945	$ 5,237	$ (8,612)	$ (92,184)	$ (154,250)
103	Ending Balance before Interest		$ 147,647	$ 147,916	$ 148,185	$ 148,455	$ 148,726	$ 148,997	$ 88,190	$ 82,849	$ 90,951	$ 96,346	$ 87,904	$ (4,112)	$ 1,332,054
104	Average Balance		$ 147,647	$ 147,916	$ 148,185	$ 148,455	$ 148,726	$ 148,997	$ 118,729	$ 85,628	$ 86,978	$ 93,727	$ 92,210	$ 41,980	$ 1,409,179
105	Interest Rate		2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
106	Interest Expense		$ 269	$ 269	$ 270	$ 270	$ 271	$ 271	$ 216	$ 156	$ 158	$ 171	$ 168	$ 76	$ 2,567
108	Ending Balance Incl Interest Expense	$ 147,647	$ 147,916	$ 148,185	$ 148,455	$ 148,726	$ 148,997	$ 149,268	$ 88,406	$ 83,005	$ 91,109	$ 96,516	$ 88,072	$ (4,036)	
109	**Total Over/Under Collection Ending Balance**	$ 129,659	$ 129,895	$ 130,132	$ 130,369	$ 130,606	$ 130,844	$ 131,083	$ 73,877	$ 72,053	$ 83,732	$ 92,735	$ 87,922	$ (354)	
110															
111	**Total Indirect Cost of Gas**	$ 129,659	$ 236	$ 237	$ 237	$ 238	$ 238	$ 238	$ 18,848	$ 18,709	$ 18,710	$ 18,742	$ 18,775	$ 18,884	$ 243,752
112															
113	**Total Cost of Gas**	$ 129,659	$ 236	$ 237	$ 237	$ 238	$ 238	$ 238	$ 717,773	$ 614,366	$ 603,772	$ 620,121	$ 655,929	$ 891,478	$ 4,234,523
114															
115	**Total Interest**	$ -	$ 236	$ 237	$ 237	$ 238	$ 238	$ 238	$ 187	$ 133	$ 142	$ 161	$ 164	$ 80	$ 2,290

Northern Utilities Inc.
Calculation of Bad Debt Expense

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

Schedules 4

Reserved for Future Use

Schedules 5A & Attachments, 5B and 5C

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2012 through October 31, 2013			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 9,964,773	Sch 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 26,827,274	Sch 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,035,662	Sch 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,728,786	Sch 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 880,250	Sch 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (5,023,450)	Sch 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 37,413,294	Sum Lines 1 through 6.

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

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

Total Annual Demand Costs $ 38,520,832

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

Pipeline	Contract ID	MDQ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Algonquin	93002F	4,211	4,211			100%	0%	0%	$ 308,943	$ 308,943	$ -	$ -
Algonquin	93201A1C	1,251	1,251			100%	0%	0%	$ 98,680	$ 98,680	$ -	$ -
Granite	10-010-FT-NN	100,000	21,326	35,529	43,145	21%	36%	43%	$ 2,962,170	$ 631,712	$ 1,052,429	$ 1,278,028
Granite	10-010-FT-NN	100,000	21,326	35,529	43,145	21%	36%	43%	$ 1,044,750	$ 222,803	$ 371,189	$ 450,757
Iroquois	R181001	6,569	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	1,100			100%	0%	0%	$ 531,242	$ 531,242	$ -	$ -
PNGTS	1997-004	33,000		33,000		0%	100%	0%	$ 12,616,989	$ -	$ 12,616,989	$ -
Tennessee	5083	4,605	4,605			100%	0%	0%	$ 1,351,367	$ 1,351,367	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 2,225,558	$ 2,225,558	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 270,275	$ -	$ 270,275	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 125,521	$ 125,521	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 198,727	$ 198,727	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 82,937	$ 82,937	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 380,937	$ 380,937	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 66,747	$ 66,747	$ -	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 12,126,617	$ -	$ 12,126,617	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 867,809	$ 867,809	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 181,905	$ 181,905	$ -	$ -
Vector	CRL-NUI-0725	17,172	17,172			100%	0%	0%	$ 1,566,952	$ 1,566,952	$ -	$ -
Vector	CRL-NUI-0727	17,086		17,086		0%	100%	0%	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	6,070	-		100%	0%	0%	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,070	6,070	-		100%	0%	0%	$ 36,602	$ 36,602	$ -	$ -
Annual Total Demand Costs									$ 38,520,832	$ 9,964,773	$ 26,827,274	$ 1,728,786

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

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

Total Annual Fixed Charges	$ 3,035,662

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2012 through October 31, 2013

Resource	Contract Quantity	Maximum Daily Quantity	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Fixed Charges
LNG Supply	125,000	5,000	5	FXW-10, Page 4	[redacted]	[redacted]
Peaking Supply 1	70,000	10,000	5	FXW-10, Page 4		
Peaking Supply 2	30,000	5,000	5	FXW-10, Page 4		
Peaking Supply 3	30,000	5,000	5	FXW-10, Page 4		
Peaking Supply 4	1,440,000	16,000	3	FXW-10, Page 4		
Total Peaking Supply Contract Demand Costs						$ 880,250

REDACTED

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2012 through October 31, 2013

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

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

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

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for January 24, 2013

Line	Supply Source	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
	Estimated Adders to NYMEX Last Day Settlement						
1	Chicago	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084
2	PNGTS Baseload	$0.390	$0.390	$0.390	$0.390	$0.390	$0.390
3	Lewiston Baseload	NA	NA	NA	NA	NA	NA
4	Tennessee Zone 6 Baseload	$0.284	$0.391	$0.423	$0.520	$0.333	$0.411
5	Niagara	$0.341	$0.341	$0.341	$0.341	$0.341	$0.341
6	Tennessee Production (Zone 0)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)	($0.082)
7	Tennessee Production (Zone L)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)	($0.024)
8	Tennessee Production (Zone 4)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	Tenessee Zone 4 Spot	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10	Peaking Supply 1	NA	NA	NA	NA	NA	NA
11	Peaking Supply 2	NA	NA	NA	NA	NA	NA
12	Peaking Supply 3	NA	NA	NA	NA	NA	NA
13	LNG	$0.284	$0.391	$0.423	$0.520	$0.333	$0.411
14	W10 Supply (Injection)	$0.084	$0.084	$0.084	$0.084	$0.084	$0.084
15	TGP FS Supply (Injection)	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015
16	W10 AMA Spot	$0.384	$0.491	$0.523	$0.620	$0.433	$0.511
17	Tennessee Zone 6 Spot	$0.284	$0.391	$0.423	$0.520	$0.333	$0.411
18	AGT Receipts	$0.154	$0.161	$0.333	$0.300	$0.223	$0.221
	Estimated NYMEX Last Day Settlement						
19	NYMEX Forecast	$3.549	$3.603	$3.655	$3.678	$3.683	$3.715

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

Fixed Demand Rates

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

Variable Transportation Commodity Rates

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

Transportation Fuel Rates

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

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

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

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

REDACTED

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

Note 1 Contracts for Peaking Supplies are pending.

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2011

•RATE SCHEDULE AFT-1

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

•RATE SCHEDULE AFT-1S

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

•OTHER FIRM RATE SCHEDULES

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

•INTERRUPTIBLE SERVICE

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

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

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

•FUEL REIMBURSEMENT PERCENTAGES

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

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

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

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

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

Projected Granite Reservation Charge 8/1/2013

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

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

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

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

(Footnotes continued on Sheet 4.01)

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

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

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

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

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity	0.0018

MEASUREMENT VARIANCE/FUEL USE FACTOR:

Minimum	0.00%
Maximum (Non-Eastchester Shipper)	1.00%
Maximum (Eastchester Shipper)	4.50%
Maximum (Brookfield Shipper)	1.20%

Historic Fuel Retention Ratios

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

REDACTED

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

REDACTED

LNG TRANSPORTATION RATE AGREEMENT

DATE: October 17, 2011

CONFIDENTIAL

CARRIER:

[redacted]

CONFIDENTIAL INFORMATION

SHIPPER:

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

EFFECTIVE DATE: 11/01/11

EXPIRATION DATE: 10/31/12

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

CONFIDENTIAL INFORMATION

OTHER TERMS AND CONDITIONS:

CONFIDENTIAL INFORMATION

[redacted]

CONFIDENTIAL INFORMATION

[redacted]

SHIPPER: **Northern Utilities Inc.**

By: ______________________ FEW

Robert Furino

Its: **Director of Energy Contracts**

REDACTED

[redacted]

CONFIDENTIAL
INFORMATION

CONFIDENTIAL

EXHIBIT 2

Unitil LNG Transportation Rate Agreement dated October 17, 2011

DIESEL FUEL ADJUSTMENT TABLE

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

CONFIDENTIAL
INFORMATION

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

[redacted]

CONFIDENTIAL INFORMATION

U.S. Energy Information Administration

Petroleum & Other Liquids

Gasoline and Diesel Fuel Update

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

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

Notice: Changes to Petroleum Marketing Survey Forms for 2013

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

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

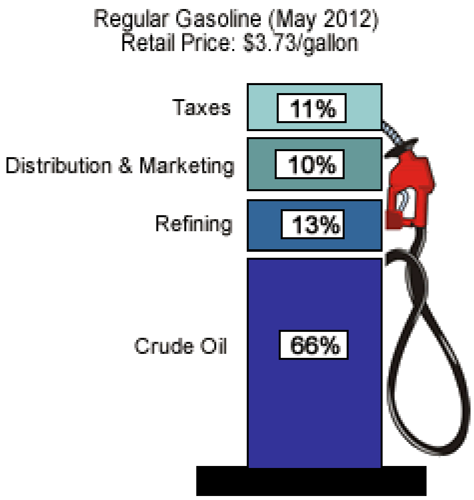
[+] See more

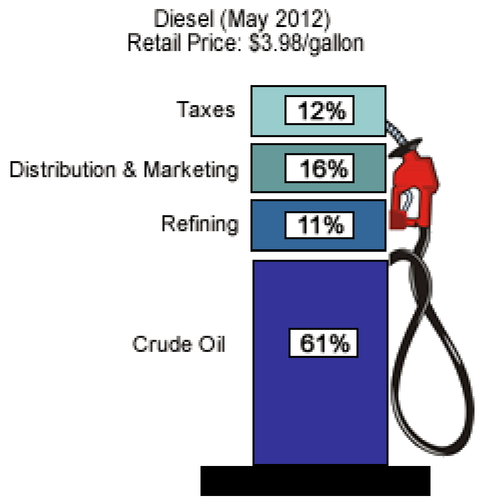
U.S. On-Highway Diesel Fuel Prices* (dollars per gallon) full history

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

**prices include all taxes*

What we pay for in a gallon of:





Statement of Transportation Rates
(Rates per DTH)

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

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

Historic Fuel Retention Ratios

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

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Fifth Revised Sheet No. 14
Superseding
Fourth Revised Sheet No. 14

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates — DELIVERY ZONE

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

Daily Base Reservation Rate 1/ — DELIVERY ZONE

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

Maximum Reservation Rates 2 /, 3 / — DELIVERY ZONE

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

Notes:
1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

Issued: January 27, 2012
Effective: February 1, 2012

Docket No. RP11-1566-009
Accepted: April 19, 2012

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum
Commodity Rates 1/, 2/

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

Maximum
Commodity Rates 1/, 2/, 3/

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

Notes:

1/ Includes a per Dth charge for (ACA) Annual Charge Adjustment of $0.0018

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.

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

FUEL AND EPCR

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

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

EPCR 3/, 4/

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

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

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

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

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

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

CURRENTLY EFFECTIVE RATES 2/01/2012

•RESERVATION CHARGES

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

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

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

•USAGE CHARGES

CDS & FT-1 USAGE-1

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

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

SCT USAGE-1

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

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

IT-1 USAGE-1

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

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1900						

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

•OTHER TRANSPORTATION SERVICES

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

			Primary Rec Pt	Secondary Rec Pt
FT-1/TMX	18.0640	0.0267	1.20%	Winter 4.80%/Summer 3.98%

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

•STORAGE SERVICES

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

•SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31

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

April 1 through November 30

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

NON-ASA RATE SCHEDULES

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

ASA STORAGE RATE SCHEDULES

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

FTS-8 M1 & M2 0.00%

- **SURCHARGES**

ACA Surcharge	
Commodity	0.0018

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

Canadian Fixed Transportation Rates

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

Canadian Variable Transportation Rates

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

Daily currency converter

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

Currency Converter

Amount: 1.00 cash rate: ☐

From: U.S. dollar

To: Canadian Dollar

Convert

Answer: 1.03

Exchange Rate: 1.0303

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

TransCanada
In business to deliver

Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

System Average Unit Cost of Transportation

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

Storage Transportation Service

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

Firm Transportation - Short Notice

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

Delivery Pressure

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

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

Union Dawn Receipt Point Surcharge

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

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

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

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

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

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

uniongas

TRANSPORTATION RATES

(A) Applicability

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

(B) Services

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

(C) Rates

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

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

Authorized Overrun (3)

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

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

Current M12 Rates and Fuel

Current OEB approved rates effective April 1, 2012

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

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

Notes:

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

If you have any questions please contact your Account Manager

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

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

The Reservation Charge applicable to this service is $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.

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

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

Negotiated Rates:

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

Rate Schedule FT-L 1/

Recourse Rates:

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

Negotiated Rates:

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

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

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

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

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s):

	Maximum Daily Reservation Quantity Dth
Alliance Interconnect	**17,172**

8. Primary Delivery Point(s):

	Maximum Daily Reservation Quantity Dth
St. Clair (US) Interconnect	**17,172**

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DTeD

Name: DON TUCHFASKY

Title: ANALYST

Telephone: (508) 836-7259

Fax: ( ) 508 - 870 - 2294

CAPACITY RELEASE TRANSACTIONS
CONFIRMATION LETTER

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

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

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

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

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

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

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

   Washington 10 Interconnect **17,086**

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

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

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DTC

Name: DON JULCHINSKY

Title: ANALYST

Telephone: (___) 508-836 7257

Fax: (___) 508-870-2294

Historic TransCanada Fuel Loss Percentages

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

Historic Fuel Retention Ratios

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

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

SHIPPER:

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

INVOICES, STATEMENTS AND NOMINATIONS

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

ALL OTHER MATTERS

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

ARTICLE VIII: FURTHER AGREEMENT

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

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

EXHIBIT I

Rates:

Monthly Deliverability Rate: $ 2.4754 per Dth

Monthly Capacity Rate: $ 0.0238 per Dth

Injection Rate: $ 0.00 per Dth

Withdrawal Rate: $ 0.00 per Dth

Authorized Overrun Rate: $ 0.05 per Dth

Interruptible Rate: $ 0.05 per Dth

Service Parameters:

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

Maximum Daily Injection Quantity (MDIQ):

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

Maximum Daily Withdrawal Quantity (MDWQ):

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

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

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

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

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

DTE Energy

Gas Midstream Services

DTE Gas Storage - Washington 10 Historic Fuel Rates

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

REDACTED

CONFIDENTIAL
OUTLINE OF PRICING AND OTHER TERMS FOR FIRM LIQUID SERVICE NORTHERN UTILITIES INC

DATE:	October 3, 2012
SELLER:	[redacted] ("Seller")
BUYER:	Northern Utilities Inc ("Buyer")
LEVEL OF SERVICE:	Firm Liquid Service
COMMENCE:	November 1, 2012
TERMINATE:	October 31, 2013
DELIVERY PERIOD:	November 1, 2012 through October 31, 2013
MDQ:	5,000 MMBtu
ACQ:	125,000 MMBtu
DELIVERY POINT:	Tailgate of Seller's Everett Marine Terminal
NOMINATION:	Pursuant to Liquid Annex guidelines (48 hrs prior notice)

PRICING:

Call Payment

The Call Payment shall equal [redacted] which shall be payable to Seller in five equal monthly installments o[redacted] November through March.

Commodity Charge

For each MMBtu of LNG ordered and delivered to Buyer, Buyer will pay to Seller a commodity rate per MMBtu equal to the [redacted] for the month in which the gas is purchased.

OTHER:

This outline is strictly confidential.

Other contract provisions including metering, measurement, billing and payment, force majeure and related provisions will be pursuant to Seller's NAESB agreement.

This proposal, and any agreement resulting there from, is subject to final [redacted] approval or equivalent. This proposal is also subject to

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2012 through October 2013		
Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (4,325,026)	Page 2
NH Division Storage Contract Capacity Assignment	$ (313,407)	Page 3
NH Division Peaking Demand	$ (308,571)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 344,864	Page 5
NH Division Net PNGTS Litigation Costs Assigned to Retail Suppliers	$ (15,956)	Page 6
NH Division Capacity Assignment Demand Revenue - Updated Forecast	$ (4,618,096)	Sum of Items Above

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

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	Assigned Pipeline Credits	Assigned Storage Credits	NH Annual Cap Assign Credit
Algonquin	93002F	$ 308,943	$ -	Y	4,211	-	(661)	-	$ (48,495)	$ -	$ (48,495)
Algonquin	93201A1C	$ 98,680	$ -	Y	1,251	-	(196)	-	$ (15,461)	$ -	$ (15,461)
Granite	10-010-FT-NN	$ 631,712	$ 1,052,429	Y	21,326	35,529	(3,347)	(3,670)	$ (99,144)	$ (108,712)	$ (207,855)
Granite	10-010-FT-NN	$ 222,803	$ 371,189	Y	21,326	35,529	(3,347)	(3,670)	$ (34,968)	$ (38,342)	$ (73,310)
Iroquois	R181001	$ 520,036	$ -	Y	6,569	-	(1,031)	-	$ (81,619)	$ -	$ (81,619)
PNGTS	1997-003	$ 531,242	$ -	Y	1,100	-	(173)	-	$ (83,550)	$ -	$ (83,550)
PNGTS	1997-004	$ -	$ 12,616,989	Y	-	33,000	-	(3,409)	$ -	$ (1,303,373)	$ (1,303,373)
Tennessee	5083	$ 1,351,367	$ -	Y	4,605	-	(723)	-	$ (212,169)	$ -	$ (212,169)
Tennessee	5083	$ 2,225,558	$ -	Y	8,550	-	(1,342)	-	$ (349,322)	$ -	$ (349,322)
Tennessee	5265	$ -	$ 270,275	Y	-	2,653	-	(274)	$ -	$ (27,914)	$ (27,914)
Tennessee	5292	$ 125,521	$ -	Y	1,406	-	(221)	-	$ (19,730)	$ -	$ (19,730)
Tennessee	31861	$ 198,727	$ -	Y	2,226	-	(349)	-	$ (31,157)	$ -	$ (31,157)
Tennessee	39735	$ 82,937	$ -	Y	929	-	(146)	-	$ (13,034)	$ -	$ (13,034)
Tennessee	41099	$ 380,937	$ -	Y	4,267	-	(670)	-	$ (59,814)	$ -	$ (59,814)
Texas Eastern	800384	$ 66,747	$ -	N	NA	NA	-	-	$ -	$ -	$ -
TransCanada	33322	$ -	$ 12,126,617	Y	-	34,000	-	(3,512)	$ -	$ (1,252,608)	$ (1,252,608)
TransCanada	29594	$ 867,809	$ -	Y	5,937	-	(932)	-	$ (136,230)	$ -	$ (136,230)
Union	M12205	$ 181,905	$ -	Y	6,003	-	(942)	-	$ (28,545)	$ -	$ (28,545)
Vector	CRL-NUI-0725	$ 1,566,952	$ -	Y	17,172	-	(2,695)	-	$ (245,920)	$ -	$ (245,920)
Vector	CRL-NUI-0727	$ -	$ 389,774	Y	-	17,086	-	(1,765)	$ -	$ (40,264)	$ (40,264)
Vector	FT-1-NUI-0122	$ 566,295	$ -	Y	6,070	-	(953)	-	$ (88,909)	$ -	$ (88,909)
Vector	FT-1-NUI-C0122	$ 36,602	$ -	Y	6,070	-	(953)	-	$ (5,747)	$ -	$ (5,747)
Total NH Capacity Assignment Credits									$ (1,553,813)	$ (2,771,213)	$ (4,325,026)

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

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

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

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

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

Month	Total Peaking Demand TCQ	Rate		Demand Revenue	
Nov-11	4,329	$	11.88	$	(51,429)
Dec-11	4,329	$	11.88	$	(51,429)
Jan-12	4,329	$	11.88	$	(51,429)
Feb-12	4,329	$	11.88	$	(51,429)
Mar-12	4,329	$	11.88	$	(51,429)
Apr-12	4,329	$	11.88	$	(51,429)

Total Division Peaking Demand Revenue $ (308,571)

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Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2012 through October 2013

Asset Management Agreeement Revenue					
Resources	Projected Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	[redacted]	Yes	Pipeline	15.69%	[redacted]
Algonquin Contract #93201A1C (1,251 Dth)		Yes	Pipeline	15.69%	
Wash 10 via Vector, TCPL, PNGTS		Yes	Storage	10.33%	
Tennessee Niagara		No	Pipeline	15.69%	
Tennessee Long-Haul		No	Pipeline	15.69%	
Total Asset Management	$ (4,810,000)				$ 344,864

Capacity Release Revenue					
Resources	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Texas Eastern Contract 800384	$ (66,701)	No	Pipeline	15.69%	$ -
Tennessee 5265	$ (83,950)	No	Pipeline	15.69%	$ -
Granite 10-010-FT-NN	$ (62,800)	No	Pipeline	10.33%	$ -
Total Capacity Release	$ (213,450)				$ -

Total Asset Management and Capacity Release Revenue	$ (5,023,450)	$ 344,864

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

PNGTS Litigation Costs	$ 151,922

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

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

Line	Description	Northern	NH Division
1	Capacity Allocation Factor		46.40%
2	Peaking Contracts	35,910	16,662
3	Peaking Plants	10,000	4,640
4	Total	45,910	21,302
5	Peaking Contracts Costs	$ 880,250	$ 408,436
6	Peaking Allocated Pipeline Demand Costs	$ 1,728,786	$ 802,157
7	Peaking Plants		$ 307,762
8	Capacity Costs (Before Cap Assignment)		$ 1,518,355
9	NH Division Peaking Capacity Assignment Rate		$ 11.88

Schedule 5C

Provided in Winter 2012–13 Cost-of-Gas Filing

Schedules 6A and 6B

Northern Utilities, Inc.
Commodity Cost by Supply Source
May 2013 through October 2013

Description	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Season
Pipeline Supplies							
Chicago	$ 100,948	$ 6,487	$ -	$ 1,437	$ 8,472	$ 309,082	$ 426,425
Lewiston Baseload	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Zone 6	$ -	$ -	$ -	$ -	$ -	$ 2,707	$ 2,707
PNGTS	$ -	$ -	$ -	$ -	$ -	$ 10,563	$ 10,563
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee Production	$ 559,547	$ 545,228	$ 561,837	$ 545,432	$ 562,853	$ 599,140	$ 3,374,038
Algonquin Receipts	$ 87,100	$ 12,943	$ -	$ -	$ 39,086	$ 120,391	$ 259,521
Tenn Zone 4 Spot	$ 269,602	$ 248,263	$ 220,189	$ 262,227	$ 259,139	$ 282,905	$ 1,542,326
TGP Zone 6 Spot	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W10 AMA Spot	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Pipeline	$1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 5,615,579
Underground Storage							
Tennessee Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10 Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supplies							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 41,993
Subtotal Peaking	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 41,993
Total Commodity Cost	$1,024,229	$ 819,739	$ 789,096	$ 816,171	$ 876,422	$ 1,331,915	$ 5,657,572

Northern Utilities, Inc. Commodity Volumes by Supply Source (Dth) May 2013 through October 2013							
Description	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Season
Pipeline Supplies							
Chicago	26,030	1,654	0	359	2,112	76,005	106,159
Lewiston Baseload	0	0	0	0	0	0	0
TGP Zone 6	0	0	0	0	0	656	656
PNGTS	0	0	0	0	0	2,572	2,572
Niagara	0	0	0	0	0	0	0
Tennessee Production	150,888	145,119	147,349	141,987	146,329	154,457	886,129
AGT Receipts	23,335	3,417	0	0	9,922	30,327	67,000
Tenn Zone 4 Spot	72,701	66,078	57,747	68,263	67,370	72,933	405,092
TGP Zone 6 Spot	0	0	0	0	0	0	0
W10 AMA Spot	0	0	0	0	0	0	0
Subtotal Pipeline	272,954	216,268	205,096	210,609	225,732	336,950	1,467,609
Underground Storage							
Tennessee Storage	0	0	0	0	0	0	0
Washington 10 Storage	0	0	0	0	0	0	0
Subtotal Storage	0	0	0	0	0	0	0
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
LNG	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Subtotal Peaking	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Total Delivered (Dth)	274,349	217,618	206,491	212,004	227,082	338,345	1,475,889

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
May 2013 through October 2013

Description	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Season
Pipeline Supplies							
Chicago	$ 3.878	$ 3.921		$ 4.007	$ 4.012	$ 4.067	$ 4.017
Lewiston Baseload							
TGP Zone 6						$ 4.126	$ 4.126
PNGTS						$ 4.107	$ 4.107
Niagara							
Tennessee Production	$ 3.708	$ 3.757	$ 3.813	$ 3.841	$ 3.846	$ 3.879	$ 3.808
AGT Receipts	$ 3.733	$ 3.788			$ 3.940	$ 3.970	$ 3.873
Tenn Zone 4 Spot	$ 3.708	$ 3.757	$ 3.813	$ 3.841	$ 3.846	$ 3.879	$ 3.807
TGP Zone 6 Spot							
W10 AMA Spot							
Subtotal Pipeline	$ 3.727	$ 3.759	$ 3.813	$ 3.842	$ 3.852	$ 3.932	$ 3.826
Underground Storage							
Tennessee Storage							
Washington 10 Storage							
Subtotal Storage							
Peaking Supplies							
Peaking Supply 1							
Peaking Supply 2							
Peaking Supply 3							
LNG	$ 5.041	$ 5.050	$ 5.068	$ 5.071	$ 5.090	$ 5.109	$ 5.072
Subtotal Peaking	$ 5.041	$ 5.050	$ 5.068	$ 5.071	$ 5.090	$ 5.109	$ 5.072
Total Cost per Dth	$ 3.733	$ 3.767	$ 3.821	$ 3.850	$ 3.859	$ 3.937	$ 3.833

