Schedules 1A and 1B

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

NH Division Total Annual Demand Cost Allocation

1	**Resource**	**Costs**
2	Pipeline & Product Demand	$ 3,799,599
3	Storage	$ 12,899,359
4	Peaking	$ 1,318,905
5	Total Gross Demand Cost	$ 18,017,863
6		
7	Capacity Assignment Demand Revenue Estimate	$ 3,303,689
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 18,017,863
9	Capacity Assignment as % of Total Gross Demand Cost	18.34%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 696,681
14	Storage	$ 2,365,179
15	Peaking	$ 241,830
16	Total Capacity Assignment Credit	$ 3,303,689
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 3,102,919
21	Storage	$ 10,534,180
22	Peaking	$ 1,077,076
23	Total Net Demand Cost (Less Capacity Assignment)	$ 14,714,174
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,229
28	Less 18.34% NH Transp. Capacity Assignment	(2,059)
29	Net Pipeline MDQ	9,170
30		
31	Net Pipeline MDQ	9,170
32	Less: Firm Sales Base Use	2,735
33	Remaining Pipeline MDQ	6,435
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$338.37
37		
38		**Costs**
39	Pipeline & Product Demand	$ 3,102,919
40	Less: Base Pipeline Use	$ 925,464
41	Remaining Pipeline Use	$ 2,177,455

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	2013-2014 Winter Period Filing, 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 C**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 18.34% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

45	**All Months**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
46	Remaining Load for All Months	2,780,965	4,457,655	5,850,045	4,833,516	3,468,685	1,731,269
47	Rank	5	3	1	2	4	6
48	% Max Month	47.54%	76.20%	100.00%	82.62%	59.29%	29.59%
49	PR	3.59%	5.64%	17.38%	3.21%	2.94%	2.59%
50	CumPR	7.98%	16.55%	37.14%	19.76%	10.92%	4.39%
51							
52	**Peak Months Only**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
53	Remaining Load for Peak Months Only	2,780,965	4,457,655	5,850,045	4,833,516	3,468,685	1,731,269
54	Rank	5	3	1	2	4	6
55	% Max Month	47.54%	76.20%	100.00%	82.62%	59.29%	29.59%
56	PR	3.59%	5.64%	17.38%	3.21%	2.94%	4.93%
57	CumPR	8.52%	17.10%	37.68%	20.31%	11.46%	4.93%

58
59 **DEMAND COST PR ALLOCATORS**

60		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
62	Pipeline - Remaining	7.98%	16.55%	37.14%	19.76%	10.92%	4.39%
63	Storage & Peaking	7.98%	16.55%	37.14%	19.76%	10.92%	4.39%
64	Capacity Release	8.52%	17.10%	37.68%	20.31%	11.46%	4.93%
65	Interr. Margins & Off Sys Sales	8.52%	17.10%	37.68%	20.31%	11.46%	4.93%

66
67 **DEMAND COSTS ALLOCATED TO MONTHS**

68		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
69	Pipeline - Base	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 77,122
70	Pipeline - Remaining	$ 173,698	$ 360,394	$ 808,708	$ 430,344	$ 237,692	$ 95,556
71	Total Pipeline	$ 250,820	$ 437,516	$ 885,830	$ 507,466	$ 314,814	$ 172,678
72							
73	Storage & Peaking	$ 926,243	$ 1,921,799	$ 4,312,427	$ 2,294,807	$ 1,267,492	$ 509,552
74							
75	Less Credits to Demand Cost						
76	Cap Rel Margins, Asset Mgt Credit, TGP Refund & PNGTS Litigation Expense	$ 398,267	$ 799,014	$ 1,761,325	$ 949,162	$ 535,632	$ 230,535
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
79							
80	Total Direct Demand Costs	$ 778,795	$ 1,560,302	$ 3,436,933	$ 1,853,111	$ 1,046,674	$ 451,695
81							
82	Indirect Demand Costs/(Credits)						
83	Miscellaneous Overhead						
84	Local Production & Storage						
85	Subtotal						

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

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

45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**
46	Remaining Load for All Months	488,265	129,675	0	18,525	135,105	823,825	24,717,532	23,122,136	1,595,396
47	Rank	8	10	12	11	9	7			
48	% Max Month	8.35%	2.22%	0.00%	0.32%	2.31%	14.08%			
49	PR	0.75%	0.19%	0.00%	0.03%	0.01%	0.82%	37.14%		
50	CumPR	0.98%	0.22%	0.00%	0.03%	0.23%	1.80%	100.00%	96.74%	3.26%

51

52	**Peak Months Only**	**Annual**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only	23,122,136	23,122,136	
54	Rank			
55	% Max Month			
56	PR	37.68%		
57	CumPR	100.00%	100.00%	0.00%

58
59 **DEMAND COST PR ALLOCATORS**

60		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**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	0.98%	0.22%	0.00%	0.03%	0.23%	1.80%	100.00%	96.74%	3.26%
63	Storage & Peaking	0.98%	0.22%	0.00%	0.03%	0.23%	1.80%	100.00%	96.74%	3.26%
64	Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

66
67 **DEMAND COSTS ALLOCATED TO MONTHS**

68		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**	**Winter**	**Summer**
69	Pipeline - Base	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 925,464	$ 462,732	$ 462,732	50.00%	50.00%
70	Pipeline - Remaining	$ 21,420	$ 4,764	$ -	$ 627	$ 4,989	$ 39,263	$ 2,177,455	$ 2,106,394	$ 71,062	96.74%	3.26%
71	Total Pipeline	$ 98,542	$ 81,886	$ 77,122	$ 77,749	$ 82,111	$ 116,385	$ 3,102,919	$ 2,569,125	$ 533,794	82.80%	17.20%
72												
73	Storage & Peaking	$ 114,221	$ 25,404	$ -	$ 3,343	$ 26,601	$ 209,367	$ 11,611,255	$ 11,232,319	$ 378,936	96.74%	3.26%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins, Asset Mgt Credit, TGP Refund & PNGTS Litigation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$4,673,935	$ 4,673,935	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 212,763	$ 107,290	$ 77,122	$ 81,091	$ 108,712	$ 325,752	$ 10,040,239	$ 9,127,510	$ 912,730	90.91%	9.09%
81												
82	Indirect Demand Costs/(Credits)											
83	Miscellaneous Overhead							$ 411,600	$ 333,160	$ 78,440	80.94%	19.06%
84	Local Production & Storage							$ 307,762	$ 307,762	$ -	100.00%	0.00%
85	Subtotal							$ 719,362	$ 640,922	$ 78,440	89.10%	10.90%

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

42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR A**	**ALLOCATORS)**
43	(Based on NH Firm Sales Sendout for Remaining Temperature Sensit	tive 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, TGP Refund & PNGTS Litigation 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

		A Total	B Capacity Assigned	C Sales	D Total	E Capacity Assigned	F Sales
1	Asset Management	($5,535,367)	($924,882)	($4,610,485)	Schedule 21, Line 89	Schedule 5B, Page 5*	A - B
2	Capacity Release Revenues	($70,950)	$0	($70,950)	Schedule 21, Line 88		A - B
3	PNGTS Litigation	$22,988	$2,344	$20,644	Schedule 5B, Page 6*	Schedule 5B, Page 5*	A - B
4	TGP Refund Balance - Demand	($16,106)	$0	($16,106)	Schedule 15, Attachment F		A - B
5	TGP Refund Balance - Commodity	$2,962	$0	$2,962	Schedule 15, Attachment F		A - B
6	Total NH Cap Rel and Asset Management	($5,596,473)	($922,538)	($4,673,935)			Sum (LN1 + LN 2 + LN 5)

*: Provided in the 2013-2014 Winter Period Filing

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	Summer
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	1,338,020	885,618	750,910	778,241	951,135	1,831,571	26,577,029	6,535,495
2	New Hampshire Sales Storage	0	0	0	0	0	0	6,900,718	0
3	New Hampshire Sales Peaking	6,726	7,053	7,603	7,605	6,567	6,211	1,296,244	41,766
4	Total New Hampshire Firm Sales Sendout	1,344,746	892,671	758,512	785,846	957,702	1,837,783	34,773,991	6,577,261
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	1,344,746	892,671	758,512	785,846	957,702	1,837,783	34,773,991	6,577,261
9	Total Firm Sales	1,327,606	944,011	823,915	860,734	949,421	1,661,106	34,457,951	6,566,792
10	Difference (LAUF & Company Use)	17,141	(51,340)	(65,403)	(74,888)	8,281	176,677	316,040	10,468
11	Percent Difference	1.27%	-5.75%	-8.62%	-9.53%	0.86%	9.61%	0.91%	0.16%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 640,265	$ 422,887	$ 360,493	$ 372,585	$ 453,393	$ 893,912	$ 14,301,451	$ 3,143,535
15	New Hampshire Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ (324,320)	$ -
16	New Hampshire Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,737,372	$ -
17	New Hampshire Total Peaking	$ 4,953	$ 5,124	$ 5,456	$ 5,396	$ 4,612	$ 4,320	$ 2,032,286	$ 29,861
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,095	$ -
19	Total New Hampshire Sales Variable Costs	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 18,752,883	$ 3,173,396
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 19,077,203	$ 3,173,396
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 18,752,883	$ 3,173,396
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.4785	$ 0.4775	$ 0.4801	$ 0.4788	$ 0.4767	$ 0.4881	$ 0.5381	$ 0.4810
27	New Hampshire Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.0122)	$ -
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.3967	$ -
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.7363	$ 0.7265	$ 0.7176	$ 0.7095	$ 0.7022	$ 0.6955	$ 1.5678	$ 0.7150
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0007	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.4798	$ 0.4795	$ 0.4825	$ 0.4810	$ 0.4782	$ 0.4888	$ 0.5393	$ 0.4825
32									
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	847,865	820,515	829,340	847,865	820,515	847,865	9,956,578	5,013,964
37	Base Commodity Cost Excld Hedging	$ 405,718	$ 391,800	$ 365,949	$ 377,981	$ 391,128	$ 413,807	$ 5,080,503	$ 2,346,382
38	Base Hedging Commodity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ (85,629)	$ -
39	Remaining Commodity Excld Hedging	$ 239,500	$ 36,211	$ -	$ -	$ 66,877	$ 484,425	$ 13,996,700	$ 827,014
40	Remaining Hedging Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ (238,691)	$ -
41	Total Commodity Excld Hedging	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 19,077,203	$ 3,173,396
42	Total Hedging	$ -	$ -	$ -	$ -	$ -	$ -	$ (324,320)	$ -
43	Total Commodity (Incl Hedging)	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 18,752,883	$ 3,173,396

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 2014 through October 2014			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Algonquin Receipts	$293,758	61,648	$4.765
Tenn Zone 4 Spot	$1,395,970	292,944	$4.765
Tennessee Production	$3,905,343	815,730	$4.788
Iroquois Receipts	$153,216	31,054	$4.934
Chicago	$418,154	83,667	$4.998
Niagara	$14,524	2,872	$5.057
Lewiston Baseload	$240,870	46,500	$5.180
LNG	$59,172	8,280	$7.146
Total Delivered Commodity Cost	$6,481,006	1,342,695	$4.827

Schedules 3A &3B

Northern Utilities, Inc.
New Hampshire Division
Schedule 3A
Page 1 of 2

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

			Winter						Summer						
	Sales Revenues								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total
2	Residential Heat & Non Heat								640,336	455,320	397,394	415,153	457,929	801,191	3,167,323
3	Sales HLF Classes								289,679	205,980	179,775	187,809	207,160	362,447	1,432,851
4	Sales LLF Classes								397,590	282,712	246,746	257,772	284,332	497,467	1,966,619
5	Total								1,327,606	944,011	823,915	860,734	949,421	1,661,106	6,566,792
6	Rates														
7	Residential Heat & Non Heat CGA								$0.6833	$0.6833	$0.6833	$0.6833	$0.6833	$0.6833	
8	Sales HLF Classes CGA								$0.6318	$0.6318	$0.6318	$0.6318	$0.6318	$0.6318	
9	Sales LLF Classes CGA								$0.7209	$0.7209	$0.7209	$0.7209	$0.7209	$0.7209	
10	Revenues														
11	Residential Heat & Non Heat								$ (437,542)	$ (311,120)	$ (271,539)	$ (283,674)	$ (312,903)	$ (547,454)	$ (2,164,232)
12	Sales HLF Classes								$ (183,019)	$ (130,138)	$ (113,582)	$ (118,658)	$ (130,884)	$ (228,994)	$ (905,275)
13	Sales LLF Classes								$ (286,623)	$ (203,807)	$ (177,879)	$ (185,828)	$ (204,975)	$ (358,624)	$ (1,417,735)
14	Total Sales								$ (907,184)	$ (645,065)	$ (563,000)	$ (588,159)	$ (648,762)	$ (1,135,072)	$ (4,487,242)
15															

			Winter						Summer						
16															
17	**Gas Costs and Credits**								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18		Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline								$ 88,966	$ 88,966	$ 88,966	$ 88,966	$ 88,966	$ 88,966	$ 533,794
21	Storage								$ 57,280	$ 57,280	$ 57,280	$ 57,280	$ 57,280	$ 57,280	$ 343,682
22	Peaking								$ 5,876	$ 5,876	$ 5,876	$ 5,876	$ 5,876	$ 5,876	$ 35,254
24	Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 152,122	$ 152,122	$ 152,122	$ 152,122	$ 152,122	$ 152,122	$ 912,730
25	NUI Commodity Costs														
26	NUI Total Pipeline Volumes								277,500	169,505	137,783	142,761	195,522	411,344	1,334,415
27	Pipeline Costs Modeled in Sendout™								$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 6,421,835
28	NYMEX Price Used for Forecast								$ 4.5500	$ 4.5680	$ 4.5990	$ 4.5860	$ 4.5570	$ 4.5650	
29	NYMEX Price Used for Update								$ 4.5500	$ 4.5680	$ 4.5990	$ 4.5860	$ 4.5570	$ 4.5650	
30	Increase/(Decrease) NYMEX Price														
31	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
32	Updated Pipeline Costs								$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	
33	Interruptible Volumes - NH								0	0	0	0	0	0	
34	Average Supply Cost ($/MMBtu)								$ 4.79	$ 4.78	$ 4.80	$ 4.79	$ 4.77	$ 4.88	
35	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
36	Total Updated Pipeline Costs								$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	
37	New Hampshire Allocated Percentage								48.22%	52.25%	54.50%	54.51%	48.65%	44.53%	
38	NH Updated Pipeline Costs								$ 640,265	$ 422,887	$ 360,493	$ 372,585	$ 453,393	$ 893,912	$ 3,143,535
39	Hedging (Gain)/Loss Estimate														
40	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
41	NYMEX NG Futures Contracts								0	0	0	0	0	0	
42	Average Purchase Price								$ 3.9930	$ -	$ -	$ -	$ -	$ 4.1030	
43	NYMEX Price Used for Forecast								$ 4.5500	$ 4.5680	$ 4.5990	$ 4.5860	$ 4.5570	$ 4.5650	
44	NYMEX Price Used for Update								$ 4.5500	$ 4.5680	$ 4.5990	$ 4.5860	$ 4.5570	$ 4.5650	
45	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
46	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	<u>New Hampshire Allocated Percentage</u>								48.22%	52.25%	54.50%	54.51%	48.65%	44.53%	
48	NH Futures Hedging (Gain)/Loss, Time Triggered								$ -	$ -	$ -	$ -	$ -	$ -	$ -
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								$ 4.5500	$ 4.5680	$ 4.5990	$ 4.5860	$ 4.5570	$ 4.5650	
53	NYMEX Price Used for Update								$ 4.5500	$ 4.5680	$ 4.5990	$ 4.5860	$ 4.5570	$ 4.5650	
54	Increase/(Decrease) NYMEX Price								-	-	-	-	-	-	
55	NUI Futures Hedging (Gain)/Loss - Allocate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	<u>New Hampshire Allocated Percentage</u>								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								$ 640,265	$ 422,887	$ 360,493	$ 372,585	$ 453,393	$ 893,912	$ 3,143,535
60	Hedging (Gain)/Loss Estimate								$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Storage								$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Peaking								$ 4,953	$ 5,124	$ 5,456	$ 5,396	$ 4,612	$ 4,320	$ 29,861
63	Total Commodity Costs								$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 3,173,396

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

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**		$ -	$ -	$ -	$ -	$ -	$ -	$ 797,340	$ 580,133	$ 518,071	$ 530,102	$ 610,127	$ 1,050,354	$ 4,086,126
75			Winter						Summer						
76									(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
77		Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
78	Working Capital														
79	Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 797,340	$ 580,133	$ 518,071	$ 530,102	$ 610,127	$ 1,050,354	$ 4,086,126
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		$ -	$ -	$ -	$ -	$ -	$ -	$ 657	$ 478	$ 427	$ 437	$ 503	$ 865	$ 3,365
82	Beginning Period Working Capital Balance		$ 861	$ 863	$ 866	$ 868	$ 870	$ 873	$ 875	$ 1,535	$ 2,018	$ 2,450	$ 2,894	$ 3,405	
83	End of Period Working Capital Allowance		$ 861	$ 863	$ 866	$ 868	$ 870	$ 873	$ 1,532	$ 2,013	$ 2,444	$ 2,887	$ 3,397	$ 4,270	
84	Interest		$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 3	$ 5	$ 6	$ 7	$ 9	$ 10	$ 54
85	End of period with Interest	$ 861	$ 863	$ 866	$ 868	$ 870	$ 873	$ 875	$ 1,535	$ 2,018	$ 2,450	$ 2,894	$ 3,405	$ 4,281	
86	Bad Debt														
92	Projected Bad Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,815	$ 3,815	$ 3,815	$ 3,815	$ 3,815	$ 3,815	$ 22,890
93	Beginning Period Bad Debt Balance		$ (3,098)	$ (3,106)	$ (3,115)	$ (3,123)	$ (3,132)	$ (3,140)	$ (3,149)	$ 663	$ 4,485	$ 8,317	$ 12,160	$ 16,013	
94	End of Period Bad Debt Balance		***$ (3,098)***	***$ (3,106)***	***$ (3,115)***	***$ (3,123)***	***$ (3,132)***	***$ (3,140)***	***$ 666***	***$ 4,478***	***$ 8,300***	***$ 12,132***	***$ 15,975***	***$ 19,828***	
95	Interest		$ (8)	$ (8)	$ (8)	$ (8)	$ (8)	$ (9)	$ (3)	$ 7	$ 17	$ 28	$ 38	$ 49	$ 85
96	End of Period Bad Debt Balance with Interest	$ (3,098)	$ (3,106)	$ (3,115)	$ (3,123)	$ (3,132)	$ (3,140)	$ (3,149)	$ 663	$ 4,485	$ 8,317	$ 12,160	$ 16,013	$ 19,877	
97	Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
98			$ -	$ -	$ -										$ -
99	Miscellaneous Overhead								$ 13,073	$ 13,073	$ 13,073	$ 13,073	$ 13,073	$ 13,073	$ 78,440
100															
101	Supplier Refund	$ (105,725)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (105,725)
100	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
101	Beginning Balance Over/Under Collection		$ 394,545	$ 394,428	$ 394,838	$ 395,940	$ 397,013	$ 398,088	$ 399,166	$ 303,345	$ 252,238	$ 221,021	$ 176,575	$ 151,457	$ 3,878,653
102	Net Costs - Revenues		$ (1,184)	$ (658)	$ 33	$ -	$ -	$ -	$ (96,771)	$ (51,859)	$ (31,856)	$ (44,984)	$ (25,562)	$ (71,645)	$ (324,485)
103	Ending Balance before Interest		$ 393,361	$ 393,770	$ 394,871	$ 395,940	$ 397,013	$ 398,088	$ 302,395	$ 251,486	$ 220,381	$ 176,038	$ 151,014	$ 79,812	$ 3,554,168
104	Average Balance		$ 393,953	$ 394,099	$ 394,854	$ 395,940	$ 397,013	$ 398,088	$ 350,780	$ 277,416	$ 236,309	$ 198,529	$ 163,794	$ 115,635	$ 3,716,411
105	Interest Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
106	Interest Expense		$ 1,067	$ 1,067	$ 1,069	$ 1,072	$ 1,075	$ 1,078	$ 950	$ 751	$ 640	$ 538	$ 444	$ 313	$ 10,065
108	Ending Balance Incl Interest Expense	$ 394,545	$ 394,428	$ 394,838	$ 395,940	$ 397,013	$ 398,088	$ 399,166	$ 303,345	$ 252,238	$ 221,021	$ 176,575	$ 151,457	$ 80,125	
109	**Total Over/Under Collection Ending Balance**	$ 392,308	$ 392,185	$ 392,588	$ 393,685	$ 394,751	$ 395,820	$ 396,892	$ 305,543	$ 258,740	$ 231,789	$ 191,630	$ 170,876	$ 104,283	
110															
111	**Total Indirect Cost of Gas**	$ 286,583	$ 1,061	$ 1,061	$ 1,063	$ 1,066	$ 1,069	$ 1,072	$ 18,495	$ 18,129	$ 17,978	$ 17,898	$ 17,881	$ 18,126	$ 401,483
112															
113	**Total Cost of Gas**	$ 286,583	$ 1,061	$ 1,061	$ 1,063	$ 1,066	$ 1,069	$ 1,072	$ 815,835	$ 598,262	$ 536,049	$ 548,000	$ 628,008	$ 1,068,479	$ 4,487,608
114															
115	**Total Interest**	$ -	$ 1,061	$ 1,061	$ 1,063	$ 1,066	$ 1,069	$ 1,072	$ 950	$ 763	$ 663	$ 573	$ 490	$ 372	$ 10,204

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2013**			
2				
3	Total	$	360,081	Company Analysis
4	Distribution	$	154,072	Company Analysis
5	Distribution (%)		42.79%	
6	Non-Distribution	$	206,009	Company Analysis
7	Non-Distribution(%)		57.21%	LN 6 / LN 3
8				
9	Non-Distribution	$	206,009	LN 6
10	Peak Period	$	189,524	Company Analysis
11	Peak Period (%)		92.00%	LN 10/ LN 9
12	Off-Peak Period	$	16,485	LN 9 - LN 10
13	Off-Peak Period (%)		8.00%	LN 12 / LN 9
14				
15	**Forecast Bad Debt Expense 12 Months Ended December 31, 2014**			
16				
17	Annual Total	$	500,000	Company Forecast
18	Annual Non-Distribution	$	286,059	LN 17* LN 7
19	Winter Non-Distribution	**$**	**263,169**	LN 18* LN 11
20	Summer Non-Distribution	$	22,890	LN 18* LN 13

Schedules 4

Reserved for Future Use

Schedule 5A & Attachment

Northern Utilities, Inc.

Estimated Gas Supply Demand Costs

November 1, 2013 through October 31, 2014

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,358,833	Sch 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 24,059,732	Sch 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	Sch 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,725,723	Sch 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 1,053,750	Sch 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,956,197)	Sch 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 26,278,687	Sum Lines 1 through 6.

Northern Utilities, Inc.

Pipeline Contract Demand Cost Estimates

November 1, 2013 through October 31, 2014

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 to Sched 5A	$ 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 to Sched 5A	$ 8,223	$ 98,680
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.5166	9	Line 3 of Page 2, Att to Sched 5A	$ 351,660	$ 3,164,940
Granite	10-010-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.7419	3	Line 3 of Page 2, Att to Sched 5A	$ 374,190	$ 1,122,570
Iroquois	R181001	RTS-1	No	6,569	Zone 1	Zone 1	$ 6.5971	12	Line 4 of Page 2, Att to Sched 5A	$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Pittsburgh	GSGT	$ 40.2456	12	Line 5 of Page 2, Att to Sched 5A	$ 44,270	$ 531,242
PNGTS	1997-004	FT	Yes	33,000	Pittsburgh	GSGT	$ 76.4666	5	Line 6 of Page 2, Att to Sched 5A	$ 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 to Sched 5A	$ 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 to Sched 5A	$ 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 to Sched 5A	$ 22,523	$ 270,275
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sched 5A	$ 10,460	$ 125,521
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sched 5A	$ 16,561	$ 198,727
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sched 5A	$ 6,911	$ 82,937
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 7.4396	12	Line 10 of Page 2, Att to Sched 5A	$ 31,745	$ 380,937
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.7640	12	Line 11 of Page 2, Att to Sched 5A	$ 5,562	$ 66,747
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 18.8540	12	Line 12 of Page 2, Att to Sched 5A	$ 641,036	$ 7,692,432
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 9.3382	12	Line 13 of Page 2, Att to Sched 5A	$ 55,441	$ 665,291
Union	M12205	M12	No	6,003	Dawn	Parkway	$ 2.2986	12	Line 14 of Page 2, Att to Sched 5A	$ 13,798	$ 165,582
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	Line 15 of Page 2, Att to Sched 5A	$ 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 to Sched 5A	$ 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 to Sched 5A	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	$ 0.4461	12	Line 18 of Page 2, Att to Sched 5A	$ 2,708	$ 32,494
Total Annual Demand Costs											$ 34,144,287

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2013 through October 31, 2014

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	24,221	35,529	40,250	24.2210%	35.5290%	40.2500%	$ 3,164,940	$ 766,580	$ 1,124,472	$ 1,273,888
Granite	10-010-FT-NN	100,000	24,221	35,529	40,250	24%	36%	40%	$ 1,122,570	$ 271,898	$ 398,838	$ 451,834
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%	$ 7,692,432	$ -	$ 7,692,432	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 665,291	$ 665,291	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 165,582	$ 165,582	$ -	$ -
Vector	CRL-NUI-0725	17,172		17,172		0%	100%	0%	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086		17,086		0%	100%	0%	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	6,070	-		100%	0%	0%	$ 566,295	$ 566,295	$ -	$ -
Vector	FT-1-NUI-C0122	6,070	6,070	-		100%	0%	0%	$ 32,494	$ 32,494	$ -	$ -
Annual Total Demand Costs									$ 34,144,287	$ 8,358,833	$ 24,059,732	$ 1,725,723

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2013 through October 31, 2014

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, Att to 5A	$ 65,664	$ 78,411	$ 144,075
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	Line 2 of Page 3, Att to 5A	$ 497	$ 687	$ 1,184
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.5480	12	Line 2 of Page 3, Att to 5A	$ 189	$ 1,398	$ 1,587
W-10	01052	Storage	Yes	3,400,000		34,000			12	Line 3 of Page 3, Att to 5A	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges	$ 3,036,846

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2013 through October 31, 2014

Resource	Contract Quantity	Maximum Daily Quantity	Months Per Year	Support for Demand Rates	Monthly Fixed Charges	Annual Fixed Charges
LNG Supply	10,000	1,000	5	Page 4, Att to 5A	[redacted]	[redacted]
Peaking Supply 1	225,000	15,000	5	Page 4, Att to 5A	[redacted]	[redacted]
Peaking Supply 2	30,000	5,000	5	Page 4, Att to 5A	[redacted]	[redacted]
Peaking Supply 3	250,000	25,000	5	Page 4, Att to 5A	[redacted]	[redacted]
Total Peaking Supply Contract Demand Costs						$ 1,053,750

REDACTED

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2013 through October 31, 2014

Asset Management Agreeement Revenue	
Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	[redacted]
Algonquin Contract #93201A1C (1,251 Dth)	[redacted]
Wash 10 via Vector, TCPL, PNGTS	[redacted]
Tennessee Niagara	[redacted]
Tennessee Long-Haul	[redacted]
Total Asset Management	$ (11,805,500)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (66,747)
Tennessee 5265	$ (83,950)
Total Capacity Release	$ (150,697)

Total Asset Management and Capacity Release Revenue	$ (11,956,197)

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for February 28, 2014

Estimated Adders to NYMEX Last Day Settlement

Line	Supply Source	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
1	Chicago	$0.139	$0.139	$0.139	$0.139	$0.139	$0.139
2	Iroquois Receipts	$0.220	$0.220	$0.220	$0.220	$0.220	$0.220
3	PNGTS Delivered						
4	PNGTS Baseload	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
5	Lewiston Baseload	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
6	Niagara	$0.350	$0.350	$0.350	$0.350	$0.350	$0.350
7	Tennessee Production (Zone 0)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)	($0.124)
8	Tennessee Production (Zone L)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	Tennessee Production (Zone 4)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10	Tenessee Zone 4 Spot	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
11	Peaking Supply 1	NA	NA	NA	NA	NA	NA
12	Peaking Supply 2	NA	NA	NA	NA	NA	NA
13	Peaking Supply 3	NA	NA	NA	NA	NA	NA
14	LNG	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
15	W10 Supply (Injection)	$0.139	$0.139	$0.139	$0.139	$0.139	$0.139
16	TGP FS Supply (Injection)	($0.030)	($0.030)	($0.030)	($0.030)	($0.030)	($0.030)
17	W10 AMA Spot	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
18	Tennessee Zone 6	$0.615	$0.615	$0.615	$0.615	$0.615	$0.615
19	AGT Receipts	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150
20							
21	NYMEX Forecast	$4.550	$4.568	$4.599	$4.586	$4.557	$4.565

Northern Utilities, Inc.
Transportation Contract Rates
November 2013 through October 2014

Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A		$ 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		$ 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		$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.5166	$ 3.7419	$ 3.7419	$ 3.7419
4	Iroquois	RTS-1	Zone 1	Zone 1		$ 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		$ 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		$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666							
7	Tennessee	FT-A	Zone 0	Zone 6		$ 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		$ 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		$ 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		$ 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	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360	$ 5.5360
12	TransCanada	FT	Dawn	E. Hereford	2	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540	$ 18.8540
13	TransCanada	FT	Parkway	Iroquois	2	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382	$ 9.3382
14	Union	M12	Dawn	Parkway		$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986	$ 2.2986
15	Vector	FT-1	Alliance	Dawn		$ 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		$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625							
17	Vector	FT-1	Alliance	St. Clair	3	$ 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		$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461	$ 0.4461

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
19	Algonquin	AFT-1 (AFT-2)	N/A	N/A		$ 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		$ 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		$ 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	4	$ 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		$ 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		$ 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	5	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055	$ 0.3055
26	Tennessee	FT-A	Zone 0	Zone 6	5	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532	$ 0.3532
27	Tennessee	FT-A	Zone L	Zone 4	5	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597	$ 0.2597
28	Tennessee	FT-A	Zone L	Zone 6	5	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078	$ 0.3078
29	Tennessee	FT-A	Zone 4	Zone 6	5	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188
30	Tennessee	FT-A	Zone 5	Zone 6	5	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896
31	TransCanada	FT	Dawn	E. Hereford		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	TransCanada	FT	Parkway	Iroquois		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Union	M12	Dawn	Parkway		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Vector	FT-1	Alliance	W-10		$ 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		$ 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		$ 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	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
37	Algonquin	AFT-1 (AFT-2)	N/A	N/A		0.92%	1.10%	1.10%	1.10%	1.10%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%
38	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		0.92%	1.10%	1.10%	1.10%	1.10%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%
39	Granite	FT-NN	N/A	N/A		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	6	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
41	PNGTS	FT	N/A	N/A	6	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		3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%	3.41%
43	Tennessee	FT-A	Zone 0	Zone 6		4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%
44	Tennessee	FT-A	Zone L	Zone 4		2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%	2.92%
45	Tennessee	FT-A	Zone L	Zone 6		3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
46	Tennessee	FT-A	Zone 4	Zone 6		1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%
47	Tennessee	FT-A	Zone 5	Zone 6		1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
48	TransCanada	FT	Dawn	E. Hereford	6	1.49%	1.49%	1.49%	1.49%	1.49%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
49	TransCanada	FT	Parkway	Iroquois	6	1.38%	1.38%	1.38%	1.38%	1.38%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%
50	Union	M12	Dawn	Parkway		0.98%	0.98%	0.98%	0.98%	0.98%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
51	Vector	FT-1	Alliance	W-10	6	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
52	Vector	FT-1	Alliance	Dawn	6	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
53	Vector	FT-1	W-10 Storage	Dawn	6	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%

Note 1	FT-1 Demand Rate = $4.876 plus FT-1 / FTS Rate = $0.66, totals to $5.536
Note 2	
Note 3	Negotiated Rate Agreement = $8.0908 per Dth, which is higher than max rate, so max rate prevails.
Note 4	RTS-1 Commodity Rate = $0.003 per Dth and ACA = $0.0018 per Dth. Total equals $0.0048
Note 5	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 6	Fuel Rates Estiamted based on 12 months historic averages.

Northern Utilities, Inc.
Underground Storage Contract Rates
November 2013 through October 2014

Line	Storage	Rate Schedule	Notes	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		$ 0.0211	$ 1.5400	$ 0.0087	0.00%	$ 0.0087	1.45%
2	Texas Eastern	SS-1		$ 0.1293	$ 5.3730				
3	W-10	Storage	1			$ -	0.40%	$ -	1.10%

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

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Canadian Fixed Transportation Rates

Line	Item	Units	Value	Reference
1	Parkway to Iroquois on TCPL			
2	Demand Toll	$CAD / GJ	$ 9.24034	Page 30
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.43662	Page 28
4	Total Demand Toll	$CAD / GJ	$ 9.67696	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.91464	Page 27
6	Total Demand Toll	$US / GJ	$ 8.8509	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Total Demand Toll	$US / Dth	$ 9.3382	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Demand Toll	$CAD / GJ	$ 18.96846	Page 29
12	Union Dawn Surcharge	$CAD / GJ	$ 0.13281	Page 28
13	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.43662	Page 28
14	Total Demand Toll	$CAD / GJ	$ 19.53789	Sum Lines Above.
15	$CAD to $US	Ratio	0.91464	Page 27
16	Total Demand Toll	$US / GJ	$ 17.8701	Line 13 times Line 14
17	GJ per Dth	Ratio	1.0551	
18	Total Demand Toll	$US / Dth	$ 18.8540	Line 15 divided by Line 16
19				
20	Dawn to Parkway on Union Pipeline			
21	Total Demand Toll	$CAD / GJ	$ 2.3820	Page 31
22	$CAD to $US	Ratio	0.91464	Page 27
23	Total Demand Toll	$US / GJ	$ 2.1787	Line 13 times Line 14
24	GJ per Dth	Ratio	1.0551	
25	Total Demand Toll	$US / Dth	$ 2.2987	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	0.91464	Page 27
30	Total Demand Toll	$US / GJ	$ 0.4228	Line 13 times Line 14
31	GJ per Dth	Ratio	1.0551	
32	Total Demand Toll	$US / Dth	$ 0.4461	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	$ -	Page 30
3	Delivery Pressure Commodity Toll	$CAD / GJ	$ -	Page 28
4	Variable Transportation Rate	$CAD / GJ	$ -	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.91464	Page 27
6	Variable Transportation Rate	$US / GJ	$ -	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ -	Line 6 divided by Line 7
9				
10	Union Dawn to East Hereford on TCPL			
11	Commodity Rate	$CAD / GJ	$ -	Page 29
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ -	Page 28
13	Variable Transportation Rate	$CAD / GJ	$ -	Line 11 plus Line 12
14	$CAD to $US	Ratio	0.91464	Page 27
15	Variable Transportation Rate	$US / GJ	$ -	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ -	Line 15 divided by Line 16

Northern Utilities, Inc.
New Hampshire Division
Attachment to Schedule 5A
Page 6 of 6

10-year currency converter

Conversions are based on Bank of Canada nominal noon exchange rates, which are published each business day at about 12:30 ET.

View or save this data in: SDMX, XML, CSV

View data for the past:

- 1 week
- 2 weeks
- 1 month
- 3 months
- 6 months
- 1 year

1.00 CAD (Canadian Dollar)

USD (U.S. dollar (noon))

Date	USD = U.S. dollar (noon)	Exchange rate
2014-01-14	0.91 USD	0.9146 [1.0934]

See Also

Daily currency converter

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

The Bank currently collects data for about 55 foreign currencies. This data is intended primarily for people with a research interest in foreign exchange markets, and represents a sampling of currencies from various regions. It is not meant to be an exhaustive listing of all world currencies.

More comprehensive currency converters are available elsewhere on the web. You may want to try **CanadianForex** or **oanda.com**.

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

Yes. The Agency accepts Bank of Canada exchange rates as the basis for calculations involving income and expenses

Schedule 5B

Provided in the Winter 2013-14 Cost-of-Gas Filing

Schedule 5C

Provided in the Winter 2013-14 Cost-of-Gas Filing

Schedules 6A and 6B

Northern Utilities, Inc.
Commodity Cost by Supply Source
May 2014 through October 2014

Description	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Season
Pipeline Supplies							
Chicago	$ 89,519	$ 13,195	$ -	$ -	$ 18,061	$ 297,379	$ 418,154
Iroquois Receipts	$ 58,697	$ 6,258	$ -	$ -	$ 15,609	$ 72,651	$ 153,216
Lewiston Baseload	$ -	$ -	$ -	$ -	$ -	$ 240,870	$ 240,870
PNGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ -	$ -	$ -	$ -	$ -	$ 14,524	$ 14,524
Tennessee Production	$ 726,751	$ 556,307	$ 593,025	$ 529,183	$ 583,131	$ 916,947	$ 3,905,343
Algonquin Receipts	$ 108,416	$ 11,204	$ -	$ -	$ 44,543	$ 129,595	$ 293,758
Tenn Zone 4 Spot	$ 344,501	$ 222,432	$ 68,437	$ 154,289	$ 270,683	$ 335,628	$ 1,395,970
Subtotal Pipeline	$1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 6,421,835
Underground Storage							
Tennessee Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10 Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supplies							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 59,172
Subtotal Peaking	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 59,172
Total Commodity Cost	$1,338,156	$ 819,203	$ 671,473	$ 693,370	$ 941,507	$ 2,017,297	$ 6,481,006

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
May 2014 through October 2014

Description	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Season
Pipeline Supplies							
Chicago	18,004	2,644	0	0	3,630	59,389	83,667
Iroquois Receipts	11,918	1,266	0	0	3,165	14,706	31,054
Lewiston Baseload	0	0	0	0	0	46,500	46,500
PNGTS	0	0	0	0	0	0	0
Niagara	0	0	0	0	0	2,872	2,872
Tennessee Production	152,273	116,609	123,528	110,534	122,487	190,300	815,730
AGT Receipts	22,793	2,346	0	0	9,350	27,159	61,648
Tenn Zone 4 Spot	72,513	46,639	14,255	32,227	56,890	70,419	292,944
Subtotal Pipeline	277,500	169,505	137,783	142,761	195,522	411,344	1,334,415
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)	278,895	170,855	139,178	144,156	196,872	412,739	1,342,695

Northern Utilities, Inc.
New Hampshire Division
Schedule 6A
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Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
May 2014 through October 2014

Description	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Season
Pipeline Supplies							
Chicago	$ 4.972	$ 4.990			$ 4.975	$ 5.007	$ 4.998
Iroquois Receipts	$ 4.925	$ 4.943			$ 4.932	$ 4.940	$ 4.934
Lewiston Baseload						$ 5.180	$ 5.180
PNGTS							
Niagara						$ 5.057	$ 5.057
Tennessee Production	$ 4.773	$ 4.771	$ 4.801	$ 4.788	$ 4.761	$ 4.818	$ 4.788
AGT Receipts	$ 4.757	$ 4.775			$ 4.764	$ 4.772	$ 4.765
Tenn Zone 4 Spot	$ 4.751	$ 4.769	$ 4.801	$ 4.788	$ 4.758	$ 4.766	$ 4.765
Subtotal Pipeline	$ 4.785	$ 4.775	$ 4.801	$ 4.788	$ 4.767	$ 4.881	$ 4.812
Underground Storage							
Tennessee Storage							
Washington 10 Storage							
Subtotal Storage							
Peaking Supplies							
Peaking Supply 1							
Peaking Supply 2							
Peaking Supply 3							
LNG	$ 7.364	$ 7.265	$ 7.177	$ 7.096	$ 7.022	$ 6.955	$ 7.146
Subtotal Peaking	$ 7.364	$ 7.265	$ 7.177	$ 7.096	$ 7.022	$ 6.955	$ 7.146
Total Cost per Dth	$ 4.798	$ 4.795	$ 4.825	$ 4.810	$ 4.782	$ 4.888	$ 4.827

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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 9	18,717	2,748	-	-	3,771	61,978	87,214
2	City Gate Delivered Volume	Sum Lines 64, 84 and 104	18,004	2,644	-	-	3,630	59,389	83,667
3	Total Purchase Cost	Line 15	$ 87,764	$ 12,937	$ -	$ -	$ 17,709	$ 291,542	$ 409,952
4	Variable Transportation Costs	Sum Lines 26, 46, 56, 66, 76, 86, 96 and 106	$ 1,755	$ 258	$ -	$ -	$ 352	$ 5,837	$ 8,202
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 89,519	$ 13,195	$ -	$ -	$ 18,061	$ 297,379	$ 418,154
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.972	$ 4.990			$ 4.975	$ 5.007	$ 4.998
7									
8	<u>Chicago Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	18,717	2,748	-	-	3,771	61,978	87,214
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.562
11	NYMEX Cost	Line 9 times Line 10	$ 85,162	$ 12,555	$ -	$ -	$ 17,185	$ 282,927	$ 397,829
12	NYMEX Basis Price	Att to Sch 5A, Line 1 of Page 1	$ 0.139	$ 0.139			$ 0.139	$ 0.139	$ 0.139
13	NYMEX Basis Costs	Line 9 times Line 12	$ 2,602	$ 382	$ -	$ -	$ 524	$ 8,615	$ 12,123
14	Total Purchase Price	Line 10 plus Line 12	$ 4.689	$ 4.707			$ 4.696	$ 4.704	$ 4.701
15	Total Purchase Cost	Line 11 plus Line 13	$ 87,764	$ 12,937	$ -	$ -	$ 17,709	$ 291,542	$ 409,952
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with Union)								
22	Received Volume	Line 9	18,717	2,748	-	-	3,771	61,978	87,214
23	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	0.93%	0.93%			0.93%	0.93%	0.93%
24	Delivered Volume	Line 22 times (1 - Line 23)	18,543	2,723	-	-	3,736	61,401	86,403
25	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2	$ 0.0018	$ 0.0018			$ 0.0018	$ 0.0018	$ 0.0018
26	Variable Transportation Costs	Line 24 times Line 25	$ 33	$ 5	$ -	$ -	$ 7	$ 111	$ 156
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	18,543	2,723	-	-	3,736	61,401	86,403
33	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.53%	0.53%			0.53%	0.53%	0.53%
34	Delivered Volume	Line 32 times (1 - Line 33)	18,445	2,708	-	-	3,716	61,076	85,945
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	18,445	2,708	-	-	3,716	61,076	85,945
43	Fuel Loss Rate	Att to Sch 5A, Line 49 of Page 2	0.94%	0.94%			0.94%	0.94%	0.94%
44	Delivered Volume	Line 42 times (1 - Line 43)	18,271	2,683	-	-	3,681	60,502	85,137
45	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2	$ -	$ -			$ -	$ -	$ -
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	18,271	2,683	-	-	3,681	60,502	85,137
53	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.20%	0.20%			0.20%	0.20%	0.20%
54	Delivered Volume	Line 52 times (1 - Line 53)	18,235	2,678	-	-	3,674	60,381	84,967
55	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0048	$ 0.0048			$ 0.0048	$ 0.0048	$ 0.0048
56	Variable Transportation Costs	Line 54 times Line 55	$ 88	$ 13	$ -	$ -	$ 18	$ 290	$ 408
57			$ 145	$ 19	$ -	$ -	$ 33	$ 361	
58	Transporation Segment 6A								
59	Tennessee Gas Pipeline (Contract 95196)								
60	Receipt Point: Wright								
61	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
62	Received Volume	Line 54	8,373	1,177	-	-	2,363	12,818	24,731
63	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%			1.06%	1.06%	1.06%
64	City Gate Delivered Volume	Line 62 times (1 - Line 63)	8,284	1,165	-	-	2,338	12,682	24,469
65	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896			$ 0.0896	$ 0.0896	$ 0.0896
66	Variable Transportation Costs	Line 64 times Line 65	$ 742	$ 104	$ -	$ -	$ 210	$ 1,136	$ 2,192
67			$ 1,810	$ 218	$ -	$ -	$ 493	$ 2,454	
68	Transportation Segment 6B								
69	Tennessee Gas Pipeline (Contract 95196)								
70	Receipt Point: Wright								
71	Delivery Point: Pleasant St. (Interconnection with Granite)								
72	Received Volume	Line 64	9,267	1,500	-	-	1,311	14,460	26,539
73	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%			1.06%	1.06%	1.06%
74	Delivered Volume	Line 72 times (1 - Line 73)	9,169	1,484	-	-	1,297	14,307	26,257
75	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896			$ 0.0896	$ 0.0896	$ 0.0896
76	Variable Transportation Costs	Line 74 times Line 75	$ 822	$ 133	$ -	$ -	$ 116	$ 1,282	$ 2,353
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	9,169	1,484	-	-	1,297	14,307	26,257
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)	9,137	1,479	-	-	1,292	14,257	26,165
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	$ 16	$ 3	$ -	$ -	$ 2	$ 26	$ 47
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	595	-	-	-	-	33,102	33,697
93	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%					1.06%	1.06%
94	Delivered Volume	Line 92 times (1 - Line 93)	589	-	-	-	-	32,751	33,340
95	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896					$ 0.0896	$ 0.0896
96	Variable Transportation Costs	Line 94 times Line 95	$ 53	$ -	$ -	$ -	$ -	$ 2,935	$ 2,987
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	589	-	-	-	-	32,751	33,340
103	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2	0.92%					0.92%	0.92%
104	City Gate Delivered Volume	Line 102 times (1 - Line 103)	583	-	-	-	-	32,450	33,033
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	$ 1	$ -	$ -	$ -	$ -	$ 58	$ 59

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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 9	12,069	1,282	-	-	3,205	14,893	31,449
2	City Gate Delivered Volume	Line 34	11,918	1,266	-	-	3,165	14,706	31,054
3	Total Purchase Cost	Line 15	$ 57,571	$ 6,138	$ -	$ -	$ 15,310	$ 71,262	$ 150,282
4	Variable Transportation Costs	Line 35	$ 1,126	$ 120	$ -	$ -	$ 299	$ 1,389	$ 2,933
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 58,697	$ 6,258	$ -	$ -	$ 15,609	$ 72,651	$ 153,216
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.925	$ 4.943			$ 4.932	$ 4.940	$ 4.934
7									
8	<u>Irqoquois Receipts Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	12,069	1,282	-	-	3,205	14,893	31,449
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.559
11	NYMEX Cost	Line 9 times Line 10	$ 54,916	$ 5,856	$ -	$ -	$ 14,605	$ 67,986	$ 143,364
12	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1	$ 0.220	$ 0.220			$ 0.220	$ 0.220	$ 0.220
13	NYMEX Basis Costs	Line 9 times Line 12	$ 2,655	$ 282	$ -	$ -	$ 705	$ 3,276	$ 6,919
14	Total Purchase Price	Line 10 plus Line 12	$ 4.770	$ 4.788			$ 4.777	$ 4.785	$ 4.779
15	Total Purchase Cost	Line 11 plus Line 13	$ 57,571	$ 6,138	$ -	$ -	$ 15,310	$ 71,262	$ 150,282
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 5								
19	Iroquois Pipeline (Contract R181001)								
20	Receipt Point: Waddington								
21	Delivery Point: Wright (Interconnection with Tennessee)								
22	Received Volume	Line 9	12,069	1,282	-	-	3,205	14,893	31,449
23	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	12,045	1,279	-	-	3,199	14,863	31,386
25	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0048
26	Variable Transportation Costs	Line 24 times Line 25	$ 58	$ 6	$ -	$ -	$ 15	$ 71	$ 151
27									
28	Transporation Segment 6A								
29	Tennessee Gas Pipeline (Contract 95196)								
30	Receipt Point: Wright								
31	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
32	Received Volume	Line 24	12,045	1,279	-	-	3,199	14,863	31,386
33	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	11,918	1,266	-	-	3,165	14,706	31,054
35	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896	$ 0.0896
36	Variable Transportation Costs	Line 34 times Line 35	$ 1,068	$ 113	$ -	$ -	$ 284	$ 1,318	$ 2,782

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

Line	City Gate Delivered Costs	Reference	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	46,500	46,500
2	City Gate Delivered Volume	Line 1	-	-	-	-	-	46,500	46,500
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ 240,870	$ 240,870
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ 240,870	$ 240,870
6	Average Delivered Price	Line 5 divided by Line 2						$ 5.180	$ 5.180
7									
8	<u>Lewiston Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	46,500	46,500
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.565
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 212,273	$ 212,273
12	NYMEX Basis Price	Att to Sch 5A, Line 4 of Page 1						$ 0.615	$ 0.615
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 28,597	$ 28,597
14	Total Purchase Price	Line 10 plus Line 12						$ 5.180	$ 5.180
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ 240,870	$ 240,870

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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 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 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	#N/A							
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: PNGTS (Westbrook, ME)
Delivered to Northern via PNGTS and Granite Pipelines

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 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 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2							
24	Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2							
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: 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	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	2,903	2,903
2	City Gate Delivered Volume	Sum Lines 24 and 44	-	-	-	-	-	2,872	2,872
3	Total Purchase Cost	Line 15	$ -	$ -	$ -	$ -	$ -	$ 14,267	$ 14,267
4	Variable Transportation Costs	Sum Lines 26, 36 and 46	$ -	$ -	$ -	$ -	$ -	$ 257	$ 257
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ -	$ -	$ -	$ -	$ -	$ 14,524	$ 14,524
6	Average Delivered Price	Line 5 divided by Line 2						$ 5.057	$ 5.057
7									
8	<u>Niagara Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	2,903	2,903
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.565
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 13,251	$ 13,251
12	NYMEX Basis Price	#N/A						$ 0.350	$ 0.350
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 1,016	$ 1,016
14	Total Purchase Price	Line 10 plus Line 12						$ 4.915	$ 4.915
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ 14,267	$ 14,267
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1A								
19	Tennessee Gas Pipeline (Contract 5292)								
20	Receipt Point: Niagara								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 9	-	-	-	-	-	2,903	2,903
23	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2						1.06%	1.06%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	2,872	2,872
25	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2						$ 0.0896	$ 0.0896
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ 257	$ 257
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	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 Off-Peak
1	City Gate Volumes - Z0	Line 2 of Page 5	12,981	671	-	-	1,322	36,416	51,391
2	City Gate Volumes - Z1	Line 2 of Page 6	-	-	-	-	-	1,900	1,900
3	City Gate Volumes - Z4	Line 2 of Page 7	139,292	115,938	123,528	110,534	121,164	151,983	762,439
4	Total City Gate Volumes	Sum Lines 1 through 3	152,273	116,609	123,528	110,534	122,487	190,300	815,730
5	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ 64,992	$ 3,373	$ -	$ -	$ 6,630	$ 182,896	$ 257,891
6	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ -	$ -	$ -	$ -	$ -	$ 9,675	$ 9,675
7	City Gate Delivered Costs - Z4	Line 5 of Page 7	$ 661,759	$ 552,934	$ 593,025	$ 529,183	$ 576,501	$ 724,375	$ 3,637,777
8	Total City Gate Delivered Costs	Sum Lines 5 through 7	$ 726,751	$ 556,307	$ 593,025	$ 529,183	$ 583,131	$ 916,947	$ 3,905,343
9	Average Delivered Price	Line 8 divided by Line 4	$ 4.773	$ 4.771	$ 4.801	$ 4.788	$ 4.761	$ 4.818	$ 4.788

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

Line	City Gate Delivered Costs	Reference	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 32	13,639	705	-	-	1,389	38,262	53,996
2	City Gate Delivered Volume	Line 44	12,981	671	-	-	1,322	36,416	51,391
3	Total Purchase Price	Line 24	$ 4.426	$ 4.444			$ 4.433	$ 4.441	$ 4.437
4	Total Purchase Cost	Line 2 times Line 3	$ 60,368	$ 3,134	$ -	$ -	$ 6,159	$ 169,923	$ 239,583
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 4,624	$ 239	$ -	$ -	$ 471	$ 12,973	$ 18,308
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 64,992	$ 3,373	$ -	$ -	$ 6,630	$ 182,896	$ 257,891
7	Average Delivered Price	Line 6 divided by Line 2	$ 5.007	$ 5.025			$ 5.014	$ 5.022	$ 5.018
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	$ 4.426	$ 4.444			$ 4.433	$ 4.441	$ 4.437
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	13,639	705	-	-	1,389	38,262	53,996
20	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.561
21	NYMEX Cost	Line 9 times Line 10	$ 62,059	$ 3,221	$ -	$ -	$ 6,331	$ 174,667	$ 246,279
22	NYMEX Basis Price	#N/A	$ (0.124)	$ (0.124)			$ (0.124)	$ (0.124)	$ (0.124)
23	NYMEX Basis Costs	Line 9 times Line 12	$ (1,691)	$ (87)	$ -	$ -	$ (172)	$ (4,745)	$ (6,696)
24	Total Purchase Price	Line 10 plus Line 12	$ 4.426	$ 4.444			$ 4.433	$ 4.441	$ 4.437
25	Total Purchase Cost	Line 11 plus Line 13	$ 60,368	$ 3,134	$ -	$ -	$ 6,159	$ 169,923	$ 239,583
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	13,639	705	-	-	1,389	38,262	53,996
33	Fuel Loss Rate	Att to Sch 5A, Line 43 of Page 2	4.49%	4.49%			4.49%	4.49%	4.49%
34	Delivered Volume	Line 32 times (1 - Line 33)	13,027	674	-	-	1,327	36,544	51,572
35	Variable Transportation Rate	Att to Sch 5A, Line 26 of Page 2	$ 0.3532	$ 0.3532			$ 0.3532	$ 0.3532	$ 0.3532
36	Variable Transportation Costs	Line 34 times Line 35	$ 4,601	$ 238	$ -	$ -	$ 469	$ 12,907	$ 18,215
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	13,027	674	-	-	1,327	36,544	51,572
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	12,981	671	-	-	1,322	36,416	51,391
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ 23	$ 1	$ -	$ -	$ 2	$ 66	$ 93
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	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 32	-	-	-	-	-	1,985	1,985
2	City Gate Delivered Volume	Line 44	-	-	-	-	-	1,900	1,900
3	Total Purchase Price	Line 24						$ 4.577	$ 4.577
4	Total Purchase Cost	Line 2 times Line 3	$ -	$ -	$ -	$ -	$ -	$ 9,085	$ 9,085
5	Variable Transportation Costs	Sum Lines 36 and 46	$ -	$ -	$ -	$ -	$ -	$ 590	$ 590
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ -	$ -	$ -	$ -	$ -	$ 9,675	$ 9,675
7	Average Delivered Price	Line 6 divided by Line 2						$ 5.093	$ 5.093
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						$ 4.577	$ 4.577
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	-	-	-	-	-	1,985	1,985
20	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.565
21	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 9,061	$ 9,061
22	NYMEX Basis Price	#N/A						$ 0.012	$ 0.012
23	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ 24	$ 24
24	Total Purchase Price	Line 10 plus Line 12						$ 4.577	$ 4.577
25	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ 9,085	$ 9,085
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	-	-	-	-	-	1,985	1,985
33	Fuel Loss Rate	Att to Sch 5A, Line 45 of Page 2						3.95%	3.95%
34	Delivered Volume	Line 32 times (1 - Line 33)	-	-	-	-	-	1,907	1,907
35	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2						$ 0.3078	$ 0.3078
36	Variable Transportation Costs	Line 34 times Line 35	$ -	$ -	$ -	$ -	$ -	$ 587	$ 587
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 10-010-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	-	-	-	-	-	1,907	1,907
43	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	-	-	-	-	-	1,900	1,900
45	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018
46	Variable Transportation Costs	Line 44 times Line 45	$ -	$ -	$ -	$ -	$ -	$ 3	$ 3
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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 9	141,737	117,974	125,696	112,474	123,291	154,651	775,823
2	City Gate Delivered Volume	Sum Lines 34	139,292	115,938	123,528	110,534	121,164	151,983	762,439
3	Total Purchase Cost	Line 15	$ 644,902	$ 538,903	$ 578,076	$ 515,806	$ 561,838	$ 705,983	$ 3,545,508
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 16,857	$ 14,031	$ 14,949	$ 13,376	$ 14,663	$ 18,393	$ 92,268
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 661,759	$ 552,934	$ 593,025	$ 529,183	$ 576,501	$ 724,375	$ 3,637,777
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.751	$ 4.769	$ 4.801	$ 4.788	$ 4.758	$ 4.766	$ 4.771
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	141,737	117,974	125,696	112,474	123,291	154,651	775,823
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.570
11	NYMEX Cost	Line 9 times Line 10	$ 644,902	$ 538,903	$ 578,076	$ 515,806	$ 561,838	$ 705,983	$ 3,545,508
12	NYMEX Basis Price	#N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.570
15	Total Purchase Cost	Line 11 plus Line 13	$ 644,902	$ 538,903	$ 578,076	$ 515,806	$ 561,838	$ 705,983	$ 3,545,508
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
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	141,737	117,974	125,696	112,474	123,291	154,651	775,823
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	139,781	116,345	123,961	110,922	121,590	152,517	765,116
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188
26	Variable Transportation Costs	Line 24 times Line 25	$ 16,606	$ 13,822	$ 14,727	$ 13,178	$ 14,445	$ 18,119	$ 90,896
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	139,781	116,345	123,961	110,922	121,590	152,517	765,116
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)	139,292	115,938	123,528	110,534	121,164	151,983	762,439
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	$ 251	$ 209	$ 222	$ 199	$ 218	$ 274	$ 1,372