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	27,065	1,717	-	372	2,192	79,285	110,632
2	City Gate Delivered Volume	Sum Lines 64, 84 and 104	26,030	1,654	-	359	2,112	76,005	106,159
3	Total Purchase Cost	Line 15	$ 97,841	$ 6,291	$ -	$ 1,394	$ 8,222	$ 299,936	$ 413,683
4	Variable Transportation Costs	Sum Lines 26, 46, 56, 66, 76, 86, 96 and 106	$ 3,107	$ 196	$ -	$ 43	$ 250	$ 9,146	$ 12,742
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 100,948	$ 6,487	$ -	$ 1,437	$ 8,472	$ 309,082	$ 426,425
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.878	$ 3.921		$ 4.007	$ 4.012	$ 4.067	$ 4.017
7									
8	Chicago Supply Costs								
9	Purchased Volumes	Sendout Optimization	27,065	1,717	-	372	2,192	79,285	110,632
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.655
11	NYMEX Cost	Line 9 times Line 10	$ 95,567	$ 6,146	$ -	$ 1,363	$ 8,038	$ 293,276	$ 404,390
12	NYMEX Basis Price	Att to Sch 5A, Line 1 of Page 1	$ 0.084	$ 0.084		$ 0.084	$ 0.084	$ 0.084	$ 0.084
13	NYMEX Basis Costs	Line 9 times Line 12	$ 2,273	$ 144	$ -	$ 31	$ 184	$ 6,660	$ 9,293
14	Total Purchase Price	Line 10 plus Line 12	$ 3.615	$ 3.663		$ 3.746	$ 3.751	$ 3.783	$ 3.739
15	Total Purchase Cost	Line 11 plus Line 13	$ 97,841	$ 6,291	$ -	$ 1,394	$ 8,222	$ 299,936	$ 413,683
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with Union)								
22	Received Volume	Line 9	27,065	1,717	-	372	2,192	79,285	110,632
23	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	1.15%	1.15%		1.15%	1.15%	1.15%	1.15%
24	Delivered Volume	Line 22 times (1 - Line 23)	26,754	1,698	-	368	2,167	78,373	109,360
25	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2	$ 0.0018	$ 0.0018		$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 48	$ 3	$ -	$ 1	$ 4	$ 141	$ 197
27									
28	Transportation Segment 3								
29	Union Pipeline (Contract M12205)								
30	Receipt Point: Dawn								
31	Delivery Point: Parkway (Interconnects with TransCanada)								
32	Received Volume	Line 24	26,754	1,698	-	368	2,167	78,373	109,360
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.52%	0.52%		0.52%	0.52%	0.52%	0.52%
34	Delivered Volume	Line 32 times (1 - Line 33)	26,615	1,689	-	366	2,155	77,966	108,791
35	Variable Transportation Rate	Att to Sch 5A, Line 33 of Page 2	$ -	$ -		$ -	$ -	$ -	$ -
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37									
38	Transportation Segment 4								
39	TransCanada Pipeline (Contract 41235)								
40	Receipt Point: Parkway								
41	Delivery Point: Iroquois								
42	Received Volume	Line 34	26,615	1,689	-	366	2,155	77,966	108,791
43	Fuel Loss Rate	Att to Sch 5A, Line 49 of Page 2	1.01%	1.01%		1.01%	1.01%	1.01%	1.01%
44	Delivered Volume	Line 42 times (1 - Line 43)	26,346	1,672	-	362	2,134	77,178	107,692
45	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2	$ 0.0215	$ 0.0215		$ 0.0215	$ 0.0215	$ 0.0215	$ 0.0215
46	Variable Transportation Costs	Line 44 times Line 45	$ 566	$ 36	$ -	$ 8	$ 46	$ 1,659	$ 2,315
47									
48	Transportation Segment 5								
49	Iroquois Pipeline (Contract R181001)								
50	Receipt Point: Waddington								
51	Delivery Point: Wright (Interconnection with Tennessee)								
52	Received Volume	Line 44	26,346	1,672	-	362	2,134	77,178	107,692
53	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.13%	0.13%		0.13%	0.13%	0.13%	0.13%
54	Delivered Volume	Line 52 times (1 - Line 53)	26,312	1,670	-	362	2,131	77,078	107,552
55	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0048	$ 0.0048		$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048
56	Variable Transportation Costs	Line 54 times Line 55	$ 126	$ 8	$ -	$ 2	$ 10	$ 370	$ 516
57									
58	Transporation Segment 6A								
59	Tennessee Gas Pipeline (Contract 95196)								
60	Receipt Point: Mendon								
61	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
62	Received Volume	Line 54	18,239	1,670	-	362	2,131	28,148	50,549
63	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%	0.91%		0.91%	0.91%	0.91%	0.91%
64	City Gate Delivered Volume	Line 62 times (1 - Line 63)	18,073	1,654	-	359	2,112	27,891	50,089
65	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902	$ 0.0902		$ 0.0902	$ 0.0902	$ 0.0902	$ 0.0902
66	Variable Transportation Costs	Line 64 times Line 65	$ 1,630	$ 149	$ -	$ 32	$ 190	$ 2,516	$ 4,518
67									
68	Transportation Segment 6B								
69	Tennessee Gas Pipeline (Contract 95196)								
70	Receipt Point: Mendon								
71	Delivery Point: Pleasant St. (Interconnection with Granite)								
72	Received Volume	Line 64	5,516	-	-	-	-	13,845	19,361
73	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%					0.91%	0.91%
74	Delivered Volume	Line 72 times (1 - Line 73)	5,466	-	-	-	-	13,719	19,185
75	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902					$ 0.0902	$ 0.0902
76	Variable Transportation Costs	Line 74 times Line 75	$ 493	$ -	$ -	$ -	$ -	$ 1,237	$ 1,731
77									
78	Transportation Segment 7B								
79	Granite State Gas Transmission (Contract 10-010-FT-NN)								
80	Receipt Point: Pleasant St.								
81	Delivery Point: Northern City Gates								
82	Received Volume	Line 74	5,466	-	-	-	-	13,719	19,185
83	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
84	City Gate Delivered Volume	Line 82 times (1 - Line 83)	5,447	-	-	-	-	13,671	19,118
85	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
86	Variable Transportation Costs	Line 84 times Line 85	$ 10	$ -	$ -	$ -	$ -	$ 25	$ 34
87									
88	Transportation Segment 6C								
89	Tennessee Gas Pipeline (Contract 41099)								
90	Receipt Point: Wright								
91	Delivery Point: Mendon (Interconnection with Algonquin)								
92	Received Volume	Line 54	2,556	-	-	-	-	35,085	37,642
93	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	0.91%					0.91%	0.91%
94	Delivered Volume	Line 92 times (1 - Line 93)	2,533	-	-	-	-	34,766	37,299
95	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0902					$ 0.0902	$ 0.0902
96	Variable Transportation Costs	Line 94 times Line 95	$ 228	$ -	$ -	$ -	$ -	$ 3,136	$ 3,364
97									
98	Transportation Segment 7C								
99	Algonquin Gas Transmission (Contract 93200F)								
100	Receipt Point: Mendon								
101	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
102	Received Volume	Line 94	2,533	-	-	-	-	34,766	37,299
103	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2	0.93%					0.93%	0.93%
104	City Gate Delivered Volume	Line 102 times (1 - Line 103)	2,510	-	-	-	-	34,443	36,952
105	Variable Transportation Rate	Att to Sch 5A, Line 19 of Page 2	$ 0.0018					$ 0.0018	$ 0.0018
106	Variable Transportation Costs	Line 104 times Line 105	$ 5	$ -	$ -	$ -	$ -	$ 62	$ 67

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 1	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Lewiston Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 3 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	658	658
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	656	656
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ 2,706	$ 2,706
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ 2,707	$ 2,707
6	Average Delivered Price	Line 5 divided by Line 2						$ 4.126	$ 4.126
7									
8	Tennessee Zone 6 Supply								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	658	658
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.699
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 2,435	$ 2,435
12	NYMEX Basis Price	Att to Sch 5A, Line 4 of Page 1						$ 0.411	$ 0.411
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 271	$ 271
14	Total Purchase Price	Line 10 plus Line 12						$ 4.110	$ 4.110
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ 2,706	$ 2,706
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	658	658
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	656	656
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	2,581	2,581
2	City Gate Delivered Volume	Line 34	-	-	-	-	-	2,572	2,572
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ 10,553	$ 10,553
4	Variable Transportation Costs	Sum Lines 26 and 36	$ -	$ -	$ -	$ -	$ -	$ 9	$ 9
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ 10,563	$ 10,563
6	Average Delivered Price	Line 5 divided by Line 2						$ 4.107	$ 4.107
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	2,581	2,581
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.699
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 9,547	$ 9,547
12	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1						$ 0.390	$ 0.390
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 1,007	$ 1,007
14	Total Purchase Price	Line 10 plus Line 12						$ 4.089	$ 4.089
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ 10,553	$ 10,553
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	PNGTS (Contract 1997-003)								
20	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
21	Delivery Point: Granite (Westbrook)								
22	Received Volume	Line 9	-	-	-	-	-	2,581	2,581
23	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2						0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	2,581	2,581
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2						$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ 5	$ 5
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	-	-	-	-	-	2,581	2,581
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	2,572	2,572
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ 5	$ 5

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Sum Lines 24 and 44	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 26, 36 and 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Niagara Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 5 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 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	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2							
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2							
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2							
34	Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2							
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	-
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	-	-	-	-	-	-	-
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	City Gate Volumes - Z0	Line 2 of Page 5	-	-	-	-	-	-	-
2	City Gate Volumes - Z1	Line 2 of Page 6	-	-	-	-	-	-	-
3	City Gate Volumes - Z4	Line 2 of Page 7	150,888	145,119	147,349	141,987	146,329	154,457	886,129
4	Total City Gate Volumes	Sum Lines 1 through 3	150,888	145,119	147,349	141,987	146,329	154,457	886,129
5	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	City Gate Delivered Costs - Z4	Line 5 of Page 7	$ 559,547	$ 545,228	$ 561,837	$ 545,432	$ 562,853	$ 599,140	$ 3,374,038
8	Total City Gate Delivered Costs	Sum Lines 5 through 7	$ 559,547	$ 545,228	$ 561,837	$ 545,432	$ 562,853	$ 599,140	$ 3,374,038
9	Average Delivered Price	Line 8 divided by Line 4	$ 3.708	$ 3.757	$ 3.813	$ 3.841	$ 3.846	$ 3.879	$ 3.808

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 32	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 44	-	-	-	-	-	-	-
3	Total Purchase Price	Line 24							
4	Total Purchase Cost	Line 2 times Line 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Sum Lines 36 and 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 6 divided by Line 2							
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	-	-
11	Storage Delivered Volume	Line 54	-	-	-	-	-	-	-
12	Total Purchase Price	Line 24							
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Average Delivered Price	Line 15 divided by Line 11							
17									
18	<u>Tennessee Zone 0 Supply Costs</u>								
19	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
20	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
21	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	NYMEX Basis Price	Att to Sch 5A, Line 6 of Page 1							
23	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Total Purchase Price	Line 10 plus Line 12							
25	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26									
27	<u>Transportation Fuel Losses and Variable Charges</u>								
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	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 43 of Page 2							
34	Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 26 of Page 2							
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	-
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	-	-	-	-	-	-	-
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 42 of Page 2							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 25 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 32	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 44	-	-	-	-	-	-	-
3	Total Purchase Price	Line 24							
4	Total Purchase Cost	Line 2 times Line 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Sum Lines 36 and 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 6 divided by Line 2							
8									
9	Tennessee Northern Storage Injection Meter Deliveries								
10	Purchased Volumes	Line 52	-	-	-	-	-	-	-
11	Storage Delivered Volume	Line 54	-	-	-	-	-	-	-
12	Total Purchase Price	Line 24							
13	Total Purchase Cost	Line 10 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Variable Transportation Costs	Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Average Delivered Price	Line 15 divided by Line 11							
17									
18	<u>Tennessee Zone L Supply Costs</u>								
19	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
20	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
21	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	NYMEX Basis Price	Att to Sch 5A, Line 7 of Page 1							
23	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Total Purchase Price	Line 10 plus Line 12							
25	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26									
27	<u>Transportation Fuel Losses and Variable Charges</u>								
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone L								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 45 of Page 2							
34	Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2							
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	-
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	-	-	-	-	-	-	-
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone L								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	-	-	-	-	-	-	-
53	Fuel Loss Rate	Att to Sch 5A, Line 44 of Page 2							
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	-	-	-	-	-	-	-
55	Variable Transportation Rate	Att to Sch 5A, Line 27 of Page 2							
56	Variable Transportation Costs	Line 54 times Line 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	153,257	147,397	149,662	144,217	148,626	156,883	900,042
2	City Gate Delivered Volume	Sum Lines 34	150,888	145,119	147,349	141,987	146,329	154,457	886,129
3	Total Purchase Cost	Line 15	$ 541,151	$ 527,535	$ 543,873	$ 528,121	$ 545,013	$ 580,309	$ 3,266,001
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 18,396	$ 17,693	$ 17,965	$ 17,311	$ 17,840	$ 18,832	$ 108,037
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 559,547	$ 545,228	$ 561,837	$ 545,432	$ 562,853	$ 599,140	$ 3,374,038
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.708	$ 3.757	$ 3.813	$ 3.841	$ 3.846	$ 3.879	$ 3.808
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	153,257	147,397	149,662	144,217	148,626	156,883	900,042
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.629
11	NYMEX Cost	Line 9 times Line 10	$ 541,151	$ 527,535	$ 543,873	$ 528,121	$ 545,013	$ 580,309	$ 3,266,001
12	NYMEX Basis Price	Att to Sch 5A, Line 8 of Page 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.629
15	Total Purchase Cost	Line 11 plus Line 13	$ 541,151	$ 527,535	$ 543,873	$ 528,121	$ 545,013	$ 580,309	$ 3,266,001
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5083)								
20	Receipt Point: Tennessee Zone 4 200 Leg Pool								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	153,257	147,397	149,662	144,217	148,626	156,883	900,042
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	151,418	145,629	147,866	142,486	146,843	155,000	889,242
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197
26	Variable Transportation Costs	Line 24 times Line 25	$ 18,125	$ 17,432	$ 17,700	$ 17,056	$ 17,577	$ 18,553	$ 106,442
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	151,418	145,629	147,866	142,486	146,843	155,000	889,242
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	150,888	145,119	147,349	141,987	146,329	154,457	886,129
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 272	$ 261	$ 265	$ 256	$ 263	$ 278	$ 1,595

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	23,554	3,449	-	-	10,015	30,611	67,629
2	City Gate Delivered Volume	Sum Lines 24	23,335	3,417	-	-	9,922	30,327	67,000
3	Total Purchase Cost	Line 15	$ 86,797	$ 12,899	$ -	$ -	$ 38,957	$ 119,997	$ 258,650
4	Variable Transportation Costs	Sum Lines 26	$ 303	$ 44	$ -	$ -	$ 129	$ 394	$ 871
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 87,100	$ 12,943	$ -	$ -	$ 39,086	$ 120,391	$ 259,521
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.733	$ 3.788			$ 3.940	$ 3.970	$ 3.873
7									
8	<u>Algonquin Receipts Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	23,554	3,449	-	-	10,015	30,611	67,629
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.630
11	NYMEX Cost	Line 9 times Line 10	$ 83,169	$ 12,344	$ -	$ -	$ 36,724	$ 113,232	$ 245,469
12	NYMEX Basis Price	Att to Sch 5A, Line 18 of Page 1	$ 0.154	$ 0.161			$ 0.223	$ 0.221	$ 0.195
13	NYMEX Basis Costs	Line 9 times Line 12	$ 3,627	$ 555	$ -	$ -	$ 2,233	$ 6,765	$ 13,181
14	Total Purchase Price	Line 10 plus Line 12	$ 3.685	$ 3.740			$ 3.890	$ 3.920	$ 3.825
15	Total Purchase Cost	Line 11 plus Line 13	$ 86,797	$ 12,899	$ -	$ -	$ 38,957	$ 119,997	$ 258,650
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Algonquin Pipeline (Contract 93201A1C)								
20	Receipt Point: Algonquin Receipt Points								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 15	23,554	3,449	-	-	10,015	30,611	67,629
23	Fuel Loss Rate	Att to Sch 5A, Line 38 of Page 2	0.93%	0.93%			0.93%	0.93%	1.20%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	23,335	3,417	-	-	9,922	30,327	67,000
25	Variable Transportation Rate	Att to Sch 5A, Line 20 of Page 2	$ 0.0130	$ 0.0130			$ 0.0130	$ 0.0130	$ 0.0130
26	Variable Transportation Costs	Line 24 times Line 25	$ 303	$ 44	$ -	$ -	$ 129	$ 394	$ 871

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	73,843	67,116	58,654	69,335	68,428	74,078	411,453
2	City Gate Delivered Volume	Sum Lines 34	72,701	66,078	57,747	68,263	67,370	72,933	405,092
3	Total Purchase Cost	Line 15	$ 260,739	$ 240,207	$ 213,148	$ 253,904	$ 250,925	$ 274,013	$ 1,492,937
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 8,864	$ 8,056	$ 7,041	$ 8,323	$ 8,214	$ 8,892	$ 49,389
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 269,602	$ 248,263	$ 220,189	$ 262,227	$ 259,139	$ 282,905	$ 1,542,326
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.708	$ 3.757	$ 3.813	$ 3.841	$ 3.846	$ 3.879	$ 3.807
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	73,843	67,116	58,654	69,335	68,428	74,078	411,453
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.628
11	NYMEX Cost	Line 9 times Line 10	$ 260,739	$ 240,207	$ 213,148	$ 253,904	$ 250,925	$ 274,013	$ 1,492,937
12	NYMEX Basis Price	Att to Sch 5A, Line 9 of Page 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.628
15	Total Purchase Cost	Line 11 plus Line 13	$ 260,739	$ 240,207	$ 213,148	$ 253,904	$ 250,925	$ 274,013	$ 1,492,937
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5265)								
20	Receipt Point: Tennessee FS-MA 300 Leg								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	73,843	67,116	58,654	69,335	68,428	74,078	411,453
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	72,957	66,310	57,950	68,503	67,607	73,189	406,515
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197	$ 0.1197
26	Variable Transportation Costs	Line 24 times Line 25	$ 8,733	$ 7,937	$ 6,937	$ 8,200	$ 8,093	$ 8,761	$ 48,660
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	72,957	66,310	57,950	68,503	67,607	73,189	406,515
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	72,701	66,078	57,747	68,263	67,370	72,933	405,092
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
36	Variable Transportation Costs	Line 34 times Line 35	$ 131	$ 119	$ 104	$ 123	$ 121	$ 131	$ 729

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Tennessee Zone 6 Supply</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 17 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 34	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 26 and 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Portland Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 16 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	PNGTS (Contract 1997-004)								
19	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
20	Delivery Point: Granite (Westbrook, Newington, Eliot)								
21	Delivery Point: Granite (Westbrook)								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 10-010-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	-	-	-	-	-	-	-
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	-	-
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Gross Withdrawn Volume	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 36	-	-	-	-	-	-	-
3	Total Withdrawal Costs	Line 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 27 and 37	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
10	Withdrawal Rate	Att to Sch 5A, Line 1 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 1 of Page 3 times Line	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	-	-	-	-	-	-	-
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 2								
20	Tennessee Gas Pipeline (Contract 5265)								
21	Receipt Point: Tennessee FS-MA Withdrawal Meter								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 16	-	-	-	-	-	-	-
24	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2							
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2							
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28									
29	Transportation Segment 3								
30	Granite State Gas Transmission (Contract 10-010-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	-	-	-	-	-	-	-
34	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Gross Withdrawn Volume	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 65	-	-	-	-	-	-	-
3	Total Withdrawal Costs	Line 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Sum Lines 27, 37, 47, 57 and 67	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Washington 10 Withdrawn Inventory (Segment 1)</u>								
9	Gross Withdrawn Volume	Sendout Optimization	-	-	-	-	-	-	-
10	Withdrawal Rate	Att to Sch 5A, Line 3 of Page 3							
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8							
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 3 of Page 3 times Line	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	-	-	-	-	-	-	-
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 2A								
20	Vector Pipeline (Contract CRL-NUI-0725)								
21	Receipt Point: Washington 10 Withdrawal Meter								
22	Delivery Point: Dawn (Interconnects with TransCanada)								
23	Received Volume	Line 15	-	-	-	-	-	-	-
24	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2							
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28									
29	Transportation Segment 2B								
30	Vector Pipeline (Contract CRL-NUI-0727)								
31	Receipt Point: Washington 10 Withdrawal Meter								
32	Delivery Point: Union Dawn (Interconnects with TransCanada)								
33	Received Volume	Line 25	-	-	-	-	-	-	-
34	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2							
35	Delivered Volume	Line 33 times (1 - Line 34)	-	-	-	-	-	-	-
36	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2							
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Transportation Segment 3								
40	TransCanada Pipeline (Contract 33322)								
41	Receipt Point: Union Dawn								
42	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)								
43	Received Volume	Line 35	-	-	-	-	-	-	-
44	Fuel Loss Rate	Att to Sch 5A, Line 48 of Page 2							
45	Delivered Volume	Line 43 times (1 - Line 44)	-	-	-	-	-	-	-
46	Variable Transportation Rate	Att to Sch 5A, Line 31 of Page 2							
47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48									
49	Transportation Segment 4								
50	PNGTS (Contract 1997-004)								
51	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
52	Delivery Point: Granite (Westbrook, Newington, Eliot)								
53	Received Volume	Line 45	-	-	-	-	-	-	-
54	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2							
55	Delivered Volume	Line 53 times (1 - Line 54)	-	-	-	-	-	-	-
56	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2							
57	Variable Transportation Costs	Line 55 times Line 56	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58									
59	Transportation Segment 5								
60	Granite State Gas Transmission (Contract 10-010-FT-NN)								
61	Receipt Point: Westbrook, Newington, Eliot								
62	Delivery Point: Northern City Gates								
63	Received Volume	Line 55	-	-	-	-	-	-	-
64	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
65	City Gate Delivered Volume	Line 63 times (1 - Line 64)	-	-	-	-	-	-	-
66	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
67	Variable Transportation Costs	Line 65 times Line 66	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Peaking Supply 1 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 10 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	2013 Off-Peak May-13	2013 Off-Peak Jun-13	2013 Off-Peak Jul-13	2013 Off-Peak Aug-13	2013 Off-Peak Sep-13	2013 Off-Peak Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Peaking Supply 2 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 11 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	-	-
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	<u>Peaking Supply 3 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 12 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Gross Withdrawn Volume	Line 9	1,395	1,350	1,395	1,395	1,350	1,395	8,280
2	City Gate Delivered Volume	Line 15	1,395	1,350	1,395	1,395	1,350	1,395	8,280
3	Total Withdrawal Costs	Line 16	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 41,993
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 41,993
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.041	$ 5.050	$ 5.068	$ 5.071	$ 5.090	$ 5.109	$ 5.072
7									
8	<u>Northern LNG Withdrawn Inventory</u>								
9	Gross Withdrawn Volume	Sendout Optimization	1,395	1,350	1,395	1,395	1,350	1,395	8,280
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8	$ 5.0408	$ 5.0505	$ 5.0682	$ 5.0714	$ 5.0899	$ 5.1090	$ 5.0717
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 41,993
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	1,395	1,350	1,395	1,395	1,350	1,395	8,280
16	Total Withdrawal Costs	Line 11 plus Line 13	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 41,993

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

Line	LNG Storage Deliveries	Reference	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	2013 Off-Peak
1	Purchased Volumes	Line 22	1,395	1,350	1,395	145	2,600	1,395	8,280
2	Storage Delivered Volume	Line 24	1,395	1,350	1,395	145	2,600	1,395	8,280
3	Total Purchase Price	Line 15	$ 3.815	$ 3.970	$ 4.057	$ 4.182	$ 4.000	$ 4.110	$ 3.995
4	Total Purchase Cost	Line 10 times Line 12	$ 5,322	$ 5,360	$ 5,660	$ 606	$ 10,400	$ 5,733	$ 33,081
5	Variable Transportation Costs	Line 26	$ 1,632	$ 1,579	$ 1,632	$ 170	$ 3,042	$ 1,632	$ 9,688
6	Total Storage Delivered Costs	Line 13 plus Line 14	$ 6,954	$ 6,939	$ 7,292	$ 776	$ 13,442	$ 7,366	$ 42,768
7	Average Delivered Price	Line 15 divided by Line 11	$ 4.985	$ 5.140	$ 5.227	$ 5.352	$ 5.170	$ 5.280	$ 5.165
8									
9	LNG Supply Costs								
10	Purchased Volumes	Sendout Optimization	1,395	1,350	1,395	145	2,600	1,395	8,280
11	Monthly NYMEX Price	Att to Sch 5A, Line 19 of Page 1	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699	$ 3.629
12	LNG Supply Costs	Line 9 times Line 10	$ 4,926	$ 4,832	$ 5,069	$ 531	$ 9,534	$ 5,160	$ 30,052
13	NYMEX Basis Price	Att to Sch 5A, Line 13 of Page 1	$ 0.284	$ 0.391	$ 0.423	$ 0.520	$ 0.333	$ 0.411	$ 0.366
14	NYMEX Basis Costs	Line 9 times Line 12	$ 396	$ 528	$ 590	$ 75	$ 866	$ 573	$ 3,029
15	Total Purchase Price	Line 10 plus Line 12	$ 3.815	$ 3.970	$ 4.057	$ 4.182	$ 4.000	$ 4.110	$ 3.995
16	Total Purchase Cost	Line 11 plus Line 13	$ 5,322	$ 5,360	$ 5,660	$ 606	$ 10,400	$ 5,733	$ 33,081
17									
18	Transportation Segment 3								
19	Trucking Contract (TransGas)								
20	Receipt Point: Distrigas Terminal								
21	Delivery Point: Northern LNG Facility (Lewiston, ME)								
22	Received Volume	Line 19 minus Line 31	1,395	1,350	1,395	145	2,600	1,395	8,280
23	Fuel Loss Rate	N/A	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Storage Delivered Volume	Line 22 times (1 - Line 23)	1,395	1,350	1,395	145	2,600	1,395	8,280
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700	$ 1.1700
26	Variable Transportation Costs	Line 24 times Line 25	$ 1,632	$ 1,579	$ 1,632	$ 170	$ 3,042	$ 1,632	$ 9,688

Schedule 7

Northern Utilities, Inc. Hedging Gains and Losses May 2013 through October 2013 As of 2/28/2013			
Description	May-13	Oct-13	Summer
NYMEX Contracts	11	11	22
Average Purchase Price	$ 3.524	$ 3.677	$ 3.601
Current NYMEX Price	$ 3.531	$ 3.699	$ 3.615
Hedging (Gains) and Losses	$ (770)	$ (2,420)	$ (3,190)

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year
Comparison of Summer 2013 vs. Summer 2012

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2012- 2013																	
Customer Charge	units @	$ 13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38								
First	50 units @	$0.4410	$22.05	$22.05	$22.05	$22.05	$22.05	$22.05	$132.30								
Over	50 units @	$0.3829	$22.59	$38.29	$52.46	$52.84	$44.42	$31.40	$241.99								
	COG 1	$0.8159	$88.93						$88.93								
	COG 2	$0.8159		$122.39					$122.39								
	COG 3	$0.8159			$152.57				$152.57								
	COG 4	$0.8935				$167.98			$167.98								
	COG 5	$0.7600					$126.16		$126.16								
	COG 6	$0.7600						$100.32	$100.32								
Winter Period 2012-2013 Avg. COG		$0.8137 *															
	LDAC	$0.0720	$7.85	$10.80	$13.46	$13.54	$11.95	$9.50	$67.10								
Summer 2013																	
Customer Charge	units @	$ 13.73								$ 13.73	$13.73	$13.73	$13.73	$ 13.73	$13.73	$82.38	
First	50 units @	$0.4410								$22.05	$22.05	$13.23	$13.23	$18.52	$22.05	$111.13	
Over	50 units @	$0.4410								$17.64	$2.21	$0.00	$0.00	$0.00	$9.26	$29.11	
	COG 1	$0.5553								$49.98						$49.98	
	COG 2	$0.5553									$30.54					$30.54	
	COG 3	$0.5553										$16.66				$16.66	
	COG 4	$0.5553											$16.66			$16.66	
	COG 5	$0.5553												$23.32		$23.32	
	COG 6	$0.5553													$39.43	$39.43	
Summer Period 2013 Avg. COG		$0.5553 *															
	LDAC	$ 0.0551								$4.96	$3.03	$1.65	$1.65	$2.31	$3.91	$17.52	
	TOTAL		$155.15	$207.26	$254.27	$270.13	$218.31	$177.00	$1,282.13	$108.36	$71.56	$45.27	$45.27	$57.89	$88.38	**$416.73**	$1,698.85

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2011 - 2012																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4395	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$131.85								
Over	50 units @	$0.3283	$19.37	$32.83	$44.98	$45.31	$38.08	$26.92	$207.49								
	COG 1	$1.0837	$118.12						$118.12								
	COG 2	$1.0837		$162.56					$162.56								
	COG 3	$1.1560			$216.17				$216.17								
	COG 4	$1.1560				$217.33			$217.33								
	COG 5	$1.2961					$215.15		$215.15								
	COG 6	$1.0920						$144.14	$144.14								
Winter Period 2011-2012 Avg. COG		$1.1518 *															
	LDAC	$ 0.0440	$4.80	$6.60	$8.23	$8.27	$7.30	$5.81	$41.01								
Summer 2012																	
Customer Charge	units @	$ 13.73								$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38	
First	50 units @	$0.4410								$22.05	$22.05	$13.23	$13.23	$18.52	$22.05	$111.13	
Over	50 units @	$0.4410								$17.64	$2.21	$0.00	$0.00	$0.00	$9.26	$29.11	
	COG 1	$0.4264								$38.38						$38.38	
	COG 2	$0.4006									$22.03					$22.03	
	COG 3	$0.4006										$12.02				$12.02	
	COG 4	$0.4297											$12.89			$12.89	
	COG 5	$0.4014												$16.86		$16.86	
	COG 6	$0.4014													$28.50	$28.50	
Summer Period 2012 Avg. COG		$0.4109 *															
	LDAC	$ 0.0642								$5.78	$3.53	$1.93	$1.93	$2.70	$4.56	$20.42	
	TOTAL		$173.76	$233.46	$300.85	$302.38	$292.01	$208.35	$1,510.82	$97.57	$63.55	$40.90	$41.78	$51.81	$78.10	**$373.71**	$1,884.53
	Change		($18.61)	($26.21)	($46.58)	($32.25)	($73.71)	($31.35)	($228.69)	$10.78	$8.01	$4.37	$3.50	$6.08	$10.28	**$43.02**	($185.68)
	% Chg		-10.71%	-11.22%	-15.48%	-10.66%	-25.24%	-15.04%	-15.14%	11.05%	12.60%	10.68%	8.37%	11.74%	13.16%	**11.51%**	-9.85%

*-Note- Weighted by usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2013 vs. Summer 2012

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2012- 2013																	
Customer Charge	units @	$ 31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
First	75 units @	$0.2701	$20.26	$20.26	$20.26	$20.26	$20.26	$20.26	$121.55								
Over	75 units @	$0.2226	$26.27	$43.18	$49.64	$41.63	$35.39	$21.37	$217.48								
	COG 1	$0.8279	$159.78						$159.78								
	COG 2	$0.8279		$222.71					$222.71								
	COG 3	$0.8279			$246.71				$246.71								
	COG 4	$0.8279				$216.91			$216.91								
	COG 5	$0.7720					$180.65		$180.65								
	COG 6	$0.7720						$132.01	$132.01								
Winter Period 2012-2013 Avg. COG		$0.8120 *															
	LDAC	$0.0233	$4.50	$6.27	$6.94	$6.10	$5.45	$3.98	$33.25								
Summer 2013																	
Customer Charge	units @	$ 31.40								$ 31.40	$31.40	$31.40	$31.40	$ 31.40	$31.40	$188.40	
First	75 units @	$0.2701								$20.26	$20.26	$19.45	$19.45	$20.26	$20.26	$119.92	
Over	75 units @	$0.2226								$9.35	$1.34	$0.00	$0.00	$3.12	$14.91	$28.72	
	COG 1	$0.5780								$67.63						$67.63	
	COG 2	$0.5780									$46.82					$46.82	
	COG 3	$0.5780										$41.62				$41.62	
	COG 4	$0.5780											$41.62			$41.62	
	COG 5	$0.5780												$51.44		$51.44	
	COG 6	$0.5780													$82.08	$82.08	
Summer Period 2013 Avg. COG		$0.5780 *															
	LDAC	$ 0.0266								$3.11	$2.15	$1.92	$1.92	$2.37	$3.78	$15.24	
		TOTAL	$242.21	$323.81	$354.95	$316.30	$273.15	$209.02	$1,719.45	$131.74	$101.97	$94.38	$94.38	$108.58	$152.42	**$683.48**	**$2,402.92**

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter 2011 - 2012																	
Customer Charge	units @	$ 18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$18.70	$112.20								
First	75 units @	$0.3370	$25.28	$25.28	$25.28	$25.28	$25.28	$25.28	$151.65								
Over	75 units @	$0.2300	$27.14	$44.62	$51.29	$43.01	$36.57	$22.08	$224.71								
	COG 1	$1.1166	$215.50						$215.50								
	COG 2	$1.1166		$300.37					$300.37								
	COG 3	$1.1889			$354.29				$354.29								
	COG 4	$1.1889				$311.49			$311.49								
	COG 5	$1.3290					$310.99		$310.99								
	COG 6	$1.1249						$192.36	$192.36								
Winter Period 2011-2012 Avg. COG		$1.1808 *															
	LDAC	$ 0.0233	$4.50	$6.27	$6.94	$6.10	$5.45	$3.98	$33.25								
Summer 2012																	
Customer Charge	units @	$ 31.40								$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40	
First	75 units @	$0.2701								$20.26	$20.26	$19.45	$19.45	$20.26	$20.26	$119.92	
Over	75 units @	$0.2226								$9.35	$1.34	$0.00	$0.00	$3.12	$14.91	$28.72	
	COG 1	$0.4597								$53.78						$53.78	
	COG 2	$0.4339									$35.15					$35.15	
	COG 3	$0.4339										$31.24				$31.24	
	COG 4	$0.4630											$33.34			$33.34	
	COG 5	$0.4347												$38.69		$38.69	
	COG 6	$0.4347													$61.73	$61.73	
Summer Period 2012 Avg. COG		$0.4431 *															
	LDAC	$ 0.0435								$5.09	$3.52	$3.13	$3.13	$3.87	$6.18	$24.93	
		TOTAL	$291.12	$395.23	$456.50	$404.58	$396.98	$262.40	$2,206.81	$119.88	$91.66	$85.22	$87.32	$97.33	$134.48	**$615.89**	**$2,822.69**
		Change	($48.91)	($71.41)	($101.55)	($88.28)	($123.83)	($53.37)	($487.36)	$11.86	$10.30	$9.16	$7.06	$11.25	$17.95	**$67.59**	**($419.77)**
		% Chg	-16.80%	-18.07%	-22.24%	-21.82%	-31.19%	-20.34%	-22.08%	9.90%	11.24%	10.75%	8.09%	11.56%	13.35%	**10.97%**	**-14.87%**

*-Note- Weighted by usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2013 vs. Summer 2012

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2012- 2013																	
Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
All	units @	$0.2016	$313.08	$519.72	$658.22	$827.16	$685.84	$498.56	$3,502.60								
	COG 1	$0.8279	$1,285.73						$1,285.73								
	COG 2	$0.8279		$2,134.33					$2,134.33								
	COG 3	$0.8279			$2,703.09				$2,703.09								
	COG 4	$0.9055				$3,715.27			$3,715.27								
	COG 5	$0.7720					$2,626.34		$2,626.34								
	COG 6	$0.7720						$1,909.16	$1,909.16								
Winter Period 2012-2013 Avg. COG		$0.8273 *															
	LDAC	$0.0435	$67.56	$112.14	$142.03	$178.48	$147.99	$107.58	$755.77								
Summer 2013																	
Customer Charge	units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
All	units @	$0.1557								$195.87	$109.15	$64.46	$33.16	$56.67	$108.83	$568.15	
	COG 1	$0.5780								$727.12						$727.12	
	COG 2	$0.5780									$405.18					$405.18	
	COG 3	$0.5780										$239.29				$239.29	
	COG 4	$0.5780											$123.11			$123.11	
	COG 5	$0.5780												$210.39		$210.39	
	COG 6	$0.5780													$404.02	$404.02	
Summer Period 2013 Avg. COG		$0.5780 *															
	LDAC	$ 0.0266								$33.46	$18.65	$11.01	$5.67	$9.68	$18.59	$97.06	
	TOTAL		$1,760.58	$2,860.40	$3,597.56	$4,815.12	$3,554.38	$2,609.50	$19,197.54	$1,050.67	$627.18	$408.97	$256.15	$370.96	$625.66	**$3,339.59**	**$22,537.14**

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
Winter 2011 - 2012																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
All	units @	$0.2235	$347.10	$576.18	$729.73	$917.02	$760.35	$552.72	$3,883.09								
	COG 1	$1.1166	$1,734.08						$1,734.08								
	COG 2	$1.1166		$2,878.59					$2,878.59								
	COG 3	$1.1889			$3,881.76				$3,881.76								
	COG 4	$1.1889				$4,878.06			$4,878.06								
	COG 5	$1.3290					$4,521.26		$4,521.26								
	COG 6	$1.1249						$2,781.88	$2,781.88								
Winter Period 2011-2012 Avg. COG		$1.1900 *															
	LDAC	$ 0.0233	$36.18	$60.07	$76.07	$95.60	$79.27	$57.62	$404.81								
Summer 2012																	
Customer Charge	units @	$ 94.21								$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26	
All	units @	$0.1557								$195.87	$109.15	$64.46	$33.16	$56.67	$108.83	$568.15	
	COG 1	$0.4597								$578.30						$578.30	
	COG 2	$0.4339									$304.16					$304.16	
	COG 3	$0.4339										$179.63				$179.63	
	COG 4	$0.4630											$98.62			$98.62	
	COG 5	$0.4347												$158.23		$158.23	
	COG 6	$0.4347													$303.86	$303.86	
Summer Period 2012 Avg. COG		$0.4447 *															
	LDAC	$ 0.0435								$54.72	$30.49	$18.01	$9.27	$15.83	$30.41	$158.73	
	TOTAL		$2,177.66	$3,575.15	$4,747.86	$5,950.98	$5,421.17	$3,452.51	$25,325.33	$923.11	$538.01	$356.31	$235.26	$324.95	$537.31	**$2,914.95**	**$28,240.28**
	Change		($417.08)	($714.74)	($1,150.31)	($1,135.86)	($1,866.79)	($843.02)	($6,127.79)	$127.56	$89.17	$52.66	$20.90	$46.01	$88.35	**$424.65**	**($5,703.14)**
	% Chg		-19.15%	-19.99%	-24.23%	-19.09%	-34.44%	-24.42%	-24.20%	13.82%	16.57%	14.78%	8.88%	14.16%	16.44%	**14.57%**	**-20.20%**

*-Note- Weighted by usage.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

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

Comparison of Summer 2013 vs. Summer 2012

		Rate	Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter 2012- 2013																	
Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
First	1,300 units @	$0.1849	$240.37	$240.37	$240.37	$240.37	$240.37	$240.37	$1,442.22								
Over	1,300 units @	$0.1482	$62.54	$116.49	$152.65	$153.09	$146.87	$84.77	$716.40								
	COG 1	$0.7507	$1,292.71						$1,292.71								
	COG 2	$0.7507		$1,565.96					$1,565.96								
	COG 3	$0.7507			$1,749.13				$1,749.13								
	COG 4	$0.8283				$1,932.42			$1,932.42								
	COG 5	$0.6948					$1,591.79		$1,591.79								
	COG 6	$0.6948						$1,300.67	$1,300.67								
Winter Period 2012-2013 Avg. COG		$0.7466 *															
	LDAC	$0.0435	$74.91	$90.74	$101.36	$101.49	$99.66	$81.43	$549.58								
Summer 2013																	
Customer Charge	units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
First	1,000 units @	$0.1325								$132.50	$132.50	$132.50	$132.50	$132.50	$132.50	$795.00	
Over	1,000 units @	$0.1011								$51.56	$37.81	$24.97	$19.21	$21.23	$32.76	$187.54	
	COG 1	$0.5180								$782.18						$782.18	
	COG 2	$0.5180									$711.73					$711.73	
	COG 3	$0.5180										$645.95				$645.95	
	COG 4	$0.5180											$616.42			$616.42	
	COG 5	$0.5180												$626.78		$626.78	
	COG 6	$0.5180													$685.83	$685.83	
Summer Period 2013 Avg. COG		$0.5180 *															
	LDAC	$ 0.0266								$40.17	$36.55	$33.17	$31.65	$32.19	$35.22	$208.94	
TOTAL			$1,764.73	$2,107.77	$2,337.71	$2,521.58	$2,172.89	$1,801.45	$12,706.13	$1,100.62	$1,012.80	$930.80	$893.99	$906.91	$980.52	$5,825.63	$18,531.76
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 2011 - 2012																	
Customer Charge	units @	$ 60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$361.80								
First	1,300 units @	$0.2155	$280.15	$280.15	$280.15	$280.15	$280.15	$280.15	$1,680.90								
Over	1,300 units @	$0.1760	$74.27	$138.34	$181.28	$181.81	$174.42	$100.67	$850.78								
	COG 1	$0.9232	$1,589.75						$1,589.75								
	COG 2	$0.9232		$1,925.80					$1,925.80								
	COG 3	$0.9955			$2,319.52				$2,319.52								
	COG 4	$0.9955				$2,322.50			$2,322.50								
	COG 5	$1.1356					$2,601.66		$2,601.66								
	COG 6	$0.9315						$1,743.77	$1,743.77								
Winter Period 2011-2012 Avg. COG		$0.9896 *															
	LDAC	$ 0.0233	$40.12	$48.60	$54.29	$54.36	$53.38	$43.62	$294.37								
Summer 2012																	
Customer Charge	units @	$ 94.21								$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26	
First	1,000 units @	$0.1325								$132.50	$132.50	$132.50	$132.50	$132.50	$132.50	$795.00	
Over	1,000 units @	$0.1011								$51.56	$37.81	$24.97	$19.21	$21.23	$32.76	$187.54	
	COG 1	$0.3835								$579.09						$579.09	
	COG 2	$0.3577									$491.48					$491.48	
	COG 3	$0.3577										$446.05				$446.05	
	COG 4	$0.3868											$460.29			$460.29	
	COG 5	$0.3585												$433.79		$433.79	
	COG 6	$0.3585													$474.65	$474.65	
Summer Period 2012 Avg. COG		$0.3673 *															
	LDAC	$ 0.0435								$65.69	$59.77	$54.24	$51.77	$52.64	$57.59	$341.69	
TOTAL			$2,044.60	$2,453.19	$2,895.53	$2,899.12	$3,169.91	$2,228.51	$15,690.85	$923.04	$815.77	$751.98	$757.98	$734.36	$791.71	$4,774.84	$20,465.69
Change			($279.86)	($345.42)	($557.82)	($377.54)	($997.01)	($427.06)	($2,984.72)	$177.58	$197.03	$178.82	$136.02	$172.55	$188.80	$1,050.79	($1,933.92)
% Chg			-13.69%	-14.08%	-19.26%	-13.02%	-31.45%	-19.16%	-19.02%	19.24%	24.15%	23.78%	17.94%	23.50%	23.85%	22.01%	-9.45%

*-Note- Weighted by usage.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2013 vs. Actual Summer 2012

Residential Heating	Summer 2012	Summer 2013
Customer Charge	$13.73	$13.73
First 50 Therms	$0.4410	$0.4410
Over 50 therms	$0.4410	$0.4410
LDAC	$0.0642	$0.0551
CGA	$0.4109	$0.5553

	Usage (Therms)	Summer 2012 Bill Amount	Summer 2013 Bill Amount	Total Bill		Base Rate		COG		LDAC	
	5	$18.31	$18.99	$0.68	3.7%	$0.00	0.0%	$0.72	3.9%	($0.05)	-0.3%
	10	$22.89	$24.24	$1.35	5.9%	$0.00	0.0%	$1.44	6.3%	($0.09)	-0.4%
	20	$32.05	$34.76	$2.71	8.4%	$0.00	0.0%	$2.89	9.0%	($0.18)	-0.6%
	25	$36.63	$40.02	$3.38	9.2%	$0.00	0.0%	$3.61	9.9%	($0.23)	-0.6%
	30	$41.21	$45.27	$4.06	9.8%	$0.00	0.0%	$4.33	10.5%	($0.27)	-0.7%
	45	$54.96	$61.04	$6.09	11.1%	$0.00	0.0%	$6.50	11.8%	($0.41)	-0.7%
Average Monthly	50	$59.54	$66.30	$6.76	11.4%	$0.00	0.0%	$7.22	12.1%	($0.46)	-0.8%
	75	$82.44	$92.59	$10.15	12.3%	$0.00	0.0%	$10.83	13.1%	($0.68)	-0.8%
	125	$128.25	$145.16	$16.91	13.2%	$0.00	0.0%	$18.05	14.1%	($1.14)	-0.9%
	150	$151.15	$171.44	$20.29	13.4%	$0.00	0.0%	$21.66	14.3%	($1.37)	-0.9%
	200	$196.96	$224.01	$27.05	13.7%	$0.00	0.0%	$28.87	14.7%	($1.82)	-0.9%

Schedule 9

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

		Summer 2012 (6 months actual)			Forecast Summer 2013 (6 months proposed)			Variance		
1	Therm Sales	5,888,480			7,625,909			1,737,429		
		.....								
2 3 4		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
5										
6	Demand Charges		$ 943,913	$ 0.1603		$ 1,049,948	$ 0.1377		$ 106,035	$ (0.0226)
7										
8	Purchased Gas		1,903,350	0.3232		2,920,655	0.3830		$ 1,017,305	$ 0.0598
9										
10	Storage & Peaking Gas		(289,188)	(0.0491)		21,832	0.0029		$ 311,020	$ 0.0520
11										
12	Hedging (Gain)/Loss		213,544	0.0363		(1,664)	(0.0002)		(215,208)	(0.0365)
13										
14										
15	Total Volumes and Cost		$ 2,771,619	$ 0.4707	$ -	$ 3,990,771	$ 0.5233	$ -	$ 1,219,152	$ 0.0526
16										
17	Prior Period Balance		($119,072)	$ (0.0202)		$ 147,647	$ 0.0194		$ 266,719	$ 0.0396
18						$ -	$ -		$ -	$ -
19	Interest		$ (8,427)	$ (0.0014)		2,290	$ 0.0003		10,717	$ 0.0017
20	Misc Credits & Costs									
21	Prior Period Adjustment									
22	Interruptible Sales Margin		-	$ -		-	$ -		-	$ -
23	Capacity Release			$ -		$ -	$ -		-	$ -
24	Working Capital Allowance		1,289	$ 0.0002		4,576	$ 0.0006		3,287	$ 0.0004
25	Bad Debt Allowance		(19,277)	$ (0.0033)		$ (617)	$ (0.0001)		18,660	$ 0.0032
26	Fuel Inventory Financing								-	$ -
27	Local Production and Storage					-	$ -		-	$ -
28	Misc Overhead		85,982	$ 0.0146		89,856	$ 0.0118		3,874	$ (0.0028)
29										
30	Total Anticipated Indirect Cost of Gas		($59,505)	$ (0.0101)		243,752	$ 0.0320		303,257	$ 0.0421
31	Total Adjusted Cost		2,712,114	$ 0.4606		4,234,523	$ 0.5553		1,522,409	$ 0.0947

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

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

Base Capacity Costs

1	**BASE SENDOUT BY CLASS**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
2	**Total Therms**									
3	Res Heat	476,200	460,839	468,668	476,200	460,839	476,200	5,599,341	2,818,946	Schedule 10B, LN 52
4	Res General	17,498	16,934	17,222	17,498	16,934	17,498	205,753	103,585	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	100,452	97,212	98,863	100,452	97,212	100,452	1,181,152	594,642	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	158,695	153,575	156,185	158,695	153,575	158,695	1,865,992	939,420	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	119,122	115,280	117,238	119,122	115,280	119,122	1,400,683	705,164	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	195,721	189,408	192,625	195,721	189,408	195,721	2,301,363	1,158,604	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	5,930	5,739	5,842	5,930	5,739	5,930	69,735	35,110	Schedule 10B, LN 58
10	G42 High Annual-High Winter	16,681	16,143	16,417	16,681	16,143	16,681	196,140	98,745	Schedule 10B, LN 59
11	Total Firm Sales	1,090,300	1,055,129	1,073,060	1,090,300	1,055,129	1,090,300	12,820,158	6,454,216	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	43.68%	43.68%	43.68%	43.68%	43.68%	43.68%			LN 3 / LN 11
15	Res General	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%			LN 5 / LN 11
17	G40 Low Annual-High Winter	14.56%	14.56%	14.56%	14.56%	14.56%	14.56%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	10.93%	10.93%	10.93%	10.93%	10.93%	10.93%			LN 7 / LN 11
19	G41 Med Annual-High Winter	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%			LN 8 / LN 11
20	G52 High Annual-Low Winter	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%			LN 9 / LN 11
21	G42 High Annual-High Winter	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%			LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			LN 11 / LN 11
23										

24	**PIPELINE BASE DEMAND COSTS**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 104,935	$ 1,259,223	$ 629,612	Schedule 1A, LN 69
26	Res Heat	$ 45,832	$ 45,832	$ 45,831	$ 45,832	$ 45,832	$ 45,832	$ 549,979	$ 274,989	LN 25 * LN 14
27	Res General	$ 1,684	$ 1,684	$ 1,684	$ 1,684	$ 1,684	$ 1,684	$ 20,209	$ 10,105	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 9,668	$ 9,668	$ 9,668	$ 9,668	$ 9,668	$ 9,668	$ 116,015	$ 58,008	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 15,273	$ 15,273	$ 15,273	$ 15,273	$ 15,273	$ 15,273	$ 183,282	$ 91,641	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 11,465	$ 11,465	$ 11,465	$ 11,465	$ 11,465	$ 11,465	$ 137,578	$ 68,789	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 18,837	$ 18,837	$ 18,837	$ 18,837	$ 18,837	$ 18,837	$ 226,045	$ 113,022	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 571	$ 571	$ 571	$ 571	$ 571	$ 571	$ 6,850	$ 3,425	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,605	$ 1,605	$ 1,605	$ 1,605	$ 1,605	$ 1,605	$ 19,265	$ 9,633	LN 25 * LN 21
34										
35	Residential	$ 47,516	$ 47,516	$ 47,515	$ 47,516	$ 47,516	$ 47,516	$ 570,189	$ 285,094	LN 26 + LN 27
36	SALES HLF CLASSES	$ 21,704	$ 21,704	$ 21,704	$ 21,704	$ 21,704	$ 21,704	$ 260,443	$ 130,222	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 35,716	$ 35,716	$ 35,716	$ 35,716	$ 35,716	$ 35,716	$ 428,592	$ 214,296	LN 29 + LN 31 + LN 33
38										

Remaining Capacity Costs

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

49

50 **REMAINING PIPELINE DEMAND**

LN		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER	
51		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 13,531	$ 2,229	$ -	$ 582	$ 5,558	$ 33,196	$ 1,810,664	$ 55,095	Schedule 1A, LN 70
53										
54	Res Heat	$ 6,686	$ 1,101	$ -	$ 287	$ 2,746	$ 16,402	$ 894,643	$ 27,222	LN 40 Col D * LN 52
55	Res General	$ 111	$ 18	$ -	$ 5	$ 46	$ 273	$ 14,870	$ 452	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 292	$ 48	$ -	$ 13	$ 120	$ 716	$ 39,064	$ 1,189	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 3,003	$ 495	$ -	$ 129	$ 1,233	$ 7,367	$ 401,806	$ 12,226	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 407	$ 67	$ -	$ 17	$ 167	$ 999	$ 54,463	$ 1,657	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 2,635	$ 434	$ -	$ 113	$ 1,082	$ 6,465	$ 352,606	$ 10,729	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 14	$ 2	$ -	$ 1	$ 6	$ 34	$ 1,835	$ 56	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 384	$ 63	$ -	$ 17	$ 158	$ 942	$ 51,379	$ 1,563	LN 47 Col D * LN 52
62	TOTAL	$ 13,531	$ 2,229	$ -	$ 582	$ 5,558	$ 33,196	$ 1,810,664	$ 55,095	Sum LN 54 : LN 61
63										
64	Residential	$ 6,797	$ 1,119	$ -	$ 292	$ 2,792	$ 16,675	$ 909,513	$ 27,675	LN 54 + LN 55
65	SALES HLF CLASSES	$ 713	$ 117	$ -	$ 31	$ 293	$ 1,748	$ 95,361	$ 2,902	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 6,022	$ 992	$ -	$ 259	$ 2,473	$ 14,773	$ 805,790	$ 24,519	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