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

Line	City Gate Delivered Costs	Reference	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 9	23,004	2,368	-	-	9,437	27,411	62,221
2	City Gate Delivered Volume	Sum Lines 24	22,793	2,346	-	-	9,350	27,159	61,648
3	Total Purchase Cost	Line 15	$ 108,120	$ 11,173	$ -	$ -	$ 44,421	$ 129,242	$ 292,957
4	Variable Transportation Costs	Sum Lines 26	$ 296	$ 31	$ -	$ -	$ 122	$ 353	$ 801
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 108,416	$ 11,204	$ -	$ -	$ 44,543	$ 129,595	$ 293,758
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.757	$ 4.775			$ 4.764	$ 4.772	$ 4.765
7									
8	<u>Algonquin Receipts Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	23,004	2,368	-	-	9,437	27,411	62,221
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.558
11	NYMEX Cost	Line 9 times Line 10	$ 104,669	$ 10,818	$ -	$ -	$ 43,006	$ 125,130	$ 283,624
12	NYMEX Basis Price	Att to Sch 5A, Line 18 of Page 1	$ 0.150	$ 0.150			$ 0.150	$ 0.150	$ 0.150
13	NYMEX Basis Costs	Line 9 times Line 12	$ 3,451	$ 355	$ -	$ -	$ 1,416	$ 4,112	$ 9,333
14	Total Purchase Price	Line 10 plus Line 12	$ 4.700	$ 4.718			$ 4.707	$ 4.715	$ 4.708
15	Total Purchase Cost	Line 11 plus Line 13	$ 108,120	$ 11,173	$ -	$ -	$ 44,421	$ 129,242	$ 292,957
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	23,004	2,368	-	-	9,437	27,411	62,221
23	Fuel Loss Rate	Att to Sch 5A, Line 38 of Page 2	0.92%	0.92%			0.92%	0.92%	1.20%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	22,793	2,346	-	-	9,350	27,159	61,648
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	$ 296	$ 31	$ -	$ -	$ 122	$ 353	$ 801

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

Line	City Gate Delivered Costs	Reference	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 Off-Peak
1	Purchased Volumes	Line 9	73,786	47,458	14,506	32,793	57,889	71,655	298,086
2	City Gate Delivered Volume	Sum Lines 34	72,513	46,639	14,255	32,227	56,890	70,419	292,944
3	Total Purchase Cost	Line 15	$ 335,726	$ 216,788	$ 66,712	$ 150,389	$ 263,798	$ 327,106	$ 1,360,518
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 8,775	$ 5,644	$ 1,725	$ 3,900	$ 6,885	$ 8,522	$ 35,451
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 344,501	$ 222,432	$ 68,437	$ 154,289	$ 270,683	$ 335,628	$ 1,395,970
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.751	$ 4.769	$ 4.801	$ 4.788	$ 4.758	$ 4.766	$ 4.765
7									
8	<u>Tennessee Zone 4 Supply Costs</u>								
9	Purchased Volumes	Sendout Optimization	73,786	47,458	14,506	32,793	57,889	71,655	298,086
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.564
11	NYMEX Cost	Line 9 times Line 10	$ 335,726	$ 216,788	$ 66,712	$ 150,389	$ 263,798	$ 327,106	$ 1,360,518
12	NYMEX Basis Price	#N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.564
15	Total Purchase Cost	Line 11 plus Line 13	$ 335,726	$ 216,788	$ 66,712	$ 150,389	$ 263,798	$ 327,106	$ 1,360,518
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5265)								
20	Receipt Point: Tennessee FS-MA 300 Leg								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	73,786	47,458	14,506	32,793	57,889	71,655	298,086
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.38%	1.38%	1.38%	1.38%	1.38%	1.38%	1.20%
24	Delivered Volume	Line 22 times (1 - Line 23)	72,768	46,803	14,306	32,340	57,090	70,666	293,973
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188	$ 0.1188
26	Variable Transportation Costs	Line 24 times Line 25	$ 8,645	$ 5,560	$ 1,699	$ 3,842	$ 6,782	$ 8,395	$ 34,924
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	72,768	46,803	14,306	32,340	57,090	70,666	293,973
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)	72,513	46,639	14,255	32,227	56,890	70,419	292,944
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	$ 84	$ 26	$ 58	$ 102	$ 127	$ 527

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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 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 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	#N/A							
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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 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 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	#N/A							
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	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 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	<u>Tennessee FS-MA Withdrawn Inventory (Segment 1)</u>								
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	Schedule 14							
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	<u>Transportation Fuel Losses and Variable Charges</u>								
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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 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	Washington 10 Withdrawn Inventory (Segment 1)								
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	Schedule 14							
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	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 2A								
20	Vector Pipeline (Contract CRL-NUI-0725)								
21	Receipt Point: Washington 10 Withdrawal Meter								
22	Delivery Point: Dawn (Interconnects with TransCanada)								
23	Received Volume	Line 15	-	-	-	-	-	-	-
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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 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 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	
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

			2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	
Line	City Gate Delivered Costs	Reference	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	2014 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 2 Costs</u>								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	NYMEX Basis Price	Att to Sch 5A, Line 11 of Page 1							
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	<u>Transportation Fuel Losses and Variable Charges</u>								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	City Gate Delivered Costs	Reference	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 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 3 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
10	Monthly Commodity Price	Att to Sch 5A, Line 21 of Page 1	$ 16.147	$ 16.147	$ 16.147	$ 16.147	$ 16.147	$ 16.147	
11	Commodity Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Basis Price	Att to Sch 5A, Line 12 of Page 1							
13	Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12							
15	Total Purchase Cost	Line 11 plus Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 10-010-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	-	-
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	-	-
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Source of Supply: Northern LNG Inventory
On-System Storage

Line	City Gate Delivered Costs	Reference	2014 Off-Peak May-14	2014 Off-Peak Jun-14	2014 Off-Peak Jul-14	2014 Off-Peak Aug-14	2014 Off-Peak Sep-14	2014 Off-Peak Oct-14	2014 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	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 59,172
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 59,172
6	Average Delivered Price	Line 5 divided by Line 2	$ 7.364	$ 7.265	$ 7.177	$ 7.096	$ 7.022	$ 6.955	$ 7.146
7									
8	Northern LNG Withdrawn Inventory								
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	Schedule 14	$ 7.3635	$ 7.2650	$ 7.1766	$ 7.0957	$ 7.0222	$ 6.9547	$ 7.1463
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 59,172
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	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 59,172

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

Line	LNG Storage Deliveries	Reference	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak	2014 Off-Peak
			May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	
1	Purchased Volumes	Line 22	1,395	1,350	1,395	1,395	1,350	1,395	8,280
2	Storage Delivered Volume	Line 24	1,395	1,350	1,395	1,395	1,350	1,395	8,280
3	Total Purchase Price	Line 15	$ 5.165	$ 5.183	$ 5.214	$ 5.201	$ 5.172	$ 5.180	$ 5.186
4	Total Purchase Cost	Line 10 times Line 12	$ 7,205	$ 6,997	$ 7,274	$ 7,255	$ 6,982	$ 7,226	$ 42,939
5	Variable Transportation Costs	Line 26	$ 1,632	$ 1,579	$ 1,632	$ 1,632	$ 1,579	$ 1,632	$ 9,688
6	Total Storage Delivered Costs	Line 13 plus Line 14	$ 8,837	$ 8,577	$ 8,906	$ 8,888	$ 8,562	$ 8,858	$ 52,627
7	Average Delivered Price	Line 15 divided by Line 11	$ 6.335	$ 6.353	$ 6.384	$ 6.371	$ 6.342	$ 6.350	$ 6.356
8									
9	<u>LNG Supply Costs</u>								
10	Purchased Volumes	Sendout Optimization	1,395	1,350	1,395	1,395	1,350	1,395	8,280
11	Monthly NYMEX Price	Att Sched 5A, Line 21 of Page 1	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565	$ 4.571
12	LNG Supply Costs	Line 9 times Line 10	$ 6,347	$ 6,167	$ 6,416	$ 6,397	$ 6,152	$ 6,368	$ 37,847
13	NYMEX Basis Price	Att Sched 5A	$ 0.615	$ 0.615	$ 0.615	$ 0.615	$ 0.615	$ 0.615	$ 0.615
14	NYMEX Basis Costs	Line 9 times Line 12	$ 858	$ 830	$ 858	$ 858	$ 830	$ 858	$ 5,092
15	Total Purchase Price	Line 10 plus Line 12	$ 5.165	$ 5.183	$ 5.214	$ 5.201	$ 5.172	$ 5.180	$ 5.186
16	Total Purchase Cost	Line 11 plus Line 13	$ 7,205	$ 6,997	$ 7,274	$ 7,255	$ 6,982	$ 7,226	$ 42,939
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	1,395	1,350	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	1,395	1,350	1,395	8,280
25	Variable Transportation Rate	FXW-10, 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	$ 1,632	$ 1,579	$ 1,632	$ 9,688

Schedule 7

Provided in Winter 2013–14 Cost-of-Gas Filing

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 738 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG Impact Only

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			48	95	124	141	112	83	**603**	43	25	15	15	16	21	**135**	**738**
Winter 2013- 2014																	
Customer Charge	units @	$ 13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38								
First	50 units @	$0.4831	$23.19	$24.16	$24.16	$24.16	$24.16	$24.16	$143.96								
Over	50 units @	$0.4250	$0.00	$19.13	$31.45	$38.68	$26.35	$14.03	$129.63								
	COG 1	$0.8530	$40.94						$40.94								
	COG 2	$0.8530		$81.04					$81.04								
	COG 3	$0.9569			$118.66				$118.66								
	COG 4	$0.9569				$134.92			$134.92								
	COG 5	$0.9569					$107.17		$107.17								
	COG 6	$0.9569						$79.42	$79.42								
Winter Period 2013-2014 Avg. COG		$0.9323 *															
	LDAC	$0.0489	$2.35	$4.65	$6.06	$6.89	$5.48	$4.06	$29.49								
Summer 2014																	
Customer Charge	units @	$ 13.73								$ 13.73	$13.73	$13.73	$13.73	$ 13.73	$13.73	$82.38	
First	50 units @	$0.4831								$20.77	$12.08	$7.25	$7.25	$7.73	$10.15	$65.22	
Over	50 units @	$0.4831								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.6833								$29.38						$29.38	
	COG 2	$0.6833									$17.08					$17.08	
	COG 3	$0.6833										$10.25				$10.25	
	COG 4	$0.6833											$10.25			$10.25	
	COG 5	$0.6833												$10.93		$10.93	
	COG 6	$0.6833													$14.35	$14.35	
Summer Period 2014 Avg. COG		$0.6833 *															
	LDAC	$ 0.0489								$2.10	$1.22	$0.73	$0.73	$0.78	$1.03	$6.60	
	TOTAL		$80.21	$142.69	$194.05	$218.38	$176.88	$135.39	$947.61	$65.99	$44.11	$31.96	$31.96	$33.17	$39.25	**$246.45**	$1,194.05

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms (1)			48	95	124	141	112	83	**603**	43	25	15	15	16	21	**135**	**738**
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	$21.17	$22.05	$22.05	$22.05	$22.05	$22.05	$131.42								
Over	50 units @	$0.3829	$0.00	$17.23	$28.33	$34.84	$23.74	$12.64	$116.78								
	COG 1	$0.8159	$39.16						$39.16								
	COG 2	$0.8159		$77.51					$77.51								
	COG 3	$0.8159			$101.17				$101.17								
	COG 4	$0.8935				$125.98			$125.98								
	COG 5	$0.7600					$85.12		$85.12								
	COG 6	$0.5700						$47.31	$47.31								
Winter Period 2012-2013 Avg. COG		$0.7898 *															
	LDAC	$ 0.0720	$3.46	$6.84	$8.93	$10.15	$8.06	$5.98	$43.42								
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								$18.96	$11.03					$29.99	
Over	50 units @	$0.4410								$0.00	$0.00					$0.00	
First (temp)	50 units @	$0.4831										$7.25	$7.25	$7.73	$10.15	$32.37	
Over (temp)	50 units @	$0.4831										$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.5553								$23.88						$23.88	
	COG 2	$0.5858									$14.65					$14.65	
	COG 3	$0.5858										$8.79				$8.79	
	COG 4	$0.5858											$8.79			$8.79	
	COG 5	$0.5858												$9.37		$9.37	
	COG 6	$0.5858													$12.30	$12.30	
Summer Period 2013 Avg. COG		$0.5761 *															
	LDAC	$ 0.0551								$2.37	$1.38	$0.83	$0.83	$0.88	$1.16	$7.44	
	TOTAL		$77.52	$137.36	$174.21	$206.76	$152.70	$101.70	$850.26	$58.94	$40.78	$30.59	$30.59	$31.71	$37.33	**$229.95**	$1,080.20
	Change		$2.69	$5.33	$19.84	$11.62	$24.18	$33.69	$97.35	$7.05	$3.33	$1.37	$1.37	$1.46	$1.92	**$16.50**	$113.85
	% Chg		3.47%	3.88%	11.39%	5.62%	15.84%	33.13%	11.45%	11.96%	8.18%	4.48%	4.48%	4.61%	5.14%	**7.18%**	10.54%

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2012 to October 2013

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 1,947 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG Impact Only

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			117	254	349	409	319	219	1,667	102	51	29	31	27	40	280	1,947
Winter 2013- 2014																	
Customer Charge	units @	$ 31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
First	75 units @	$0.3122	$23.42	$23.42	$23.42	$23.42	$23.42	$23.42	$140.49								
Over	75 units @	$0.2647	$11.12	$47.38	$72.53	$88.41	$64.59	$38.12	$322.14								
	COG 1	$0.8664	$101.37						$101.37								
	COG 2	$0.8664		$220.07					$220.07								
	COG 3	$0.9703			$338.63				$338.63								
	COG 4	$0.9703				$396.85			$396.85								
	COG 5	$0.9703					$309.53		$309.53								
	COG 6	$0.9703						$212.50	$212.50								
Winter Period 2013-2014 Avg. COG		$0.9472 *															
	LDAC	$0.0227	$2.66	$5.77	$7.92	$9.28	$7.24	$4.97	$37.84								
Summer 2014																	
Customer Charge	units @	$ 31.40								$ 31.40	$31.40	$31.40	$31.40	$ 31.40	$31.40	$188.40	
First	75 units @	$0.3122								$23.42	$15.92	$9.05	$9.68	$8.43	$12.49	$78.99	
Over	75 units @	$0.2647								$7.15	$0.00	$0.00	$0.00	$0.00	$0.00	$7.15	
	COG 1	$0.7209								$73.53						$73.53	
	COG 2	$0.7209									$36.77					$36.77	
	COG 3	$0.7209										$20.91				$20.91	
	COG 4	$0.7209											$22.35			$22.35	
	COG 5	$0.7209												$19.46		$19.46	
	COG 6	$0.7209													$28.84	$28.84	
Summer Period 2014 Avg. COG		$0.7209 *															
	LDAC	$ 0.0227								$2.32	$1.16	$0.66	$0.70	$0.61	$0.91	$6.36	
	TOTAL		$169.96	$328.03	$473.90	$549.36	$436.17	$310.40	$2,267.81	$137.81	$85.25	$62.02	$64.13	$59.91	$73.63	**$482.74**	**$2,750.56**

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			117	254	349	409	319	219	1,667	102	51	29	31	27	40	280	1,947
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	$9.35	$39.85	$60.99	$74.35	$54.31	$32.05	$270.90								
	COG 1	$0.8279	$96.86						$96.86								
	COG 2	$0.8279		$210.29					$210.29								
	COG 3	$0.8279			$288.94				$288.94								
	COG 4	$0.9055				$370.35			$370.35								
	COG 5	$0.7720					$246.27		$246.27								
	COG 6	$0.5820						$127.46	$127.46								
Winter Period 2012-2013 Avg. COG		$0.8039 *															
	LDAC	$ 0.0435	$5.09	$11.05	$15.18	$17.79	$13.88	$9.53	$72.51								
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	$13.78					$34.03	
Over	75 units @	$0.2226								$6.01	$0.00					$6.01	
First (temp)	75 units @	$0.3122										$9.05	$9.68	$8.43	$12.49	$39.65	
Over (temp)	75 units @	$0.2647										$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.5780								$58.96						$58.96	
	COG 2	$0.6085									$31.03					$31.03	
	COG 3	$0.6085										$17.65				$17.65	
	COG 4	$0.6085											$18.86			$18.86	
	COG 5	$0.6085												$16.43		$16.43	
	COG 6	$0.6085													$24.34	$24.34	
Summer Period 2013 Avg. COG		$0.5974 *															
	LDAC	$ 0.0266								$2.71	$1.36	$0.77	$0.82	$0.72	$1.06	$7.45	
	TOTAL		$162.96	$312.84	$416.77	$514.15	$366.12	$220.70	$1,993.53	$119.34	$77.57	$58.87	$60.77	$56.98	$69.29	**$442.81**	**$2,436.34**
	Change		$7.00	$15.19	$57.13	$35.21	$70.05	$89.70	$274.29	$18.47	$7.68	$3.15	$3.36	$2.93	$4.34	**$39.93**	**$314.22**
	% Chg		4.29%	4.86%	13.71%	6.85%	19.13%	40.65%	13.76%	15.48%	9.90%	5.34%	5.54%	5.14%	6.26%	**9.02%**	**12.90%**

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2012 to October 2013

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 20,671 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG Impact Only

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,458	2,656	3,385	3,917	3,140	2,271	16,827	1,216	702	394	401	449	682	**3,844**	**20,671**
Winter 2013- 2014																	
Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
All	units @	$0.2437	$355.31	$647.27	$824.92	$954.57	$765.22	$553.44	$4,100.74								
	COG 1	$0.8664	$1,263.21						$1,263.21								
	COG 2	$0.8664		$2,301.16					$2,301.16								
	COG 3	$0.9703			$3,284.47				$3,284.47								
	COG 4	$0.9703				$3,800.67			$3,800.67								
	COG 5	$0.9703					$3,046.74		$3,046.74								
	COG 6	$0.9703						$2,203.55	$2,203.55								
Winter Period 2013-2014 Avg. COG		$0.9449 *															
	LDAC	$0.0227	$33.10	$60.29	$76.84	$88.92	$71.28	$51.55	$381.97								
Summer 2014																	
Customer Charge	units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
All	units @	$0.1978								$240.52	$138.86	$77.93	$79.32	$88.81	$134.90	$760.34	
	COG 1	$0.7209								$876.61						$876.61	
	COG 2	$0.7209									$506.07					$506.07	
	COG 3	$0.7209										$284.03				$284.03	
	COG 4	$0.7209											$289.08			$289.08	
	COG 5	$0.7209												$323.68		$323.68	
	COG 6	$0.7209													$491.65	$491.65	
Summer Period 2014 Avg. COG		$0.7209 *															
	LDAC	$ 0.0227								$27.60	$15.94	$8.94	$9.10	$10.19	$15.48	$87.26	
	TOTAL		$1,745.83	$3,102.93	$4,280.44	$4,938.36	$3,977.45	$2,902.76	$20,947.77	$1,238.95	$755.07	$465.12	$471.71	$516.90	$736.24	**$4,184.00**	**$25,131.77**

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,458	2,656	3,385	3,917	3,140	2,271	16,827	1,216	702	394	401	449	682	**3,844**	20,671
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	$293.93	$535.45	$682.42	$789.67	$633.02	$457.83	$3,392.32								
	COG 1	$0.8279	$1,207.08						$1,207.08								
	COG 2	$0.8279		$2,198.90					$2,198.90								
	COG 3	$0.8279			$2,802.44				$2,802.44								
	COG 4	$0.9055				$3,546.84			$3,546.84								
	COG 5	$0.7720					$2,424.08		$2,424.08								
	COG 6	$0.5820						$1,321.72	$1,321.72								
Winter Period 2012-2013 Avg. COG		$0.8023 *															
	LDAC	$ 0.0435	$63.42	$115.54	$147.25	$170.39	$136.59	$98.79	$731.97								
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								$189.33	$109.30					$298.63	
All (temp)	units @	$0.1978										$77.93	$79.32	$88.81	$134.90	$380.96	
	COG 1	$0.5780								$702.85						$702.85	
	COG 2	$0.6085									$427.17					$427.17	
	COG 3	$0.6085										$239.75				$239.75	
	COG 4	$0.6085											$244.01			$244.01	
	COG 5	$0.6085												$273.22		$273.22	
	COG 6	$0.6085													$415.00	$415.00	
Summer Period 2013 Avg. COG		$0.5989 *															
	LDAC	$ 0.0266								$32.35	$18.67	$10.48	$10.67	$11.94	$18.14	$102.25	
	TOTAL		$1,658.64	$2,944.10	$3,726.32	$4,601.11	$3,287.90	$1,972.55	$18,190.63	$1,018.73	$649.35	$422.37	$428.20	$468.18	$662.25	**$3,649.09**	**$21,839.72**
	Change		$87.19	$158.83	$554.12	$337.25	$689.54	$930.20	$2,757.14	$220.22	$105.72	$42.75	$43.51	$48.72	$74.00	**$534.91**	**$3,292.05**
	% Chg		5.26%	5.39%	14.87%	7.33%	20.97%	47.16%	15.16%	21.62%	16.28%	10.12%	10.16%	10.41%	11.17%	**14.66%**	**15.07%**

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2012 to October 2013

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 18,215 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG Impact Only

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,380	1,709	1,897	2,021	1,824	1,600	10,431	1,457	1,265	1,122	1,252	1,373	1,315	7,784	18,215
Winter 2013- 2014																	
Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
First	1,300 units @	$0.2270	$295.10	$295.10	$295.10	$295.10	$295.10	$295.10	$1,770.60								
Over	1,300 units @	$0.1903	$15.22	$77.83	$113.61	$137.21	$99.72	$57.09	$500.68								
	COG 1	$0.7762	$1,071.16						$1,071.16								
	COG 2	$0.7762		$1,326.53					$1,326.53								
	COG 3	$0.8801			$1,669.55				$1,669.55								
	COG 4	$0.8801				$1,778.68			$1,778.68								
	COG 5	$0.8801					$1,605.30		$1,605.30								
	COG 6	$0.8801						$1,408.16	$1,408.16								
Winter Period 2013-2014 Avg. COG		$0.8493 *															
	LDAC	$0.0227	$31.33	$38.79	$43.06	$45.88	$41.40	$36.32	$236.78								
Summer 2014																	
Customer Charge	units @	$ 94.21								$ 94.21	$94.21	$94.21	$94.21	$ 94.21	$94.21	$565.26	
First	1,000 units @	$0.1746								$174.60	$174.60	$174.60	$174.60	$174.60	$174.60	$1,047.60	
Over	1,000 units @	$0.1432								$65.44	$37.95	$17.47	$36.09	$53.41	$45.11	$255.47	
	COG 1	$0.6318								$920.53						$920.53	
	COG 2	$0.6318									$799.23					$799.23	
	COG 3	$0.6318										$708.88				$708.88	
	COG 4	$0.6318											$791.01			$791.01	
	COG 5	$0.6318												$867.46		$867.46	
	COG 6	$0.6318													$830.82	$830.82	
Summer Period 2014 Avg. COG		$0.6318 *															
	LDAC	$ 0.0227								$33.07	$28.72	$25.47	$28.42	$31.17	$29.85	$176.70	
	TOTAL		$1,507.02	$1,832.46	$2,215.53	$2,351.08	$2,135.73	$1,890.88	$11,932.70	$1,287.86	$1,134.70	$1,020.63	$1,124.33	$1,220.85	$1,174.59	$6,962.96	$18,895.66

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,380	1,709	1,897	2,021	1,824	1,600	10,431	1,457	1,265	1,122	1,252	1,373	1,315	7,784	18,215
Winter 2012 - 2013																	
Customer Charge	units @	$ 64.21	$64.21	$64.21	$64.21	$64.21	$64.21	$64.21	$385.26								
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	$11.86	$60.61	$88.48	$106.85	$77.66	$44.46	$389.91								
	COG 1	$0.7507	$1,035.97						$1,035.97								
	COG 2	$0.7507		$1,282.95					$1,282.95								
	COG 3	$0.7507			$1,424.08				$1,424.08								
	COG 4	$0.8283				$1,673.99			$1,673.99								
	COG 5	$0.6948					$1,267.32		$1,267.32								
	COG 6	$0.5048						$807.68	$807.68								
Winter Period 2012-2013 Avg. COG		$0.7182 *															
	LDAC	$ 0.0435	$60.03	$74.34	$82.52	$87.91	$79.34	$69.60	$453.75								
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					$265.00	
Over	1,000 units @	$0.1011								$46.20	$26.79					$72.99	
First (temp)	1,000 units @	$0.1746										$174.60	$174.60	$174.60	$174.60	$698.40	
Over (temp)	1,000 units @	$0.1432										$17.47	$36.09	$53.41	$45.11	$152.08	
	COG 1	$0.5180								$754.73						$754.73	
	COG 2	$0.5485									$693.85					$693.85	
	COG 3	$0.5485										$615.42				$615.42	
	COG 4	$0.5485											$686.72			$686.72	
	COG 5	$0.5485												$753.09		$753.09	
	COG 6	$0.5485													$721.28	$721.28	
Summer Period 2013 Avg. COG		$0.5428 *															
	LDAC	$ 0.0266								$38.76	$33.65	$29.85	$33.30	$36.52	$34.98	$207.05	
	TOTAL		$1,412.43	$1,722.48	$1,899.65	$2,173.34	$1,728.90	$1,226.32	$10,163.12	$1,066.39	$981.00	$931.54	$1,024.92	$1,111.84	$1,070.17	$6,185.87	$16,348.99
	Change		$94.58	$109.98	$315.88	$177.74	$406.84	$664.56	$1,769.58	$221.46	$153.70	$89.09	$99.41	$109.02	$104.41	$777.08	$2,546.66
	% Chg		6.70%	6.39%	16.63%	8.18%	23.53%	54.19%	17.41%	20.77%	15.67%	9.56%	9.70%	9.81%	9.76%	12.56%	15.58%