LN		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER	
69		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 89,700	$ 14,774	$ -	$ 3,857	$ 36,846	$ 220,065	$ 12,003,312	$ 365,241	Schedule 1A, LN 73
71										
72	Res Heat	$ 44,321	$ 7,300	$ -	$ 1,906	$ 18,205	$ 108,733	$ 5,930,794	$ 180,464	LN 40 Col D * LN 70
73	Res General	$ 737	$ 121	$ -	$ 32	$ 303	$ 1,807	$ 98,577	$ 3,000	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 1,935	$ 319	$ -	$ 83	$ 795	$ 4,748	$ 258,962	$ 7,880	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 19,905	$ 3,278	$ -	$ 856	$ 8,176	$ 48,835	$ 2,663,662	$ 81,051	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 2,698	$ 444	$ -	$ 116	$ 1,108	$ 6,619	$ 361,048	$ 10,986	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 17,468	$ 2,877	$ -	$ 751	$ 7,175	$ 42,855	$ 2,337,505	$ 71,126	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 91	$ 15	$ -	$ 4	$ 37	$ 223	$ 12,163	$ 370	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 2,545	$ 419	$ -	$ 109	$ 1,046	$ 6,244	$ 340,602	$ 10,364	LN 47 Col D * LN 70
80	TOTAL	$ 89,700	$ 14,774	$ -	$ 3,857	$ 36,846	$ 220,065	$ 12,003,312	$ 365,241	Sum LN 72 : LN 79
81										
82	Residential	$ 45,057	$ 7,421	$ -	$ 1,937	$ 18,508	$ 110,540	$ 6,029,370	$ 183,464	LN 72 + LN 73
83	SALES HLF CLASSES	$ 4,724	$ 778	$ -	$ 203	$ 1,941	$ 11,590	$ 632,173	$ 19,236	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 39,919	$ 6,575	$ -	$ 1,716	$ 16,397	$ 97,934	$ 5,341,769	$ 162,541	LN 75 + LN 77 + LN 79

85

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

LN		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER	
87		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,180,758)	$ -	Schedule 1A, LN 76
89										
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,077,505)	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (17,909)	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (47,048)	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (483,933)	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (65,595)	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (424,677)	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,210)	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (61,881)	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,180,758)	$ -	Sum LN 90 : LN 97
99										
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,095,414)	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (114,853)	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (970,491)	$ -	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

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

121

122 **REMAINING RE-ENTRY FEE CREDIT**

LN		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER	
123		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
124	NH DIVISION - RE-ENTRY FEE CREDITS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 78
125										
126	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 124
127	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 124
128	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 124
129	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 124
130	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 124
131	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 124
132	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 124
133	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 124
134	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 126 : LN 133
135										
136	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 126 + LN 127
137	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 128 + LN 130 + LN 132
138	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 129 + LN 131 + LN 133

139

140 **TOTAL NON-BASE CAPACITY COSTS**

LN		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER	
141		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
142	Res Heat	$ 51,006	$ 8,401	$ -	$ 2,193	$ 20,951	$ 125,135	$ 5,747,932	$ 207,687	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 848	$ 140	$ -	$ 36	$ 348	$ 2,080	$ 95,537	$ 3,452	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 2,227	$ 367	$ -	$ 96	$ 915	$ 5,464	$ 250,977	$ 9,068	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 22,908	$ 3,773	$ -	$ 985	$ 9,410	$ 56,201	$ 2,581,534	$ 93,277	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 3,105	$ 511	$ -	$ 134	$ 1,275	$ 7,618	$ 349,916	$ 12,643	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 20,103	$ 3,311	$ -	$ 864	$ 8,258	$ 49,320	$ 2,265,433	$ 81,856	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 105	$ 17	$ -	$ 4	$ 43	$ 257	$ 11,788	$ 426	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 2,929	$ 482	$ -	$ 126	$ 1,203	$ 7,186	$ 330,101	$ 11,927	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 103,231	$ 17,002	$ -	$ 4,438	$ 42,404	$ 253,261	$ 11,633,218	$ 420,336	Sum LN 142 : LN 149
151										
152	Residential	$ 51,854	$ 8,540	$ -	$ 2,229	$ 21,300	$ 127,215	$ 5,843,469	$ 211,139	LN 142 + LN 143
153	SALES HLF CLASSES	$ 5,437	$ 895	$ -	$ 234	$ 2,233	$ 13,338	$ 612,681	$ 22,138	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 45,940	$ 7,566	$ -	$ 1,975	$ 18,871	$ 112,707	$ 5,177,068	$ 187,060	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER	
157		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**	
158	Res Heat	$ 96,838	$ 54,232	$ 45,831	$ 48,025	$ 66,783	$ 170,967	$ 6,297,911	$ 482,676	LN 142 + LN 26
159	Res General	$ 2,532	$ 1,824	$ 1,684	$ 1,721	$ 2,032	$ 3,764	$ 115,747	$ 13,557	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 11,895	$ 10,035	$ 9,668	$ 9,764	$ 10,583	$ 15,132	$ 366,992	$ 67,076	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 38,182	$ 19,046	$ 15,273	$ 16,258	$ 24,683	$ 71,475	$ 2,764,816	$ 184,918	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 14,570	$ 11,976	$ 11,465	$ 11,598	$ 12,740	$ 19,083	$ 487,494	$ 81,432	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 38,940	$ 22,148	$ 18,837	$ 19,701	$ 27,095	$ 68,157	$ 2,491,478	$ 194,878	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 675	$ 588	$ 571	$ 575	$ 614	$ 827	$ 18,638	$ 3,851	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 4,535	$ 2,088	$ 1,605	$ 1,731	$ 2,809	$ 8,792	$ 349,366	$ 21,560	LN 149 + LN 33
166	TOTAL	$ 208,167	$ 121,937	$ 104,935	$ 109,374	$ 147,339	$ 358,196	$ 12,892,441	$ 1,049,948	Sum LN 158 : LN 165
167										
168	Residential	$ 99,370	$ 56,056	$ 47,515	$ 49,745	$ 68,815	$ 174,731	$ 6,413,658	$ 496,233	LN 158 + LN 159
169	SALES HLF CLASSES	$ 27,140	$ 22,599	$ 21,704	$ 21,937	$ 23,937	$ 35,042	$ 873,124	$ 152,359	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 81,656	$ 43,282	$ 35,716	$ 37,691	$ 54,587	$ 148,423	$ 5,605,659	$ 401,356	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								27.52%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								72.48%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2012 - 2013 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Normal Winter	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	Summer
1	Res Heat	609,832	484,639	465,688	480,656	519,784	771,524	16,426,972	3,332,123
2	Res General	22,409	17,808	17,112	17,662	19,100	28,350	369,628	122,442
3	**Total Residential**	**632,241**	**502,447**	**482,800**	**498,318**	**538,884**	**799,875**	**16,796,599**	**3,454,565**
4	G50 Low Annual-Low Winter	128,641	102,232	98,234	101,392	109,646	162,749	1,663,807	702,894
5	G40 Low Annual-High Winter	203,228	161,507	155,191	160,180	173,219	257,112	7,828,389	1,110,437
6	G51 Med Annual-Low Winter	152,550	121,233	116,492	120,237	130,025	192,998	1,969,961	833,535
7	G41 Med Annual-High Winter	250,645	199,189	191,400	197,552	213,634	317,101	5,978,565	1,369,522
8	G52 High Annual-Low Winter	6,860	6,046	5,805	5,980	6,227	7,318	120,363	38,235
9	G42 High Annual-High Winter	21,362	16,976	16,313	16,837	18,208	27,026	574,149	116,721
10	**Total C&I**	**763,285**	**607,183**	**583,436**	**602,178**	**650,958**	**964,304**	**18,135,234**	**4,171,344**
11	**Total Sales**	**1,395,526**	**1,109,630**	**1,066,236**	**1,100,496**	**1,189,842**	**1,764,179**	**34,931,833**	**7,625,909**
12									
13	Residential Heat & Non Heat	632,241	502,447	482,800	498,318	538,884	799,875	16,796,599	3,454,565
14	SALES HLF CLASSES	288,051	229,511	220,532	227,609	245,897	363,065	3,754,131	1,574,665
15	SALES LLF CLASSES	475,234	377,673	362,904	374,569	405,061	601,239	14,381,103	2,596,680
16	**Total Firm Sales**	**1,395,526**	**1,109,630**	**1,066,236**	**1,100,496**	**1,189,842**	**1,764,179**	**34,931,833**	**7,625,909**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccoun	Unaccounted For)							
20	Normal Winter	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
21	Res Heat	613,735	487,740	468,668	483,732	523,110	776,385	16,529,408	3,353,371
22	Res General	22,552	17,922	17,222	17,775	19,222	28,529	371,941	123,223
23	G50 Low Annual-Low Winter	129,464	102,886	98,863	102,041	110,347	163,774	1,674,247	707,376
24	G40 Low Annual-High Winter	204,528	162,540	156,185	161,205	174,328	258,732	7,877,121	1,117,518
25	G51 Med Annual-Low Winter	153,527	122,009	117,238	121,006	130,857	194,214	1,982,322	838,851
26	G41 Med Annual-High Winter	252,249	200,464	192,625	198,817	215,002	319,099	6,015,875	1,378,256
27	G52 High Annual-Low Winter	6,904	6,084	5,842	6,018	6,267	7,364	121,116	38,479
28	G42 High Annual-High Winter	21,499	17,085	16,417	16,945	18,324	27,196	577,729	117,465
29	**Subtotal**								
30	Residential	636,287	505,663	485,890	501,507	542,333	804,914	16,901,349	3,476,594
31	SALES HLF CLASSES	289,895	230,980	221,943	229,066	247,471	365,352	3,777,685	1,584,706
32	SALES LLF CLASSES	478,276	380,090	365,227	376,966	407,653	605,027	14,470,725	2,613,239
33	**Total Firm Sales**	1,404,458	1,116,732	1,073,060	1,107,539	1,197,457	1,775,293	35,149,759	7,674,538

Northern Utilities - NEW HAMPSHIRE DIVISION
2012 - 2013 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes	
	Normal Winter	
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 & Unaccou	Unaccounted For)
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Company Use, LAUF, BTU)
22	Res General	LN 2 x Adj factor (Company Use, LAUF, BTU)
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Company Use, LAUF, BTU)
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Company Use, LAUF, BTU)
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Company Use, LAUF, BTU)
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Company Use, LAUF, BTU)
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Company Use, LAUF, BTU)
28	G42 High Annual-High Winter	LN 9 x Adj factor (Company Use, LAUF, BTU)
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

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

34		
35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	15,361
37	Res General	564
38	G50 Low Annual-Low Winter	3,240
39	G40 Low Annual-High Winter	5,119
40	G51 Med Annual-Low Winter	3,843
41	G41 Med Annual-High Winter	6,314
42	G52 High Annual-Low Winter	191
43	G42 High Annual-High Winter	538
44	**Subtotal**	-
45	Residential	15,926
46	SALES HLF CLASSES	7,274
47	SALES LLF CLASSES	11,971
48	**Total Firm Sales**	**35,171**

49	**BASE SENDOUT BY CLASS - Therms**								
50	Days per Month	31	30	31	31	30	31		
51		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
52	Res Heat	476,200	460,839	468,668	476,200	460,839	476,200	5,599,341	2,818,946
53	Res General	17,498	16,934	17,222	17,498	16,934	17,498	205,753	103,585
54	G50 Low Annual-Low Winter	100,452	97,212	98,863	100,452	97,212	100,452	1,181,152	594,642
55	G40 Low Annual-High Winter	158,695	153,575	156,185	158,695	153,575	158,695	1,865,992	939,420
56	G51 Med Annual-Low Winter	119,122	115,280	117,238	119,122	115,280	119,122	1,400,683	705,164
57	G41 Med Annual-High Winter	195,721	189,408	192,625	195,721	189,408	195,721	2,301,363	1,158,604
58	G52 High Annual-Low Winter	5,930	5,739	5,842	5,930	5,739	5,930	69,735	35,110
59	G42 High Annual-High Winter	16,681	16,143	16,417	16,681	16,143	16,681	196,140	98,745
60	**Subtotal**								
61	Residential	493,699	477,773	485,890	493,699	477,773	493,699	5,805,094	2,922,531
62	SALES HLF CLASSES	225,504	218,230	221,943	225,504	218,230	225,504	2,651,570	1,334,916
63	SALES LLF CLASSES	371,097	359,126	365,227	371,097	359,126	371,097	4,363,494	2,196,768
64	**Total Firm Sales**	1,090,300	1,055,129	1,073,060	1,090,300	1,055,129	1,090,300	12,820,158	6,454,216
65									

66	**REMAINING SENDOUT BY CLASS - Therms**								
67		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
68	Res Heat	137,535	26,901	-	7,532	62,272	300,185	10,930,067	534,425
69	Res General	5,054	989	-	277	2,288	11,031	166,188	19,638
70	G50 Low Annual-Low Winter	29,012	5,675	-	1,589	13,136	63,322	493,095	112,734
71	G40 Low Annual-High Winter	45,834	8,965	-	2,510	20,752	100,037	6,011,129	178,098
72	G51 Med Annual-Low Winter	34,405	6,729	-	1,884	15,577	75,092	581,638	133,687
73	G41 Med Annual-High Winter	56,528	11,057	-	3,096	25,594	123,378	3,714,512	219,652
74	G52 High Annual-Low Winter	974	345	-	88	528	1,434	51,381	3,369
75	G42 High Annual-High Winter	4,818	942	-	264	2,181	10,515	381,589	18,720
76	**Subtotal**								
77	Residential	142,589	27,890	-	7,809	64,560	311,215	11,096,255	554,063
78	SALES HLF CLASSES	64,390	12,750	-	3,561	29,241	139,848	1,126,115	249,790
79	SALES LLF CLASSES	107,179	20,964	-	5,870	48,527	233,930	10,107,231	416,470
80	**Total Firm Sales**	314,158	61,603	-	17,239	142,328	684,994	22,329,601	1,220,323

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

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

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

	Total Division Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	484,431	429,260	55,171	12.9%	4,190	50,981	450,511	33,920	7.5%	11,047	22,873
Jun	354,205	348,153	6,053	1.7%	2,574	3,479	340,672	13,533	4.0%	8,399	5,134
Jul	286,323	300,179	-13,855	-4.6%	810	-14,665	277,859	8,465	3.0%	6,901	1,564
Aug	297,936	302,241	-4,305	-1.4%	326	-4,630	277,161	20,775	7.5%	6,899	13,876
Sep	314,137	303,338	10,799	3.6%	253	10,546	305,657	8,480	2.8%	7,585	895
Oct	424,265	361,315	62,950	17.4%	423	62,527	342,200	82,065	24.0%	8,425	73,639
Off-Peak	2,161,298	2,044,485	116,812	5.7%	7,807	109,005	1,994,060	167,238	8.4%	49,299	117,939

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	29,298	29,015	283	1.0%	28,597	701	2.5%
Jun	29,184	28,970	214	0.7%	28,482	702	2.5%
Jul	29,058	28,980	78	0.3%	28,354	704	2.5%
Aug	28,995	28,964	31	0.1%	28,291	704	2.5%
Sep	29,081	29,057	24	0.1%	28,377	704	2.5%
Oct	29,265	29,231	34	0.1%	28,562	703	2.5%
Off-Peak	29,147	29,036	111	0.4%	28,444	703	2.5%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	16.53	14.79	1.74	11.8%	15.75	0.78	5.0%
Jun	12.14	12.02	0.12	1.0%	11.96	0.18	1.5%
Jul	9.85	10.36	-0.50	-4.9%	9.80	0.05	0.5%
Aug	10.28	10.44	-0.16	-1.5%	9.80	0.48	4.9%
Sep	10.80	10.44	0.36	3.5%	10.77	0.03	0.3%
Oct	14.50	12.36	2.14	17.3%	11.98	2.52	21.0%
Off-Peak	74.15	70.41	3.74	5.3%	70.11	4.04	5.8%

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

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

	Residential Non-Heat Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	2,680	2,449	231	9.4%	-24	255	2,674	5	0.2%	-102	108
Jun	2,150	2,188	-38	-1.7%	92	-130	2,265	-115	-5.1%	-86	-29
Jul	1,954	1,735	219	12.6%	78	141	2,121	-167	-7.9%	-81	-86
Aug	1,704	1,627	76	4.7%	73	3	1,684	20	1.2%	-64	85
Sep	1,742	1,742	1	0.0%	73	-73	1,901	-159	-8.4%	-74	-85
Oct	2,014	1,700	315	18.5%	86	228	1,872	143	7.6%	-74	217
Off-Peak	12,244	11,440	804	7.0%	405	400	12,517	-273	-2.2%	-482	209

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1,593	1,608	-15	-1.0%	1,656	-63	-3.8%
Jun	1,600	1,535	65	4.2%	1,663	-63	-3.8%
Jul	1,597	1,528	69	4.5%	1,660	-63	-3.8%
Aug	1,593	1,524	69	4.5%	1,656	-63	-3.8%
Sep	1,576	1,512	64	4.2%	1,639	-63	-3.9%
Oct	1,541	1,466	75	5.1%	1,604	-63	-4.0%
Off-Peak	1,583	1,529	54	3.5%	1,646	-63	-3.9%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1.68	1.52	0.16	10.5%	1.61	0.07	4.2%
Jun	1.34	1.43	-0.08	-5.7%	1.36	-0.02	-1.3%
Jul	1.22	1.14	0.09	7.8%	1.28	-0.05	-4.2%
Aug	1.07	1.07	0.00	0.2%	1.02	0.05	5.2%
Sep	1.11	1.15	-0.05	-4.0%	1.16	-0.05	-4.7%
Oct	1.31	1.16	0.15	12.8%	1.17	0.14	12.0%
Off-Peak	7.74	7.48	0.25	3.4%	7.60	0.14	1.8%

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

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

	Residential Heat Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	104,940	82,376	22,564	27.4%	1,150	21,413	96,347	8,593	8.9%	3,059	5,534
Jun	58,957	49,473	9,484	19.2%	341	9,143	57,942	1,015	1.8%	1,848	-832
Jul	37,651	36,166	1,485	4.1%	1	1,485	37,861	-210	-0.6%	1,213	-1,423
Aug	32,980	31,340	1,640	5.2%	-40	1,680	30,381	2,600	8.6%	975	1,624
Sep	33,234	34,156	-921	-2.7%	-69	-852	33,803	-569	-1.7%	1,082	-1,650
Oct	65,449	49,470	15,979	32.3%	-62	16,041	40,922	24,527	59.9%	1,299	23,228
Off-Peak	333,212	282,980	50,232	17.8%	766	49,466	297,256	35,956	12.1%	9,489	26,467

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	21,297	21,004	293	1.4%	20,642	655	3.2%
Jun	21,207	21,062	145	0.7%	20,552	655	3.2%
Jul	21,103	21,103	0	0.0%	20,448	655	3.2%
Aug	21,068	21,095	-27	-0.1%	20,413	655	3.2%
Sep	21,133	21,176	-43	-0.2%	20,478	655	3.2%
Oct	21,292	21,319	-27	-0.1%	20,637	655	3.2%
Off-Peak	21,184	21,127	57	0.3%	20,528	655	3.2%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	4.93	3.92	1.01	25.6%	4.67	0.26	5.6%
Jun	2.78	2.35	0.43	18.4%	2.82	-0.04	-1.4%
Jul	1.78	1.71	0.07	4.1%	1.85	-0.07	-3.6%
Aug	1.57	1.49	0.08	5.4%	1.49	0.08	5.2%
Sep	1.57	1.61	-0.04	-2.5%	1.65	-0.08	-4.7%
Oct	3.07	2.32	0.75	32.5%	1.98	1.09	55.0%
Off-Peak	15.73	13.39	2.34	17.4%	14.48	1.24	8.6%

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

	Total Division C&I Metered Deliveries (Dth)										
	2012-2013	2012-2013 Compared to 2011-2012					2012-2013 Compared to 2010-2011				
	Forecast	2011-2012 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2010-2011 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	376,812	344,436	32,376	9.4%	287	32,089	351,490	25,322	7.2%	6,101	19,221
Jun	293,098	296,492	-3,394	-1.1%	202	-3,595	280,465	12,634	4.5%	4,938	7,696
Jul	246,718	262,278	-15,560	-5.9%	386	-15,945	237,876	8,842	3.7%	4,278	4,563
Aug	263,252	269,273	-6,021	-2.2%	-453	-5,569	245,096	18,156	7.4%	4,425	13,731
Sep	279,160	267,441	11,720	4.4%	140	11,580	269,953	9,207	3.4%	4,844	4,363
Oct	356,801	310,146	46,656	15.0%	-657	47,313	299,406	57,395	19.2%	5,274	52,121
Off-Peak	1,815,841	1,750,065	65,776	3.8%	-91	65,867	1,684,286	131,555	7.8%	29,912	101,643

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

	Total Division Meter Counts						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	6,408	6,403	5	0.1%	6,299	109	1.7%
Jun	6,377	6,373	4	0.1%	6,267	110	1.8%
Jul	6,358	6,349	9	0.1%	6,246	112	1.8%
Aug	6,334	6,345	-11	-0.2%	6,222	112	1.8%
Sep	6,372	6,369	3	0.1%	6,260	112	1.8%
Oct	6,432	6,446	-14	-0.2%	6,321	111	1.8%
Off-Peak	6,381	6,381	0	0.0%	6,269	111	1.8%

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

	Total Division Use Per Meter						
	2012-2013	Compared to 2011-2012			Compared to 2010-2011		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	58.80	53.79	5.01	9.3%	55.80	3.00	5.4%
Jun	45.96	46.52	-0.56	-1.2%	44.75	1.21	2.7%
Jul	38.80	41.31	-2.51	-6.1%	38.08	0.72	1.9%
Aug	41.56	42.44	-0.88	-2.1%	39.39	2.17	5.5%
Sep	43.81	41.99	1.82	4.3%	43.12	0.68	1.6%
Oct	55.47	48.11	7.36	15.3%	47.37	8.10	17.1%
Off-Peak	284.59	274.27	10.32	3.8%	268.66	15.88	5.9%

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

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

Forecast Calendar 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
May-13	2,241	60,983	20,323	12,864	25,064	15,255	2,136	686	0	139,553
Jun-13	1,781	48,464	16,151	10,223	19,919	12,123	1,698	605	0	110,963
Jul-13	1,711	46,569	15,519	9,823	19,140	11,649	1,631	580	0	106,624
Aug-13	1,766	48,066	16,018	10,139	19,755	12,024	1,684	598	0	110,050
Sep-13	1,910	51,978	17,322	10,965	21,363	13,002	1,821	623	0	118,984
Oct-13	2,835	77,152	25,711	16,275	31,710	19,300	2,703	732	0	176,418
Off-Peak	12,244	333,212	111,044	70,289	136,952	83,354	11,672	3,824	0	762,591

Forecast Calendar 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
May-13	2,241	60,983	26,458	16,003	47,343	29,742	26,500	99,292	83,494	392,057
Jun-13	1,781	48,464	21,027	12,718	37,624	23,637	21,060	87,505	75,026	328,841
Jul-13	1,711	46,569	20,204	12,221	36,153	22,712	20,237	84,020	69,965	313,791
Aug-13	1,766	48,066	20,854	12,613	37,315	23,442	20,887	86,558	79,093	330,594
Sep-13	1,910	51,978	22,551	13,640	40,352	25,351	22,587	90,128	77,852	346,350
Oct-13	2,835	77,152	33,473	20,246	59,896	37,628	33,527	105,920	78,987	449,665
Off-Peak	12,244	333,212	144,568	87,441	258,682	162,513	144,798	553,422	464,417	2,161,298

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	36%
Jun-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	34%
Jul-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	34%
Aug-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	33%
Sep-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	34%
Oct-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	39%
Off-Peak	100%	100%	77%	80%	53%	51%	8%	1%	0%	35%

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

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

Month	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-13	2,680	104,940	37,240	13,137	40,676	15,691	1,756	686	0	216,804
Jun-13	2,150	58,957	17,249	11,906	24,910	14,225	1,492	605	0	131,494
Jul-13	1,954	37,651	10,073	11,087	14,382	13,019	1,070	580	0	89,817
Aug-13	1,704	32,980	9,341	11,510	12,717	13,184	1,725	598	0	83,759
Sep-13	1,742	33,234	10,446	11,391	14,814	12,864	2,446	623	0	87,562
Oct-13	2,014	65,449	26,694	11,258	29,454	14,370	3,183	732	0	153,155
Off-Peak	12,244	333,212	111,044	70,289	136,952	83,354	11,672	3,824	0	762,591

Forecast Billed Distribution Service Usage (Dth)

Month	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-13	2,680	104,940	48,483	16,342	76,830	30,592	21,778	99,292	83,494	484,431
Jun-13	2,150	58,957	22,456	14,811	47,051	27,734	18,514	87,505	75,026	354,205
Jul-13	1,954	37,651	13,114	13,793	27,165	25,383	13,278	84,020	69,965	286,323
Aug-13	1,704	32,980	12,161	14,319	24,020	25,704	21,397	86,558	79,093	297,936
Sep-13	1,742	33,234	13,600	14,171	27,982	25,081	30,347	90,128	77,852	314,137
Oct-13	2,014	65,449	34,753	14,006	55,634	28,018	39,484	105,920	78,987	424,265
Off-Peak	12,244	333,212	144,568	87,441	258,682	162,513	144,798	553,422	464,417	2,161,298

Forecast Sales Service Percentage

Month	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	45%
Jun-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	37%
Jul-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	31%
Aug-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	28%
Sep-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	28%
Oct-13	100%	100%	77%	80%	53%	51%	8%	1%	0%	36%
Off-Peak	100%	100%	77%	80%	53%	51%	8%	1%	0%	35%

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)
May-13	392,057	0.02%	78	216,804	-77,252	139,553	139,631	0.58%	815	140,446
Jun-13	328,841	0.02%	66	131,494	-20,531	110,963	111,029	0.58%	648	111,677
Jul-13	313,791	0.02%	63	89,817	16,806	106,624	106,686	0.58%	623	107,309
Aug-13	330,594	0.02%	66	83,759	26,291	110,050	110,116	0.58%	642	110,758
Sep-13	346,350	0.02%	69	87,562	31,423	118,984	119,053	0.58%	695	119,748
Oct-13	449,665	0.02%	90	153,155	23,263	176,418	176,508	0.58%	1,030	177,538
Off-Peak	2,161,298	0.02%	432	762,591	0	762,591	763,023	0.58%	4,453	767,476

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

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

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

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

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
2	**Total Therms**								
3	Res Heat	476,200	460,839	468,668	476,200	460,839	476,200	5,599,341	2,818,946
4	Res General	17,498	16,934	17,222	17,498	16,934	17,498	205,753	103,585
5	G50 Low Annual-Low Winter	100,452	97,212	98,863	100,452	97,212	100,452	1,181,152	594,642
6	G40 Low Annual-High Winter	158,695	153,575	156,185	158,695	153,575	158,695	1,865,992	939,420
7	G51 Med Annual-Low Winter	119,122	115,280	117,238	119,122	115,280	119,122	1,400,683	705,164
8	G41 Med Annual-High Winter	195,721	189,408	192,625	195,721	189,408	195,721	2,301,363	1,158,604
9	G52 High Annual-Low Winter	5,930	5,739	5,842	5,930	5,739	5,930	69,735	35,110
10	G42 High Annual-High Winter	16,681	16,143	16,417	16,681	16,143	16,681	196,140	98,745
11	Total Firm Sales	1,090,300	1,055,129	1,073,060	1,090,300	1,055,129	1,090,300	12,820,158	6,454,216
12	**% of Total**								
13	Res Heat	43.68%	43.68%	43.68%	43.68%	43.68%	43.68%		
14	Res General	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%		
15	G50 Low Annual-Low Winter	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%		
16	G40 Low Annual-High Winter	14.56%	14.56%	14.56%	14.56%	14.56%	14.56%		
17	G51 Med Annual-Low Winter	10.93%	10.93%	10.93%	10.93%	10.93%	10.93%		
18	G41 Med Annual-High Winter	17.95%	17.95%	17.95%	17.95%	17.95%	17.95%		
19	G52 High Annual-Low Winter	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%		
20	G42 High Annual-High Winter	1.53%	1.53%	1.53%	1.53%	1.53%	1.53%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
23	TOTAL BASE COMMODITY Excld Hedging	$ 406,314	$ 396,608	$ 409,155	$ 418,860	$ 406,450	$ 428,674	$ 5,316,990	$ 2,466,061
24	Res Heat	$ 177,462	$ 173,223	$ 178,702	$ 182,942	$ 177,521	$ 187,228	$ 2,322,252	$ 1,077,078
25	Res General	$ 6,521	$ 6,365	$ 6,567	$ 6,722	$ 6,523	$ 6,880	$ 85,333	$ 39,578
26	G50 Low Annual-Low Winter	$ 37,435	$ 36,540	$ 37,696	$ 38,591	$ 37,447	$ 39,495	$ 489,867	$ 227,204
27	G40 Low Annual-High Winter	$ 59,140	$ 57,727	$ 59,553	$ 60,966	$ 59,159	$ 62,394	$ 773,895	$ 358,938
28	G51 Med Annual-Low Winter	$ 44,392	$ 43,332	$ 44,703	$ 45,763	$ 44,407	$ 46,835	$ 580,915	$ 269,433
29	G41 Med Annual-High Winter	$ 72,938	$ 71,196	$ 73,448	$ 75,190	$ 72,962	$ 76,952	$ 954,460	$ 442,685
30	G52 High Annual-Low Winter	$ 2,210	$ 2,157	$ 2,228	$ 2,278	$ 2,211	$ 2,332	$ 28,922	$ 13,415
31	G42 High Annual-High Winter	$ 6,216	$ 6,068	$ 6,260	$ 6,408	$ 6,218	$ 6,558	$ 81,346	$ 37,729
32									
33	Residential	$ 183,983	$ 179,588	$ 185,269	$ 189,664	$ 184,045	$ 194,108	$ 2,407,586	$ 1,116,656
34	SALES HLF CLASSES	$ 84,037	$ 82,030	$ 84,626	$ 86,632	$ 84,065	$ 88,662	$ 1,099,703	$ 510,052
35	SALES LLF CLASSES	$ 138,294	$ 134,990	$ 139,260	$ 142,564	$ 138,340	$ 145,904	$ 1,809,701	$ 839,353

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
37	TOTAL BASE HEDGING COMMODITY	$ (308)	$ -	$ -	$ -	$ -	$ (783)	$ 247,233	$ (1,091)
38	Res Heat	$ (134)	$ -	$ -	$ -	$ -	$ (342)	$ 107,982	$ (476)
39	Res General	$ (5)	$ -	$ -	$ -	$ -	$ (13)	$ 3,968	$ (18)
40	G50 Low Annual-Low Winter	$ (28)	$ -	$ -	$ -	$ -	$ (72)	$ 22,778	$ (100)
41	G40 Low Annual-High Winter	$ (45)	$ -	$ -	$ -	$ -	$ (114)	$ 35,985	$ (159)
42	G51 Med Annual-Low Winter	$ (34)	$ -	$ -	$ -	$ -	$ (86)	$ 27,012	$ (119)
43	G41 Med Annual-High Winter	$ (55)	$ -	$ -	$ -	$ -	$ (141)	$ 44,381	$ (196)
44	G52 High Annual-Low Winter	$ (2)	$ -	$ -	$ -	$ -	$ (4)	$ 1,345	$ (6)
45	G42 High Annual-High Winter	$ (5)	$ -	$ -	$ -	$ -	$ (12)	$ 3,782	$ (17)
46									
47	Residential	$ (139)	$ -	$ -	$ -	$ -	$ (355)	$ 111,950	$ (494)
48	SALES HLF CLASSES	$ (64)	$ -	$ -	$ -	$ -	$ (162)	$ 51,135	$ (226)
49	SALES LLF CLASSES	$ (105)	$ -	$ -	$ -	$ -	$ (267)	$ 84,149	$ (371)

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

Base Commodity Costs

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

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

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

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

Remaining Commodity Costs

		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER
50	**REMAINING SENDOUT BY CLASS**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
51	**Total Therms**								
52	Res Heat	137,535	26,901	-	7,532	62,272	300,185	10,930,067	534,425
53	Res General	5,054	989	-	277	2,288	11,031	166,188	19,638
54	G50 Low Annual-Low Winter	29,012	5,675	-	1,589	13,136	63,322	493,095	112,734
55	G40 Low Annual-High Winter	45,834	8,965	-	2,510	20,752	100,037	6,011,129	178,098
56	G51 Med Annual-Low Winter	34,405	6,729	-	1,884	15,577	75,092	581,638	133,687
57	G41 Med Annual-High Winter	56,528	11,057	-	3,096	25,594	123,378	3,714,512	219,652
58	G52 High Annual-Low Winter	974	345	-	88	528	1,434	51,381	3,369
59	G42 High Annual-High Winter	4,818	942	-	264	2,181	10,515	381,589	18,720
60	Total Firm Sales	314,158	61,603	-	17,239	142,328	684,994	22,329,601	1,220,323
61	**% of Total**								
62	Res Heat	43.78%	43.67%	43.69%	43.69%	43.75%	43.82%		
63	Res General	1.61%	1.60%	1.61%	1.61%	1.61%	1.61%		
64	G50 Low Annual-Low Winter	9.23%	9.21%	9.22%	9.22%	9.23%	9.24%		
65	G40 Low Annual-High Winter	14.59%	14.55%	14.56%	14.56%	14.58%	14.60%		
66	G51 Med Annual-Low Winter	10.95%	10.92%	10.93%	10.93%	10.94%	10.96%		
67	G41 Med Annual-High Winter	17.99%	17.95%	17.96%	17.96%	17.98%	18.01%		
68	G52 High Annual-Low Winter	0.31%	0.56%	0.51%	0.51%	0.37%	0.21%		
69	G42 High Annual-High Winter	1.53%	1.53%	1.53%	1.53%	1.53%	1.54%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
72	REMAINING COMMODITY Excld Hedging	$ 118,014	$ 24,058	$ 916	$ 7,527	$ 55,713	$ 270,199	$ 8,929,745	$ 476,427
73	Res Heat	$ 51,665	$ 10,506	$ 400	$ 3,289	$ 24,375	$ 118,409	$ 4,370,920	$ 208,645
74	Res General	$ 1,898	$ 386	$ 15	$ 121	$ 896	$ 4,351	$ 66,476	$ 7,667
75	G50 Low Annual-Low Winter	$ 10,898	$ 2,216	$ 84	$ 694	$ 5,142	$ 24,978	$ 197,325	$ 44,012
76	G40 Low Annual-High Winter	$ 17,218	$ 3,501	$ 133	$ 1,096	$ 8,123	$ 39,460	$ 2,403,664	$ 69,531
77	G51 Med Annual-Low Winter	$ 12,924	$ 2,628	$ 100	$ 823	$ 6,098	$ 29,620	$ 232,759	$ 52,193
78	G41 Med Annual-High Winter	$ 21,235	$ 4,318	$ 164	$ 1,352	$ 10,018	$ 48,667	$ 1,485,487	$ 85,754
79	G52 High Annual-Low Winter	$ 366	$ 135	$ 5	$ 39	$ 207	$ 566	$ 20,515	$ 1,316
80	G42 High Annual-High Winter	$ 1,810	$ 368	$ 14	$ 115	$ 854	$ 4,148	$ 152,597	$ 7,309
81									
82	Residential	$ 53,564	$ 10,892	$ 415	$ 3,410	$ 25,271	$ 122,760	$ 4,437,396	$ 216,311
83	SALES HLF CLASSES	$ 24,188	$ 4,979	$ 189	$ 1,555	$ 11,446	$ 55,164	$ 450,599	$ 97,521
84	SALES LLF CLASSES	$ 40,262	$ 8,187	$ 312	$ 2,563	$ 18,995	$ 92,275	$ 4,041,749	$ 162,594

85	**REMAINING COMMODITY HEDGING COSTS**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
86	TOTAL REMAINING COMMODITY HEDGING	$ (87)	$ -	$ -	$ -	$ -	$ (487)	$ 406,058	$ (573)
87	Res Heat	$ (38)	$ -	$ -	$ -	$ -	$ (213)	$ 199,926	$ (251)
88	Res General	$ (1)	$ -	$ -	$ -	$ -	$ (8)	$ 2,827	$ (9)
89	G50 Low Annual-Low Winter	$ (8)	$ -	$ -	$ -	$ -	$ (45)	$ 7,385	$ (53)
90	G40 Low Annual-High Winter	$ (13)	$ -	$ -	$ -	$ -	$ (71)	$ 112,088	$ (84)
91	G51 Med Annual-Low Winter	$ (9)	$ -	$ -	$ -	$ -	$ (53)	$ 8,697	$ (63)
92	G41 Med Annual-High Winter	$ (16)	$ -	$ -	$ -	$ -	$ (88)	$ 67,242	$ (103)
93	G52 High Annual-Low Winter	$ (0)	$ -	$ -	$ -	$ -	$ (1)	$ 913	$ (1)
94	G42 High Annual-High Winter	$ (1)	$ -	$ -	$ -	$ -	$ (7)	$ 6,979	$ (9)
95								$ -	$ -
96	Residential	$ (39)	$ -	$ -	$ -	$ -	$ (221)	$ 202,754	$ (260)
97	SALES HLF CLASSES	$ (18)	$ -	$ -	$ -	$ -	$ (99)	$ 16,995	$ (117)
98	SALES LLF CLASSES	$ (30)	$ -	$ -	$ -	$ -	$ (166)	$ 186,309	$ (196)

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

Remaining Commodity Costs

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

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

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

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
100	TOTAL COMMODITY Excld Hedging	$ 524,328	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 698,872	$ 14,246,735	$ 2,942,487
101	Res Heat	$ 229,127	$ 183,729	$ 179,102	$ 186,230	$ 201,897	$ 305,637	$ 6,693,172	$ 1,285,722
102	Res General	$ 8,419	$ 6,751	$ 6,581	$ 6,843	$ 7,419	$ 11,231	$ 151,809	$ 47,245
103	G50 Low Annual-Low Winter	$ 48,333	$ 38,757	$ 37,781	$ 39,284	$ 42,589	$ 64,473	$ 687,192	$ 271,216
104	G40 Low Annual-High Winter	$ 76,357	$ 61,228	$ 59,686	$ 62,062	$ 67,283	$ 101,854	$ 3,177,560	$ 428,470
105	G51 Med Annual-Low Winter	$ 57,316	$ 45,960	$ 44,803	$ 46,586	$ 50,505	$ 76,456	$ 813,674	$ 321,625
106	G41 Med Annual-High Winter	$ 94,173	$ 75,514	$ 73,612	$ 76,542	$ 82,981	$ 125,619	$ 2,439,947	$ 528,440
107	G52 High Annual-Low Winter	$ 2,576	$ 2,292	$ 2,232	$ 2,317	$ 2,417	$ 2,897	$ 49,437	$ 14,731
108	G42 High Annual-High Winter	$ 8,026	$ 6,436	$ 6,274	$ 6,523	$ 7,072	$ 10,706	$ 233,944	$ 45,038
109									
110	Residential	$ 237,547	$ 190,480	$ 185,684	$ 193,074	$ 209,316	$ 316,868	$ 6,844,982	$ 1,332,968
111	SALES HLF CLASSES	$ 108,225	$ 87,009	$ 84,816	$ 88,187	$ 95,511	$ 143,825	$ 1,550,303	$ 607,573
112	SALES LLF CLASSES	$ 178,556	$ 143,177	$ 139,572	$ 145,127	$ 157,336	$ 238,179	$ 5,851,450	$ 1,001,947
113	**TOTAL HEDGING COMMODITY COSTS**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
114	TOTAL HEDGING COMMODITY	$ (394)	$ -	$ -	$ -	$ -	$ (1,270)	$ 653,291	$ (1,664)
115	Res Heat	$ (172)	$ -	$ -	$ -	$ -	$ (555)	$ 307,908	$ (728)
116	Res General	$ (6)	$ -	$ -	$ -	$ -	$ (20)	$ 6,795	$ (27)
117	G50 Low Annual-Low Winter	$ (36)	$ -	$ -	$ -	$ -	$ (117)	$ 30,163	$ (153)
118	G40 Low Annual-High Winter	$ (57)	$ -	$ -	$ -	$ -	$ (185)	$ 148,074	$ (242)
119	G51 Med Annual-Low Winter	$ (43)	$ -	$ -	$ -	$ -	$ (139)	$ 35,709	$ (182)
120	G41 Med Annual-High Winter	$ (71)	$ -	$ -	$ -	$ -	$ (228)	$ 111,623	$ (299)
121	G52 High Annual-Low Winter	$ (2)	$ -	$ -	$ -	$ -	$ (5)	$ 2,258	$ (7)
122	G42 High Annual-High Winter	$ (6)	$ -	$ -	$ -	$ -	$ (19)	$ 10,761	$ (25)
123									
124	Residential	$ (179)	$ -	$ -	$ -	$ -	$ (576)	$ 314,703	$ (754)
125	SALES HLF CLASSES	$ (81)	$ -	$ -	$ -	$ -	$ (261)	$ 68,130	$ (343)
126	SALES LLF CLASSES	$ (134)	$ -	$ -	$ -	$ -	$ (433)	$ 270,458	$ (567)
127	TOTAL COMMODITY	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**SUMMER**
128	Res Heat	$ 228,955	$ 183,729	$ 179,102	$ 186,230	$ 201,897	$ 305,082	$ 7,001,080	$ 1,284,995
129	Res General	$ 8,413	$ 6,751	$ 6,581	$ 6,843	$ 7,419	$ 11,211	$ 158,605	$ 47,218
130	G50 Low Annual-Low Winter	$ 48,297	$ 38,757	$ 37,781	$ 39,284	$ 42,589	$ 64,355	$ 717,355	$ 271,063
131	G40 Low Annual-High Winter	$ 76,300	$ 61,228	$ 59,686	$ 62,062	$ 67,283	$ 101,669	$ 3,325,633	$ 428,227
132	G51 Med Annual-Low Winter	$ 57,273	$ 45,960	$ 44,803	$ 46,586	$ 50,505	$ 76,317	$ 849,383	$ 321,443
133	G41 Med Annual-High Winter	$ 94,102	$ 75,514	$ 73,612	$ 76,542	$ 82,981	$ 125,390	$ 2,551,570	$ 528,141
134	G52 High Annual-Low Winter	$ 2,574	$ 2,292	$ 2,232	$ 2,317	$ 2,417	$ 2,892	$ 51,694	$ 14,724
135	G42 High Annual-High Winter	$ 8,020	$ 6,436	$ 6,274	$ 6,523	$ 7,072	$ 10,687	$ 244,705	$ 45,012
136	Total Firm Sales	$ 523,934	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 697,603	$ 14,900,025	$ 2,940,823
137									
138	Residential	$ 237,368	$ 190,480	$ 185,684	$ 193,074	$ 209,316	$ 316,292	$ 7,159,685	$ 1,332,213
139	SALES HLF CLASSES	$ 108,144	$ 87,009	$ 84,816	$ 88,187	$ 95,511	$ 143,564	$ 1,618,432	$ 607,230
140	SALES LLF CLASSES	$ 178,422	$ 143,177	$ 139,572	$ 145,127	$ 157,336	$ 237,746	$ 6,121,908	$ 1,001,380
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								37.75%
144	SALES LLF CLASSES								62.25%

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	
100	TOTAL COMMODITY Excld Hedging	Schedule 1B, LN 41
101	Res Heat	LN 24 + LN 73
102	Res General	LN 25 + LN 74
103	G50 Low Annual-Low Winter	LN 26 + LN 75
104	G40 Low Annual-High Winter	LN 27 + LN 76
105	G51 Med Annual-Low Winter	LN 28 + LN 77
106	G41 Med Annual-High Winter	LN 29 + LN 78
107	G52 High Annual-Low Winter	LN 30 + LN 79
108	G42 High Annual-High Winter	LN 31 + LN 80
109		
110	Residential	LN 101 + LN 102
111	SALES HLF CLASSES	LN 103 + LN 105 + LN 107
112	SALES LLF CLASSES	LN 104 + LN 106 + LN 108

113	**TOTAL HEDGING COMMODITY COSTS**	
114	TOTAL HEDGING COMMODITY	Schedule 1B, LN 42
115	Res Heat	LN 38 + LN 87
116	Res General	LN 39 + LN 88
117	G50 Low Annual-Low Winter	LN 40 + LN 89
118	G40 Low Annual-High Winter	LN 41 + LN 90
119	G51 Med Annual-Low Winter	LN 42 + LN 91
120	G41 Med Annual-High Winter	LN 43 + LN 92
121	G52 High Annual-Low Winter	LN 44 + LN 93
122	G42 High Annual-High Winter	LN 45 + LN 94
123		
124	Residential	LN 115 + LN 116
125	SALES HLF CLASSES	LN 117 + LN 119 + LN 121
126	SALES LLF CLASSES	LN 118 + LN 120 + LN 122

127	**TOTAL COMMODITY**	
128	Res Heat	LN 101 + LN 115
129	Res General	LN 102 + LN 116
130	G50 Low Annual-Low Winter	LN 103 + LN 117
131	G40 Low Annual-High Winter	LN 104 + LN 118
132	G51 Med Annual-Low Winter	LN 105 + LN 119
133	G41 Med Annual-High Winter	LN 106 + LN 120
134	G52 High Annual-Low Winter	LN 107 + LN 121
135	G42 High Annual-High Winter	LN 108 + LN 122
136	Total Firm Sales	Sum LN 128 : LN 135
137		
138	Residential	LN 128 + LN 129
139	SALES HLF CLASSES	LN 130 + LN 132 + LN 134
140	SALES LLF CLASSES	LN 131 + LN 133 + LN 135
141		
142	% ALLOCATION BETWEEN SALES HLF AND LLF	
143	SALES HLF CLASSES	LN 139 / (LN 139 + LN 140)
144	SALES LLF CLASSES	LN 140 / (LN 139 + LN 140)

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

Northern Utilities, Inc. Normal Weather - Sales Service Only Commodity Volumes by Supply Source (Dth) May 2013 through October 2013							
Description	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Season
Pipeline Supplies							
Chicago	26,030	1,654	0	359	2,112	76,005	106,159
Lewiston Baseload	0	0	0	0	0	0	0
TGP Zone 6	0	0	0	0	0	656	656
PNGTS	0	0	0	0	0	2,572	2,572
Niagara	0	0	0	0	0	0	0
Tennessee Production	150,888	145,119	147,349	141,987	146,329	154,457	886,129
AGT Receipts	23,335	3,417	0	0	9,922	30,327	67,000
Subtotal Pipeline	200,253	150,190	147,349	142,346	158,362	264,017	1,062,517
Underground Storage							
Tenn Zone 4 Spot	72,701	66,078	57,747	68,263	67,370	72,933	405,092
Tennessee Storage	0	0	0	0	0	0	0
Tennesse Storage Path	72,701	66,078	57,747	68,263	67,370	72,933	405,092
W10 AMA Spot	0	0	0	0	0	0	0
Washington 10 Storage	0	0	0	0	0	0	0
W10 Storage Path	0	0	0	0	0	0	0
Subtotal Storage	72,701	66,078	57,747	68,263	67,370	72,933	405,092
Peaking Supplies							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
Peaking Supply 3	0	0	0	0	0	0	0
Peaking Supply 4	0	0	0	0	0	0	0
LNG	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Subtotal Peaking	1,350	1,395	1,395	1,260	1,395	1,350	8,145
Total Delivered (Dth)	700,535	1,021,784	1,182,700	1,030,775	903,476	610,129	5,449,399

Schedule 11B

Provided in the Winter 2012-2013 Cost-of-Gas Filing

Northern Utilities, Inc. Normal Weather - Sales Service Only Capacity Utilization by Supply Source May 2013 through October 2013			
Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Chicago	106,159	998,109	11%
Lewiston Baseload	0	1,012,000	0%
TGP Zone 6	656	916,872	0%
PNGTS	2,572	170,023	2%
Niagara	0	361,609	0%
Tennessee Production	886,129	2,033,604	44%
AGT Receipts	67,000	194,068	35%
Subtotal Pipeline	1,062,517	5,492,217	19%
Underground Storage			
Tenn Zone 4 Spot	405,092		
Tennessee Storage	0		
Tennesse Storage Path	405,092	436,194	93%
W10 AMA Spot	0		
Washington 10 Storage	0		
W10 Storage Path	0	0	
Subtotal Storage	405,092	436,194	93%
Peaking Supplies			
Peaking Supply 1	0	0	
Peaking Supply 2	0	0	
Peaking Supply 3	0	0	
Peaking Supply 4	0	0	
LNG	8,280	1,649,928	1%
Subtotal Peaking	8,145	1,649,928	0%
Total Delivered (Dth)	5,449,399	7,578,339	72%

Schedule 11D

Provided in the Winter 2012-2013 Cost-of-Gas Filing

Schedule 11E

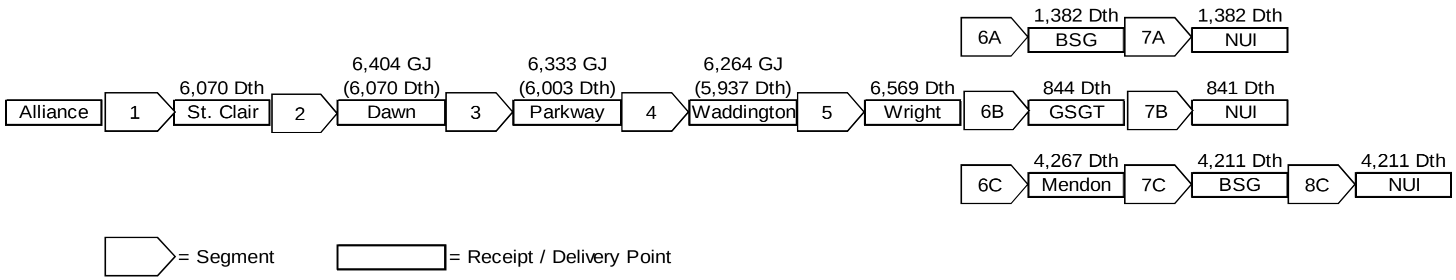
Provided in the Winter 2012-2013 Cost-of-Gas Filing