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2012 to October 2013

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2014 vs. Actual Summer 2013

Residential Heating	**Summer 2013**	**Summer 2014**
Customer Charge	$13.73	$13.73
First 50 Therms	$0.4410	$0.4831
Over 50 therms	$0.4410	$0.4831
LDAC	$0.0551	$0.0489
CGA	$0.5761	$0.6833

	Usage (Therms)	**Summer 2013 Bill Amount**	**Summer 2014 Bill Amount**	**Total Bill**		**Base Rate**		**COG**		**LDAC**	
	5	$19.09	$19.81	$0.72	3.7%	$0.21	1.1%	$0.54	2.8%	($0.03)	-0.2%
	10	$24.45	$25.88	$1.43	5.9%	$0.42	1.7%	$1.07	4.4%	($0.06)	-0.2%
	20	$35.17	$38.04	$2.86	8.1%	$0.84	2.4%	$2.14	6.1%	($0.12)	-0.3%
Average Monthly	25	$40.53	$44.11	$3.58	8.8%	$1.05	2.6%	$2.68	6.6%	($0.16)	-0.4%
	30	$45.90	$50.19	$4.29	9.4%	$1.26	2.7%	$3.22	7.0%	($0.19)	-0.4%
	45	$61.98	$68.42	$6.44	10.4%	$1.89	3.0%	$4.82	7.8%	($0.28)	-0.5%
	50	$67.34	$74.50	$7.16	10.6%	$2.11	3.1%	$5.36	8.0%	($0.31)	-0.5%
	75	$94.14	$104.88	$10.73	11.4%	$3.16	3.4%	$8.04	8.5%	($0.47)	-0.5%
	125	$147.75	$165.64	$17.89	12.1%	$5.27	3.6%	$13.40	9.1%	($0.78)	-0.5%
	150	$174.56	$196.03	$21.47	12.3%	$6.32	3.6%	$16.08	9.2%	($0.93)	-0.5%
	200	$228.17	$256.79	$28.62	12.5%	$8.43	3.7%	$21.44	9.4%	($1.24)	-0.5%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 738 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG and Docket No. 13-086 Proposed LDAC and Distribution Increases

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms(1)			48	95	124	141	112	83	603	43	25	15	15	16	21	135	738
Winter 2013- 2014																		
Customer Charge	units @	$ 13.73		$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38								
First	50 units @	$0.4831		$23.19	$24.16	$24.16	$24.16	$24.16	$24.16	$143.96								
Over	50 units @	$0.4250		$0.00	$19.13	$31.45	$38.68	$26.35	$14.03	$129.63								
	COG 1	$0.8530		$40.94						$40.94								
	COG 2	$0.8530			$81.04					$81.04								
	COG 3	$0.9569				$118.66				$118.66								
	COG 4	$0.9569					$134.92			$134.92								
	COG 5	$0.9569						$107.17		$107.17								
	COG 6	$0.9569							$79.42	$79.42								
Winter Period 2013-2014 Avg. COG		$0.9323	*															
	LDAC	$0.0489		$2.35	$4.65	$6.06	$6.89	$5.48	$4.06	$29.49								
Summer 2014																		
Customer Charge	units @	$ 20.01	(2)								$ 20.01	$20.01	$20.01	$20.01	$ 20.01	$20.01	$120.06	
First	50 units @	$0.5104									$21.95	$12.76	$7.66	$7.66	$8.17	$10.72	$68.90	
Over	50 units @	$0.5104									$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.6833									$29.38						$29.38	
	COG 2	$0.6833										$17.08					$17.08	
	COG 3	$0.6833											$10.25				$10.25	
	COG 4	$0.6833												$10.25			$10.25	
	COG 5	$0.6833													$10.93		$10.93	
	COG 6	$0.6833														$14.35	$14.35	
Summer Period 2014 Avg. COG		$0.6833	*															
	LDAC	$ 0.0692	(3)								$2.98	$1.73	$1.04	$1.04	$1.11	$1.45	$9.34	
	TOTAL			$80.21	$142.69	$194.05	$218.38	$176.88	$135.39	$947.61	$74.31	$51.58	$38.95	$38.95	$40.22	$46.53	**$290.55**	$1,238.16

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms (1)			48	95	124	141	112	83	603	43	25	15	15	16	21	135	738
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		$21.17	$22.05	$22.05	$22.05	$22.05	$22.05	$131.42								
Over	50 units @	$0.3829		$0.00	$17.23	$28.33	$34.84	$23.74	$12.64	$116.78								
	COG 1	$0.8159		$39.16						$39.16								
	COG 2	$0.8159			$77.51					$77.51								
	COG 3	$0.8159				$101.17				$101.17								
	COG 4	$0.8935					$125.98			$125.98								
	COG 5	$0.7600						$85.12		$85.12								
	COG 6	$0.5700							$47.31	$47.31								
Winter Period 2012-2013 Avg. COG		$0.7898	*															
	LDAC	$ 0.0720		$3.46	$6.84	$8.93	$10.15	$8.06	$5.98	$43.42								
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									$18.96	$11.03					$29.99	
Over	50 units @	$0.4410									$0.00	$0.00					$0.00	
First (temp)	50 units @	$0.4831											$7.25	$7.25	$7.73	$10.15	$32.37	
Over (temp)	50 units @	$0.4831											$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.5553									$23.88						$23.88	
	COG 2	$0.5858										$14.65					$14.65	
	COG 3	$0.5858											$8.79				$8.79	
	COG 4	$0.5858												$8.79			$8.79	
	COG 5	$0.5858													$9.37		$9.37	
	COG 6	$0.5858														$12.30	$12.30	
Summer Period 2013 Avg. COG		$0.5761	*															
	LDAC	$ 0.0551									$2.37	$1.38	$0.83	$0.83	$0.88	$1.16	$7.44	
	TOTAL			$77.52	$137.36	$174.21	$206.76	$152.70	$101.70	$850.26	$58.94	$40.78	$30.59	$30.59	$31.71	$37.33	**$229.95**	$1,080.20
	Change			$2.69	$5.33	$19.84	$11.62	$24.18	$33.69	$97.35	$15.37	$10.81	$8.36	$8.36	$8.50	$9.20	**$60.61**	$157.96
	% Chg			3.47%	3.88%	11.39%	5.62%	15.84%	33.13%	11.45%	26.08%	26.50%	27.34%	27.34%	26.81%	24.63%	**26.36%**	14.62%

*-Note- Weighted by usage.
(1) Actual Weather Normalized Usage from November 2012 to October 2013.
(2) Includes distribution rates as filed March 4, 2014 in Docket No. 13-086.
(3) Includes proposed RCE of $0.0042 and RPC of $0.0161 filed in Docket No. 13-086.

Northern Utilities, Inc.
New Hampshire Division
Summer 2014
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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 1,947 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG and Docket No. 13-086 Proposed LDAC and Distribution Increases

				Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
Typical Usage: therms(1)				117	254	349	409	319	219	**1,667**	102	51	29	31	27	40	**280**	**1,947**
Winter 2013- 2014																		
Customer Charge	units @	$ 31.40		$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
First	75 units @	$0.3122		$23.42	$23.42	$23.42	$23.42	$23.42	$23.42	$140.49								
Over	75 units @	$0.2647		$11.12	$47.38	$72.53	$88.41	$64.59	$38.12	$322.14								
	COG 1	$0.8664		$101.37						$101.37								
	COG 2	$0.8664			$220.07					$220.07								
	COG 3	$0.9703				$338.63				$338.63								
	COG 4	$0.9703					$396.85			$396.85								
	COG 5	$0.9703						$309.53		$309.53								
	COG 6	$0.9703							$212.50	$212.50								
Winter Period 2013-2014 Avg. COG		$0.9472	*															
	LDAC	$0.0227		$2.66	$5.77	$7.92	$9.28	$7.24	$4.97	$37.84								
Summer 2014																		
Customer Charge	units @	$ 63.18	(2)								$ 63.18	$63.18	$63.18	$63.18	$ 63.18	$63.18	$379.08	
First	75 units @	$0.1513									$11.35	$7.72	$4.39	$4.69	$4.09	$6.05	$38.28	
Over	75 units @	$0.1513									$4.09	$0.00	$0.00	$0.00	$0.00	$0.00	$4.09	
	COG 1	$0.7209									$73.53						$73.53	
	COG 2	$0.7209										$36.77					$36.77	
	COG 3	$0.7209											$20.91				$20.91	
	COG 4	$0.7209												$22.35			$22.35	
	COG 5	$0.7209													$19.46		$19.46	
	COG 6	$0.7209														$28.84	$28.84	
Summer Period 2014 Avg. COG		$0.7209	*															
	LDAC	$ 0.0430	(3)								$4.39	$2.19	$1.25	$1.33	$1.16	$1.72	$12.04	
	TOTAL			$169.96	$328.03	$473.90	$549.36	$436.17	$310.40	$2,267.81	$156.53	$109.86	$89.72	$91.55	$87.89	$99.79	**$635.34**	**$2,903.15**

				Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
Typical Usage: therms(1)				117	254	349	409	319	219	**1,667**	102	51	29	31	27	40	**280**	**1,947**
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		$9.35	$39.85	$60.99	$74.35	$54.31	$32.05	$270.90								
	COG 1	$0.8279		$96.86						$96.86								
	COG 2	$0.8279			$210.29					$210.29								
	COG 3	$0.8279				$288.94				$288.94								
	COG 4	$0.9055					$370.35			$370.35								
	COG 5	$0.7720						$246.27		$246.27								
	COG 6	$0.5820							$127.46	$127.46								
Winter Period 2012-2013 Avg. COG		$0.8039	*															
	LDAC	$ 0.0435		$5.09	$11.05	$15.18	$17.79	$13.88	$9.53	$72.51								
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	$13.78					$34.03	
Over	75 units @	$0.2226									$6.01	$0.00					$6.01	
First (temp)	75 units @	$0.3122											$9.05	$9.68	$8.43	$12.49	$39.65	
Over (temp)	75 units @	$0.2647											$0.00	$0.00	$0.00	$0.00	$0.00	
	COG 1	$0.5780									$58.96						$58.96	
	COG 2	$0.6085										$31.03					$31.03	
	COG 3	$0.6085											$17.65				$17.65	
	COG 4	$0.6085												$18.86			$18.86	
	COG 5	$0.6085													$16.43		$16.43	
	COG 6	$0.6085														$24.34	$24.34	
Summer Period 2013 Avg. COG		$0.5974	*															
	LDAC	$ 0.0266									$2.71	$1.36	$0.77	$0.82	$0.72	$1.06	$7.45	
	TOTAL			$162.96	$312.84	$416.77	$514.15	$366.12	$220.70	$1,993.53	$119.34	$77.57	$58.87	$60.77	$56.98	$69.29	**$442.81**	**$2,436.34**
	Change			$7.00	$15.19	$57.13	$35.21	$70.05	$89.70	$274.29	$37.19	$32.29	$30.85	$30.78	$30.91	$30.50	**$192.53**	**$466.81**
	% Chg			4.29%	4.86%	13.71%	6.85%	19.13%	40.65%	13.76%	31.17%	41.63%	52.40%	50.66%	54.26%	44.01%	**43.48%**	**19.16%**

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2012 to October 2013.

(2) Includes distribution rates as filed March 4, 2014 in Docket No. 13-086.

(3) Includes proposed RCE of $0.0042 and RPC of $0.0161 filed in Docket No. 13-086.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 20,671 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG and Docket No. 13-086 Proposed LDAC and Distribution Increases

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms(1)			1,458	2,656	3,385	3,917	3,140	2,271	16,827	1,216	702	394	401	449	682	**3,844**	**20,671**
Winter 2013- 2014																		
Customer Charge	units @	$ 94.21		$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
All	units @	$0.2437		$355.31	$647.27	$824.92	$954.57	$765.22	$553.44	$4,100.74								
	COG 1	$0.8664		$1,263.21						$1,263.21								
	COG 2	$0.8664			$2,301.16					$2,301.16								
	COG 3	$0.9703				$3,284.47				$3,284.47								
	COG 4	$0.9703					$3,800.67			$3,800.67								
	COG 5	$0.9703						$3,046.74		$3,046.74								
	COG 6	$0.9703							$2,203.55	$2,203.55								
Winter Period 2013-2014 Avg. COG		$0.9449	*															
	LDAC	$0.0227		$33.10	$60.29	$76.84	$88.92	$71.28	$51.55	$381.97								
Summer 2014																		
Customer Charge	units @	$ 184.26	(2)								$ 184.26	$184.26	$184.26	$184.26	$ 184.26	$184.26	$1,105.56	
All	units @	$0.1519									$184.71	$106.63	$59.85	$60.91	$68.20	$103.60	$583.90	
	COG 1	$0.7209									$876.61						$876.61	
	COG 2	$0.7209										$506.07					$506.07	
	COG 3	$0.7209											$284.03				$284.03	
	COG 4	$0.7209												$289.08			$289.08	
	COG 5	$0.7209													$323.68		$323.68	
	COG 6	$0.7209														$491.65	$491.65	
Summer Period 2014 Avg. COG		$0.7209	*															
	LDAC	$ 0.0430	(3)								$52.29	$30.19	$16.94	$17.24	$19.31	$29.33	$165.29	
	TOTAL			$1,745.83	$3,102.93	$4,280.44	$4,938.36	$3,977.45	$2,902.76	$20,947.77	$1,297.87	$827.15	$545.09	$551.50	$595.45	$808.84	**$4,625.90**	**$25,573.66**

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms(1)			1,458	2,656	3,385	3,917	3,140	2,271	16,827	1,216	702	394	401	449	682	**3,844**	20,671
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		$293.93	$535.45	$682.42	$789.67	$633.02	$457.83	$3,392.32								
	COG 1	$0.8279		$1,207.08						$1,207.08								
	COG 2	$0.8279			$2,198.90					$2,198.90								
	COG 3	$0.8279				$2,802.44				$2,802.44								
	COG 4	$0.9055					$3,546.84			$3,546.84								
	COG 5	$0.7720						$2,424.08		$2,424.08								
	COG 6	$0.5820							$1,321.72	$1,321.72								
Winter Period 2012-2013 Avg. COG		$0.8023	*															
	LDAC	$ 0.0435		$63.42	$115.54	$147.25	$170.39	$136.59	$98.79	$731.97								
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									$189.33	$109.30					$298.63	
All (temp)	units @	$0.1978											$77.93	$79.32	$88.81	$134.90	$380.96	
	COG 1	$0.5780									$702.85						$702.85	
	COG 2	$0.6085										$427.17					$427.17	
	COG 3	$0.6085											$239.75				$239.75	
	COG 4	$0.6085												$244.01			$244.01	
	COG 5	$0.6085													$273.22		$273.22	
	COG 6	$0.6085														$415.00	$415.00	
Summer Period 2013 Avg. COG		$0.5989	*															
	LDAC	$ 0.0266									$32.35	$18.67	$10.48	$10.67	$11.94	$18.14	$102.25	
	TOTAL			$1,658.64	$2,944.10	$3,726.32	$4,601.11	$3,287.90	$1,972.55	$18,190.63	$1,018.73	$649.35	$422.37	$428.20	$468.18	$662.25	**$3,649.09**	**$21,839.72**
	Change			$87.19	$158.83	$554.12	$337.25	$689.54	$930.20	$2,757.14	$279.14	$177.80	$122.71	$123.29	$127.27	$146.59	**$976.80**	**$3,733.94**
	% Chg			5.26%	5.39%	14.87%	7.33%	20.97%	47.16%	15.16%	27.40%	27.38%	29.05%	28.79%	27.18%	22.13%	**26.77%**	**17.10%**

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2012 to October 2013.

(2) Includes distribution rates as filed March 4, 2014 in Docket No. 13-086

(3) Includes proposed RCE of $0.0042 and RPC of $0.0161 filed in Docket No. 13-086

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 18,215 therms/year

Comparison of Summer 2014 vs. Summer 2013 COG and Docket No. 13-086 Proposed LDAC and Distribution Increases

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,380	1,709	1,897	2,021	1,824	1,600	**10,431**	1,457	1,265	1,122	1,252	1,373	1,315	**7,784**	**18,215**
Winter 2013- 2014																	
Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
First	1,300 units @	$0.2270	$295.10	$295.10	$295.10	$295.10	$295.10	$295.10	$1,770.60								
Over	1,300 units @	$0.1903	$15.22	$77.83	$113.61	$137.21	$99.72	$57.09	$500.68								
	COG 1	$0.7762	$1,071.16						$1,071.16								
	COG 2	$0.7762		$1,326.53					$1,326.53								
	COG 3	$0.8801			$1,669.55				$1,669.55								
	COG 4	$0.8801				$1,778.68			$1,778.68								
	COG 5	$0.8801					$1,605.30		$1,605.30								
	COG 6	$0.8801						$1,408.16	$1,408.16								
Winter Period 2013-2014 Avg. COG		$0.8493 *															
	LDAC	$0.0227	$31.33	$38.79	$43.06	$45.88	$41.40	$36.32	$236.78								
Summer 2014																	
Customer Charge	units @	$ 184.26 (2)								$ 184.26	$184.26	$184.26	$184.26	$ 184.26	$184.26	$1,105.56	
First	1,000 units @	$0.1108								$110.80	$110.80	$110.80	$110.80	$110.80	$110.80	$664.80	
Over	1,000 units @	$0.0897								$40.99	$23.77	$10.94	$22.60	$33.46	$28.26	$160.02	
	COG 1	$0.6318								$920.53						$920.53	
	COG 2	$0.6318									$799.23					$799.23	
	COG 3	$0.6318										$708.88				$708.88	
	COG 4	$0.6318											$791.01			$791.01	
	COG 5	$0.6318												$867.46		$867.46	
	COG 6	$0.6318													$830.82	$830.82	
Summer Period 2014 Avg. COG		$0.6318 *															
	LDAC	$ 0.0430 (3)								$62.65	$54.40	$48.25	$53.84	$59.04	$56.55	$334.71	
	TOTAL		$1,507.02	$1,832.46	$2,215.53	$2,351.08	$2,135.73	$1,890.88	$11,932.70	$1,319.24	$1,172.45	$1,063.13	$1,162.51	$1,255.02	$1,210.68	$7,183.03	$19,115.73

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
Typical Usage: therms(1)			1,380	1,709	1,897	2,021	1,824	1,600	**10,431**	1,457	1,265	1,122	1,252	1,373	1,315	**7,784**	**18,215**
Winter 2012 - 2013																	
Customer Charge	units @	$ 64.21	$64.21	$64.21	$64.21	$64.21	$64.21	$64.21	$385.26								
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	$11.86	$60.61	$88.48	$106.85	$77.66	$44.46	$389.91								
	COG 1	$0.7507	$1,035.97						$1,035.97								
	COG 2	$0.7507		$1,282.95					$1,282.95								
	COG 3	$0.7507			$1,424.08				$1,424.08								
	COG 4	$0.8283				$1,673.99			$1,673.99								
	COG 5	$0.6948					$1,267.32		$1,267.32								
	COG 6	$0.5048						$807.68	$807.68								
Winter Period 2012-2013 Avg. COG		$0.7182 *															
	LDAC	$ 0.0435	$60.03	$74.34	$82.52	$87.91	$79.34	$69.60	$453.75								
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					$265.00	
Over	1,000 units @	$0.1011								$46.20	$26.79					$72.99	
First (temp)	1,000 units @	$0.1746										$174.60	$174.60	$174.60	$174.60	$698.40	
Over (temp)	1,000 units @	$0.1432										$17.47	$36.09	$53.41	$45.11	$152.08	
	COG 1	$0.5180								$754.73						$754.73	
	COG 2	$0.5485									$693.85					$693.85	
	COG 3	$0.5485										$615.42				$615.42	
	COG 4	$0.5485											$686.72			$686.72	
	COG 5	$0.5485												$753.09		$753.09	
	COG 6	$0.5485													$721.28	$721.28	
Summer Period 2013 Avg. COG		$0.5428 *															
	LDAC	$ 0.0266								$38.76	$33.65	$29.85	$33.30	$36.52	$34.98	$207.05	
	TOTAL		$1,412.43	$1,722.48	$1,899.65	$2,173.34	$1,728.90	$1,226.32	$10,163.12	$1,066.39	$981.00	$931.54	$1,024.92	$1,111.84	$1,070.17	**$6,185.87**	**$16,348.99**
	Change		$94.58	$109.98	$315.88	$177.74	$406.84	$664.56	$1,769.58	$252.84	$191.45	$131.59	$137.59	$143.18	$140.50	**$997.16**	**$2,766.73**
	% Chg		6.70%	6.39%	16.63%	8.18%	23.53%	54.19%	17.41%	23.71%	19.52%	14.13%	13.42%	12.88%	13.13%	**16.12%**	**16.92%**

*-Note- Weighted by usage.

(1) Actual Weather Normalized Usage from November 2012 to October 2013.

(2) Includes distribution rates as filed March 4, 2014 in Docket No. 13-086.

(3) Includes proposed RCE of $0.0042 and RPC of $0.0161 filed in Docket No. 13-086.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2014 vs. Actual Summer 2013

Residential Heating

	Summer 2013	Summer 2014
Customer Charge	$13.73	$20.01
First 50 Therms	$0.4410	$0.5104
Over 50 therms	$0.4410	$0.5104
LDAC	$0.0551	$0.0692
CGA	$0.5761	$0.6833

	Usage (Therms)	Summer 2013 Bill Amount	Summer 2014 Bill Amount	Total Bill		Base Rate		COG		LDAC	
	5	$19.09	$26.32	$7.23	37.9%	$6.63	34.7%	$0.54	2.8%	$0.07	0.4%
	10	$24.45	$32.64	$8.19	33.5%	$6.97	28.5%	$1.07	4.4%	$0.14	0.6%
	20	$35.17	$45.27	$10.09	28.7%	$7.67	21.8%	$2.14	6.1%	$0.28	0.8%
Average Monthly	25	$40.53	$51.58	$11.05	27.3%	$8.02	19.8%	$2.68	6.6%	$0.35	0.9%
	30	$45.90	$57.90	$12.00	26.1%	$8.36	18.2%	$3.22	7.0%	$0.42	0.9%
	45	$61.98	$76.84	$14.86	24.0%	$9.40	15.2%	$4.82	7.8%	$0.63	1.0%
	50	$67.34	$83.16	$15.82	23.5%	$9.75	14.5%	$5.36	8.0%	$0.71	1.1%
	75	$94.14	$114.73	$20.58	21.9%	$11.49	12.2%	$8.04	8.5%	$1.06	1.1%
	125	$147.75	$177.87	$30.12	20.4%	$14.96	10.1%	$13.40	9.1%	$1.76	1.2%
	150	$174.56	$209.45	$34.89	20.0%	$16.69	9.6%	$16.08	9.2%	$2.12	1.2%
	200	$228.17	$272.59	$44.42	19.5%	$20.16	8.8%	$21.44	9.4%	$2.82	1.2%

Schedule 9

Northern Utilities, Inc.
New Hampshire Division
Revised Schedule 9
Page 1 of 1

Northern Utilities New Hampshire Division
Period Covered: May 1, 2014 - October 30, 2014
Variance Analysis

		2013 Summer (6 months actual)			Forecast Summer 2014 (6 months proposed)			Variance		
1	Therm Sales	6,433,420			6,566,792			133,372		
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		$ 1,049,948	$ 0.1632		$ 912,730	$ 0.1390		$ (137,218)	$ (0.0242)
7										
8	Purchased Gas		3,196,278	0.4968		3,143,535	0.4787		$ (52,743)	$ (0.0181)
9										
10	Storage & Peaking Gas		116,344	0.0181		29,861	0.0045		$ (86,483)	$ (0.0135)
11										
12	Hedging (Gain)/Loss		107,396	0.0167		-	-		(107,396)	(0.0167)
13										
14										
15	Total Volumes and Cost		$ 4,469,966	$ 0.6948	$ -	$ 4,086,126	$ 0.6222	$ -	$ (383,840)	$ (0.0726)
16										
17	Prior Period Balance		$147,647	$ 0.0230		$ 394,545	$ 0.0601		$ 246,898	$ 0.0371
18						$ -	$ -		$ -	$ -
19	Interest		$ 3,683	$ 0.0006		10,204	$ 0.0016		6,521	$ 0.0010
20	Refunds from Suppliers		-	$ -		(105,725)	$ (0.0161)		(105,725)	$ (0.0161)
21	Off-system Sales		(469,368)	$ (0.0730)						
22	Prior Period Adjustment									
23	Interruptible Revenues					-	$ -		-	$ -
24	Capacity Release & Asset Management		-	$ -		$ -	$ -		-	$ -
25	Working Capital Allowance		861	$ 0.0001		4,226	$ 0.0006		3,365	$ 0.0005
26	Bad Debt Allowance		(3,098)	$ (0.0005)		$ 19,792	$ 0.0030		22,890	$ 0.0035
27	Fuel Inventory Financing		-	$ -		-	$ -		-	$ -
28	Local Production and Storage			$ -		-	$ -		-	$ -
29	Misc Overhead		89,856	$ 0.0140		78,440	$ 0.0119		(11,416)	$ (0.0020)
30										
31	Total Anticipated Indirect Cost of Gas		($230,419)	$ (0.0358)		401,483	$ 0.0611		631,902	$ 0.0970
32	Total Adjusted Cost		4,239,547	$ 0.6590		4,487,608	$ 0.6833		248,061	$ 0.0243

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-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**SUMMER**	
2	**Total Therms**									
3	Res Heat	394,202	381,486	385,589	394,202	381,486	394,202	4,632,800	2,331,168	Schedule 10B, LN 52
4	Res General	14,744	14,268	14,421	14,744	14,268	14,744	173,272	87,188	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	80,012	77,431	78,263	80,012	77,431	80,012	932,501	473,160	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	126,489	122,409	123,725	126,489	122,409	126,489	1,486,542	748,010	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	96,792	93,669	94,677	96,792	93,669	96,792	1,137,528	572,390	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	108,821	105,311	106,444	108,821	105,311	108,821	1,278,904	643,529	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	8,198	7,933	8,019	8,198	7,933	8,198	96,344	48,479	Schedule 10B, LN 58
10	G42 High Annual-High Winter	18,608	18,008	18,201	18,608	18,008	18,608	218,686	110,040	Schedule 10B, LN 59
11	Total Firm Sales	847,865	820,515	829,340	847,865	820,515	847,865	9,956,578	5,013,964	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	46.49%	46.49%	46.49%	46.49%	46.49%	46.49%			LN 3 / LN 11
15	Res General	1.74%	1.74%	1.74%	1.74%	1.74%	1.74%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	9.44%	9.44%	9.44%	9.44%	9.44%	9.44%			LN 5 / LN 11
17	G40 Low Annual-High Winter	14.92%	14.92%	14.92%	14.92%	14.92%	14.92%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	11.42%	11.42%	11.42%	11.42%	11.42%	11.42%			LN 7 / LN 11
19	G41 Med Annual-High Winter	12.83%	12.83%	12.83%	12.83%	12.83%	12.83%			LN 8 / LN 11
20	G52 High Annual-Low Winter	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%			LN 9 / LN 11
21	G42 High Annual-High Winter	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%			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-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**SUMMER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 77,122	$ 925,464	$ 462,732	Schedule 1A, LN 69
26	Res Heat	$ 35,857	$ 35,857	$ 35,857	$ 35,857	$ 35,857	$ 35,857	$ 430,626	$ 215,140	LN 25 * LN 14
27	Res General	$ 1,341	$ 1,341	$ 1,341	$ 1,341	$ 1,341	$ 1,341	$ 16,106	$ 8,046	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 7,278	$ 7,278	$ 7,278	$ 7,278	$ 7,278	$ 7,278	$ 86,662	$ 43,667	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 138,176	$ 69,033	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 8,804	$ 8,804	$ 8,804	$ 8,804	$ 8,804	$ 8,804	$ 105,735	$ 52,825	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 9,898	$ 9,898	$ 9,898	$ 9,898	$ 9,898	$ 9,898	$ 118,876	$ 59,390	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 746	$ 746	$ 746	$ 746	$ 746	$ 746	$ 8,955	$ 4,474	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,693	$ 1,693	$ 1,693	$ 1,693	$ 1,693	$ 1,693	$ 20,327	$ 10,155	LN 25 * LN 21
34										
35	Residential	$ 37,198	$ 37,198	$ 37,198	$ 37,198	$ 37,198	$ 37,198	$ 446,732	$ 223,187	LN 26 + LN 27
36	SALES HLF CLASSES	$ 16,828	$ 16,828	$ 16,828	$ 16,828	$ 16,828	$ 16,828	$ 201,352	$ 100,966	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 23,096	$ 23,096	$ 23,096	$ 23,096	$ 23,096	$ 23,096	$ 277,380	$ 138,579	LN 29 + LN 31 + LN 33
38										

Remaining Capacity Costs

		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	21,721	1,536	20,185	50.13%	Company Analysis
41	Res General	368	56	312	0.77%	Company Analysis
42	G50 Low Annual-Low Winter	936	324	612	1.52%	Company Analysis
43	G40 Low Annual-High Winter	9,106	512	8,594	21.34%	Company Analysis
44	G51 Med Annual-Low Winter	1,531	384	1,147	2.85%	Company Analysis
45	G41 Med Annual-High Winter	7,907	631	7,276	18.07%	Company Analysis
46	G52 High Annual-Low Winter	151	19	132	0.33%	Company Analysis
47	G42 High Annual-High Winter	2,061	54	2,007	4.99%	Company Analysis
48	TOTAL	43,781	3,517	40,264	100.00%	Sum LN 40 : LN 47

49

50 **REMAINING PIPELINE DEMAND**

51		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	SUMMER	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 21,420	$ 4,764	$ -	$ 627	$ 4,989	$ 39,263	$ 2,177,455	$ 71,062	Schedule 1A, LN 70
53										
54	Res Heat	$ 10,738	$ 2,388	$ -	$ 314	$ 2,501	$ 19,683	$ 1,091,589	$ 35,624	LN 40 Col D * LN 52
55	Res General	$ 166	$ 37	$ -	$ 5	$ 39	$ 304	$ 16,849	$ 550	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 326	$ 72	$ -	$ 10	$ 76	$ 597	$ 33,095	$ 1,080	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 4,572	$ 1,017	$ -	$ 134	$ 1,065	$ 8,380	$ 464,764	$ 15,168	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 610	$ 136	$ -	$ 18	$ 142	$ 1,118	$ 62,015	$ 2,024	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 3,871	$ 861	$ -	$ 113	$ 901	$ 7,095	$ 393,464	$ 12,841	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 70	$ 16	$ -	$ 2	$ 16	$ 129	$ 7,131	$ 233	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 1,068	$ 237	$ -	$ 31	$ 249	$ 1,957	$ 108,548	$ 3,542	LN 47 Col D * LN 52
62	TOTAL	$ 21,420	$ 4,764	$ -	$ 627	$ 4,989	$ 39,263	$ 2,177,455	$ 71,062	Sum LN 54 : LN 61
63										
64	Residential	$ 10,904	$ 2,425	$ -	$ 319	$ 2,539	$ 19,987	$ 1,108,438	$ 36,174	LN 54 + LN 55
65	SALES HLF CLASSES	$ 1,006	$ 224	$ -	$ 29	$ 234	$ 1,844	$ 102,241	$ 3,337	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 9,510	$ 2,115	$ -	$ 278	$ 2,215	$ 17,432	$ 966,776	$ 31,551	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

69		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	SUMMER	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 114,221	$ 25,404	$ -	$ 3,343	$ 26,601	$ 209,367	$ 11,611,255	$ 378,936	Schedule 1A, LN 73
71										
72	Res Heat	$ 57,261	$ 12,735	$ -	$ 1,676	$ 13,336	$ 104,959	$ 5,820,888	$ 189,966	LN 40 Col D * LN 70
73	Res General	$ 884	$ 197	$ -	$ 26	$ 206	$ 1,620	$ 89,845	$ 2,932	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 1,736	$ 386	$ -	$ 51	$ 404	$ 3,182	$ 176,477	$ 5,759	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 24,380	$ 5,422	$ -	$ 713	$ 5,678	$ 44,688	$ 2,478,351	$ 80,882	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 3,253	$ 724	$ -	$ 95	$ 758	$ 5,963	$ 330,694	$ 10,792	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 20,640	$ 4,590	$ -	$ 604	$ 4,807	$ 37,832	$ 2,098,141	$ 68,473	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 374	$ 83	$ -	$ 11	$ 87	$ 686	$ 38,029	$ 1,241	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 5,694	$ 1,266	$ -	$ 167	$ 1,326	$ 10,437	$ 578,831	$ 18,890	LN 47 Col D * LN 70
80	TOTAL	$ 114,221	$ 25,404	$ -	$ 3,343	$ 26,601	$ 209,367	$ 11,611,255	$ 378,936	Sum LN 72 : LN 79
81										
82	Residential	$ 58,144	$ 12,932	$ -	$ 1,702	$ 13,542	$ 106,579	$ 5,910,733	$ 192,898	LN 72 + LN 73
83	SALES HLF CLASSES	$ 5,363	$ 1,193	$ -	$ 157	$ 1,249	$ 9,831	$ 545,199	$ 17,793	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 50,713	$ 11,279	$ -	$ 1,484	$ 11,811	$ 92,958	$ 5,155,322	$ 168,245	LN 75 + LN 77 + LN 79

85

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

87		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	SUMMER	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,673,935)	$ -	Schedule 1A, LN 76
89										
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,343,110)	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (36,166)	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (71,038)	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (997,623)	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (133,116)	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (844,575)	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,308)	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (233,000)	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,673,935)	$ -	Sum LN 90 : LN 97
99										
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,379,276)	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (219,462)	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,075,197)	$ -	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

105		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	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**

123		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	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**

141		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	SUMMER	
142	Res Heat	$ 67,999	$ 15,124	$ -	$ 1,990	$ 15,837	$ 124,642	$ 4,569,367	$ 225,590	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 1,050	$ 233	$ -	$ 31	$ 244	$ 1,924	$ 70,528	$ 3,482	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 2,062	$ 459	$ -	$ 60	$ 480	$ 3,779	$ 138,533	$ 6,839	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 28,952	$ 6,439	$ -	$ 847	$ 6,743	$ 53,069	$ 1,945,493	$ 96,049	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 3,863	$ 859	$ -	$ 113	$ 900	$ 7,081	$ 259,593	$ 12,816	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 24,510	$ 5,451	$ -	$ 717	$ 5,708	$ 44,927	$ 1,647,030	$ 81,314	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 444	$ 99	$ -	$ 13	$ 103	$ 814	$ 29,852	$ 1,474	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 6,762	$ 1,504	$ -	$ 198	$ 1,575	$ 12,394	$ 454,380	$ 22,433	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 135,641	$ 30,168	$ -	$ 3,969	$ 31,590	$ 248,630	$ 9,114,776	$ 449,998	Sum LN 142 : LN 149
151										
152	Residential	$ 69,048	$ 15,357	$ -	$ 2,021	$ 16,081	$ 126,566	$ 4,639,895	$ 229,072	LN 142 + LN 143
153	SALES HLF CLASSES	$ 6,369	$ 1,417	$ -	$ 186	$ 1,483	$ 11,674	$ 427,979	$ 21,129	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 60,224	$ 13,394	$ -	$ 1,762	$ 14,026	$ 110,390	$ 4,046,902	$ 199,796	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

157		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	SUMMER	
158	Res Heat	$ 103,855	$ 50,980	$ 35,857	$ 37,847	$ 51,693	$ 160,498	$ 4,999,993	$ 440,731	LN 142 + LN 26
159	Res General	$ 2,391	$ 1,575	$ 1,341	$ 1,372	$ 1,586	$ 3,265	$ 86,634	$ 11,528	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 9,339	$ 7,736	$ 7,278	$ 7,338	$ 7,758	$ 11,057	$ 225,195	$ 50,507	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 40,457	$ 17,945	$ 11,505	$ 12,353	$ 18,248	$ 64,574	$ 2,083,669	$ 165,082	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 12,667	$ 9,663	$ 8,804	$ 8,917	$ 9,704	$ 15,885	$ 365,328	$ 65,641	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 34,409	$ 15,350	$ 9,898	$ 10,616	$ 15,607	$ 54,826	$ 1,765,906	$ 140,704	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 1,190	$ 844	$ 746	$ 759	$ 849	$ 1,560	$ 38,808	$ 5,948	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 8,454	$ 3,196	$ 1,693	$ 1,890	$ 3,267	$ 14,087	$ 474,707	$ 32,588	LN 149 + LN 33
166	TOTAL	$ 212,763	$ 107,290	$ 77,122	$ 81,091	$ 108,712	$ 325,752	$ 10,040,239	$ 912,730	Sum LN 158 : LN 165
167										
168	Residential	$ 106,246	$ 52,555	$ 37,198	$ 39,218	$ 53,279	$ 163,763	$ 5,086,627	$ 452,259	LN 158 + LN 159
169	SALES HLF CLASSES	$ 23,197	$ 18,244	$ 16,828	$ 17,014	$ 18,311	$ 28,502	$ 629,331	$ 122,096	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 83,320	$ 36,491	$ 23,096	$ 24,859	$ 37,122	$ 133,487	$ 4,324,281	$ 338,375	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								27%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								73%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2013 - 2014 Period

	Forecasted Normal Sales By Class- Therms								
Line	Calendar Month Firm Sales Volumes								
No.	Normal Winter	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
1	Res Heat	617,250	438,904	383,067	400,185	441,419	772,306	16,708,899	3,053,132
2	Res General	23,086	16,416	14,327	14,967	16,510	28,885	352,776	114,191
3	**Total Residential**	**640,336**	**455,320**	**397,394**	**415,153**	**457,929**	**801,191**	**17,061,674**	**3,167,323**
4	G50 Low Annual-Low Winter	125,284	89,085	77,752	81,226	89,595	156,756	1,382,849	619,698
5	G40 Low Annual-High Winter	198,059	140,833	122,916	128,409	141,640	247,813	7,682,498	979,669
6	G51 Med Annual-Low Winter	151,558	107,768	94,057	98,261	108,385	189,631	1,850,081	749,660
7	G41 Med Annual-High Winter	170,395	121,161	105,747	110,473	121,856	213,198	5,279,434	842,830
8	G52 High Annual-Low Winter	12,836	9,127	7,966	8,322	9,180	16,061	273,905	63,493
9	G42 High Annual-High Winter	29,137	20,718	18,082	18,890	20,837	36,456	927,510	144,120
10	**Total C&I**	**687,269**	**488,692**	**426,521**	**445,581**	**491,492**	**859,914**	**17,396,276**	**3,399,469**
11	**Total Sales**	**1,327,606**	**944,011**	**823,915**	**860,734**	**949,421**	**1,661,106**	**34,457,951**	**6,566,792**
12									
13	Residential Heat & Non Heat	640,336	455,320	397,394	415,153	457,929	801,191	17,061,674	3,167,323
14	SALES HLF CLASSES	289,679	205,980	179,775	187,809	207,160	362,447	3,506,835	1,432,851
15	SALES LLF CLASSES	397,590	282,712	246,746	257,772	284,332	497,467	13,889,441	1,966,619
16	**Total Firm Sales**	**1,327,606**	**944,011**	**823,915**	**860,734**	**949,421**	**1,661,106**	**34,457,951**	**6,566,792**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccou	Unaccounted For)							
20	Normal Winter	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**SUMMER**
21	Res Heat	621,214	441,777	385,589	402,815	444,301	777,227	16,813,682	3,072,924
22	Res General	23,234	16,523	14,421	15,066	16,617	29,069	355,001	114,931
23	G50 Low Annual-Low Winter	126,088	89,668	78,263	81,760	90,180	157,755	1,391,615	623,715
24	G40 Low Annual-High Winter	199,331	141,754	123,725	129,253	142,564	249,392	7,730,566	986,019
25	G51 Med Annual-Low Winter	152,532	108,473	94,677	98,906	109,093	190,839	1,861,789	754,519
26	G41 Med Annual-High Winter	171,489	121,954	106,444	111,199	122,651	214,557	5,312,510	848,294
27	G52 High Annual-Low Winter	12,919	9,187	8,019	8,377	9,240	16,163	275,627	63,905
28	G42 High Annual-High Winter	29,324	20,854	18,201	19,014	20,973	36,688	933,320	145,054
29	**Subtotal**								
30	Residential	644,448	458,300	400,011	417,881	460,919	806,297	17,168,683	3,187,854
31	SALES HLF CLASSES	291,539	207,328	180,959	189,043	208,513	364,757	3,529,031	1,442,139
32	SALES LLF CLASSES	400,143	284,562	248,370	259,466	286,188	500,637	13,976,396	1,979,367
33	**Total Firm Sales**	1,336,130	950,190	829,340	866,390	955,620	1,671,690	34,674,110	6,609,360

Northern Utilities - NEW HAMPSHIRE DIVISION
2013 - 2014 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) x 10
22	Res General	LN 2 x Adj factor (Company Use, LAUF, BTU) x 10
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Company Use, LAUF, BTU) x 10
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Company Use, LAUF, BTU) x 10
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Company Use, LAUF, BTU) x 10
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Company Use, LAUF, BTU) x 10
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Company Use, LAUF, BTU) x 10
28	G42 High Annual-High Winter	LN 9 x Adj factor (Company Use, LAUF, BTU) x 10
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

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

34		
35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	12,716
37	Res General	476
38	G50 Low Annual-Low Winter	2,581
39	G40 Low Annual-High Winter	4,080
40	G51 Med Annual-Low Winter	3,122
41	G41 Med Annual-High Winter	3,510
42	G52 High Annual-Low Winter	264
43	G42 High Annual-High Winter	600
44	**Subtotal**	-
45	Residential	13,192
46	SALES HLF CLASSES	5,968
47	SALES LLF CLASSES	8,191
48	**Total Firm Sales**	**27,350**

49	**BASE SENDOUT BY CLASS - Therms**								
50	Days per Month	31	30	31	31	30	31		
51		**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**SUMMER**
52	Res Heat	394,202	381,486	385,589	394,202	381,486	394,202	4,632,800	2,331,168
53	Res General	14,744	14,268	14,421	14,744	14,268	14,744	173,272	87,188
54	G50 Low Annual-Low Winter	80,012	77,431	78,263	80,012	77,431	80,012	932,501	473,160
55	G40 Low Annual-High Winter	126,489	122,409	123,725	126,489	122,409	126,489	1,486,542	748,010
56	G51 Med Annual-Low Winter	96,792	93,669	94,677	96,792	93,669	96,792	1,137,528	572,390
57	G41 Med Annual-High Winter	108,821	105,311	106,444	108,821	105,311	108,821	1,278,904	643,529
58	G52 High Annual-Low Winter	8,198	7,933	8,019	8,198	7,933	8,198	96,344	48,479
59	G42 High Annual-High Winter	18,608	18,008	18,201	18,608	18,008	18,608	218,686	110,040
60	**Subtotal**								
61	Residential	408,946	395,754	400,011	408,946	395,754	408,946	4,806,072	2,418,356
62	SALES HLF CLASSES	185,001	179,033	180,959	185,001	179,033	185,001	2,166,373	1,094,029
63	SALES LLF CLASSES	253,918	245,727	248,370	253,918	245,727	253,918	2,984,133	1,501,579
64	**Total Firm Sales**	847,865	820,515	829,340	847,865	820,515	847,865	9,956,578	5,013,964
65									
66	**REMAINING SENDOUT BY CLASS - Therms**								
67		**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**SUMMER**
68	Res Heat	227,012	60,291	-	8,613	62,815	383,025	12,180,882	741,756
69	Res General	8,490	2,255	-	322	2,349	14,326	181,729	27,742
70	G50 Low Annual-Low Winter	46,077	12,237	-	1,748	12,750	77,743	459,114	150,555
71	G40 Low Annual-High Winter	72,842	19,346	-	2,764	20,156	122,903	6,244,024	238,010
72	G51 Med Annual-Low Winter	55,740	14,804	-	2,115	15,424	94,047	724,261	182,129
73	G41 Med Annual-High Winter	62,667	16,643	-	2,378	17,340	105,736	4,033,606	204,765
74	G52 High Annual-Low Winter	4,721	1,254	-	179	1,306	7,965	179,282	15,426
75	G42 High Annual-High Winter	10,716	2,846	-	407	2,965	18,080	714,633	35,014
76	**Subtotal**								
77	Residential	235,502	62,546	-	8,935	65,165	397,351	12,362,610	769,498
78	SALES HLF CLASSES	106,538	28,295	-	4,042	29,480	179,756	1,362,658	348,110
79	SALES LLF CLASSES	146,225	38,835	-	5,548	40,461	246,719	10,992,263	477,788
80	**Total Firm Sales**	488,265	129,675	-	18,525	135,105	823,825	24,717,532	1,595,396

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)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 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	465,075	484,053	-18,977	-3.9%	18,135	-37,112	429,260	35,815	8.3%	25,967	9,848
Jun	377,322	377,016	306	0.1%	14,585	-14,279	348,153	29,169	8.4%	21,383	7,787
Jul	327,299	310,556	16,744	5.4%	13,727	3,017	300,179	27,121	9.0%	19,109	8,012
Aug	329,697	320,392	9,305	2.9%	15,448	-6,143	302,241	27,456	9.1%	20,993	6,463
Sep	328,757	328,259	498	0.2%	18,295	-17,797	303,338	25,419	8.4%	22,979	2,440
Oct	393,389	396,543	-3,154	-0.8%	23,849	-27,003	361,315	32,074	8.9%	29,671	2,402
Off-Peak	2,221,539	2,216,817	4,722	0.2%	105,126	-100,405	2,044,485	177,054	8.7%	140,737	36,316

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

	Total Division Meter Counts						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	30,770	29,659	1,111	3.7%	29,015	1,755	6.0%
Jun	30,749	29,604	1,145	3.9%	28,970	1,779	6.1%
Jul	30,825	29,520	1,305	4.4%	28,980	1,845	6.4%
Aug	30,976	29,551	1,425	4.8%	28,964	2,012	6.9%
Sep	31,258	29,608	1,650	5.6%	29,057	2,201	7.6%
Oct	31,631	29,837	1,794	6.0%	29,231	2,400	8.2%
Off-Peak	31,035	29,630	1,405	4.7%	29,036	1,999	6.9%

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						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	15.11	16.32	-1.21	-7.4%	14.79	0.32	2.2%
Jun	12.27	12.74	-0.46	-3.6%	12.02	0.25	2.1%
Jul	10.62	10.52	0.10	0.9%	10.36	0.26	2.5%
Aug	10.64	10.84	-0.20	-1.8%	10.44	0.21	2.0%
Sep	10.52	11.09	-0.57	-5.1%	10.44	0.08	0.7%
Oct	12.44	13.29	-0.85	-6.4%	12.36	0.08	0.6%
Off-Peak	71.58	74.82	-3.24	-4.3%	70.41	1.20	1.7%

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)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 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	2,336	2,454	-118	-4.8%	37	-155	2,449	-113	-4.6%	-113	0
Jun	2,184	2,788	-604	-21.7%	47	-651	2,188	-4	-0.2%	-4	0
Jul	1,738	840	898	106.9%	15	882	1,735	3	0.2%	3	0
Aug	1,633	1,600	33	2.0%	-96	129	1,627	5	0.3%	5	0
Sep	1,760	1,580	179	11.3%	-74	253	1,742	18	1.0%	18	0
Oct	1,769	1,677	92	5.5%	-49	141	1,700	69	4.1%	69	0
Off-Peak	11,419	10,940	479	4.4%	-168	647	11,440	-21	-0.2%	8	-29

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						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	1,534	1,511	23	1.5%	1,608	-74	-4.6%
Jun	1,532	1,507	25	1.7%	1,535	-3	-0.2%
Jul	1,531	1,503	28	1.8%	1,528	3	0.2%
Aug	1,529	1,627	-98	-6.0%	1,524	5	0.3%
Sep	1,527	1,602	-75	-4.7%	1,512	15	1.0%
Oct	1,526	1,572	-46	-2.9%	1,466	60	4.1%
Off-Peak	1,530	1,554	-24	-1.5%	1,529	1	0.1%

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

	Total Division Use Per Meter						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	1.52	1.62	-0.10	-6.2%	1.52	0.00	0.0%
Jun	1.43	1.85	-0.42	-22.9%	1.43	0.00	0.0%
Jul	1.14	0.56	0.58	103.1%	1.14	0.00	0.0%
Aug	1.07	0.98	0.08	8.6%	1.07	0.00	0.0%
Sep	1.15	0.99	0.17	16.8%	1.15	0.00	0.0%
Oct	1.16	1.07	0.09	8.7%	1.16	0.00	0.0%
Off-Peak	7.46	7.04	0.42	6.0%	7.48	0.00	0.0%

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

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

	Residential Heat Metered Deliveries (Dth)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 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	88,466	92,585	-4,118	-4.4%	3,780	-7,899	82,376	6,090	7.4%	6,090	0
Jun	52,994	53,140	-146	-0.3%	2,260	-2,406	49,473	3,522	7.1%	3,522	0
Jul	38,835	33,739	5,096	15.1%	1,675	3,421	36,166	2,668	7.4%	2,668	0
Aug	33,872	32,286	1,586	4.9%	1,957	-371	31,340	2,532	8.1%	2,532	0
Sep	37,138	33,702	3,436	10.2%	2,330	1,106	34,156	2,982	8.7%	2,982	0
Oct	54,009	45,054	8,955	19.9%	3,228	5,727	49,470	4,539	9.2%	4,539	0
Off-Peak	305,313	290,505	14,808	5.1%	16,189	-1,381	282,980	22,333	7.9%	22,588	-255

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						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	22,557	21,672	885	4.1%	21,004	1,553	7.4%
Jun	22,561	21,641	920	4.3%	21,062	1,499	7.1%
Jul	22,660	21,588	1,072	5.0%	21,103	1,557	7.4%
Aug	22,799	21,496	1,303	6.1%	21,095	1,704	8.1%
Sep	23,025	21,536	1,489	6.9%	21,176	1,849	8.7%
Oct	23,275	21,719	1,556	7.2%	21,319	1,956	9.2%
Off-Peak	22,813	21,609	1,204	5.6%	21,127	1,686	8.0%

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

	Total Division Use Per Meter						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	3.92	4.27	-0.35	-8.2%	3.92	0.00	0.0%
Jun	2.35	2.46	-0.11	-4.3%	2.35	0.00	0.0%
Jul	1.71	1.56	0.15	9.7%	1.71	0.00	0.0%
Aug	1.49	1.50	-0.02	-1.1%	1.49	0.00	0.0%
Sep	1.61	1.56	0.05	3.1%	1.61	0.00	0.0%
Oct	2.32	2.07	0.25	11.9%	2.32	0.00	0.0%
Off-Peak	13.38	13.44	-0.06	-0.5%	13.39	0.00	0.0%

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

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

	Total Division C&I Metered Deliveries (Dth)										
	2013-2014	2013-2014 Compared to 2012-2013					2013-2014 Compared to 2011-2012				
	Forecast	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2011-2012 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	374,273	389,014	-14,741	-3.8%	12,210	-26,951	344,436	29,837	8.7%	14,861	14,976
Jun	322,144	321,088	1,056	0.3%	9,931	-8,875	296,492	25,652	8.7%	13,152	12,500
Jul	286,727	275,977	10,750	3.9%	8,805	1,945	262,278	24,449	9.3%	11,778	12,671
Aug	294,192	286,506	7,687	2.7%	9,793	-2,106	269,273	24,919	9.3%	12,847	12,072
Sep	289,860	292,977	-3,118	-1.1%	10,683	-13,801	267,441	22,419	8.4%	14,148	8,271
Oct	337,611	349,812	-12,200	-3.5%	15,215	-27,416	310,146	27,466	8.9%	18,511	8,955
Off-Peak	1,904,807	1,915,373	-10,566	-0.6%	66,557	-77,122	1,750,065	154,742	8.8%	85,408	69,334

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						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	6,679	6,476	203	3.1%	6,403	276	4.3%
Jun	6,656	6,456	200	3.1%	6,373	283	4.4%
Jul	6,634	6,429	205	3.2%	6,349	285	4.5%
Aug	6,648	6,428	220	3.4%	6,345	303	4.8%
Sep	6,706	6,470	236	3.6%	6,369	337	5.3%
Oct	6,831	6,546	285	4.3%	6,446	385	6.0%
Off-Peak	6,692	6,468	225	3.5%	6,381	311	4.9%

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

	Total Division Use Per Meter						
	2013-2014	Compared to 2012-2013			Compared to 2011-2012		
	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	56.04	60.07	-4.03	-6.7%	53.79	2.24	4.2%
Jun	48.40	49.73	-1.33	-2.7%	46.52	1.88	4.0%
Jul	43.22	42.93	0.29	0.7%	41.31	1.91	4.6%
Aug	44.25	44.57	-0.32	-0.7%	42.44	1.82	4.3%
Sep	43.22	45.28	-2.06	-4.5%	41.99	1.23	2.9%
Oct	49.43	53.44	-4.01	-7.5%	48.11	1.31	2.7%
Off-Peak	284.63	296.15	-11.52	-3.9%	274.27	10.39	3.8%

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
Sales Service Deliveries Forecast by Rate Class

Forecast Calendar Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-14	2,309	61,725	19,806	12,528	17,039	15,156	2,914	1,284	0	132,761
Jun-14	1,642	43,890	14,083	8,908	12,116	10,777	2,072	913	0	94,401
Jul-14	1,433	38,307	12,292	7,775	10,575	9,406	1,808	797	0	82,392
Aug-14	1,497	40,019	12,841	8,123	11,047	9,826	1,889	832	0	86,073
Sep-14	1,651	44,142	14,164	8,960	12,186	10,839	2,084	918	0	94,942
Oct-14	2,889	77,231	24,781	15,676	21,320	18,963	3,646	1,606	0	166,111
Off-Peak	11,419	305,313	97,967	61,970	84,283	74,966	14,412	6,349	0	656,679
Total	35,278	1,670,890	768,250	138,285	527,943	185,008	92,751	27,391	0	3,445,795