Schedule 12

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

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

Capacity Path Diagram

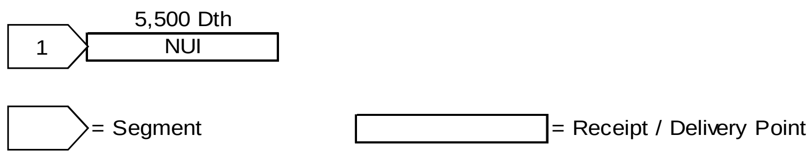


Capacity Path Detail

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

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

Capacity Path Diagram

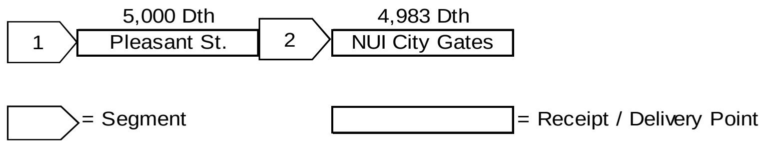


Capacity Path Detail

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

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

Capacity Path Diagram

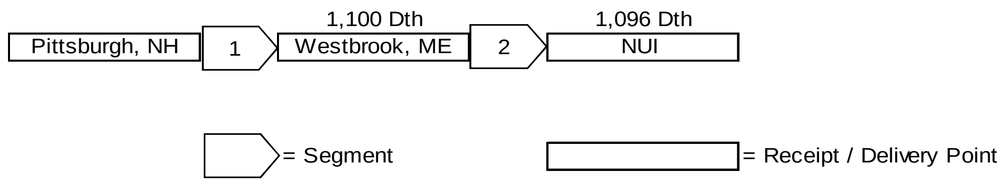


Capacity Path Detail

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

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

Capacity Path Diagram

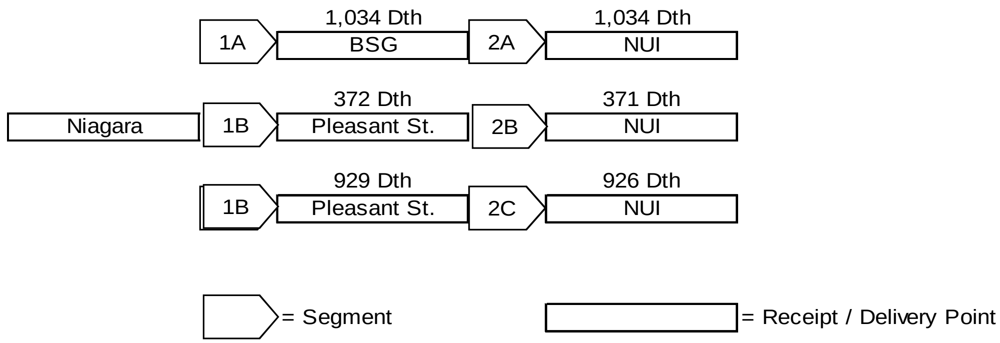


Capacity Path Detail

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

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

Capacity Path Diagram

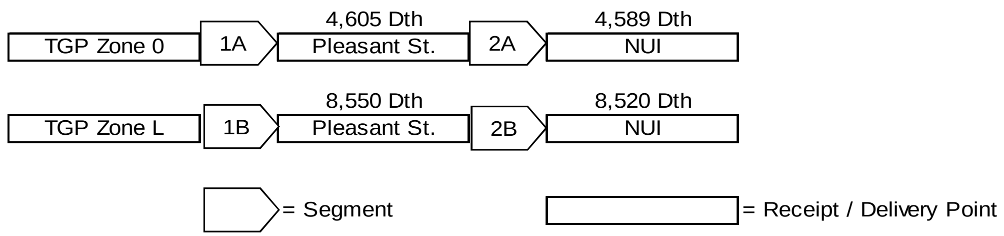


Capacity Path Detail

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

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

Capacity Path Diagram



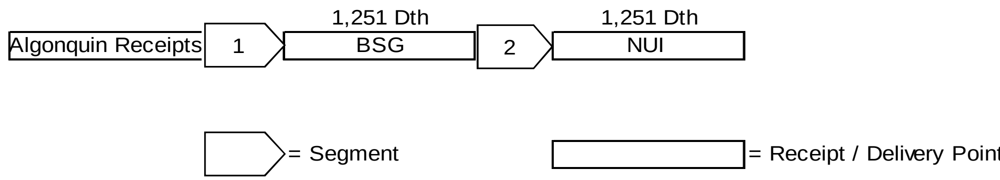
Capacity Path Detail

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

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

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

Capacity Path Diagram

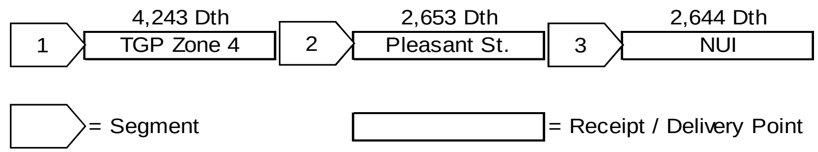


Capacity Path Detail

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

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

Capacity Path Diagram



Capacity Path Detail

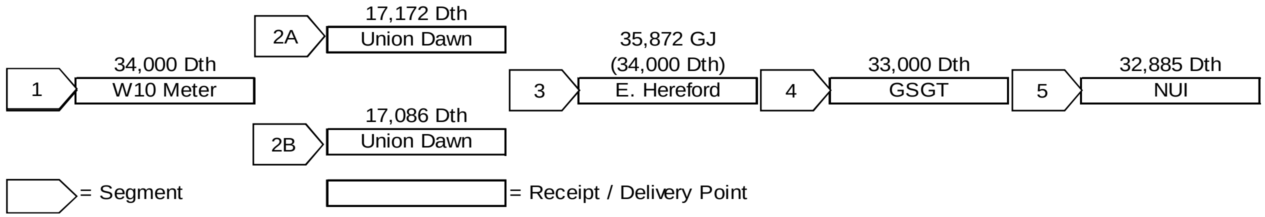
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	3/31/2015	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2015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

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

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

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

Capacity Path Diagram



Capacity Path Detail

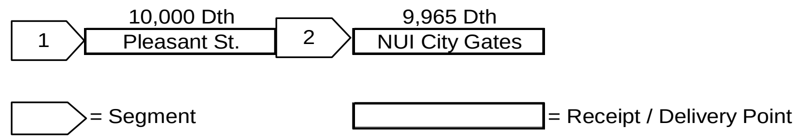
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector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

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

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

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

Capacity Path Diagram



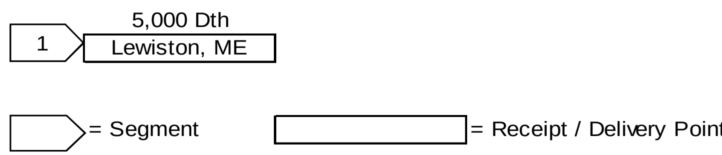
Capacity Path Detail

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

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

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

Capacity Path Diagram



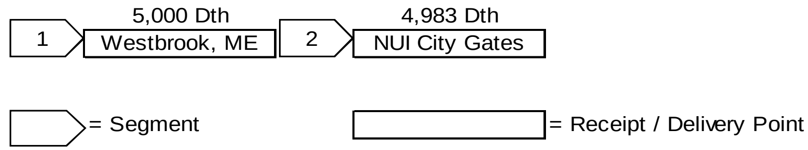
Capacity Path Detail

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

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

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

Capacity Path Diagram



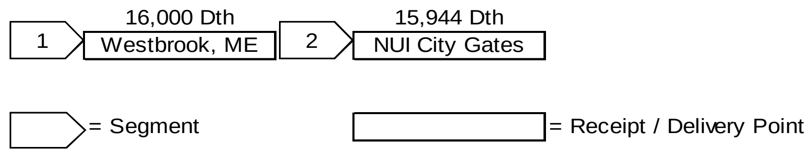
Capacity Path Detail

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

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

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

Capacity Path Diagram



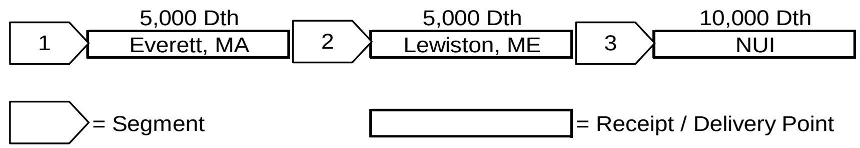
Capacity Path Detail

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

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

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

Capacity Path Diagram



Capacity Path Detail

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

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

Schedule 13

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

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

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

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

Schedule 14

Northern Utilities, Inc.
Storage Inventory and Activity Costs

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-12	190,898	-	-	190,898	$ 538,848	$ 2.82	NA	$ -	$ 2.82	$ -	$ 538,848	2.19%	$ 982	$ 538,848	$ -
Dec-12	190,898	-	-	190,898	$ 538,848	$ 2.82	NA	$ -	$ 2.82	$ -	$ 538,848	2.19%	$ 982	$ 538,848	$ -
Jan-13	190,898	-	61,274	129,624	$ 538,848	$ 2.82	NA	$ -	$ 2.82	$ 172,959	$ 365,889	2.19%	$ 824	$ 365,889	$ 172,959
Feb-13	129,624	-	55,345	74,279	$ 365,889	$ 2.82	NA	$ -	$ 2.82	$ 156,221	$ 209,667	2.19%	$ 524	$ 209,667	$ 156,221
Mar-13	74,279	-	60,963	13,316	$ 209,667	$ 2.82	NA	$ -	$ 2.82	$ 172,081	$ 37,586	2.19%	$ 225	$ 37,586	$ 172,081
Apr-13	13,316	-	13,316	-	$ 37,586	$ 2.82	NA	$ -	$ 2.82	$ 37,586	$ -	2.19%	$ 34	$ -	$ 37,586
May-13	-	39,454	-	39,454	-	NA	$ 3.62	$ 142,931	$ 3.62	$ -	$ 142,931	2.19%	$ 130	$ 142,931	$ -
Jun-13	39,454	38,182	-	77,636	$ 142,931	$ 3.62	$ 3.67	$ 140,181	$ 3.65	$ -	$ 283,113	2.19%	$ 388	$ 283,113	$ -
Jul-13	77,636	39,454	-	117,090	$ 283,113	$ 3.65	$ 3.73	$ 147,060	$ 3.67	$ -	$ 430,172	2.19%	$ 650	$ 430,172	$ -
Aug-13	117,090	39,454	-	156,544	$ 430,172	$ 3.67	$ 3.76	$ 148,180	$ 3.69	$ -	$ 578,353	2.19%	$ 919	$ 578,352	$ -
Sep-13	156,544	34,354	-	190,898	$ 578,353	$ 3.69	$ 3.76	$ 129,198	$ 3.71	$ -	$ 707,551	2.19%	$ 1,171	$ 707,550	$ -
Oct-13	190,898	-	-	190,898	$ 707,551	$ 3.71	NA	$ -	$ 3.71	$ -	$ 707,551	2.19%	$ 1,289	$ 707,550	$ -

Washington 10 Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-12	2,502,740	-	-	2,502,740	$ 8,416,715	$ 3.36	NA	$ -	$ 3.36	$ -	$ 8,416,715	2.19%		$ 8,416,715	$ -
Dec-12	2,502,740	-	214,240	2,288,500	$ 8,416,715	$ 3.36	NA	$ -	$ 3.36	$ 720,489	$ 7,696,225	2.19%		$ 7,696,225	$ 720,489
Jan-13	2,288,500	-	598,676	1,689,824	$ 7,696,225	$ 3.36	NA	$ -	$ 3.36	$2,013,346	$ 5,682,879	2.19%		$ 5,682,879	$2,013,346
Feb-13	1,689,824	-	523,266	1,166,558	$ 5,682,879	$ 3.36	NA	$ -	$ 3.36	$1,759,744	$ 3,923,135	2.19%		$ 3,923,135	$1,759,744
Mar-13	1,166,558	-	314,219	852,340	$ 3,923,135	$ 3.36	NA	$ -	$ 3.36	$1,056,717	$ 2,866,418	2.19%		$ 2,866,418	$1,056,717
Apr-13	852,339	371,281	-	1,223,621	$ 2,866,418	$ 3.36	$ 3.65	$1,356,119	$ 3.45	$ -	$ 4,222,537	2.19%		$ 4,222,537	$ -
May-13	1,223,621	383,658	-	1,607,279	$ 4,222,537	$ 3.45	$ 3.70	$1,418,816	$ 3.51	$ -	$ 5,641,354	2.19%		$ 5,641,354	$ -
Jun-13	1,607,278	371,281	-	1,978,560	$ 5,641,354	$ 3.51	$ 3.75	$1,391,192	$ 3.55	$ -	$ 7,032,546	2.19%		$ 7,032,546	$ -
Jul-13	1,978,560	383,658	-	2,362,217	$ 7,032,546	$ 3.55	$ 3.80	$1,459,071	$ 3.59	$ -	$ 8,491,616	2.19%		$ 8,491,616	$ -
Aug-13	2,362,218	140,523	-	2,502,740	$ 8,491,616	$ 3.59	$ 3.83	$ 538,417	$ 3.61	$ -	$ 9,030,033	2.19%		$ 9,030,033	$ -
Sep-13	2,502,740	-	-	2,502,740	$ 9,030,033	$ 3.61	NA	$ -	$ 3.61	$ -	$ 9,030,033	2.19%		$ 9,030,033	$ -
Oct-13	2,502,740	-	-	2,502,740	$ 9,030,033	$ 3.61	NA	$ -	$ 3.61	$ -	$ 9,030,033	2.19%		$ 9,030,033	$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawn Value plus Charges
Nov-12	12,500	1,350	1,350	12,500	$ 56,138	$ 4.49	$ 5.40	$ 7,286	$ 4.58	$ 6,182	$ 57,241	2.19%	$ 103	$ 57,241	$ 6,182
Dec-12	12,500	145	1,395	11,250	$ 57,241	$ 4.58	$ 7.48	$ 1,085	$ 4.61	$ 6,435	$ 51,892	2.19%	$ 99	$ 51,892	$ 6,435
Jan-13	11,250	1,395	1,395	11,250	$ 51,892	$ 4.61	$ 6.88	$ 9,598	$ 4.86	$ 6,784	$ 54,706	2.19%	$ 97	$ 54,706	$ 6,784
Feb-13	11,250	1,260	1,260	11,250	$ 54,706	$ 4.86	$ 6.73	$ 8,477	$ 5.05	$ 6,364	$ 56,819	2.19%	$ 102	$ 56,819	$ 6,364
Mar-13	11,250	1,395	1,395	11,250	$ 56,819	$ 5.05	$ 5.21	$ 7,269	$ 5.07	$ 7,070	$ 57,018	2.19%	$ 104	$ 57,018	$ 7,070
Apr-13	11,250	2,600	1,350	12,500	$ 57,018	$ 5.07	$ 4.96	$ 12,883	$ 5.05	$ 6,813	$ 63,088	2.19%	$ 109	$ 63,088	$ 6,813
May-13	12,500	1,395	1,395	12,500	$ 63,088	$ 5.05	$ 4.99	$ 6,954	$ 5.04	$ 7,032	$ 63,010	2.19%	$ 115	$ 63,010	$ 7,032
Jun-13	12,500	1,350	1,350	12,500	$ 63,010	$ 5.04	$ 5.14	$ 6,939	$ 5.05	$ 6,818	$ 63,131	2.19%	$ 115	$ 63,131	$ 6,818
Jul-13	12,500	1,395	1,395	12,500	$ 63,131	$ 5.05	$ 5.23	$ 7,292	$ 5.07	$ 7,070	$ 63,352	2.19%	$ 115	$ 63,352	$ 7,070
Aug-13	12,500	145	1,395	11,250	$ 63,352	$ 5.07	$ 5.35	$ 776	$ 5.07	$ 7,075	$ 57,054	2.19%	$ 110	$ 57,054	$ 7,075
Sep-13	11,250	2,600	1,350	12,500	$ 57,054	$ 5.07	$ 5.17	$ 13,442	$ 5.09	$ 6,871	$ 63,624	2.19%	$ 110	$ 63,624	$ 6,871
Oct-13	12,500	1,395	1,395	12,500	$ 63,624	$ 5.09	$ 5.28	$ 7,366	$ 5.11	$ 7,127	$ 63,863	2.19%	$ 116	$ 63,863	$ 7,127

Schedule 15

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER SEASON BALANCE
November 2011 - October 2012

	AMOUNT	
Summer Season Beg. Balance	($119,072)	SCHEDULE 2
Less: Reported Collections	($2,582,455)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$2,857,601	SCHEDULE 4
Add: Interest	($8,427)	SCHEDULE 2
Summer Season Ending Balance	$147,647	

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER SEASON ACCOUNTS
November 2011 - October 2012
Acct 191.10

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total
SUMMER SEASON													
Summer Season Account Beginning Balance*	$ (119,072)	$ (329,649)	$ (402,306)	$ (400,801)	$ (402,023)	$ (396,840)	$ (397,959)	$ (267,470)	$ (242,584)	$ (168,146)	$ (68,911)	$ (53,445)	$ (119,072)
Plus: Cost of Firm Gas (Schedule 4)	$ (8,357)	$ (70,763)	$ 3,493	$ -	$ 6,882	$ -	$ 569,360	$ 409,557	$ 388,290	$ 423,780	$ 435,989	$ 699,370	$ 2,857,601
Less: Reported Collections (Schedule 3)	$ (201,612)	$ (905)	$ (902)	$ (136)	$ (619)	$ (45)	$ (437,971)	$ (383,981)	$ (313,297)	$ (324,224)	$ (420,358)	$ (498,406)	$ (2,582,455)
Summer Season Account Ending Balance	$ (329,042)	$ (401,316)	$ (399,715)	$ (400,937)	$ (395,759)	$ (396,884)	$ (266,570)	$ (241,894)	$ (167,591)	$ (68,591)	$ (53,280)	$ 147,519	$ 156,074
Month's Average Balance	$ (224,057)	$ (365,482)	$ (401,010)	$ (400,869)	$ (398,891)	$ (396,862)	$ (332,265)	$ (254,682)	$ (205,087)	$ (118,368)	$ (61,095)	$ 47,037	
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	$ (607)	$ (990)	$ (1,086)	$ (1,086)	$ (1,080)	$ (1,075)	$ (900)	$ (690)	$ (555)	$ (321)	$ (165)	$ 127	$ (8,427)
Summer Season Account Ending Balance w/int	$ (329,649)	$ (402,306)	$ (400,801)	$ (402,023)	$ (396,840)	$ (397,959)	$ (267,470)	$ (242,584)	$ (168,146)	$ (68,911)	$ (53,445)	$ 147,647	$ 147,647

* Adjustments to Beginning Balance:

	Nov-11
Ending Balance from Prior Filing	$ (104,463)
Adjustment related to final method used in allocating Allowance changes due to Rate Case	$ 15,032
Adjustment to reflect cost impact of revised commodity allocators 2009 and 2010 Off-Peak Periods	$ (29,641)
Total Adjustments	$ (14,609)
Adjusted Ending Balance (as shown above)	$ (119,072)

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2011 - October 2012

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total
Accrued Revenue	$ (597,610)	$ -	$ -	$ -	$ -	$ -	$ 223,762	$ (64,887)	$ (11,910)	$ 12,929	$ 87,002	$ 57,548	$ (293,167)
Billed Revenue	$ 799,222	$ 905	$ 902	$ 136	$ 619	$ 45	$ 214,210	$ 448,868	$ 325,207	$ 311,296	$ 333,356	$ 440,858	$ 2,875,622
Calendarized Revenue	$ 201,612	$ 905	$ 902	$ 136	$ 619	$ 45	$ 437,971	$ 383,981	$ 313,297	$ 324,224	$ 420,358	$ 498,406	$ 2,582,455

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2011 - October 2012

Commodity Costs	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total Off Peak**
Chesapeake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 120,818	$ 138,569	$ -	$ -	$ 10,414	**$ 269,801**
DTE	$ 48,536		$ -	$ -	$ -	$ -	$ -	$ 72,388	$ 83,346	$ 100,895	$ 109,182	$ 93,734	**$ 508,081**
Distrigas	$ 51,653	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 51,653**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 131,492	$ 171,530	$ 131,762	**$ 434,784**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 145,487	$ -	$ -	$ -	$ -	**$ 145,487**
Hiltz	$ -	$ (99)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (99)**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,420	$ -	**$ 11,420**
Repsol	$ 271,525	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 271,525**
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sequent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
South Jersey Resources	$ -	$ -	$ -	$ -	$ 11,402	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 11,402**
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Virginia Power	$ 273,846	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,846)	$ -	$ -	**$ 269,000**
Subtotal - Commodity Supply	$ 645,560	$ (99)	$ -	$ -	$ 11,402	$ -	$ -	$ 338,694	$ 221,915	$ 227,542	$ 292,132	$ 235,909	**$ 1,973,055**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 137	$ 104	$ 80	$ 112	$ 100	$ 129	**$ 663**
Portland	$ 57	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26	$ -	$ -	$ 56	**$ 138**
Tennessee	$ 3,331	$ 384	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,297	$ 6,179	$ 7,295	$ 7,932	**$ 32,418**
Subtotal - Commodity Transportation	$ 3,388	$ 384	$ -	$ -	$ -	$ -	$ 137	$ 104	$ 7,403	$ 6,291	$ 7,395	$ 8,117	**$ 33,219**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 341,151	$ 231,564	$ 249,642	$ 299,489	$ 277,253	$ 545,188	**$ 1,944,287**
Commodity Cost Reversals	$ (648,112)	$ -	$ -	$ -	$ -	$ -	$ -	$ (341,151)	$ (231,564)	$ (249,642)	$ (299,489)	$ (277,253)	**$ (2,047,211)**
Subtotal - Estimates	$ (648,112)	$ -	$ -	$ -	$ -	$ -	$ 341,151	$ (109,587)	$ 18,078	$ 49,847	$ (22,236)	$ 267,935	**$ (102,924)**
Subtotal - Supply	$ 836	$ 285	$ -	$ -	$ 11,402	$ -	$ 341,288	$ 229,211	$ 247,396	$ 283,680	$ 277,291	$ 511,961	**$ 1,903,350**
Withdrawal - Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,116	$ 46,035	$ 2,752	$ 1,471	$ 26,108	$ 5,323	**$ 96,804**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ 317	$ (58)	$ (56)	$ 361	$ (457)	$ 1,075	**$ 1,181**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,083	$ (6,769)	$ (19,912)	$ (12,784)	$ 7,841	$ 22,978	**$ (4,563)**
Off System Sales	$ (60,816)	$ -	$ -	$ -	$ (4,520)	$ -	$ -	$ (51,697)	$ (55,545)	$ (57,689)	$ 0	$ (33,540)	**$ (263,807)**
Net OBA Adjustment	$ (14,674)	$ -	$ -	$ -	$ -	$ -	$ (7,408)	$ (5,966)	$ 18	$ (2,676)	$ 274	$ 3,043	**$ (27,388)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,992	$ 4,100	$ 4,854	$ 5,046	$ 4,703	$ 2,612	**$ 25,307**
Transportation Charges	$ 5,481	$ (71,048)	$ 3,493	$ -	$ -	$ -	$ -	$ -	$ 6,259	$ 1,766	$ (19,247)	$ 7,972	**$ (65,325)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 121,426	$ 2,067	$ 1,955	$ 1,758	$ 1,367	$ 84,971	**$ 213,544**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Subtotal - Other Commodity	$ (70,009)	$ (71,048)	$ 3,493	$ -	$ (4,520)	$ -	$ 137,526	$ (12,288)	$ (59,676)	$ (62,747)	$ 20,589	$ 94,433	**$ (24,247)**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (81,103)	$ (60,118)	$ (31,197)	$ -	$ (33,540)	$ (112,213)	**$ (318,171)**
Sales for Resale Reversals	$ 60,816	$ -	$ -	$ -	$ -	$ -	$ -	$ 81,103	$ 60,118	$ 31,197	$ -	$ 33,540	**$ 266,774**
Subtotal - Estimates	$ 60,816	$ -	$ -	$ -	$ -	$ -	$ (81,103)	$ 20,985	$ 28,921	$ 31,197	$ (33,540)	$ (78,673)	**$ (51,397)**
Total Commodity Costs	**$ (8,357)**	**$ (70,763)**	**$ 3,493**	**$ -**	**$ 6,882**	**$ -**	**$ 397,711**	**$ 237,908**	**$ 216,641**	**$ 252,130**	**$ 264,340**	**$ 527,721**	**$ 1,827,707**
Demand Costs													
Assigned Summer Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 157,319	$ 157,319	$ 157,319	$ 157,319	$ 157,319	$ 157,319	**$ 943,912**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,331	$ 14,330	$ 14,331	$ 14,331	$ 14,331	$ 14,331	**$ 85,982**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 171,649**	**$ 171,648**	**$ 171,649**	**$ 171,649**	**$ 171,649**	**$ 171,649**	**$ 1,029,895**
Total Gas Costs	**$ (8,357)**	**$ (70,763)**	**$ 3,493**	**$ -**	**$ 6,882**	**$ -**	**$ 569,360**	**$ 409,557**	**$ 388,290**	**$ 423,780**	**$ 435,989**	**$ 699,370**	**$ 2,857,601**

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2011 - October 2012

Commodity Volumes:	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total Off Peak**
Chesapeake													
DTE													
Distrigas													
Emera Energy													
Hess													
Hiltz													
JP Morgan													
Repsol													
Sempra													
Sequent													
South Jersey Resources													
Spark Energy													
Sprague Energy													
Total Gas & Power													
Virginia Power													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Trans													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Sales for Resale Estimates													
Sales for Resale Reversals													
Subtotal - Estimates													
Total Commodity Volumes													
Demand:													
Summer Demand Volumes													
Miscellaneous Overhead (930.00.99)													
Total Demand Volumes													
Total Volumes													

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2011 - October 2012

Commodity Costs per Unit:	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total Off Peak**
Chesapeake													
DTE													
Distrigas													
Emera Energy													
Hess													
Hiltz													
JP Morgan													
Repsol													
Sempra													
Sequent													
South Jersey Resources													
Spark Energy													
Sprague Energy													
Total Gas & Power													
Virginia Power													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportatio													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Costs per unit													
Demand Costs													
Per Unit Summer Demand Costs													
Miscellaneous Overhead													
Total Demand Costs													
Total Costs													

NORTHERN UTILITIES, INC. - MAINE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2011 - October 2012