Forecast Calendar Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-14	2,309	61,725	26,396	16,212	40,022	34,667	24,044	93,277	87,041	385,692
Jun-14	1,642	43,890	20,362	12,418	34,013	29,367	22,204	88,562	82,931	335,390
Jul-14	1,433	38,307	18,094	11,019	30,811	26,585	20,413	81,797	76,640	305,099
Aug-14	1,497	40,019	18,853	11,483	32,014	27,626	21,166	84,759	79,409	316,825
Sep-14	1,651	44,142	20,261	12,368	33,450	28,891	21,634	86,036	80,536	328,970
Oct-14	2,889	77,231	32,016	19,720	46,552	40,384	26,844	102,605	95,562	443,803
Off-Peak	11,419	305,313	135,982	83,221	216,862	187,521	136,305	537,036	502,120	2,115,778
Total	35,278	1,670,890	962,131	186,570	1,199,678	467,995	516,286	1,471,763	1,010,437	7,521,028

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-14	100%	100%	75%	77%	43%	44%	12%	1%	0%	34%
Jun-14	100%	100%	69%	72%	36%	37%	9%	1%	0%	28%
Jul-14	100%	100%	68%	71%	34%	35%	9%	1%	0%	27%
Aug-14	100%	100%	68%	71%	35%	36%	9%	1%	0%	27%
Sep-14	100%	100%	70%	72%	36%	38%	10%	1%	0%	29%
Oct-14	100%	100%	77%	79%	46%	47%	14%	2%	0%	37%
Off-Peak	100%	100%	72%	74%	39%	40%	11%	1%	0%	31%
Total	100%	100%	80%	74%	44%	40%	18%	2%	0%	46%

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

Forecast Bill Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-14	2,336	88,466	33,263	10,307	26,599	14,536	4,183	1,407		181,096
Jun-14	2,184	52,994	16,665	10,325	15,396	12,198	2,354	944		113,061
Jul-14	1,738	38,835	10,662	10,286	9,543	10,844	1,922	757		84,585
Aug-14	1,633	33,872	9,794	10,300	7,936	13,569	1,237	804		79,143
Sep-14	1,760	37,138	10,427	11,565	9,259	11,456	1,746	779		84,129
Oct-14	1,769	54,009	17,157	9,188	15,549	12,364	2,970	1,659		114,664
Off-Peak	11,419	305,313	97,967	61,970	84,283	74,966	14,412	6,349	0	656,679
Total	35,278	1,670,890	768,250	138,285	527,943	185,008	92,751	27,391	0	3,445,795

Forecast Bill Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-14	2,336	88,466	43,950	14,398	61,106	34,281	21,228	114,680	84,629	465,075
Jun-14	2,184	52,994	24,140	14,115	38,772	31,452	24,577	101,921	87,166	377,322
Jul-14	1,738	38,835	15,502	13,567	25,638	28,681	22,001	102,784	78,554	327,299
Aug-14	1,633	33,872	13,522	13,501	22,905	31,992	27,780	99,200	85,293	329,697
Sep-14	1,760	37,138	15,038	15,570	28,345	29,068	29,962	95,644	76,232	328,757
Oct-14	1,769	54,009	23,830	12,069	40,096	32,047	10,757	22,806	90,245	287,628
Off-Peak	11,419	305,313	135,982	83,221	216,862	187,521	136,305	537,036	502,120	2,115,778
Total	35,278	1,670,890	962,131	186,570	1,199,678	467,995	516,286	1,471,763	1,010,437	7,521,028

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
May-14	100%	100%	76%	72%	44%	42%	20%	1%	0%	39%
Jun-14	100%	100%	69%	73%	40%	39%	10%	1%	0%	30%
Jul-14	100%	100%	69%	76%	37%	38%	9%	1%	0%	26%
Aug-14	100%	100%	72%	76%	35%	42%	4%	1%	0%	24%
Sep-14	100%	100%	69%	74%	33%	39%	6%	1%	0%	26%
Oct-14	100%	100%	72%	76%	39%	39%	28%	7%	0%	40%
Peak	100%	100%	81%	74%	45%	39%	21%	2%	0%	52%
Total	100%	100%	80%	74%	44%	40%	18%	2%	0%	46%

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)	Net Unbilled Sales Service Deliveries (Dth)	Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Lost and Unaccounted For (Percent)	Lost and Unaccounted For (Dth)	Estimated Division Sales Service Sendout (Dth)	Estimated Company-Managed Sales	Total Estimated City-Gate Sendout Requirement
Nov-13	743,511	0.02%	149	196,714	161,197	357,910	358,059	0.58%	2,089	360,148	49,745	409,893
Dec-13	979,136	0.02%	196	428,187	99,091	527,279	527,474	0.58%	3,078	530,552	218,878	749,430
Jan-14	1,183,125	0.02%	237	597,266	68,403	665,669	665,906	0.58%	3,885	669,791	298,470	968,261
Feb-14	1,023,258	0.02%	205	652,263	-95,782	556,481	556,685	0.58%	3,248	559,933	268,623	828,556
Mar-14	869,971	0.02%	174	539,306	-110,329	428,977	429,151	0.58%	2,504	431,655	159,184	590,839
Apr-14	606,248	0.02%	121	375,380	-122,580	252,800	252,921	0.58%	1,475	254,396	0	254,396
May-14	385,692	0.02%	77	181,096	-48,336	132,761	132,838	0.58%	775	133,613	0	133,613
Jun-14	335,390	0.02%	67	113,061	-18,660	94,401	94,468	0.58%	551	95,019	0	95,019
Jul-14	305,099	0.02%	61	84,585	-2,193	82,392	82,453	0.58%	481	82,934	0	82,934
Aug-14	316,825	0.02%	63	79,143	6,930	86,073	86,137	0.58%	502	86,639	0	86,639
Sep-14	328,970	0.02%	66	84,129	10,813	94,942	95,008	0.58%	554	95,562	0	95,562
Oct-14	443,803	0.02%	89	114,664	51,446	166,111	166,199	0.58%	970	167,169	0	167,169
Peak	5,405,250	0.02%	1,081	2,789,116	0	2,789,116	2,790,197	0.58%	16,278	2,806,475	994,900	3,801,375
Off-Peak	2,115,778	0.02%	423	656,679	0	656,679	657,102	0.58%	3,834	660,936	0	660,936
Annual	7,521,028	0.02%	1,504	3,445,795	0	3,445,795	3,447,299	0.58%	20,112	3,467,411	994,900	4,462,311

Attachment 3 to Schedule 10B

Provided in the Winter 2013-14 Cost-of-Gas Filing

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
2	**Total Therms**								
3	Res Heat	394,202	381,486	385,589	394,202	381,486	394,202	4,632,800	2,331,168
4	Res General	14,744	14,268	14,421	14,744	14,268	14,744	173,272	87,188
5	G50 Low Annual-Low Winter	80,012	77,431	78,263	80,012	77,431	80,012	932,501	473,160
6	G40 Low Annual-High Winter	126,489	122,409	123,725	126,489	122,409	126,489	1,486,542	748,010
7	G51 Med Annual-Low Winter	96,792	93,669	94,677	96,792	93,669	96,792	1,137,528	572,390
8	G41 Med Annual-High Winter	108,821	105,311	106,444	108,821	105,311	108,821	1,278,904	643,529
9	G52 High Annual-Low Winter	8,198	7,933	8,019	8,198	7,933	8,198	96,344	48,479
10	G42 High Annual-High Winter	18,608	18,008	18,201	18,608	18,008	18,608	218,686	110,040
11	Total Firm Sales	847,865	820,515	829,340	847,865	820,515	847,865	9,956,578	5,013,964
12	**% of Total**								
13	Res Heat	46.49%	46.49%	46.49%	46.49%	46.49%	46.49%		
14	Res General	1.74%	1.74%	1.74%	1.74%	1.74%	1.74%		
15	G50 Low Annual-Low Winter	9.44%	9.44%	9.44%	9.44%	9.44%	9.44%		
16	G40 Low Annual-High Winter	14.92%	14.92%	14.92%	14.92%	14.92%	14.92%		
17	G51 Med Annual-Low Winter	11.42%	11.42%	11.42%	11.42%	11.42%	11.42%		
18	G41 Med Annual-High Winter	12.83%	12.83%	12.83%	12.83%	12.83%	12.83%		
19	G52 High Annual-Low Winter	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%		
20	G42 High Annual-High Winter	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
23	TOTAL BASE COMMODITY Excld Hedging	$ 405,718	$ 391,800	$ 365,949	$ 377,981	$ 391,128	$ 413,807	$ 5,080,503	$ 2,346,382
24	Res Heat	$ 188,632	$ 182,161	$ 170,143	$ 175,736	$ 181,849	$ 192,393	$ 2,363,628	$ 1,090,916
25	Res General	$ 7,055	$ 6,813	$ 6,364	$ 6,573	$ 6,801	$ 7,196	$ 88,402	$ 40,801
26	G50 Low Annual-Low Winter	$ 38,287	$ 36,974	$ 34,534	$ 35,669	$ 36,910	$ 39,050	$ 476,471	$ 221,424
27	G40 Low Annual-High Winter	$ 60,527	$ 58,451	$ 54,594	$ 56,389	$ 58,351	$ 61,734	$ 758,425	$ 350,046
28	G51 Med Annual-Low Winter	$ 46,316	$ 44,728	$ 41,776	$ 43,150	$ 44,651	$ 47,240	$ 580,360	$ 267,861
29	G41 Med Annual-High Winter	$ 52,073	$ 50,286	$ 46,969	$ 48,513	$ 50,200	$ 53,111	$ 652,490	$ 301,152
30	G52 High Annual-Low Winter	$ 3,923	$ 3,788	$ 3,538	$ 3,655	$ 3,782	$ 4,001	$ 49,154	$ 22,687
31	G42 High Annual-High Winter	$ 8,904	$ 8,599	$ 8,031	$ 8,295	$ 8,584	$ 9,082	$ 111,572	$ 51,495
32									
33	Residential	$ 195,687	$ 188,975	$ 176,506	$ 182,309	$ 188,651	$ 199,589	$ 2,452,031	$ 1,131,717
34	SALES HLF CLASSES	$ 88,526	$ 85,489	$ 79,849	$ 82,474	$ 85,343	$ 90,291	$ 1,105,986	$ 511,972
35	SALES LLF CLASSES	$ 121,504	$ 117,336	$ 109,594	$ 113,197	$ 117,135	$ 123,927	$ 1,522,487	$ 702,693

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
37	TOTAL BASE HEDGING COMMODITY	$ -	$ -	$ -	$ -	$ -	$ -	$ (85,629)	$ -
38	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (39,879)	$ -
39	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,492)	$ -
40	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,950)	$ -
41	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,796)	$ -
42	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,792)	$ -
43	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,009)	$ -
44	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (829)	$ -
45	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,882)	$ -
46									
47	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (41,370)	$ -
48	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,571)	$ -
49	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (25,687)	$ -

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

Base Commodity Costs

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

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

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

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

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
51	**Total Therms**								
52	Res Heat	227,012	60,291	-	8,613	62,815	383,025	12,180,882	741,756
53	Res General	8,490	2,255	-	322	2,349	14,326	181,729	27,742
54	G50 Low Annual-Low Winter	46,077	12,237	-	1,748	12,750	77,743	459,114	150,555
55	G40 Low Annual-High Winter	72,842	19,346	-	2,764	20,156	122,903	6,244,024	238,010
56	G51 Med Annual-Low Winter	55,740	14,804	-	2,115	15,424	94,047	724,261	182,129
57	G41 Med Annual-High Winter	62,667	16,643	-	2,378	17,340	105,736	4,033,606	204,765
58	G52 High Annual-Low Winter	4,721	1,254	-	179	1,306	7,965	179,282	15,426
59	G42 High Annual-High Winter	10,716	2,846	-	407	2,965	18,080	714,633	35,014
60	Total Firm Sales	488,265	129,675	-	18,525	135,105	823,825	24,717,532	1,595,396
61	**% of Total**								
62	Res Heat	46.49%	46.49%	46.49%	46.49%	46.49%	46.49%		
63	Res General	1.74%	1.74%	1.74%	1.74%	1.74%	1.74%		
64	G50 Low Annual-Low Winter	9.44%	9.44%	9.44%	9.44%	9.44%	9.44%		
65	G40 Low Annual-High Winter	14.92%	14.92%	14.92%	14.92%	14.92%	14.92%		
66	G51 Med Annual-Low Winter	11.42%	11.42%	11.42%	11.42%	11.42%	11.42%		
67	G41 Med Annual-High Winter	12.83%	12.83%	12.83%	12.83%	12.83%	12.83%		
68	G52 High Annual-Low Winter	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%		
69	G42 High Annual-High Winter	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
72	REMAINING COMMODITY Excld Hedging	$ 239,500	$ 36,211	$ -	$ -	$ 66,877	$ 484,425	$ 13,996,700	$ 827,014
73	Res Heat	$ 111,352	$ 16,836	$ -	$ -	$ 31,093	$ 225,226	$ 6,898,058	$ 384,508
74	Res General	$ 4,165	$ 630	$ -	$ -	$ 1,163	$ 8,424	$ 102,901	$ 14,381
75	G50 Low Annual-Low Winter	$ 22,601	$ 3,417	$ -	$ -	$ 6,311	$ 45,714	$ 259,085	$ 78,044
76	G40 Low Annual-High Winter	$ 35,730	$ 5,402	$ -	$ -	$ 9,977	$ 72,269	$ 3,536,107	$ 123,378
77	G51 Med Annual-Low Winter	$ 27,341	$ 4,134	$ -	$ -	$ 7,635	$ 55,302	$ 410,050	$ 94,411
78	G41 Med Annual-High Winter	$ 30,739	$ 4,648	$ -	$ -	$ 8,583	$ 62,175	$ 2,284,269	$ 106,145
79	G52 High Annual-Low Winter	$ 2,316	$ 350	$ -	$ -	$ 647	$ 4,684	$ 101,525	$ 7,996
80	G42 High Annual-High Winter	$ 5,256	$ 795	$ -	$ -	$ 1,468	$ 10,632	$ 404,705	$ 18,150
81									
82	Residential	$ 115,517	$ 17,466	$ -	$ -	$ 32,256	$ 233,650	$ 7,000,959	$ 398,889
83	SALES HLF CLASSES	$ 52,258	$ 7,901	$ -	$ -	$ 14,592	$ 105,700	$ 770,660	$ 180,451
84	SALES LLF CLASSES	$ 71,725	$ 10,845	$ -	$ -	$ 20,028	$ 145,075	$ 6,225,080	$ 247,673

85	**REMAINING COMMODITY HEDGING COSTS**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
86	TOTAL REMAINING COMMODITY HEDGING	$ -	$ -	$ -	$ -	$ -	$ -	$ (238,691)	$ -
87	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (118,029)	$ -
88	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,597)	$ -
89	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,316)	$ -
90	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (61,904)	$ -
91	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,658)	$ -
92	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (39,487)	$ -
93	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,693)	$ -
94	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,008)	$ -
95								$ -	$ -
96	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (119,625)	$ -
97	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,666)	$ -
98	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (108,400)	$ -

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-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	Summer
100	TOTAL COMMODITY Excld Hedging	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 19,077,203	$ 3,173,396
101	Res Heat	$ 299,984	$ 198,997	$ 170,143	$ 175,736	$ 212,943	$ 417,620	$ 9,261,686	$ 1,475,423
102	Res General	$ 11,220	$ 7,443	$ 6,364	$ 6,573	$ 7,964	$ 15,619	$ 191,304	$ 55,182
103	G50 Low Annual-Low Winter	$ 60,888	$ 40,391	$ 34,534	$ 35,669	$ 43,221	$ 84,765	$ 735,556	$ 299,468
104	G40 Low Annual-High Winter	$ 96,257	$ 63,853	$ 54,594	$ 56,389	$ 68,328	$ 134,003	$ 4,294,532	$ 473,424
105	G51 Med Annual-Low Winter	$ 73,658	$ 48,861	$ 41,776	$ 43,150	$ 52,285	$ 102,541	$ 990,411	$ 362,272
106	G41 Med Annual-High Winter	$ 82,812	$ 54,934	$ 46,969	$ 48,513	$ 58,784	$ 115,286	$ 2,936,759	$ 407,297
107	G52 High Annual-Low Winter	$ 6,239	$ 4,138	$ 3,538	$ 3,655	$ 4,428	$ 8,685	$ 150,679	$ 30,683
108	G42 High Annual-High Winter	$ 14,160	$ 9,393	$ 8,031	$ 8,295	$ 10,052	$ 19,713	$ 516,277	$ 69,646
109									
110	Residential	$ 311,204	$ 206,440	$ 176,506	$ 182,309	$ 220,907	$ 433,239	$ 9,452,990	$ 1,530,606
111	SALES HLF CLASSES	$ 140,784	$ 93,391	$ 79,849	$ 82,474	$ 99,935	$ 195,991	$ 1,876,645	$ 692,424
112	SALES LLF CLASSES	$ 193,229	$ 128,181	$ 109,594	$ 113,197	$ 137,163	$ 269,002	$ 7,747,568	$ 950,367

113	**TOTAL HEDGING COMMODITY COSTS**	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	Summer
114	TOTAL HEDGING COMMODITY	$ -	$ -	$ -	$ -	$ -	$ -	$ (324,320)	$ -
115	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ (157,907)	$ -
116	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,088)	$ -
117	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,266)	$ -
118	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (74,700)	$ -
119	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,449)	$ -
120	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (50,496)	$ -
121	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,522)	$ -
122	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,891)	$ -
123									
124	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ (160,995)	$ -
125	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (29,238)	$ -
126	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ (134,087)	$ -

127	TOTAL COMMODITY	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	Summer
128	Res Heat	$ 299,984	$ 198,997	$ 170,143	$ 175,736	$ 212,943	$ 417,620	$ 9,103,779	$ 1,475,423
129	Res General	$ 11,220	$ 7,443	$ 6,364	$ 6,573	$ 7,964	$ 15,619	$ 188,216	$ 55,182
130	G50 Low Annual-Low Winter	$ 60,888	$ 40,391	$ 34,534	$ 35,669	$ 43,221	$ 84,765	$ 724,289	$ 299,468
131	G40 Low Annual-High Winter	$ 96,257	$ 63,853	$ 54,594	$ 56,389	$ 68,328	$ 134,003	$ 4,219,832	$ 473,424
132	G51 Med Annual-Low Winter	$ 73,658	$ 48,861	$ 41,776	$ 43,150	$ 52,285	$ 102,541	$ 974,961	$ 362,272
133	G41 Med Annual-High Winter	$ 82,812	$ 54,934	$ 46,969	$ 48,513	$ 58,784	$ 115,286	$ 2,886,263	$ 407,297
134	G52 High Annual-Low Winter	$ 6,239	$ 4,138	$ 3,538	$ 3,655	$ 4,428	$ 8,685	$ 148,157	$ 30,683
135	G42 High Annual-High Winter	$ 14,160	$ 9,393	$ 8,031	$ 8,295	$ 10,052	$ 19,713	$ 507,386	$ 69,646
136	Total Firm Sales	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 18,752,883	$ 3,173,396
137									
138	Residential	$ 311,204	$ 206,440	$ 176,506	$ 182,309	$ 220,907	$ 433,239	$ 9,291,995	$ 1,530,606
139	SALES HLF CLASSES	$ 140,784	$ 93,391	$ 79,849	$ 82,474	$ 99,935	$ 195,991	$ 1,847,408	$ 692,424
140	SALES LLF CLASSES	$ 193,229	$ 128,181	$ 109,594	$ 113,197	$ 137,163	$ 269,002	$ 7,613,481	$ 950,367
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								42.15%
144	SALES LLF CLASSES								57.85%

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)

Schedule 11A

Northern Utilities, Inc.
New Hampshire Division
Schedule 11A
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Northern Utilities, Inc.
Normal Weather - Sales Service & Company Managed Sendout
Commodity Volumes by Supply Source (Dth)
May 2014 through October 2014

Description	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Season
Pipeline Supplies							
Tennessee Production	152,273	116,609	123,528	110,534	122,487	190,300	815,730
Chicago	18,004	2,644	0	0	3,630	59,389	83,667
Algonquin Receipts	22,793	2,346	0	0	9,350	27,159	61,648
TGP Zone 6	0	0	0	0	0	0	0
Niagara	0	0	0	0	0	2,872	2,872
Iroquois Receipts	11,918	1,266	0	0	3,165	14,706	31,054
PNGTS	0	0	0	0	0	0	0
PNGTS Delivered	0	0	0	0	0	0	0
Lewiston Baseload	0	0	0	0	0	46,500	46,500
Subtotal Pipeline	204,987	122,866	123,528	110,534	138,632	340,925	1,041,471
Underground Storage							
Tenn Zone 4 Spot	72,513	46,639	14,255	32,227	56,890	70,419	292,944
Tennessee Storage	0	0	0	0	0	0	0
Tennesse Storage Path	72,513	46,639	14,255	32,227	56,890	70,419	292,944
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	72,513	46,639	14,255	32,227	56,890	70,419	292,944
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)	278,895	170,855	139,178	144,156	196,872	412,739	1,342,695

Schedule 11B

Provided in the Winter 2013-14 Cost-of-Gas Filing

Schedule 11C

Northern Utilities, Inc.
Normal Weather - Sales Service & Company Managed Sendout
Capacity Utilization by Supply Source
May 2014 through October 2014

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Tennessee Production	815,730	2,086,578	39%
Chicago Path (includes Iroquois Receipts)	114,721	1,183,856	10%
Algonquin Receipts	61,648	230,184	27%
TGP Zone 6	0	0	
Niagara	2,872	428,168	1%
PNGTS	0	177,343	0%
PNGTS Delivered	0	0	
Lewiston Baseload	46,500	46,500	100%
Subtotal Pipeline	1,041,471	4,152,629	25%
Underground Storage			
Tenn Zone 4 Spot	292,944		
Tennessee Storage	0		
Tennesse Storage Path	292,944	437,167	67%
W10 AMA Spot	0		
Washington 10 Storage	0		
W10 Storage Path	0	0	
Subtotal Storage	292,944	437,167	67%
Peaking Supplies			
Peaking Supply 1	0	0	
Peaking Supply 2	0	0	
Peaking Supply 3	0	0	
LNG	8,280	1,810,000	0%
Subtotal Peaking	8,280	1,810,000	0%
Total Delivered (Dth)	1,342,695	6,399,796	21%

Schedule 11D

Provided in the Winter 2013-14 Cost-of-Gas Filing

Schedule 11E

Provided in the Winter 2013-14 Cost-of-Gas Filing

Schedule 12

Provided in the Winter 2013-14 Cost-of-Gas Filing

Schedule 13

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2013 through October 2014

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	768,250	44%	80%
G50	138,285	8%	74%
G41	527,943	30%	44%
G51	185,008	11%	40%
G42	92,751	5%	18%
G52	27,391	2%	2%
Special Contracts	-	0%	0%
Total C&I	1,739,628	100%	30%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
T40	193,881	5%	20%
T50	48,285	1%	26%
T41	671,735	16%	56%
T51	282,987	7%	60%
T42	423,535	10%	82%
T52	1,444,373	35%	98%
Special Contracts	1,010,437	25%	100%
Total C&I	4,075,233	100%	70%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G/T40	962,131	17%
G/T50	186,570	3%
G/T41	1,199,678	21%
G/T51	467,995	8%
G/T42	516,286	9%
G/T52	1,471,763	25%
Special Contracts	1,010,437	17%
Total C&I	5,814,860	100%

Schedule 14

Northern Utilities, Inc.
New Hampshire Division
Schedule 14
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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-13	196,837	-	-	196,837	$ 734,398	$ 3.73	NA	$ -	$ 3.73	$ -	$ 734,398	2.19%	$ 1,338	$ 734,398	$ -
Dec-13	196,837	-	-	196,837	$ 734,398	$ 3.73	NA	$ -	$ 3.73	$ -	$ 734,398	2.19%	$ 1,338	$ 734,398	$ -
Jan-14	196,837	-	74,946	121,891	$ 734,398	$ 3.73	NA	$ -	$ 3.73	$ 279,624	$ 454,774	2.19%	$ 1,083	$ 454,774	$ 279,624
Feb-14	121,891	-	67,693	54,198	$ 454,774	$ 3.73	NA	$ -	$ 3.73	$ 252,563	$ 202,211	2.19%	$ 598	$ 202,211	$ 252,563
Mar-14	54,198	-	54,198	-	$ 202,211	$ 3.73	NA	$ -	$ 3.73	$ 202,211	$ -	2.19%	$ 184	$ -	$ 202,211
Apr-14	-	-	-	-	$ -	NA	NA	$ -	$ -	$ -	$ -	2.19%	$ -	$ -	$ -
May-14	-	40,682	-	40,682		$ -	$ 4.63	$ 188,312	$ 4.63	$ -	$ 188,312	2.19%	$ 172	$ 188,312	$ -
Jun-14	40,682	39,369	-	80,051	$ 188,312	$ 4.63	$ 4.64	$ 182,695	$ 4.63	$ -	$ 371,007	2.19%	$ 510	$ 371,007	$ -
Jul-14	80,051	40,682	-	120,733	$ 371,007	$ 4.63	$ 4.66	$ 189,665	$ 4.64	$ -	$ 560,672	2.19%	$ 849	$ 560,672	$ -
Aug-14	120,733	40,682	-	161,414	$ 560,672	$ 4.64	$ 4.66	$ 189,393	$ 4.65	$ -	$ 750,065	2.19%	$ 1,194	$ 750,064	$ -
Sep-14	161,414	35,423	-	196,837	$ 750,065	$ 4.65	$ 4.63	$ 164,130	$ 4.64	$ -	$ 914,195	2.19%	$ 1,516	$ 914,194	$ -
Oct-14	196,837	-	-	196,837	$ 914,195	$ 4.64	NA	$ -	$ 4.64	$ -	$ 914,195	2.19%	$ 1,666	$ 914,194	$ -

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-13	2,580,600	-	31,081	2,549,519	$ 9,979,181	$ 3.87	NA	$ -	$ 3.87	$ 120,189	$ 9,858,991	2.19%		$ 9,858,991	$ 120,189
Dec-13	2,549,519	-	577,271	1,972,249	$ 9,858,991	$ 3.87	NA	$ -	$ 3.87	$2,232,305	$ 7,626,686	2.19%		$ 7,626,686	$2,232,305
Jan-14	1,972,249	-	748,149	1,224,100	$ 7,626,686	$ 3.87	NA	$ -	$ 3.87	$2,893,092	$ 4,733,594	2.19%		$ 4,733,594	$2,893,092
Feb-14	1,224,100	-	629,869	594,231	$ 4,733,594	$ 3.87	NA	$ -	$ 3.87	$2,435,704	$ 2,297,890	2.19%		$ 2,297,890	$2,435,704
Mar-14	594,231	-	372,264	221,967	$ 2,297,890	$ 3.87	NA	$ -	$ 3.87	$1,439,544	$ 858,346	2.19%		$ 858,346	$1,439,544
Apr-14	221,967	382,832	-	604,799	$ 858,346	$ 3.87	$ 4.88	$1,869,771	$ 4.51	$ -	$ 2,728,117	2.19%		$ 2,728,117	$ -
May-14	604,799	395,593	-	1,000,392	$ 2,728,117	$ 4.51	$ 4.80	$1,898,263	$ 4.62	$ -	$ 4,626,380	2.19%		$ 4,626,380	$ -
Jun-14	1,000,392	382,832	-	1,383,224	$ 4,626,380	$ 4.62	$ 4.81	$1,841,492	$ 4.68	$ -	$ 6,467,872	2.19%		$ 6,467,872	$ -
Jul-14	1,383,224	395,593	-	1,778,817	$ 6,467,872	$ 4.68	$ 4.83	$1,911,452	$ 4.71	$ -	$ 8,379,324	2.19%		$ 8,379,324	$ -
Aug-14	1,778,817	395,593	-	2,174,410	$ 8,379,324	$ 4.71	$ 4.83	$1,908,813	$ 4.73	$ -	$ 10,288,138	2.19%		$ 10,288,138	$ -
Sep-14	2,174,410	382,832	-	2,557,242	$10,288,138	$ 4.73	$ 4.80	$1,838,816	$ 4.74	$ -	$ 12,126,954	2.19%		$ 12,126,954	$ -
Oct-14	2,557,242	23,358	-	2,580,600	$12,126,954	$ 4.74	$ 4.82	$ 112,529	$ 4.74	$ -	$ 12,239,484	2.19%		$ 12,239,484	$ -

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-13	11,250	2,600	1,350	12,500	$ 77,809	$ 6.92	$ 5.93	$ 15,423	$ 6.73	$ 9,088	$ 84,145	2.19%	$ 148	$ 84,145	$ 9,088
Dec-13	12,500	1,395	1,395	12,500	$ 84,145	$ 6.73	$ 9.50	$ 13,257	$ 7.01	$ 9,779	$ 87,623	2.19%	$ 156	$ 87,623	$ 9,779
Jan-14	12,500	145	1,395	11,250	$ 87,623	$ 7.01	$12.38	$ 1,795	$ 7.07	$ 9,865	$ 79,554	2.19%	$ 152	$ 79,554	$ 9,865
Feb-14	11,250	1,260	1,260	11,250	$ 79,554	$ 7.07	$12.61	$ 15,889	$ 7.63	$ 9,613	$ 85,829	2.19%	$ 151	$ 85,829	$ 9,613
Mar-14	11,250	1,395	1,395	11,250	$ 85,829	$ 7.63	$ 8.42	$ 11,739	$ 7.72	$ 10,764	$ 86,805	2.19%	$ 157	$ 86,805	$ 10,764
Apr-14	11,250	2,600	1,350	12,500	$ 86,805	$ 7.72	$ 6.45	$ 16,770	$ 7.48	$ 10,096	$ 93,479	2.19%	$ 164	$ 93,479	$ 10,096
May-14	12,500	1,395	1,395	12,500	$ 93,479	$ 7.48	$ 6.36	$ 8,878	$ 7.37	$ 10,276	$ 92,080	2.19%	$ 169	$ 92,080	$ 10,276
Jun-14	12,500	1,350	1,350	12,500	$ 92,080	$ 7.37	$ 6.37	$ 8,606	$ 7.27	$ 9,814	$ 90,872	2.19%	$ 167	$ 90,872	$ 9,814
Jul-14	12,500	1,395	1,395	12,500	$ 90,872	$ 7.27	$ 6.40	$ 8,922	$ 7.18	$ 10,019	$ 89,776	2.19%	$ 165	$ 89,776	$ 10,019
Aug-14	12,500	1,395	1,395	12,500	$ 89,776	$ 7.18	$ 6.39	$ 8,913	$ 7.10	$ 9,908	$ 88,781	2.19%	$ 163	$ 88,781	$ 9,908
Sep-14	12,500	1,350	1,350	12,500	$ 88,781	$ 7.10	$ 6.37	$ 8,595	$ 7.03	$ 9,492	$ 87,885	2.19%	$ 161	$ 87,885	$ 9,492
Oct-14	12,500	1,395	1,395	12,500	$ 87,885	$ 7.03	$ 6.38	$ 8,901	$ 6.97	$ 9,717	$ 87,069	2.19%	$ 159	$ 87,069	$ 9,717

Schedule 15

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER SEASON BALANCE
November 2012 - October 2013

	AMOUNT	
Summer Season Beg. Balance	$147,647	SCHEDULE 2
Less: Reported Collections	($3,847,239)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$4,090,454	SCHEDULE 4
Add: Interest	$3,683	SCHEDULE 2
Summer Season Ending Balance	$394,545	

FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER SEASON ACCOUNTS
November 2012 - October 2013
Acct 191.10

	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
SUMMER SEASON													
Summer Season Account Beginning Balance	$ 147,647	$ (39,108)	$ (54,249)	$ (54,512)	$ (54,169)	$ (54,383)	$ (54,490)	$ 58,541	$ 359,313	$ 244,453	$ 230,384	$ 508,959	$ 147,647
Plus: Cost of Firm Gas (Schedule 4)	$ (4,279)	$ (14,607)	$ 10	$ -	$ 27	$ -	$ 826,649	$ 789,749	$ 386,333	$ 465,395	$ 874,366	$ 766,811	$ 4,090,454
Less: Reported Collections (Schedule 3)	$ (182,623)	$ (408)	$ (126)	$ 491	$ (94)	$ 40	$ (713,624)	$ (489,543)	$ (502,009)	$ (480,107)	$ (596,790)	$ (882,447)	$ (3,847,239)
Summer Season Account Ending Balance	$ (39,255)	$ (54,123)	$ (54,365)	$ (54,022)	$ (54,236)	$ (54,343)	$ 58,536	$ 358,748	$ 243,637	$ 229,741	$ 507,959	$ 393,323	$ 390,862
Month's Average Balance	$ 54,196	$ (46,616)	$ (54,307)	$ (54,267)	$ (54,202)	$ (54,363)	$ 2,023	$ 208,644	$ 301,475	$ 237,097	$ 369,171	$ 451,141	
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	$ 147	$ (126)	$ (147)	$ (147)	$ (147)	$ (147)	$ 5	$ 565	$ 816	$ 642	$ 1,000	$ 1,222	$ 3,683
Summer Season Account Ending Balance w/int	$ (39,108)	$ (54,249)	$ (54,512)	$ (54,169)	$ (54,383)	$ (54,490)	$ 58,541	$ 359,313	$ 244,453	$ 230,384	$ 508,959	$ 394,545	$ 394,545

FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
November 2012 - October 2013

	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
Accrued Revenue	$ (304,442)	$ -	$ -	$ -	$ -	$ -	$ 331,278	$ (160,044)	$ 54,664	$ 21,135	$ 129,122	$ 272,056	$ 343,768
Billed Revenue	$ 487,066	$ 408	$ 126	$ (491)	$ 94	$ (40)	$ 382,346	$ 649,587	$ 447,345	$ 458,972	$ 467,668	$ 610,391	$ 3,503,471
Calendarized Revenue	$ 182,623	$ 408	$ 126	$ (491)	$ 94	$ (40)	$ 713,624	$ 489,543	$ 502,009	$ 480,107	$ 596,790	$ 882,447	$ 3,847,239

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER SEASON
November 2012 - October 2013

Commodity 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 Off Peak**
Chesapeake	$ 125,590	$ -	$ -	$ -	$ -	$ -	$ -	$ 220,999	$ 226,018	$ 201,845	$ 190,857	$ 194,906	**$ 1,160,214**
DTE	$ 249,872	$ -	$ -	$ -	$ -	$ -	$ -	$ 151,756	$ 152,911	$ 141,702	$ 135,948	$ 137,926	**$ 970,116**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Emera Energy	$ 158,153	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,834	$ 60,558	$ 143,453	**$ 388,997**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,078	$ -	$ -	$ -	**$ 48,078**
South Western	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 208,572	$ 214,076	$ 39,581	$ -	$ -	**$ 462,229**
Subtotal - Commodity Supply	$ 533,615	$ -	$ -	$ -	$ -	$ -	$ -	$ 581,327	$ 641,083	$ 409,962	$ 387,362	$ 476,285	**$ 3,029,633**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 128	$ 130	$ 41	$ 62	$ 108	$ 67	**$ 536**
Portland	$ 53	$ -	$ -	$ -	$ 27	$ -	$ -	$ 54	$ 2,684	$ 55	$ 56	$ 55	**$ 2,984**
Tennessee	$ 11,504	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,684	$ 12,358	$ 8,529	$ 8,643	$ 11,347	**$ 65,065**
Subtotal - Commodity Transportation	$ 11,557	$ -	$ -	$ -	$ 27	$ -	$ 128	$ 12,867	$ 15,084	$ 8,646	$ 8,807	$ 11,469	**$ 68,585**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 594,098	$ 656,373	$ 418,546	$ 399,117	$ 487,687	$ 643,248	**$ 3,199,069**
Commodity Cost Reversals	$ (545,188)	$ -	$ -	$ -	$ -	$ -	$ -	$ (594,098)	$ (656,373)	$ (418,546)	$ (399,117)	$ (487,687)	**$ (3,101,009)**
Subtotal - Estimates	$ (545,188)	$ -	$ -	$ -	$ -	$ -	$ 594,098	$ 62,275	$ (237,827)	$ (19,429)	$ 88,570	$ 155,561	**$ 98,060**
Subtotal - Supply	$ (16)	$ -	$ -	$ -	$ 27	$ -	$ 594,226	$ 656,469	$ 418,339	$ 399,179	$ 484,739	$ 643,315	**$ 3,196,278**
Withdrawal - Underground Storage	$ 11	$ -	$ -	$ -	$ -	$ -	$ 16,069	$ 33	$ (48)	$ -	$ -	$ 39	**$ 16,105**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,457	$ 8,359	$ (1,853)	$ (14,586)	$ 22,546	$ 34,806	**$ 96,729**
Off System Sales	$ (112,213)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (23,615)	$ (217,270)	$ (116,270)	$ -	**$ (469,368)**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,545	$ (5,074)	$ (10,068)	$ (1,050)	$ 4,429	$ 1,936	**$ (5,282)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,280	$ 9,440	$ 10,687	$ 9,428	$ 7,910	$ 7,107	**$ 53,853**
Transportation Charges	$ (4,274)	$ (14,607)	$ 10	$ -	$ -	$ -	$ -	$ (15,849)	$ (3,465)	$ (1,925)	$ 8,758	$ (24,634)	**$ (55,988)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,896)	$ (29,981)	$ 42	$ 652	$ 156,015	$ 15,564	**$ 107,396**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal - Other Commodity	$ (116,476)	$ (14,607)	$ 10	$ -	$ -	$ -	$ 42,456	$ (33,073)	$ (28,319)	$ (224,751)	$ 83,389	$ 34,817	**$ (256,553)**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (23,615)	$ (217,270)	$ (116,270)	$ -	$ (101,288)	**$ (458,443)**
Sales for Resale Reversals	$ 112,213	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,615	$ 217,270	$ 116,270	$ -	**$ 469,368**
Subtotal - Estimates	$ 112,213	$ -	$ -	$ -	$ -	$ -	$ -	$ (23,615)	$ (193,655)	$ 101,000	$ 116,270	$ (101,288)	**$ 10,925**
Total Commodity Costs	**$ (4,279)**	**$ (14,607)**	**$ 10**	**$ -**	**$ 27**	**$ -**	**$ 636,682**	**$ 599,782**	**$ 196,365**	**$ 275,428**	**$ 684,398**	**$ 576,844**	**$ 2,950,650**
Demand Costs													
Assigned Summer Demand Costs (See DG 12-068)	$ -	$ -	$ -	$ -	$ -	$ -	$ 174,991	$ 174,991	$ 174,991	$ 174,991	$ 174,991	$ 174,991	**$ 1,049,948**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,976	$ 14,976	$ 14,976	$ 14,976	$ 14,976	$ 14,976	**$ 89,856**
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 189,967**	**$ 189,967**	**$ 189,967**	**$ 189,967**	**$ 189,967**	**$ 189,967**	**$ 1,139,804**
Total Gas Costs	**$ (4,279)**	**$ (14,607)**	**$ 10**	**$ -**	**$ 27**	**$ -**	**$ 826,649**	**$ 789,749**	**$ 386,333**	**$ 465,395**	**$ 874,366**	**$ 766,811**	**$ 4,090,454**

FORM III
Schedule 4
Page 2 of 9

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2012 - October 2013

REDACTED

Commodity Volumes:	**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 Off Peak**
Chesapeake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distrigas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Repsol	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Western	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sales for Resale Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sales for Resale Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2012 - October 2013

REDACTED

Commodity Costs per Unit:	**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 Off Peak**
Chesapeake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distrigas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Repsol	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Western	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NORTHERN UTILITIES, INC. - MAINE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2012 - October 2013

Commodity 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 Off Peak**
Chesapeake	$ 125,339	$ -	$ -	$ -	$ -	$ -	$ -	$ 216,622	$ 197,078	$ 188,873	$ 173,722	$ 168,928	**$ 1,070,562**
DTE	$ 249,373	$ -	$ -	$ -	$ -	$ -	$ -	$ 148,751	$ 133,332	$ 132,595	$ 123,742	$ 119,543	**$ 907,337**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Emera Energy	$ 157,837	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,109	$ 55,121	$ 124,333	**$ 362,399**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,922	$ -	$ -	$ -	**$ 41,922**
South Western	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 204,442	$ 186,665	$ 37,037	$ -	$ -	**$ 428,144**
Subtotal - Commodity Supply	$ 532,549	$ -	$ -	$ -	$ -	$ -	$ -	$ 569,816	$ 558,997	$ 383,615	$ 352,585	$ 412,804	**$ 2,810,365**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 125	$ 113	$ 38	$ 56	$ 94	$ 69	**$ 496**
Portland	$ 53	$ -	$ -	$ -	$ 25	$ -		$ 53	$ 2,341	$ 52	$ 51	$ 48	**$ 2,621**
Tennessee	$ 11,481	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,433	$ 10,776	$ 7,981	$ 7,867	$ 9,835	**$ 60,372**
Subtotal - Commodity Transportation	$ 11,534	$ -	$ -	$ -	$ 25	$ -	$ 125	$ 12,599	$ 13,155	$ 8,089	$ 8,012	$ 9,951	**$ 63,489**
Commodity Cost Estimates							$ 582,334	$ 572,329	$ 391,647	$ 363,284	$ 422,687	$ 659,401	**$ 2,991,682**
Commodity Cost Reversals	$ (544,099)	$ -	$ -	$ -	$ -	$ -	$ -	$ (582,334)	$ (572,329)	$(391,647)	$(363,284)	$ (422,687)	**$ (2,876,380)**
Subtotal - Estimates	$ (544,099)	$ -	$ -	$ -	$ -	$ -	$ 582,334	$ (10,005)	$ (180,682)	$ (28,363)	$ 59,403	$ 236,714	**$ 115,302**
Subtotal - Supply	$ (16)	$ -	$ -	$ -	$ 25	$ -	$ 582,459	$ 572,409	$ 391,470	$ 363,341	$ 419,999	$ 659,469	**$ 2,989,156**
Withdrawal - Underground Storage	$ 11	$ -	$ -	$ -	$ -	$ -	$ 15,751	$ 33	$ (45)	$ -	$ -	$ 40	**$ 15,790**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,518	$ 7,288	$ (1,734)	$ (13,276)	$ 19,541	$ 35,680	**$ 94,017**
Off System Sales	$ (111,989)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (20,591)	$(203,307)	$(105,831)	$ -	**$ (441,718)**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,455	$ (4,424)	$ (9,421)	$ (956)	$ 3,839	$ 1,984	**$ (4,523)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,097	$ 8,231	$ 10,000	$ 8,582	$ 6,856	$ 7,285	**$ 50,052**
Transportation Charges	$ (4,266)	$ (16,996)	$ 11	$ -	$ -	$ -	$ -	$ (15,535)	$ (3,992)	$ (1,801)	$ 7,971	$ (21,351)	**$ (55,959)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (25,755)	$ (5,933)	$ 14,340	$ 13,193	$ 10,544	$ 15,955	**$ 22,343**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 637	$ 403	$ 372	$ 561	$ 397	$ 524	**$ 2,895**
Subtotal - Other Commodity	$ (116,243)	$ (16,996)	$ 11	$ -	$ -	$ -	$ 50,702	$ (9,937)	$ (11,070)	$(197,004)	$ (56,683)	$ 40,117	**$ (317,103)**
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (20,591)	$ (203,307)	$(105,831)	$ -	$ (103,831)	**(433,560)**
Sales for Resale Reversals	$ 111,989	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,591	$ 203,307	$ 105,831	$ -	**441,718**
Subtotal - Estimates	$ 111,989	$ -	$ -	$ -	$ -	$ -	$ -	$ (20,591)	$ (182,716)	$ 97,476	$ 105,831	$ (103,831)	**$ 8,158**
Total Commodity Costs	**$ (4,270)**	**$ (16,996)**	**$ 11**	**$ -**	**$ 25**	**$ -**	**$ 633,161**	**$ 541,881**	**$ 197,684**	**$ 263,813**	**$ 469,148**	**$ 595,755**	**$ 2,680,211**
Demand Costs													
Assigned Summer Demand Costs (See 2012-413)	$ -	$ -	$ -	$ -	$ -	$ -	$ 172,313	$ 172,313	$ 172,313	$ 172,313	$ 172,313	$ 172,313	$ 1,033,876
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,195	$ 2,195	$ 2,195	$ 2,195	$ 2,195	$ 2,195	$ 13,170
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 174,508**	**$ 174,508**	**$ 174,508**	**$ 174,508**	**$ 174,508**	**$ 174,508**	**$ 1,047,046**
Total Gas Costs	**$ (4,270)**	**$ (16,996)**	**$ 11**	**$ -**	**$ 25**	**$ -**	**$ 807,669**	**$ 716,388**	**$ 372,192**	**$ 438,321**	**$ 643,655**	**$ 770,263**	**$ 3,727,257**

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NORTHERN UTILITIES, INC. - MAINE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2012 - October 2013

REDACTED

Commodity Volumes:	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 Off Peak
Chesapeake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distrigas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Repsol	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Western	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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NORTHERN UTILITIES, INC. - MAINE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2012 - October 2013

REDACTED

Commodity Costs per Unit:	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 Off Peak
Chesapeake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distrigas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Repsol	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Western	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
November 2012 - October 2013

Commodity 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 Off Peak
Chesapeake	$ 250,929	$ -	$ -	$ -	$ -	$ -	$ -	$ 437,621	$ 423,096	$ 390,718	$ 364,579	$ 363,834	**$ 2,230,777**
DTE	$ 499,246	$ -	$ -	$ -	$ -	$ -	$ -	$ 300,508	$ 286,243	$ 274,297	$ 259,690	$ 257,469	**$ 1,877,452**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Emera Energy	$ 315,989	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,943	$ 115,678	$ 267,786	**$ 751,396**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,000	$ -	$ -	$ -	**$ 90,000**
South Western	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 413,014	$ 400,741	$ 76,618	$ -	$ -	**$ 890,373**
Subtotal - Commodity Supply	$ 1,066,164	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,151,143	$ 1,200,080	$ 793,576	$ 739,947	$ 889,089	**$ 5,839,998**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 253	$ 243	$ 80	$ 118	$ 202	$ 136	**$ 1,032**
Portland	$ 106	$ -	$ -	$ -	$ 52	$ -	$ -	$ 107	$ 5,025	$ 107	$ 106	$ 103	**$ 5,605**
Tennessee	$ 22,985	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,116	$ 23,134	$ 16,510	$ 16,510	$ 21,182	**$ 125,437**
Subtotal - Commodity Transportation	$ 23,092	$ -	$ -	$ -	$ 52	$ -	$ 253	$ 25,466	$ 28,238	$ 16,735	$ 16,818	$ 21,421	**$ 132,074**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,176,432	$ 1,228,702	$ 810,193	$ 762,401	$ 910,374	$ 1,302,649	**$ 6,190,751**
Commodity Cost Reversals	$ (1,089,287)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,176,432)	$ (1,228,702)	$ (810,193)	$ (762,401)	$ (910,374)	**$ (5,977,389)**
Subtotal - Estimates	$ (1,089,287)	$ -	$ -	$ -	$ -	$ -	$ 1,176,432	$ 52,270	$ (418,509)	$ (47,792)	$ 147,973	$ 392,275	**$ 213,362**
Subtotal - Supply	$ (31)	$ -	$ -	$ -	$ 52	$ -	$ 1,176,685	$ 1,228,879	$ 809,809	$ 762,519	$ 904,738	$ 1,302,784	**$ 6,185,435**
Withdrawal - Underground Storage	$ 23	$ -	$ -	$ -	$ -	$ -	$ 31,820	$ 66	$ (92)	$ -	$ -	$ 79	**$ 31,895**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 93,975	$ 15,647	$ (3,587)	$ (27,862)	$ 42,088	$ 70,485	**$ 190,746**
Off System Sales	$ (224,203)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (44,206)	$ (420,576)	$ (222,101)	$ -	**$ (911,085)**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,000	$ (9,498)	$ (19,489)	$ (2,005)	$ 8,268	$ 3,920	**$ (9,805)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,377	$ 17,672	$ 20,688	$ 18,010	$ 14,766	$ 14,392	**$ 103,905**
Transportation Charges	$ (8,540)	$ (31,603)	$ 21	$ -	$ -	$ -	$ -	$ (31,385)	$ (7,457)	$ (3,727)	$ 16,729	$ (45,985)	**$ (111,947)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (60,651)	$ (35,915)	$ 14,382	$ 13,845	$ 166,559	$ 31,518	**$ 129,739**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 637	$ 403	$ 372	$ 561	$ 397	$ 524	**$ 2,895**
Subtotal - Other Commodity	$ (232,719)	$ (31,603)	$ 21	$ -	$ -	$ -	$ 93,158	$ (43,010)	$ (39,388)	$ (421,754)	$ 26,706	$ 74,934	$ (573,656)
Sales for Resale Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (44,206)	$ (420,577)	$ (222,101)	$ -	$ (205,119)	$ (892,003)
Sales for Resale Reversals	$ 224,202	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,206	$ 420,577	$ 222,101	$ -	$ 911,086
Subtotal - Estimates	$ 224,202	$ -	$ -	$ -	$ -	$ -	$ -	$ (44,206)	$ (376,371)	$ 198,476	$ 222,101	$ (205,119)	**$ 19,083**
Total Commodity Costs	**$ (8,549)**	**$ (31,603)**	**$ 21**	**$ -**	**$ 52**	**$ -**	**$ 1,269,843**	**$ 1,141,663**	**$ 394,050**	**$ 539,241**	**$ 1,153,546**	**$ 1,172,599**	**$ 5,630,861**
Demand Costs													
Assigned Summer Demand Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 347,304	$ 347,304	$ 347,304	$ 347,304	$ 347,304	$ 347,304	$ 2,083,824
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,171	$ 17,171	$ 17,171	$ 17,171	$ 17,171	$ 17,171	$ 103,026
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 364,475**	**$ 364,475**	**$ 364,475**	**$ 364,475**	**$ 364,475**	**$ 364,475**	**$ 2,186,850**
Total Costs	**$ (8,549)**	**$ (31,603)**	**$ 21**	**$ -**	**$ 52**	**$ -**	**$ 1,634,318**	**$ 1,506,138**	**$ 758,525**	**$ 903,716**	**$ 1,518,021**	**$ 1,537,074**	**$ 7,817,711**

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NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
November 2012 - October 2013

REDACTED

Commodity Volumes:	**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 Off Peak**
Chesapeake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distrigas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Repsol	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Western	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Volumes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
2013 SUMMER SEASON COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
November 2012 - October 2013

REDACTED

Commodity Costs per Unit:	**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 Off Peak**
Chesapeake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DTE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distrigas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emera Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Repsol	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Jersey Resources	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Granite	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennessee	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Commodity Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Volume Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - Underground Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal - LNG Vaporization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATV Reconciliation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net OBA Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LNG Boiloff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Propane	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Other Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off System Sales Reversals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal - Estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Commodity Costs per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013 SUMMER SEASON COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2012 - October 2013

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
Throughput IN													
BTU Factor	1.027	1.031	1.034	1.026	1.024	1.025	1.029	1.028	1.025	1.022	1.028	1.034	
GST Meter Throughput (MCF)	685,674	783,117	1,020,632	899,906	809,744	554,200	384,902	317,797	297,308	312,850	329,531	442,456	6,838,117
Salem Meter (MCF)	40,169	52,707	66,624	58,701	49,074	27,692	15,702	11,992	10,261	11,661	12,337	21,451	378,371
GST Meter Throughpurt (DTH)	704,187	807,394	1,055,333	923,304	829,178	568,055	396,064	326,695	304,741	319,733	338,758	457,500	7,030,941
Salem Meter (DTH)	41,254	54,341	68,889	60,227	50,252	28,384	16,157	12,328	10,518	11,918	12,682	22,180	389,130
LNG/Propane													-
Total Throughput	745,441	861,735	1,124,223	983,531	879,430	596,439	412,222	339,023	315,258	331,650	351,440	479,680	7,420,071
Throughput OUT													
Residential Gas													
Charged	106,027	207,324	272,653	310,432	247,341	183,306	95,039	55,928	34,579	33,886	35,282	46,731	1,628,528
Uncharged Current	90,715	201,459	235,209	169,042	164,975	85,733	41,554	27,276	21,954	28,336	50,467	86,052	1,202,771
Uncharged Prior	(44,600)	(90,715)	(201,459)	(235,209)	(169,042)	(164,975)	(85,733)	(41,554)	(27,276)	(21,954)	(28,336)	(50,467)	(1,161,319)
Total Residential Gas	**152,142**	**318,069**	**306,402**	**244,265**	**243,274**	**104,064**	**50,860**	**41,650**	**29,257**	**40,268**	**57,413**	**82,316**	1,669,981
Interruptible	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-
Commercial/Industrial Gas													
Charged	111,808	210,859	276,412	319,577	256,065	181,397	103,907	61,002	42,826	45,170	45,494	57,832	1,712,349
Uncharged Current	84,449	196,719	233,922	179,583	176,141	96,076	47,498	34,080	26,636	35,900	46,976	76,149	1,234,130
Uncharged Prior	(45,529)	(84,449)	(196,719)	(233,922)	(179,583)	(176,141)	(96,076)	(47,498)	(34,080)	(26,636)	(35,900)	(46,976)	(1,203,510)
Total C/I Gas	**150,728**	**323,129**	**313,615**	**265,238**	**252,623**	**101,332**	**55,329**	**47,583**	**35,382**	**54,433**	**56,570**	**87,006**	1,742,969
Transportation													
Charged	331,672	384,015	452,727	446,251	424,388	350,333	285,107	260,086	233,151	241,336	247,483	291,980	3,948,529
Uncharged Current	166,172	260,422	289,006	208,080	233,085	161,856	134,529	106,007	102,203	122,512	146,659	215,133	2,145,664
Uncharged Prior	(118,632)	(166,172)	(260,422)	(289,006)	(208,080)	(233,085)	(161,856)	(134,529)	(106,007)	(102,203)	(122,512)	(146,659)	(2,049,163)
Total Transportation	**379,212**	**478,265**	**481,311**	**365,325**	**449,393**	**279,104**	**257,780**	**231,564**	**229,347**	**261,645**	**271,630**	**360,454**	**4,045,030**
Company Use	**114**	**218**	**263**	**321**	**286**	**210**	**107**	**108**	**103**	**171**	**121**	**83**	**2,105**
Total Throughput OUT	**682,197**	**1,119,680**	**1,101,591**	**875,150**	**945,576**	**484,710**	**364,077**	**320,906**	**294,090**	**356,517**	**385,733**	**529,859**	**7,460,085**
Total Throughput IN	**745,441**	**861,735**	**1,124,223**	**983,531**	**879,430**	**596,439**	**412,222**	**339,023**	**315,258**	**331,650**	**351,440**	**479,680**	**7,420,071**
Difference IN/OUT	63,244	(257,946)	22,632	108,381	(66,146)	111,729	48,145	18,117	21,169	(24,867)	(34,293)	(50,179)	(40,014)
%													-0.54%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED SUMMER SEASON WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
November 2012 - October 2013