Commodity Costs:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total Off Peak
Chesapeake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,670	$ 128,578	$ -	$ -	$ 8,736	**$ 254,984**
DTE	$ 47,514	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,502	$ 77,336	$ 85,465	$ 91,078	$ 78,634	**$ 450,529**
Distrigas	$ 50,565	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	**$ 50,565**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 111,382	$ 143,089	$ 110,536	**$ 365,007**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 141,697	$ -	$ -	$ -	$ -	**$ 141,697**
Hiltz	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,526	$ -	**$ 9,526**
Repsol	$ 265,802	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 265,802**
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sequent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
South Jersey Resources	$ -	$ -	$ -	$ -	$ 10,798	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 10,798**
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Virginia Power	$ 268,074		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,104)	$ -	$ -	**$ 263,969**
Subtotal - Commodity Supply	$ 631,954	$ -	$ -	$ -	$ 10,798	$ -	$ -	$ 329,869	$ 205,914	$ 192,742	$ 243,693	$ 197,907	**$ 1,812,878**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 133	$ 97	$ 68	$ 94	$ 84	$ 129	**$ 605**
Portland	$ 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25	$ -	$ -	$ 47	**$ 127**
Tennessee	$ 3,261	$ 363	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,771	$ 5,234	$ 6,086	$ 6,654	**$ 28,369**
Subtotal - Commodity Transportation	$ 3,316	$ 363	$ -	$ -	$ -	$ -	$ 133	$ 97	$ 6,864	$ 5,328	$ 6,170	$ 6,830	**$ 29,101**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 332,261	$ 214,868	$ 211,464	$ 249,830	$ 232,592	$ 544,099	**$ 1,785,114**
Commodity Cost Reversals	$ (634,515)	$ -	$ -	$ -	$ -	$ -	$ -	$ (332,261)	$ (214,868)	$ (211,464)	$ (249,830)	$ (232,592)	**$ (1,875,530)**
Subtotal - Estimates	$ (634,515)	$ -	$ -	$ -	$ -	$ -	$ 332,261	$ (117,393)	$ (3,404)	$ 38,366	$ (17,238)	$ 311,507	**$ (90,416)**
Subtotal - Supply	$ 755	$ 363	$ -	$ -	$ 10,798	$ -	$ 332,394	$ 212,573	$ 209,374	$ 236,436	$ 232,625	$ 516,244	**$ 1,751,563**
Withdrawal - Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,722	$ 42,715	$ 2,447	$ 1,227	$ 21,902	$ 5,300	**$ 88,314**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ 309	$ (54)	$ (48)	$ 302	$ (384)	$ 1,072	**$ 1,198**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,977	$ (6,281)	$ (16,867)	$ (10,664)	$ 6,578	$ 22,932	**$ (325)**
Off System Sales	$ (59,540)	$ -	$ -	$ -	$ -	$ -	$ -	$ (50,350)	$ (51,540)	$ (48,867)	$ 0	$ (28,137)	**$ (238,433)**
Net OBA Adjustment	$ (12,846)	$ -	$ -	$ -	$ -	$ -	$ (7,215)	$ (5,536)	$ 15	$ (2,232)	$ 230	$ 3,037	**$ (24,547)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,888	$ 3,804	$ 4,112	$ 4,209	$ 3,945	$ 2,607	**$ 22,565**
Transportation Charges	$ 5,366	$ (62,350)	$ 3,782	$ -	$ -	$ -	$ -	$ -	$ 5,807	$ 1,496	$ (16,056)	$ 6,688	**$ (55,267)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 118,262	$ 1,918	$ 1,656	$ 1,467	$ 1,146	$ 84,801	**$ 209,251**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 499	$ 477	$ 453	$ 543	$ 613	$ 659	**$ 3,243**
Subtotal - Other Commodity	$ (67,020)	$ (62,350)	$ 3,782	$ -	$ -	$ -	$ 134,441	$ (13,306)	$ (53,964)	$ (52,519)	$ 17,975	$ 98,958	**$ 5,998**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (78,990)	$ (55,783)	$ (26,425)	$ -	$ (28,137)	$ (111,989)	**(301,324)**
Sales for Resale Reversals	$ 59,540	$ -	$ -	$ -	$ -	$ -	$ -	$ 78,990	$ 55,783	$ 26,425	$ -	$ 28,137	**248,875**
Subtotal - Estimates	$ 59,540	$ -	$ -	$ -	$ -	$ -	$ (78,990)	$ 23,207	$ 29,358	$ 26,425	$ (28,137)	$ (83,852)	**$ (52,449)**
Total Commodity Costs	**$ (6,725)**	**$ (61,987)**	**$ 3,782**	**$ -**	**$ 10,798**	**$ -**	**$ 387,846**	**$ 222,474**	**$ 184,768**	**$ 210,341**	**$ 222,463**	**$ 531,350**	**$ 1,705,112**
Demand Costs													
Assigned Summer Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 142,053	$ 142,053	$ 142,053	$ 142,053	$ 142,053	$ 142,053	$ 852,315
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,570	$ 1,570	$ 1,570	$ 1,570	$ 1,570	$ 1,570	$ 9,419
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 143,622**	**$ 143,622**	**$ 143,622**	**$ 143,622**	**$ 143,622**	**$ 143,622**	**$ 861,734**
Total Gas Costs	**$ (6,725)**	**$ (61,987)**	**$ 3,782**	**$ -**	**$ 10,798**	**$ -**	**$ 531,468**	**$ 366,096**	**$ 328,391**	**$ 353,964**	**$ 366,086**	**$ 674,972**	**$ 2,566,845**

REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2011 - October 2012

Commodity Volumes:	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total Off Peak**
Chesapeake	[redacted]												
DTE													
Distrigas													
Emera Energy													
Hess													
Hiltz													
JP Morgan													
Repsol													
Sempra													
Sequent													
South Jersey Resources													
Spark Energy													
Sprague Energy													
Total Gas & Power													
Virginia Power													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Trans													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Volumes													
Demand Costs:													
Summer Demand Volumes													
Miscellaneous Overhead (930.00.99)													
Total Demand Volumes													
Total Volumes													

REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2011 - October 2012

Commodity Costs per Unit:	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total Off Peak**
Chesapeake													
DTE													
Distrigas													
Emera Energy													
Hess													
Hiltz													
JP Morgan													
Repsol													
Sempra													
Sequent													
South Jersey Resources													
Spark Energy													
Sprague Energy													
Total Gas & Power													
Virginia Power													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportati													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Costs per unit													
Demand Costs													
Per Unit Summer Demand Costs													
Miscellaneous Overhead													
Total Demand Costs													
Total Gas Costs													

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2011 - October 2012

Commodity Costs:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total Off Peak
Chesapeake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 238,488	$ 267,147	$ -	$ -	$ 19,151	**$ 524,786**
DTE	$ 96,050	$ -	$ -	$ -	$ -	$ -	$ -	$ 142,891	$ 160,682	$ 186,360	$ 200,260	$ 172,368	**$ 958,611**
Distrigas	$ 102,218	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 102,218**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 242,874	$ 314,619	$ 242,298	**$ 799,791**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 287,184	$ -	$ -	$ -	$ -	**$ 287,184**
Hiltz	$ -	$ (99)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (99)**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,946	$ -	**$ 20,946**
Repsol	$ 537,327	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 537,327**
Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sequent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
South Jersey Resources	$ -	$ -	$ -	$ -	$ 22,200	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 22,200**
Spark Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sprague Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Gas & Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Virginia Power	$ 541,919	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,950)	$ -	$ -	**$ 532,969**
Subtotal - Commodity Supply	$ 1,277,514	$ (99)	$ -	$ -	$ 22,200	$ -	$ -	$ 668,563	$ 427,829	$ 420,284	$ 535,825	$ 433,816	**$ 3,785,933**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 270	$ 201	$ 148	$ 206	$ 184	$ 258	**$ 1,268**
Portland	$ 112	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51	$ -	$ -	$ 103	**$ 265**
Tennessee	$ 6,592	$ 747	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,068	$ 11,413	$ 13,381	$ 14,585	**$ 60,786**
Subtotal - Commodity Transportation	$ 6,704	$ 747	$ -	$ -	$ -	$ -	$ 270	$ 201	$ 14,267	$ 11,619	$ 13,565	$ 14,946	**$ 62,320**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 673,412	$ 446,432	$ 461,106	$ 549,319	$ 509,845	$ 1,089,287	**$ 3,729,401**
Commodity Cost Reversals	$ (1,282,627)	$ -	$ -	$ -	$ -	$ -	$ -	$ (673,412)	$ (446,432)	$ (461,106)	$ (549,319)	$ (509,845)	**$ (3,922,741)**
Subtotal - Estimates	$ (1,282,627)	$ -	$ -	$ -	$ -	$ -	$ 673,412	$ (226,980)	$ 14,674	$ 88,213	$ (39,474)	$ 579,442	**$ (193,340)**
Subtotal - Supply	$ 1,591	$ 648	$ -	$ -	$ 22,200	$ -	$ 673,682	$ 441,784	$ 456,770	$ 520,116	$ 509,916	$ 1,028,205	**$ 3,654,913**
Withdrawal - Underground Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,838	$ 88,750	$ 5,199	$ 2,698	$ 48,010	$ 10,623	**$ 185,118**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ 626	$ (112)	$ (104)	$ 663	$ (841)	$ 2,147	**$ 2,379**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,060	$ (13,049)	$ (36,779)	$ (23,448)	$ 14,419	$ 45,909	**$ (4,888)**
Off System Sales	$ (120,356)	$ -	$ -	$ -	$ (4,520)	$ -	$ -	$ (102,047)	$ (107,085)	$ (106,556)	$ 1	$ (61,678)	**$ (502,240)**
Net OBA Adjustment	$ (27,520)	$ -	$ -	$ -	$ -	$ -	$ (14,623)	$ (11,502)	$ 33	$ (4,908)	$ 505	$ 6,080	**$ (51,935)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,880	$ 7,904	$ 8,966	$ 9,255	$ 8,648	$ 5,219	**$ 47,872**
Transportation Charges	$ 10,846	$ (133,398)	$ 7,275	$ -	$ -	$ -	$ -	$ -	$ 12,066	$ 3,261	$ (35,302)	$ 14,659	**$ (120,592)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,688	$ 3,985	$ 3,611	$ 3,225	$ 2,513	$ 169,772	**$ 422,794**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 499	$ 477	$ 453	$ 543	$ 613	$ 659	**$ 3,243**
Subtotal - Other Commodity	$ (137,030)	$ (133,398)	$ 7,275	$ -	$ (4,520)	$ -	$ 271,967	$ (25,594)	$ (113,639)	$ (115,266)	$ 38,564	$ 193,391	$ (18,249)
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (160,093)	$ (115,901)	$ (57,622)	$ -	$ (61,677)	$ (224,202)	$ (619,495)
Sales for Resale Reversals	$ 120,356	$ -	$ -	$ -	$ -	$ -	$ -	$ 160,093	$ 115,901	$ 57,622	$ -	$ 61,677	$ 515,649
Subtotal - Estimates	$ 120,356	$ -	$ -	$ -	$ -	$ -	$ (160,093)	$ 44,192	$ 58,279	$ 57,622	$ (61,677)	$ (162,525)	**$ (103,846)**
Total Commodity Costs	**$ (15,082)**	**$ (132,749)**	**$ 7,275**	**$ -**	**$ 17,680**	**$ -**	**$ 785,556**	**$ 460,382**	**$ 401,409**	**$ 462,472**	**$ 486,803**	**$ 1,059,071**	**$ 3,532,818**
Demand Costs													
Assigned Summer Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 299,371	$ 299,371	$ 299,371	$ 299,371	$ 299,371	$ 299,371	$ 1,796,227
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,900	$ 15,900	$ 15,900	$ 15,900	$ 15,900	$ 15,900	$ 95,401
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 315,272**	**$ 315,271**	**$ 315,272**	**$ 315,272**	**$ 315,272**	**$ 315,272**	**$ 1,891,628**
Total Costs	**$ (15,082)**	**$ (132,749)**	**$ 7,275**	**$ -**	**$ 17,680**	**$ -**	**$ 1,100,828**	**$ 775,653**	**$ 716,681**	**$ 777,743**	**$ 802,075**	**$ 1,374,342**	**$ 5,424,446**

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2011 - October 2012

Commodity Volumes:	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total Off Peak**
Chesapeake													
DTE													
Distrigas													
Emera Energy													
Hess													
Hiltz													
JP Morgan													
Repsol													
Sempra													
Sequent													
South Jersey Resources													
Spark Energy													
Sprague Energy													
Total Gas & Power													
Virginia Power													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Trans													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Volumes													
Demand Costs:													
Summer Demand Volumes													
Miscellaneous Overhead (930.00.99)													
Total Demand Volumes													
Total Volumes													

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2012 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2011 - October 2012

Commodity Costs per Unit:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total Off Peak
Chesapeake	[redacted]												
DTE													
Distrigas													
Emera Energy													
Hess													
Hiltz													
JP Morgan													
Repsol													
Sempra													
Sequent													
South Jersey Resources													
Spark Energy													
Sprague Energy													
Total Gas & Power													
Virginia Power													
Subtotal - Commodity Supply													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportat													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Estimates													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
LNG Boiloff													
Transportation													
Hedging Costs													
Propane													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Subtotal - Estimates													
Total Commodity Costs per unit													
Demand Costs													
Per Unit Summer Demand Costs													
Miscellaneous Overhead													
Total Demand Costs													
Total Costs													

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2012 SUMMER SEASON COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2011 - October 2012

New Hampshire	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total
Throughput IN													
BTU Factor	1.047	1.037	1.032	1.03	1.035	1.028	1.029	1.031	1.032	1.031	1.029	1.031	
GST Meter Throughput (MCF)	528,465	774,469	924,402	771,024	625,991	456,655	353,621	305,807	274,541	291,876	301,056	396,348	6,004,255
Salem Meter (MCF)	28,517	46,797	58,942	47,478	34,494	21,251	14,628	11,332	10,022	10,329	11,898	18,768	314,456
GST Meter Throughpurt (DTH)	553,303	803,124	953,983	794,155	647,901	469,441	363,876	315,287	283,326	300,924	309,787	408,635	6,203,742
Salem Meter (DTH)	29,857	48,528	60,828	48,902	35,701	21,846	15,052	11,683	10,343	10,649	12,243	19,350	324,984
LNG/Propane													-
Total Throughput	583,160	851,653	1,014,811	843,057	683,602	491,287	378,928	326,970	293,669	311,573	322,030	427,985	6,528,726
Throughput OUT													
Residential Gas													
Charged	110,616	149,104	259,735	253,799	215,755	135,293	84,825	51,662	37,901	32,967	35,898	51,170	1,418,725
Uncharged Current	95,865	147,129	160,385	159,951	120,325	62,968	27,867	20,751	20,951	20,712	37,187	44,600	918,689
Uncharged Prior	(67,389)	(95,865)	(147,129)	(160,385)	(159,951)	(120,325)	(62,968)	(27,867)	(20,751)	(20,951)	(20,712)	(37,187)	(941,479)
Total Residential Gas	**139,091**	**200,368**	**272,991**	**253,365**	**176,129**	**77,936**	**49,724**	**44,547**	**38,101**	**32,727**	**52,373**	**58,583**	1,395,935
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	125,070	166,260	276,762	263,638	214,109	136,423	86,733	56,312	43,445	43,441	44,774	58,206	1,515,173
Uncharged Current	106,073	159,767	171,210	167,289	122,384	65,190	35,098	25,937	25,556	27,371	32,208	45,529	983,611
Uncharged Prior	(65,381)	(106,073)	(159,767)	(171,210)	(167,289)	(122,384)	(65,190)	(35,098)	(25,937)	(25,556)	(27,371)	(32,208)	(1,003,463)
Total C/I Gas	**165,762**	**219,954**	**288,205**	**259,717**	**169,205**	**79,229**	**56,642**	**47,151**	**43,064**	**45,256**	**49,611**	**71,528**	1,495,321
Transportation													
Charged	292,655	346,450	409,128	387,150	370,314	299,313	257,702	240,179	218,833	225,833	222,666	251,939	3,522,162
Uncharged Current	175,999	227,831	201,618	200,264	177,881	108,333	90,115	74,961	84,312	88,587	98,502	118,632	1,647,034
Uncharged Prior	(155,863)	(175,999)	(227,831)	(201,618)	(200,264)	(177,881)	(108,333)	(90,115)	(74,961)	(84,312)	(88,587)	(98,502)	(1,684,265)
Total Transportation	**312,791**	**398,282**	**382,915**	**385,796**	**347,931**	**229,765**	**239,484**	**225,024**	**228,184**	**230,109**	**232,581**	**272,069**	**3,484,931**
Company Use	**116**	**166**	**274**	**310**	**248**	**178**	**90**	**69**	**77**	**153**	**171**	**110**	**1,961**
Total Throughput OUT	**617,760**	**818,769**	**944,385**	**899,188**	**693,512**	**387,108**	**345,939**	**316,790**	**309,426**	**308,245**	**334,736**	**402,289**	**6,378,148**
Total Throughput IN	**583,160**	**851,653**	**1,014,811**	**843,057**	**683,602**	**491,287**	**378,928**	**326,970**	**293,669**	**311,573**	**322,030**	**427,985**	**6,528,726**
Difference IN/OUT	(34,600)	32,884	70,426	(56,131)	(9,910)	104,179	32,989	10,180	(15,757)	3,328	(12,706)	25,696	150,578
%													2.31%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER SEASON WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2011 - October 2012

SUMMER SEASON - Acct 182.21

		BEGINNING BALANCE (2)	WORKING CAP ALLOWANCE (1)	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
November 2011*	$	(400)	(7)	0.0824%	248	241	(159)	(279)	3.25%	(1)	(160)
December	$	(160)	(58)	0.0824%	1	(57)	(217)	(188)	3.25%	(1)	(217)
January 2012	$	(217)	3	0.0824%	1	4	(214)	(216)	3.25%	(1)	(214)
February	$	(214)	0	0.0824%	0	0	(214)	(214)	3.25%	(1)	(215)
March	$	(215)	6	0.0824%	1	6	(208)	(211)	3.25%	(1)	(209)
April	$	(209)	0	0.0824%	0	0	(209)	(209)	3.25%	(1)	(209)
May	$	(209)	469	0.0824%	(180)	289	79	(65)	3.25%	(0)	79
June	$	79	337	0.0824%	(139)	199	278	179	3.25%	0	278
July	$	278	320	0.0824%	(125)	195	473	376	3.25%	1	474
August	$	474	349	0.0824%	(101)	248	722	598	3.25%	2	724
September	$	724	359	0.0824%	(151)	208	932	828	3.25%	2	934
October	$	934	576	0.0824%	(224)	352	1,286	1,110	3.25%	3	1,289

(1) Working Capital Allowance calculated by taking Total Gas Costs on Sch 4, page 2 of 2, and multiplying by (9.25/365) * Interest Rate

(2) Adjustments to Beginning Balance:	Nov-11
Ending Balance from Prior Filing	($952)
Adjustment related to final method used in allocating Allowance changes due to Rate Case	$569
Adjustment to reflect cost impact of revised commodity allocators 2009 and 2010 Off-Peak Periods plus interest	($17)
Total Adjustments	$552
Adjusted Ending Balance	($400)

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SUMMER SEASON BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2011 - October 2012

SUMMER SEASON- Acct 182.22

	BEGINNING BALANCE (1)	BAD DEBT ALLOWANCE	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2011*	(353)	1,616		(1,213)	403	50	(151)	3.25%	(0)	50
December	50	(6,028)		(5)	(6,033)	(5,983)	(2,967)	3.25%	(8)	(5,991)
January 2012	(5,991)	2,960		(5)	2,955	(3,036)	(4,514)	3.25%	(12)	(3,048)
February	(3,048)	749		(1)	748	(2,300)	(2,674)	3.25%	(7)	(2,307)
March	(2,307)	3,436		(4)	3,432	1,125	(591)	3.25%	(2)	1,123
April	1,123	429		(0)	428	1,551	1,337	3.25%	4	1,555
May	1,555	959		(5,289)	(4,329)	(2,774)	(610)	3.25%	(2)	(2,776)
June	(2,776)	277		(4,842)	(4,565)	(7,341)	(5,058)	3.25%	(14)	(7,354)
July	(7,354)	2,577		(4,013)	(1,436)	(8,790)	(8,072)	3.25%	(22)	(8,812)
August	(8,812)	2,031		(3,922)	(1,891)	(10,703)	(9,758)	3.25%	(26)	(10,729)
September	(10,729)	1,102		(5,333)	(4,231)	(14,961)	(12,845)	3.25%	(35)	(14,996)
October	(14,996)	2,079		(6,313)	(4,235)	(19,230)	(17,113)	3.25%	(46)	(19,277)

(1) Adjustments to Beginning Balance:	Nov-11
Ending Balance from Prior Filing	($1,283)
Adjustment related to final method used in allocating Allowance changes due to Rate Case	$1,049
Adjustment to reflect cost impact of revised commodity allocators 2009 and 2010 Off-Peak Periods plus interest	($118)
Total Adjustments	$931
Adjusted Ending Balance	($353)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2012

	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	TOTAL
Forecast Calendar Month Sales	134,649	108,336	105,728	107,572	116,580	173,792	746,657
Actual Sales	106,365	91,696	81,165	77,983	101,984	129,654	588,848
Difference	(28,284)	(16,640)	(24,563)	(29,589)	(14,596)	(44,137)	(157,810)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	106,365	91,696	81,165	77,983	101,984	129,654	588,848
Actual Sales	106,365	91,696	81,165	77,983	101,984	129,654	588,848
Weather Variance	-	-	-	-	-	-	-
Total Variance Excluding Weather (excl weather effect)	(28,284)	(16,640)	(24,563)	(29,589)	(14,596)	(44,137)	(157,810)
Variance-difference due to meter count							(42,301)
-difference in load pattern							(115,509)
SALES							(157,810)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2012

	NORMAL MMBtu			METERS		
	2012 Forecast	2012 Actual	Difference	2012 Forecast	2012 Actual	Difference
Res Heat	331,818	265,814	(66,005)	126,876	126,759	(117)
Res General	12,184	10,746	(1,438)	9,318	9,173	(145)
Total Res	344,002	276,560	(67,442)	136,194	135,932	(262)
G-40	94,552	87,321	(7,231)	25,865	25,254	(611)
G-50	73,750	63,774	(9,975)	5,735	5,131	(604)
G-41	117,518	73,882	(43,635)	2,356	2,098	(258)
G-51	98,617	69,209	(29,408)	1,026	868	(158)
G-42	14,493	12,932	(1,562)	102	58	(44)
G-52	3,726	5,170	1,444	24	41	17
Total C & I	402,655	312,288	(90,367)	35,109	33,450	(1,659)
Total Company	746,657	588,848	(157,810)	171,303	169,382	(1,921)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2012 Forecast	2012 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.62	2.10	(0.52)	(306)	(65,699)	(66,005)	-19.89%
Res General	1.31	1.17	(0.14)	(190)	(1,248)	(1,438)	-11.80%
Total Res	3.92	3.27	(0.65)	(496)	(66,947)	(67,442)	-19.61%
G-40	3.66	3.46	(0.20)	(2,232)	(4,999)	(7,231)	-7.65%
G-50	12.86	12.43	(0.43)	(7,771)	(2,205)	(9,975)	-13.53%
G-41	49.87	35.22	(14.66)	(12,883)	(30,752)	(43,635)	-37.13%
G-51	96.13	79.73	(16.40)	(15,177)	(14,232)	(29,408)	-29.82%
G-42	141.93	222.96	81.03	(6,261)	4,700	(1,562)	-10.77%
G-52	152.31	126.09	(26.22)	2,519	(1,075)	1,444	38.75%
Total C & I	11.47	9.34	(2.13)	(41,805)	(48,562)	(90,367)	-22.44%
Total Company	4.36	3.48	(0.88)	(42,301)	(115,509)	(157,810)	-21.14%

Schedule 16

Provided in Winter 2012-13 Cost-of-Gas Filing

Schedule 17

Provided in Winter 2012-13 Cost-of-Gas Filing

Schedule 18

Provided in Winter 2012-13 Cost-of-Gas Filing

Schedule 19

Provided in Winter 2012-13 Cost-of-Gas Filing

Schedule 20

Northern Utilities, Inc.
Hedging Plan for 2014-15
Hedging Program as approved in Docket No. DG 09-141
Total Company

		Off-Peak Season		Peak Season								
		May-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Peak Season	Off-Peak Season	Total Contracts
	Ceilings*	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD			
Scheduled Purchases	04/26/13	1	1	2	2	3	3	2	1	13	2	15
	05/29/13	1	1	2	3	3	2	2	1	13	2	15
	06/26/13	1	1	2	3	3	2	2	1	13	2	15
	07/29/13	1	1	1	2	3	3	2	2	13	2	15
	08/28/13	1	1	2	2	3	3	2	1	13	2	15
	09/26/13	1	1	2	3	2	2	2	2	13	2	15
	10/29/13	1	2	1	2	3	3	2	1	12	3	15
	11/25/13	1	1	2	2	3	2	2	1	12	2	14
	12/27/13	1	1	2	3	2	2	2	2	13	2	15
	01/29/14	1	1	1	2	3	2	3	1	12	2	14
	02/26/14	1	1	2	2	3	2	2	1	12	2	14
	03/27/14	0	2	1	3	2	3	2	2	13	2	15
Make-Up Purchases (white area) Scheduled Sales (gray area)	04/28/14	-11								0	-11	-11
	05/28/14									0	0	0
	06/26/14									0	0	0
	07/29/14									0	0	0
	08/27/14									0	0	0
	09/26/14		-14							0	-14	-14
	10/29/14			-20						-20	0	-20
	11/24/14				-29					-29	0	-29
	12/29/14					-33				-33	0	-33
	01/28/15						-29			-29	0	-29
	02/25/15							-25		-25	0	-25
	03/27/15								-16	-16	0	-16
	Scheduled	11	14	20	29	33	29	25	16	152	25	177

* Ceiling Prices will be provided in April 2013.
If Maine PUC approves new hedging plan for Maine Division, futures contracts will be recalculated for New Hampshire Division only.

Northern Utilities, Inc.
3-Year Outlook for Annual Hedging Plans
Hedging Program as approved in Docket No. DG 09-141
Total Company

Line	Description	City-Gate Volumes	Percent of Sendout	Financial Contracts	City-Gate Volumes	Percent of Sendout	Financial Contracts	City-Gate Volumes	Percent of Sendout	Financial Contracts
	SUMMER PERIOD	SUMMER 2014			SUMMER 2015			SUMMER 2016		
1	Sendout Requirement (May, Oct)	623,678			634,688			645,699		
2	Financial Hedge Volume	250,000	40%	25	250,000	39%	25	260,000	40%	26
	WINTER PERIOD	WINTER 2014-15			WINTER 2015-16			WINTER 2016-17		
1	Sendout Requirement (Nov-Apr)	5,695,762			5,805,475			5,805,475		
2	Target Hedged Volume (70%)	3,987,033	70%		4,063,833	70%		4,063,833	70%	
3	Washington 10 Storage	2,226,075	39%		2,226,075	38%		2,226,075	38%	
4	Tennessee Storage	236,594	4%		236,594	4%		236,594	4%	
5	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
6	Physically Hedged Volume (=3+4+5)	2,462,669	43%		2,462,669	42%		2,462,669	42%	
7	Financial Hedge Volume (=2-6)	1,520,000	27%	152	1,600,000	28%	160	1,600,000	28%	160
8	Total Hedged Volume (=6+7)	3,982,669	70%		4,062,669	70%		4,062,669	70%	
	HEDGE PLAN YEAR	PLAN YEAR 2014-15			PLAN YEAR 2015-16			PLAN YEAR 2016-17		
9	Financial Hedge Volume	1,770,000	28%	177	1,850,000	29%	185	1,860,000	29%	186

If Maine PUC approves new hedging plan for Maine Division, futures contracts will be recalculated for New Hampshire Division only.

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts
2				
3	SUMMER PERIOD		SUMMER 2013	
4				
5	Sendout Requirement (May, Oct)	612,694		
6	Currently Held Financial Contracts	200,000	33%	20
7	Planned Financial Contracts	40,000	7%	4
8	Projected Volume Hedged	260,000	42%	26
9	Target Volume Hedged	250,000	41%	25
10	Projected Position Relative to Target Long/(Short)	10,000	2%	1
11				
12	WINTER PERIOD		WINTER 2013-14	
13				
14	Sendout Requirement	5,572,676		
15	Washington 10 Storage	2,226,075	40%	
16	Tennessee Storage	236,594	4%	
17	Fixed Price Physical Contracts	0	0%	
18	Currently Held Financial Contracts	1,220,000	22%	122
19	Planned Financial Contracts	250,000	4%	25
20	Projected Volume Hedged	3,932,669	71%	
21	Target Volume Hedged	3,900,000	70%	390
22	Projected Position Relative to Target Long/(Short)	30,000	1%	3

This update reflects financial hedging program activity through January 2013, including changes in expeced sendout requirements associated with the Company's latest sales forecast.

Schedule 21

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

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 9,964,773
Storage Demand	$ 29,862,936
Peaking Demand	$ 2,609,036
Subtotal Demand	$ 42,436,744
Capacity Release (Credit)	$ (213,450)
Asset Management (Credit)	$ (4,810,000)
Total Net Demand Costs	$ 37,413,294

Proportional Responsibility (PR) Allocators

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

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Pipeline Sendout	1,200,612	1,036,548	894,806	806,994	851,301	750,718	565,888	463,400	428,421	444,101	462,409	637,572	8,542,771
Rank	1	2	3	5	4	6	8	9	12	11	10	7	
% Max Month	100.00%	86.33%	74.53%	67.22%	70.91%	62.53%	47.13%	38.60%	35.68%	36.99%	38.51%	53.10%	
PR	13.67%	5.90%	1.21%	0.94%	0.92%	1.57%	1.07%	0.01%	2.97%	0.12%	0.15%	0.85%	29.38%
CumPR	29.38%	15.72%	9.81%	7.68%	8.60%	6.74%	4.32%	3.25%	2.97%	3.09%	3.24%	5.17%	100.00%
Product and Pipeline Demand Costs	$ 2,927,701	$ 1,566,012	$ 977,802	$ 765,507	$ 857,440	$ 672,092	$ 430,583	$ 324,255	$ 296,315	$ 308,146	$ 323,342	$ 515,578	$ 9,964,773

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	504,390	574,802	556,260	574,802	574,802	551,060	240,566	3,576,682
Design Year Pipeline Sendout	1,200,612	1,036,548	894,806	806,994	851,301	750,718	565,888	463,400	428,421	444,101	462,409	637,572	8,542,771
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	40.2%	50.4%	54.6%	57.3%	56.4%	54.4%	27.4%	29.5%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 270,093	$ 216,974	$ 176,893	$ 169,775	$ 173,837	$ 175,813	$ 141,243	$ 1,324,628

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	-	633,108	1,000,249	910,767	662,958	300,043	-	-	-	-	-	-	3,507,125
Rank	6	4	1	2	3	5	6	6	6	6	6	6	
% Max Month	0.00%	63.30%	100.00%	91.05%	66.28%	30.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	8.32%	8.95%	12.39%	0.99%	6.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.65%
CumPR	0.00%	14.32%	36.65%	27.71%	15.32%	6.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ -	$ 4,277,544	$ 10,945,374	$ 8,273,831	$ 4,574,603	$1,791,584	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,862,936
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 270,093	$ 216,974	$ 176,893	$ 169,775	$ 173,837	$ 175,813	$ 141,243	$ 1,324,628
TOTAL	$ -	$ 4,277,544	$ 10,945,374	$ 8,273,831	$ 4,574,603	$2,061,677	$ 216,974	$ 176,893	$ 169,775	$ 173,837	$ 175,813	$ 141,243	$ 31,187,564

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	1,350	20,942	52,053	18,307	1,395	21,414	1,395	1,350	1,395	1,395	1,350	4,325	126,671
Rank	12	3	1	4	9	2	8	11	7	6	10	5	
% Max Month	2.59%	40.23%	100.00%	35.17%	2.68%	41.14%	2.68%	2.59%	2.68%	2.68%	2.59%	8.31%	
PR	0.22%	1.69%	58.86%	6.72%	0.01%	0.45%	0.00%	0.00%	0.00%	0.00%	0.00%	1.13%	69.07%
CumPR	0.22%	9.75%	69.07%	8.07%	0.23%	10.21%	0.23%	0.22%	0.23%	0.23%	0.22%	1.35%	100.00%
Peaking Demand Costs	$ 5,639	$ 254,484	$ 1,802,045	$ 210,470	$ 5,889	$ 266,307	$ 5,889	$ 5,639	$ 5,889	$ 5,889	$ 5,639	$ 35,256	$ 2,609,036

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

LN	Description	Source / Calculation
1		
2		
3	Pipeline Demand	Schedule 5
4	Storage Demand	Schedule 5
5	Peaking Demand	Schedule 5
6	Subtotal Demand	Sum LN 3 : LN 5
7		
8	Capacity Release (Credit)	Schedule 5
9	Asset Management (Credit)	Schedule 5
10	Total Net Demand Costs	Sum LN 6 : LN 9
11		
12		
13	**Proportional Responsibility (PR) Allocators**	
14		
15	**Allocation of Product and Pipeline Demand Costs (including Injections) to Months**	
16		
17	Design Year Pipeline Sendout	Company Analysis
18	Rank	LN 17 Ranking
19	% Max Month	LN 17 / LN 17 MAX
20	PR	The difference between LN 19 for the month and LN 19 for next highest rank
21	CumPR	Cumulative Values, LN 20
22	Product and Pipeline Demand Costs	LN 21 * LN 3
23		
24	**Allocation of Storage Injection Fees to Months**	
25		
26	Storage Injection Volume	Company Analysis
27	Design Year Pipeline Sendout	LN 17
28	% of Deliveries Injected	LN 26 / Sum (LN 26 : LN 27)
29	Injection Fees	LN 28 * LN 22
30		
31	**Allocation of Storage Demand Costs to Months**	
32		
33	Design Year Storage	Company Analysis
34	Rank	LN 33 Ranking
35	% Max Month	LN 33 / LN 33 MAX
36	PR	The difference between LN 35 for the month and LN 35 for next highest rank
37	CumPR	Cumulative Values, LN 36
38	Storage Demand Costs	LN 37 * LN 4
39	Plus Injection Fees	LN 29
40	TOTAL	LN 38 + LN 39
41		
42	**Allocation of Peaking Demand Costs to Months**	
43		
44	Design Year Peaking Volumes	Company Analysis
45	Rank	Rank LN 44
46	% Max Month	LN 44 / LN 44 MAX
47	PR	The difference between LN 46 for the month and LN 46 for next highest rank
48	CumPR	Cumulative Values, LN 47
49	Peaking Demand Costs	LN 48 * LN 5

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

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL
Pipeline & Product Demand	$ 2,927,701	$ 1,566,012	$ 977,802	$ 765,507	$ 857,440	$ 672,092	$ 430,583	$ 324,255	$ 296,315	$ 308,146	$ 323,342	$ 515,578	$ 9,964,773
Storage Incld Inj Fees	$ -	$ 4,277,544	$ 10,945,374	$ 8,273,831	$ 4,574,603	$2,061,677	$ 216,974	$ 176,893	$ 169,775	$ 173,837	$ 175,813	$ 141,243	$ 31,187,564
Peaking	$ 5,639	$ 254,484	$ 1,802,045	$ 210,470	$ 5,889	$ 266,307	$ 5,889	$ 5,639	$ 5,889	$ 5,889	$ 5,639	$ 35,256	$ 2,609,036
Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (270,093)	$ (216,974)	$ (176,893)	$ (169,775)	$ (173,837)	$ (175,813)	$ (141,243)	$ (1,324,628)
Less: Capacity Release	$ (42,690)	$ (42,690)	$ (42,690)	$ (42,690)	$ (42,690)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (213,450)
Less: Asset Mgmt	$ (801,667)	$ (801,667)	$ (801,667)	$ (801,667)	$ (801,667)	$ (801,667)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,810,000)
Total Demand	$ 2,088,983	$ 5,253,683	$ 12,880,864	$ 8,405,451	$ 4,593,575	$1,928,316	$ 436,473	$ 329,894	$ 302,205	$ 314,036	$ 328,980	$ 550,834	$ 37,413,294

Capacity Cost Allocator based on Design Year Firm Sendout

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

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

Allocation of Demand Costs by Division

Maine	$1,114,506	$2,773,866	$6,864,371	$4,558,516	$2,450,580	$1,049,110	$239,949	$180,455	$167,527	$173,536	$180,032	$302,232	$20,054,678
New Hampshire	$974,476	$2,479,817	$6,016,494	$3,846,935	$2,142,996	$879,206	$196,524	$149,439	$134,678	$140,499	$148,949	$248,602	$17,358,616
Total	$ 2,088,983	$ 5,253,683	$ 12,880,864	$ 8,405,451	$ 4,593,575	$ 1,928,316	$ 436,473	$ 329,894	$ 302,205	$ 314,036	$ 328,980	$ 550,834	$ 37,413,294

Detailed Allocation of Demand Costs by Division

Maine	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	
Pipeline & Product Demand	$ 1,561,976	$ 826,831	$ 521,083	$ 415,156	$ 457,427	$ 365,655	$ 236,711	$ 177,370	$ 164,262	$ 170,282	$ 176,946	$ 282,887	$ 5,356,586	53.76%
Storage Incld Injection Fees	$ -	$ 2,258,479	$ 5,832,924	$ 4,487,134	$ 2,440,458	$ 1,121,666	$ 119,280	$ 96,762	$ 94,115	$ 96,062	$ 96,212	$ 77,497	$ 16,720,590	53.61%
Peaking	$ 3,008	$ 134,364	$ 960,332	$ 114,144	$ 3,142	$ 144,886	$ 3,238	$ 3,084	$ 3,265	$ 3,254	$ 3,086	$ 19,344	$ 1,395,147	53.47%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (146,946)	$ (119,280)	$ (96,762)	$ (94,115)	$ (96,062)	$ (96,212)	$ (77,497)	$ (726,874)	54.87%
Capacity Release (Credit)	$ (22,776)	$ (22,540)	$ (22,750)	$ (23,152)	$ (22,774)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (113,992)	53.40%
Asset Management (Credit)	$ (427,702)	$ (423,268)	$ (427,218)	$ (434,767)	$ (427,673)	$ (436,151)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,576,779)	53.57%
Total Allocated Demand	$ 1,114,506	$ 2,773,866	$ 6,864,371	$ 4,558,516	$ 2,450,580	$ 1,049,110	$ 239,949	$ 180,455	$ 167,527	$ 173,536	$ 180,032	$ 302,232	$ 20,054,678	53.60%

New Hampshire	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	
Pipeline & Product Demand	$ 1,365,725	$ 739,181	$ 456,719	$ 350,351	$ 400,013	$ 306,437	$ 193,872	$ 146,885	$ 132,053	$ 137,865	$ 146,396	$ 232,691	$ 4,608,187	46.24%
Storage Incld Injection Fees	$ -	$ 2,019,065	$ 5,112,450	$ 3,786,696	$ 2,134,145	$ 940,011	$ 97,694	$ 80,131	$ 75,661	$ 77,775	$ 79,601	$ 63,746	$ 14,466,973	46.39%
Peaking	$ 2,630	$ 120,120	$ 841,713	$ 96,326	$ 2,748	$ 121,421	$ 2,652	$ 2,554	$ 2,625	$ 2,635	$ 2,553	$ 15,912	$ 1,213,889	46.53%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (123,148)	$ (97,694)	$ (80,131)	$ (75,661)	$ (77,775)	$ (79,601)	$ (63,746)	$ (597,754)	45.13%
Capacity Release	$ (19,914)	$ (20,150)	$ (19,940)	$ (19,538)	$ (19,916)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (99,458)	46.60%
Asset Management	$ (373,964)	$ (378,399)	$ (374,449)	$ (366,900)	$ (373,994)	$ (365,516)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,233,221)	46.43%
Total Allocated Demand	$ 974,476	$ 2,479,817	$ 6,016,494	$ 3,846,935	$ 2,142,996	$ 879,206	$ 196,524	$ 149,439	$ 134,678	$ 140,499	$ 148,949	$ 248,602	$ 17,358,616	46.40%

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

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

Schedule 22

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	SUMMER
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	272,954	216,268	205,096	210,609	225,732	336,950	5,103,124	1,467,609
3	Total Storage	0	0	0	0	0	0	1,805,740	0
4	Total Peaking	1,395	1,350	1,395	1,395	1,350	1,395	16,425	8,280
5	Subtotal	274,349	217,618	206,491	212,004	227,082	338,345	6,925,288	1,475,889
6	Less Interruptible - Maine	0	0	0	0	0	0	0	0
7	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
8	Total Firm Supply	274,349	217,618	206,491	212,004	227,082	338,345	6,925,288	1,475,889
9	Total Firm Pipeline Sendout	272,954	216,268	205,096	210,609	225,732	336,950	5,103,124	1,467,609
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 21,716,230	$ 5,615,579
12	NYMEX Price Used for Forecast	$3.531	$3.579	$3.634	$3.662	$3.667	$3.699		
13	NYMEX Price Used for Update	$3.531	$3.579	$3.634	$3.662	$3.667	$3.699		
14	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
15	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -		
16	Total Updated Pipeline Costs	$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 21,716,230	$ 5,615,579
17									
18	Total Pipeline	$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 21,716,230	$ 5,615,579
19	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,265,688	$ -
20	Total Peaking	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 80,990	$ 41,993
21	Subtotal	$ 1,024,229	$ 819,739	$ 789,096	$ 816,171	$ 876,422	$ 1,331,915	$ 28,062,908	$ 5,657,572
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	11	-	-	-	-	11	144	22
26	Average Purchase Price	$ 3.524	$ -	$ -	$ -	$ -	$ 3.677		
27	NYMEX Price Used for Forecast	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699		
28	NYMEX Price Used for Update	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699		
29	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
30	Futures Hedging (Gain)/Loss - Allocate	$ (770)	$ -	$ -	$ -	$ -	$ (2,420)	$ 1,296,120	$ (3,190)
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	-	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699		
35	NYMEX Price Used for Update	$ 3.531	$ 3.579	$ 3.634	$ 3.662	$ 3.667	$ 3.699		
36	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 21,716,230	$ 5,615,579
41	Average Supply Cost ($/MMBtu)	$ 3.727	$ 3.759	$ 3.813	$ 3.842	$ 3.852	$ 3.932		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 21,716,230	$ 5,615,579
46	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,265,688	$ -
47	Total Peaking	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 80,990	$ 41,993
48	Firm Sales Variable Costs Excld Hedge	$ 1,024,229	$ 819,739	$ 789,096	$ 816,171	$ 876,422	$ 1,331,915	$ 28,062,908	$ 5,657,572
49	Plus Hedging (Gain)/Loss	$ (770)	$ -	$ -	$ -	$ -	$ (2,420)	$ 1,296,120	$ (3,190)
50	Total Firm Sales Variable Costs	$ 1,023,459	$ 819,739	$ 789,096	$ 816,171	$ 876,422	$ 1,329,495	$ 29,359,028	$ 5,654,382

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Schedule 6A, page 2
3	Total Storage	Schedule 6A, page 2
4	Total Peaking	Schedule 6A, page 2
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Company Analysis
7	Less Interruptible - New Hampshire	Company Analysis
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Schedule 6A, page 1
12	NYMEX Price Used for Forecast	Attachment to Schedule 6B, page 1 Line 10
13	NYMEX Price Used for Update	Attachment to Schedule 6B, page 1 Line 10
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 1
20	Total Peaking	Schedule 6A, page 1
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)	
25	NYMEX NG Futures Contracts	Schedule 7
26	Average Purchase Price	Schedule 7
27	NYMEX Price Used for Forecast	Line 12
28	NYMEX Price Used for Update	
29	Increase/(Decrease) NYMEX Price	LN 28 - LN 27
30	Futures Hedging (Gain)/Loss - Allocate	(LN 26 - LN 27 - LN 29) * LN 25*10,000
31	Price Triggered NYMEX Contracts (NH Only)	
32	NYMEX NG Futures Contracts	Schedule 7
33	Average Purchase Price	Schedule 7
34	NYMEX Price Used for Forecast	Line 14
35	NYMEX Price Used for Update	
36	Increase/(Decrease) NYMEX Price	LN 35 - LN 34
37	Futures Hedging (Gain)/Loss (NH ONLY)	(LN 33 - LN 34 - LN 36) * LN 32*10,000
38		
39	Interruptible Cost Estimate	
40	Variable Pipeline Costs Excld Hedges	LN 16
41	Average Supply Cost ($/MMBtu)	LN 40 / LN 2
42	Interruptible Cost - Maine	LN 41 * LN 6
43	Interruptible Cost - New Hampshire	LN 41 * LN 7
44		
45	Firm Sales Pipeline Commodity Excld Hedge	LN 40 - LN 42 - LN 43
46	Total Storage	LN 19
47	Total Peaking	LN 20
48	Firm Sales Variable Costs Excld Hedge	Sum LN 45 : LN 47
49	Plus Hedging (Gain)/Loss	LN 30
50	Total Firm Sales Variable Costs	LN 48 + LN 49

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

51 **Commodity Allocation Factors**

52 Firm Sales Sendout for Normal Winter, MMBtu

Line		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	OFF-PEAK
53		**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**OFF-PEAK**
54	Maine	133,903	105,941	99,182	101,246	107,334	160,807	3,410,280	708,413
55	New Hampshire	140,446	111,673	107,306	110,754	119,746	177,529	3,514,976	767,454
56	Total	274,349	217,614	206,488	212,000	227,080	338,336	6,925,256	1,475,867
57									
58	**Percentage of Total**								
59	Maine	48.81%	48.68%	48.03%	47.76%	47.27%	47.53%	49.24%	48.00%
60	New Hampshire	51.19%	51.32%	51.97%	52.24%	52.73%	52.47%	50.76%	52.00%
61	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
62									

63 **Commodity Allocation by Jurisdiction**

Line		May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL	OFF-PEAK
64	**Maine**								
65	Firm Sales Pipeline Commodity Excld Hedge	$ 496,469	$ 395,754	$ 375,629	$ 386,405	$ 411,011	$ 629,655	$ 10,678,566	$ 2,694,923
66	Hedging (Gains) Losses	$ (376)	$ -	$ -	$ -	$ -	$ (1,150)	$ 642,829	$ (1,526)
67	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,102,668	$ -
68	Peaking	$ 3,432	$ 3,319	$ 3,396	$ 3,379	$ 3,248	$ 3,387	$ 39,520	$ 20,161
69	Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Total Maine Commodity Costs	$ 499,526	$ 399,073	$ 379,025	$ 389,783	$ 414,259	$ 631,892	$ 14,463,584	$ 2,713,559
71	Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,333	$ -
72	Total Maine Variable Costs	$ 499,526	$ 399,073	$ 379,025	$ 389,783	$ 414,259	$ 631,892	$ 14,467,917	$ 2,713,559
73	**New Hampshire**								
74	Firm Sales Pipeline Commodity Excld Hedge	$ 520,728	$ 417,167	$ 406,397	$ 422,692	$ 458,539	$ 695,133	$ 11,037,664	$ 2,920,655
75	Hedging (Gains) Losses	$ (394)	$ -	$ -	$ -	$ -	$ (1,270)	$ 653,291	$ (1,664)
76	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,163,020	$ -
77	Peaking	$ 3,600	$ 3,499	$ 3,674	$ 3,696	$ 3,624	$ 3,740	$ 41,470	$ 21,832
78	New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Total New Hampshire Commodity Costs	$ 523,934	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 697,603	$ 14,895,444	$ 2,940,823
80	New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,581	$ -
81	Total New Hampshire Variable Costs	$ 523,934	$ 420,666	$ 410,071	$ 426,388	$ 462,163	$ 697,603	$ 14,900,025	$ 2,940,823
82	**Northern Utilities**								
83	Firm Sales Pipeline Commodity Excld Hedge	$ 1,017,197	$ 812,921	$ 782,026	$ 809,096	$ 869,550	$ 1,324,788	$ 21,716,230	$ 5,615,579
84	Hedging (Gains) Losses	$ (770)	$ -	$ -	$ -	$ -	$ (2,420)	$ 1,296,120	$ (3,190)
85	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,265,688	$ -
86	Peaking	$ 7,032	$ 6,818	$ 7,070	$ 7,075	$ 6,871	$ 7,127	$ 80,990	$ 41,993
87	Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Total Northern Commodity Costs	$ 1,023,459	$ 819,739	$ 789,096	$ 816,171	$ 876,422	$ 1,329,495	$ 29,359,028	$ 5,654,382
89	Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,915	$ -
90	Total Northern Variable Costs	$ 1,023,459	$ 819,739	$ 789,096	$ 816,171	$ 876,422	$ 1,329,495	$ 29,367,943	$ 5,654,382
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	Company Analysis
55	New Hampshire	Schedule 10B, LN 33 / 10
56	Total	LN 54 + LN 55
57		
58	**Percentage of Total**	
59	Maine	LN 54 / LN 56
60	New Hampshire	LN 55 / LN 56
61	Total	LN 59 + LN 60
62		
63	**Commodity Allocation by Jurisdiction**	
64	**Maine**	
65	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 59
66	Hedging (Gains) Losses	LN 30 * LN 59
67	Storage	LN 46 * LN 59
68	Peaking	LN 47 * LN 59
69	Maine Interruptible	LN 42
70	Total Maine Commodity Costs	Sum LN 65 : LN 69
71	Maine Inventory Finance Costs	LN 112
72	Total Maine Variable Costs	LN 70 + LN 71
73	**New Hampshire**	
74	Firm Sales Pipeline Commodity Excld Hedge	LN 45 * LN 60
75	Hedging (Gains) Losses	LN 30 * LN 60
76	Storage	LN 46 * LN 60
77	Peaking	LN 47 * LN 60
78	New Hampshire Interruptible	LN 43
79	Total New Hampshire Commodity Costs	Sum LN 74 : LN 78
80	New Hampshire Inventory Finance Costs	LN 117
81	Total New Hampshire Variable Costs	LN 79 + LN 80
82	**Northern Utilities**	
83	Firm Sales Pipeline Commodity Excld Hedge	LN 65 + LN 74
84	Hedging (Gains) Losses	LN 66 + LN 75
85	Storage	LN 67 + LN 76
86	Peaking	LN 68 + LN 77
87	Northern Interruptible	LN 69 + LN 78
88	Total Northern Commodity Costs	LN 70 + LN 79
89	Northern Inventory Finance Costs	LN 71 + LN 80
90	Total Northern Variable Costs	LN 88 + LN 89
91		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

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

95									
96	**Col A**	**Col H**	**Col I**	**Col J**	**Col K**	**Col L**	**Col M**	**Col N**	**Col P**
97									
98	**Inventory Finance Charge**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**TOTAL**	**OFF-PEAK**
99	Storage	$ 130	$ 388	$ 650	$ 919	$ 1,171	$ 1,289	$ 8,119	$ 4,547
100	Peaking	$ 115	$ 115	$ 115	$ 110	$ 110	$ 116	$ 1,295	$ 681
101	Total	$ 245	$ 503	$ 765	$ 1,028	$ 1,281	$ 1,405	$ 9,414	$ 5,228
102									
103	**Inventory Finance Charge Allocation by Jurisdiction**								
104	Maine	$ 120	$ 245	$ 367	$ 491	$ 606	$ 668	$ 4,568	$ 2,497
105	New Hampshire	$ 125	$ 258	$ 398	$ 537	$ 676	$ 737	$ 4,846	$ 2,731
106	Total	$ 245	$ 503	$ 765	$ 1,028	$ 1,281	$ 1,405	$ 9,414	$ 5,228
107									
108	**Inventory Finance Charge Allocation by Month**								
109	**Maine**								
110	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,231,373	0
111	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	94.86%	0.00%
112	ME Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,333	$ -
113									
114	**New Hampshire**								
115	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,232,960	0
116	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	94.53%	0.00%
117	NH Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,581	$ -

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**

LN		
95		
96		
97		
98	**Inventory Finance Charge**	
99	Storage	"Schedule 14 - Carrying Costs"
100	Peaking	"Schedule 14 - Carrying Costs"
101	Total	Sum LN 99 : LN 100
102		
103	**Inventory Finance Charge Allocation by Jurisdiction**	
104	Maine	LN 101 * LN 59
105	New Hampshire	LN 101 * LN 60
106	Total	Sum LN 104 : LN 105
107		
108	**Inventory Finance Charge Allocation by Month**	
109	**Maine**	
110	Firm Sales Remaining Sendout	Company Analysis
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 Col N
112	ME Allocated Inventory Finance Charge	LN 104 Col N * LN 111
113		
114	**New Hampshire**	
115	Firm Sales Remaining Sendout	NH Schedule 10B, LN 80 / 10
116	Monthly % Sendout of Total Winter	LN 115 / LN 115 Col N
117	NH Allocated Inventory Finance Charge	LN 105 Col N* LN 116

Schedule 23

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

		Winter	Summer	Total	
1	Demand	$ 11,842,494	$ 1,049,948	$ 12,892,441	Schedule 1A, LN 80
2	Commodity	$ 11,959,202	$ 2,940,823	$ 14,900,025	Schedule 1B, LN 43
3	Total	$ 23,801,696	$ 3,990,771	$ 27,792,467	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	27,305,924	7,625,909	34,931,833	Schedule 10B, LN 11
6	Forecasted Residential Sales (Therms)	13,342,035	3,454,565	16,796,599	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.4337	$0.1377		LN 1 / LN 5
9	Average Commodity Rate	$0.4380	$0.3856		LN 2 / LN 5
10	Average Rate	$0.8717	$0.5233		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 5,917,425	$ 496,233	$ 6,413,658	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 5,786,399	$ 475,694	$ 6,262,092	LN 8 * LN 6
15	**Demand Reallocation:**	$ 131,026	$ 20,539	$ 151,566	LN 13 - LN 14
16	**HLF Allocation**	$ 15,939	$ 5,652	$ 21,590	LN 15 * LN 20
17	**LLF Allocation**	$ 115,087	$ 14,888	$ 129,975	LN 15 * LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	12.16%	27.52%		Schedule 10A, LN 173
21	LLF	87.84%	72.48%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 5,827,472	$ 1,332,213	$ 7,159,685	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 5,843,424	$ 1,332,080	$ 7,175,504	LN 9 * LN 6
25	**Commodity Reallocation:**	$ (15,952)	$ 133	$ (15,819)	LN 23 - LN 24
26	**HLF Allocation**	$ (2,631)	$ 50	$ (2,580)	LN 25 * LN 30
27	**LLF Allocation**	$ (13,321)	$ 83	$ (13,238)	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	16.49%	37.75%		Schedule 10C, LN 143
31	LLF	83.51%	62.25%		Schedule 10C, LN 144

Schedule 24

Provided in Winter 2012-13 Cost-of-Gas Filing