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 2012	$ 1,289	(4)	0.0824%	(73)	(76)	1,213	1,251	3.25%	3	1,216
December	$ 1,216	(12)	0.0824%	(0)	(12)	1,204	1,210	3.25%	3	1,207
January 2013	$ 1,207	0	0.0824%	(0)	(0)	1,207	1,207	3.25%	3	1,211
February	$ 1,211	0	0.0824%	0	0	1,211	1,211	3.25%	3	1,214
March	$ 1,214	0	0.0824%	(0)	(0)	1,214	1,214	3.25%	3	1,217
April	$ 1,217	0	0.0824%	0	0	1,217	1,217	3.25%	3	1,220
May	$ 1,220	681	0.0824%	(762)	(81)	1,140	1,180	3.25%	3	1,143
June	$ 1,143	651	0.0824%	(490)	160	1,303	1,223	3.25%	3	1,307
July	$ 1,307	318	0.0824%	(513)	(195)	1,112	1,209	3.25%	3	1,115
August	$ 1,115	383	0.0824%	(489)	(105)	1,010	1,063	3.25%	3	1,013
September	$ 1,013	720	0.0824%	(610)	110	1,123	1,068	3.25%	3	1,126
October	$ 1,126	632	0.0824%	(900)	(268)	858	992	3.25%	3	861

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SUMMER SEASON BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
November 2012 - October 2013

SUMMER SEASON- Acct 182.22

	BEGINNING BALANCE (1)	BAD DEBT ALLOWANCE	BAD DEBT COLLECTIONS	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D = B + C	E = A + D	F = (A + E) / 2	G	H = F * (G / 12)	I = E + H
November 2012	(19,277)	133	(2,200)	(2,067)	(21,344)	(20,310)	3.25%	(55)	(21,399)
December	(21,399)	4,448	(5)	4,444	(16,955)	(19,177)	3.25%	(52)	(17,007)
January 2013	(17,007)	925	(2)	923	(16,084)	(16,545)	3.25%	(45)	(16,128)
February	(16,128)	464	5	469	(15,659)	(15,894)	3.25%	(43)	(15,702)
March	(15,702)	692	(1)	691	(15,011)	(15,357)	3.25%	(42)	(15,053)
April	(15,053)	1,402	1	1,403	(13,650)	(14,352)	3.25%	(39)	(13,689)
May	(13,689)	616	138	754	(12,935)	(13,312)	3.25%	(36)	(12,971)
June	(12,971)	697	33	730	(12,241)	(12,606)	3.25%	(34)	(12,275)
July	(12,275)	1,877	63	1,940	(10,335)	(11,305)	3.25%	(31)	(10,365)
August	(10,365)	2,085	51	2,136	(8,229)	(9,297)	3.25%	(25)	(8,254)
September	(8,254)	1,905	72	1,977	(6,277)	(7,265)	3.25%	(20)	(6,296)
October	(6,296)	3,097	114	3,212	(3,085)	(4,691)	3.25%	(13)	(3,098)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2013

	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	TOTAL
Forecast Billed Month Sales	216,804	131,494	89,817	83,759	87,562	153,155	762,591
Actual Sales	187,661	117,038	74,249	79,056	80,775	104,563	643,342
Difference	(29,143)	(14,456)	(15,568)	(4,703)	(6,787)	(48,592)	(119,249)
Variance-difference due to meter count							(19,092)
-difference in load pattern							(100,158)
SALES							(119,250)

Attachment C
Page 2 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
SUMMER SEASON 2013

	NORMAL MMBtu			METERS		
	2013 Forecast	2013 Actual	Difference	2013 Forecast	2013 Actual	Difference
Res Heat	333,212	290,505	(42,707)	21,592	21,609	16
Res General	12,244	10,940	(1,305)	1,684	1,554	(130)
Total Res	345,456	301,445	(44,012)	23,276	23,162	(114)
G-40	111,044	91,343	(19,701)	4,365	4,318	(47)
G-50	70,289	58,249	(12,040)	948	803	(145)
G-41	136,952	94,261	(42,691)	384	381	(3)
G-51	83,354	78,983	(4,371)	157	150	(8)
G-42	11,672	12,327	655	12	9	(3)
G-52	3,824	6,733	2,909	5	7	2
Total C & I	417,135	341,897	(75,238)	5,871	5,668	(203)
Total Company	762,591	643,342	(119,250)	29,147	28,830	(317)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2013 Forecast	2013 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	15.43	13.44	(1.99)	251	(42,958)	(42,707)	-12.82%
Res General	7.27	7.04	(0.23)	(947)	(357)	(1,305)	-10.65%
Total Res	22.70	20.49	(2.22)	(696)	(43,316)	(44,012)	-12.74%
G-40	25.44	21.15	(4.28)	(1,202)	(18,499)	(19,701)	-17.74%
G-50	74.17	72.54	(1.63)	(10,727)	(1,313)	(12,040)	-17.13%
G-41	357.09	247.51	(109.58)	(961)	(41,730)	(42,691)	-31.17%
G-51	529.82	528.32	(1.50)	(4,146)	(225)	(4,371)	-5.24%
G-42	967.70	1,320.76	353.06	(2,640)	3,295	655	5.61%
G-52	729.19	961.87	232.68	1,280	1,629	2,909	76.07%
Total C & I	71.05	60.33	(10.73)	(18,396)	(56,842)	(75,238)	-18.04%
Total Company	26.16	22.32	(3.85)	(19,092)	(100,158)	(119,250)	-15.64%

Schedule 16

Provided in Winter 2013-14 Cost-of-Gas Filing

Schedule 17

Provided in the Winter 2013-14 Cost-of-Gas Filing

Schedule 18

Provided in Winter 2013-14 Cost-of-Gas Filing

Schedule 19

Provided in Winter 2013-14 Cost-of-Gas Filing

Schedule 20

Northern Utilities, Inc.
Hedging Plan for 2015-16
Total Company

Schedule 20
Page 1 of 2

		Peak Season					
		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Total Contracts
	Strike Prices*	$5.550	$5.800	$6.800	$6.900	$7.000	
Scheduled Option Purchases	04/28/14	27					27
	05/29/14		42				42
	06/26/14			52			52
	07/29/14				41		41
	08/28/14					33	33
	09/26/14						0
	10/29/14						0
	11/26/14						0
	12/29/14						0
	01/29/15						0
	02/26/15						0
	03/27/15						0
Expiration Schedule	04/27/15						0
	05/27/15						0
	06/25/15						0
	07/28/15						0
	08/26/15						0
	09/25/15						0
	10/28/15	-27					-27
	11/25/15		-42				-42
	12/28/15			-52			-52
	01/27/16				-41		-41
	02/24/16					-33	-33
	03/28/16						0
	Scheduled	27	42	52	41	33	195

Futures Price*	$4.091	$4.249	$4.379	$4.350	$4.295	
2.50%	$0.1023	$0.1062	$0.1095	$0.1088	$0.1074	
Option Budget	$27,621	$44,604	$56,940	$44,608	$35,442	$209,215

* Futures and strike prices shown reflect market prices on February 07, 2014. Actual strike prices will reflect transactions made.

Northern proposes an option budget equal to 2.5 percent of the value of the futures contracts at the time the options are purchased. The calculation above shows the expected dollar budget using recent market data. Actual program expenditures will be the result of applying the budget percentage to futures contract value at the time of purchase.

Northern Utilities, Inc.
3-Year Outlook for Annual Hedging Plans
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
	WINTER PERIOD	WINTER 2015-16			WINTER 2016-17			WINTER 2017-18		
1	Sendout Requirement (Nov-Mar)	6,026,887			6,237,828			6,456,152		
2	Target Hedged Volume (70%)	4,218,821	70%		4,366,480	70%		4,519,307	70%	
3	Washington 10 Storage	2,036,330	34%		2,036,330	33%		2,036,330	32%	
4	Tennessee Storage	232,403	4%		232,403	4%		232,403	4%	
5	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
6	Physically Hedged Volume (=3+4+5)	2,268,733	38%		2,268,733	36%		2,268,733	35%	
7	Financial Hedge Volume (=2-6)	1,950,000	32%	195	2,100,000	34%	210	2,250,000	35%	225
8	Total Hedged Volume (=6+7)	4,218,733	70%		4,368,733	70%		4,518,733	70%	

Schedule 21

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

1 Total Fixed Capacity Costs To Be Allocated

2		**NUI Total**
3	Pipeline Demand	$ 8,358,833
4	Storage Demand	$ 27,096,578
5	Peaking Demand	$ 2,779,473
6	Subtotal Demand	$ 38,234,884
7		
8	Capacity Release (Credit)	$ (150,697)
9	Asset Management (Credit)	$ (11,805,500)
10	Total Net Demand Costs	$ 26,278,687

11

12

13 Proportional Responsibility (PR) Allocators

14

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

		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
17	Design Year Pipeline Sendout	955,303	974,347	907,918	817,518	988,132	800,051	604,773	414,629	362,777	371,552	460,011	718,491	8,375,501
18	Rank	3	2	4	5	1	6	8	10	12	11	9	7	
19	% Max Month	96.68%	98.60%	91.88%	82.73%	100.00%	80.97%	61.20%	41.96%	36.71%	37.60%	46.55%	72.71%	
20	PR	1.60%	0.96%	2.29%	0.35%	1.40%	1.38%	1.83%	0.44%	3.06%	0.08%	0.51%	1.64%	15.54%
21	CumPR	13.18%	14.14%	11.58%	9.29%	15.54%	8.94%	5.92%	3.58%	3.06%	3.14%	4.09%	7.56%	100.00%
22	Product and Pipeline Demand Costs	$ 1,101,407	$ 1,181,954	$ 967,792	$ 776,614	$ 1,298,563	$ 747,062	$ 494,649	$ 298,923	$ 255,735	$ 262,483	$ 341,578	$ 632,073	$ 8,358,833

23

24 Allocation of Storage Injection Fees to Months

		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
26	Storage Injection Volume	-	-	-	-	-	-	53,366	51,644	53,366	53,366	47,595	-	259,337
27	Design Year Pipeline Sendout	955,303	974,347	907,918	817,518	988,132	800,051	604,773	414,629	362,777	371,552	460,011	718,491	8,375,501
28	% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.1%	11.1%	12.8%	12.6%	9.4%	0.0%	3.0%
29	Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,109	$ 33,109	$ 32,795	$ 32,965	$ 32,028	$ -	$ 171,006

30

31 Allocation of Storage Demand Costs to Months

		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
33	Design Year Storage	248,332	755,610	1,014,492	899,456	553,670	17,407	-	-	-	-	-	-	3,488,967
34	Rank	5	3	1	2	4	6	7	7	7	7	7	7	
35	% Max Month	24.48%	74.48%	100.00%	88.66%	54.58%	1.72%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
36	PR	4.55%	6.64%	11.34%	7.09%	7.52%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	37.43%
37	CumPR	4.84%	19.00%	37.43%	26.09%	12.36%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
38	Storage Demand Costs	$ 1,311,066	$ 5,147,831	$ 10,141,410	$ 7,068,856	$ 3,349,927	$ 77,488	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,096,578
39	Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,109	$ 33,109	$ 32,795	$ 32,965	$ 32,028	$ -	$ 171,006
40	TOTAL	$ 1,311,066	$ 5,147,831	$ 10,141,410	$ 7,068,856	$ 3,349,927	$ 77,488	$ 40,109	$ 33,109	$ 32,795	$ 32,965	$ 32,028	$ -	$ 27,267,584

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42 Allocation of Peaking Demand Costs to Months

		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
44	Design Year Peaking Volumes	1,350	56,216	185,462	100,504	1,395	1,393	4,710	1,350	1,395	1,395	1,668	1,395	358,233
45	Rank	12	3	1	2	9	10	4	11	8	7	5	6	
46	% Max Month	0.73%	30.31%	100.00%	54.19%	0.75%	0.75%	2.54%	0.73%	0.75%	0.75%	0.90%	0.75%	
47	PR	0.06%	9.26%	45.81%	11.94%	0.00%	0.00%	0.41%	0.00%	0.00%	0.00%	0.03%	0.00%	67.51%
48	CumPR	0.06%	9.76%	67.51%	21.70%	0.06%	0.06%	0.50%	0.06%	0.06%	0.06%	0.09%	0.06%	100.00%
49	Peaking Demand Costs	$ 1,686	$ 271,270	$ 1,876,384	$ 603,141	$ 1,754	$ 1,750	$ 13,971	$ 1,686	$ 1,754	$ 1,754	$ 2,571	$ 1,754	$ 2,779,473

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

1		
2		
3	Pipeline Demand	Schedule 5A, PG 1, LN 1
4	Storage Demand	Schedule 5A, PG 1, LN 2 & 3
5	Peaking Demand	Schedule 5A, PG 1, LN 4 & 5
6	Subtotal Demand	Sum LN 3 : LN 5
7		
8	Capacity Release (Credit)	Schedule 5A, PG 6
9	Asset Management (Credit)	Schedule 5A, PG 6
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 BETWEEN ME & NH DIVISIONS

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual
50	Pipeline & Product Demand	$ 1,101,407	$ 1,181,954	$ 967,792	$ 776,614	$ 1,298,563	$ 747,062	$ 494,649	$ 298,923	$ 255,735	$ 262,483	$ 341,578	$ 632,073	$ 8,358,833
51	Storage Incld Inj Fees	$ 1,311,066	$ 5,147,831	$ 10,141,410	$ 7,068,856	$ 3,349,927	$ 77,488	$ 40,109	$ 33,109	$ 32,795	$ 32,965	$ 32,028	$ -	$ 27,267,584
52	Peaking	$ 1,686	$ 271,270	$ 1,876,384	$ 603,141	$ 1,754	$ 1,750	$ 13,971	$ 1,686	$ 1,754	$ 1,754	$ 2,571	$ 1,754	$ 2,779,473
53	Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ (40,109)	$ (33,109)	$ (32,795)	$ (32,965)	$ (32,028)	$ -	$ (171,006)
54	Less: Capacity Release	$ (30,139)	$ (30,139)	$ (30,139)	$ (30,139)	$ (30,139)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (150,697)
55	Less: Asset Mgmt	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$ (1,967,583)	$(1,967,583)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,805,500)
56	Total Demand	$ 416,436	$ 4,603,332	$ 10,987,863	$ 6,450,888	$ 2,652,521	$(1,141,283)	$ 508,620	$ 300,609	$ 257,488	$ 264,237	$ 344,149	$ 633,827	$ 26,278,687

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

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual
60	**Therms**													
61	Maine	649,566	937,853	1,106,199	957,290	818,364	442,815	335,372	231,013	201,853	207,340	256,254	391,341	6,535,260
62	New Hampshire	555,419	848,319	1,001,673	860,188	724,832	376,035	274,111	184,966	162,319	165,607	205,425	328,545	5,687,439
63	Total	1,204,985	1,786,172	2,107,872	1,817,478	1,543,196	818,850	609,483	415,979	364,172	372,947	461,679	719,886	12,222,699

64	**Percentage of Total**	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual
65	Maine	53.91%	52.51%	52.48%	52.67%	53.03%	54.08%	55.03%	55.53%	55.43%	55.60%	55.50%	54.36%	52.77%
66	New Hampshire	46.09%	47.49%	47.52%	47.33%	46.97%	45.92%	44.97%	44.47%	44.57%	44.40%	44.50%	45.64%	47.23%
67	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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69 **Allocation of Demand Costs by Division**

70	Maine	$224,486	$2,417,040	$5,766,367	$3,397,769	$1,406,644	($617,179)	$279,871	$166,942	$142,720	$146,902	$191,019	$344,558	$13,867,141
71	New Hampshire	$191,950	$2,186,292	$5,221,496	$3,053,119	$1,245,877	($524,104)	$228,749	$133,666	$114,768	$117,334	$153,130	$289,269	$12,411,546
72	Total	$ 416,436	$ 4,603,332	$ 10,987,863	$ 6,450,888	$ 2,652,521	$ (1,141,283)	$ 508,620	$ 300,609	$ 257,488	$ 264,237	$ 344,149	$ 633,827	$ 26,278,687

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

74	**Maine**	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	
75	Pipeline & Product Demand	$ 593,730	$ 620,601	$ 507,892	$ 409,053	$ 688,634	$ 403,994	$ 272,184	$ 166,006	$ 141,748	$ 145,927	$ 189,592	$ 343,605	$ 4,482,966	53.63%
76	Storage Incld Injection Fees	$ 706,751	$ 2,702,936	$ 5,322,153	$ 3,723,261	$ 1,776,482	$ 41,904	$ 22,070	$ 18,387	$ 18,178	$ 18,327	$ 17,777	$ -	$ 14,368,225	52.69%
77	Peaking	$ 909	$ 142,434	$ 984,715	$ 317,682	$ 930	$ 946	$ 7,687	$ 936	$ 972	$ 975	$ 1,427	$ 953	$ 1,460,568	52.55%
78	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ (22,070)	$ (18,387)	$ (18,178)	$ (18,327)	$ (17,777)	$ -	$ (94,739)	55.40%
79	Capacity Release (Credit)	$ (16,247)	$ (15,825)	$ (15,817)	$ (15,875)	$ (15,983)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (79,747)	52.92%
80	Asset Management (Credit)	$ (1,060,657)	$ (1,033,105)	$ (1,032,576)	$ (1,036,352)	$ (1,043,419)	$ (1,064,023)	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,270,132)	53.11%
81	**Total Allocated Demand**	$ 224,486	$ 2,417,040	$ 5,766,367	$ 3,397,769	$ 1,406,644	$ (617,179)	$ 279,871	$ 166,942	$ 142,720	$ 146,902	$ 191,019	$ 344,558	$ 13,867,141	52.77%

82

83	**New Hampshire**	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	
84	Pipeline & Product Demand	$ 507,676	$ 561,354	$ 459,900	$ 367,561	$ 609,929	$ 343,068	$ 222,465	$ 132,917	$ 113,986	$ 116,555	$ 151,986	$ 288,469	$ 3,875,867	46.37%
85	Storage Incld Injection Fees	$ 604,316	$ 2,444,895	$ 4,819,257	$ 3,345,595	$ 1,573,445	$ 35,584	$ 18,039	$ 14,722	$ 14,618	$ 14,638	$ 14,251	$ -	$ 12,899,359	47.31%
86	Peaking	$ 777	$ 128,836	$ 891,669	$ 285,458	$ 824	$ 804	$ 6,283	$ 750	$ 782	$ 779	$ 1,144	$ 800	$ 1,318,905	47.45%
87	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,039)	$ (14,722)	$ (14,618)	$ (14,638)	$ (14,251)	$ -	$ (76,267)	
88	Capacity Release	$ (13,892)	$ (14,314)	$ (14,322)	$ (14,265)	$ (14,156)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (70,950)	47.08%
89	Asset Management	$ (906,927)	$ (934,478)	$ (935,007)	$ (931,231)	$ (924,165)	$ (903,560)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,535,367)	46.89%
90	**Total Allocated Demand**	$ 191,950	$ 2,186,292	$ 5,221,496	$ 3,053,119	$ 1,245,877	$ (524,104)	$ 228,749	$ 133,666	$ 114,768	$ 117,334	$ 153,130	$ 289,269	$ 12,411,546	47.23%

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

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-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	Summer
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	277,500	169,505	137,783	142,761	195,522	411,344	5,438,402	1,334,415
3	Total Storage	0	0	0	0	0	0	1,414,044	0
4	Total Peaking	1,395	1,350	1,395	1,395	1,350	1,395	264,157	8,280
5	Subtotal	278,895	170,855	139,178	144,156	196,872	412,739	7,116,603	1,342,695
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	278,895	170,855	139,178	144,156	196,872	412,739	7,116,603	1,342,695
9	Total Firm Pipeline Sendout	277,500	169,505	137,783	142,761	195,522	411,344	5,438,402	1,334,415
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 29,290,747	$ 6,421,835
12	NYMEX Price Used for Forecast	$4.550	$4.568	$4.599	$4.586	$4.557	$4.565		
13	NYMEX Price Used for Update	$4.550	$4.568	$4.599	$4.586	$4.557	$4.565		
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	$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 29,290,747	$ 6,421,835
17									
18	Total Pipeline	$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 29,290,747	$ 6,421,835
19	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,609,262	$ -
20	Total Peaking	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 4,144,277	$ 59,171
21	Subtotal	$ 1,338,156	$ 819,203	$ 671,473	$ 693,369	$ 941,507	$ 2,017,297	$ 39,044,286	$ 6,481,006
22									
23	Hedging (Gain)/Loss Estimate								
24	Time Triggered NYMEX Contracts (Allocated between ME and NH)								
25	NYMEX NG Futures Contracts	-	-	-	-	-	-	147	-
26	Average Purchase Price	$ 3.993	$ -	$ -	$ -	$ -	$ 4.103		
27	NYMEX Price Used for Forecast	$ 4.550	$ 4.579	$ 4.579	$ 4.579	$ 4.579	$ 4.579		
28	NYMEX Price Used for Update	$ 4.550	$ 4.579	$ 4.579	$ 4.579	$ 4.579	$ 4.579		
29	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
30	Futures Hedging (Gain)/Loss - Allocate	$ -	$ -	$ -	$ -	$ -	$ -	$ (650,110)	$ -
31	Price Triggered NYMEX Contracts (NH Only)								
32	NYMEX NG Futures Contracts	-	-	-	-	-	-	-	-
33	Average Purchase Price	$ -	$ -	$ -	$ -	$ -	$ -		
34	NYMEX Price Used for Forecast	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565		
35	NYMEX Price Used for Update	$ 4.550	$ 4.568	$ 4.599	$ 4.586	$ 4.557	$ 4.565		
36	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
37	Futures Hedging (Gain)/Loss (NH ONLY)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Interruptible Cost Estimate								
40	Variable Pipeline Costs Excld Hedges	$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 29,290,747	$ 6,421,835
41	Average Supply Cost ($/MMBtu)	$ 4.785	$ 4.775	$ 4.801	$ 4.788	$ 4.767	$ 4.881		
42	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	Firm Sales Pipeline Commodity Excld Hedge	$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 29,290,747	$ 6,421,835
46	Total Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,609,262	$ -
47	Total Peaking	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 4,144,277	$ 59,171
48	Firm Sales Variable Costs Excld Hedge	$ 1,338,156	$ 819,203	$ 671,473	$ 693,369	$ 941,507	$ 2,017,297	$ 39,044,286	$ 6,481,006
49	Plus Hedging (Gain)/Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ (650,110)	$ -
50	Total Firm Sales Variable Costs	$ 1,338,156	$ 819,203	$ 671,473	$ 693,369	$ 941,507	$ 2,017,297	$ 38,394,176	$ 6,481,006

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™	0
12	NYMEX Price Used for Forecast	Attachment to Schedule 5A, PG 1, LN 21
13	NYMEX Price Used for Update	Attachment to Schedule 5A, PG 1, LN 21
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	Line 13
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 12
35	NYMEX Price Used for Update	Line 13
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

53		May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Annual	Summer
54	Maine	143,495	86,845	69,240	72,292	100,882	208,268	3,624,340	681,022
55	New Hampshire	133,613	95,019	82,934	86,639	95,562	167,169	3,467,411	660,936
56	Total	277,108	181,864	152,174	158,931	196,444	375,437	7,091,751	1,341,958
57									
58	**Percentage of Total**								
59	Maine	51.78%	47.75%	45.50%	45.49%	51.35%	55.47%	51.11%	50.75%
60	New Hampshire	48.22%	52.25%	54.50%	54.51%	48.65%	44.53%	48.89%	49.25%
61	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
62									
63	**Commodity Allocation by Jurisdiction**								
64	**Maine**								
65	Firm Sales Pipeline Commodity Excld Hedge	$ 687,619	$ 386,508	$ 300,969	$ 310,887	$ 478,634	$ 1,113,683	$ 14,989,296	$ 3,278,300
66	Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ (325,790)	$ -
67	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,871,891	$ -
68	Peaking	$ 5,319	$ 4,684	$ 4,555	$ 4,502	$ 4,868	$ 5,382	$ 2,111,991	$ 29,310
69	Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Total Maine Commodity Costs	$ 692,938	$ 391,192	$ 305,524	$ 315,389	$ 483,502	$ 1,119,065	$ 19,647,388	$ 3,307,610
71	Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,264	$ -
72	Total Maine Variable Costs	$ 692,938	$ 391,192	$ 305,524	$ 315,389	$ 483,502	$ 1,119,065	$ 19,653,652	$ 3,307,610
73	**New Hampshire**								
74	Firm Sales Pipeline Commodity Excld Hedge	$ 640,265	$ 422,887	$ 360,493	$ 372,585	$ 453,393	$ 893,912	$ 14,301,451	$ 3,143,535
75	Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ (324,320)	$ -
76	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,737,372	$ -
77	Peaking	$ 4,953	$ 5,124	$ 5,456	$ 5,396	$ 4,612	$ 4,320	$ 2,032,286	$ 29,861
78	New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Total New Hampshire Commodity Costs	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 18,746,789	$ 3,173,396
80	New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,095	$ -
81	Total New Hampshire Variable Costs	$ 645,218	$ 428,011	$ 365,949	$ 377,981	$ 458,005	$ 898,232	$ 18,752,883	$ 3,173,396
82	**Northern Utilities**								
83	Firm Sales Pipeline Commodity Excld Hedge	$ 1,327,884	$ 809,395	$ 661,462	$ 683,471	$ 932,027	$ 2,007,595	$ 29,290,747	$ 6,421,835
84	Hedging (Gains) Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ (650,110)	$ -
85	Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,609,262	$ -
86	Peaking	$ 10,272	$ 9,808	$ 10,011	$ 9,898	$ 9,480	$ 9,702	$ 4,144,277	$ 59,171
87	Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Total Northern Commodity Costs	$ 1,338,156	$ 819,203	$ 671,473	$ 693,369	$ 941,507	$ 2,017,297	$ 38,394,176	$ 6,481,006
89	Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,359	$ -
90	Total Northern Variable Costs	$ 1,338,156	$ 819,203	$ 671,473	$ 693,369	$ 941,507	$ 2,017,297	$ 38,406,536	$ 6,481,006
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-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Annual**	**Summer**
99	Storage	$ 172	$ 510	$ 849	$ 1,194	$ 1,516	$ 1,666	$ 10,447	$ 5,905
100	Peaking	$ 169	$ 167	$ 165	$ 163	$ 161	$ 159	$ 1,912	$ 983
101	Total	$ 341	$ 676	$ 1,013	$ 1,357	$ 1,677	$ 1,825	$ 12,359	$ 6,889
102									
103	**Inventory Finance Charge Allocation by Jurisdiction**								
104	Maine	$ 176	$ 323	$ 461	$ 617	$ 861	$ 1,012	$ 6,264	$ 3,451
105	New Hampshire	$ 164	$ 353	$ 552	$ 740	$ 816	$ 813	$ 6,095	$ 3,438
106	Total	$ 341	$ 676	$ 1,013	$ 1,357	$ 1,677	$ 1,825	$ 12,359	$ 6,889
107									
108	**Inventory Finance Charge Allocation by Month**								
109	**Maine**								
110	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,530,136	0
111	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
112	ME Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,264	$ -
113									
114	**New Hampshire**								
115	Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,312,214	0
116	Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
117	NH Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,095	$ -

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

92 **Northern Utilities**
93 **Simplified Market Based Allocator (MBA) Calculations**
94 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**
95
96
97

98	**Inventory Finance Charge**	
99	Storage	0
100	Peaking	0
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	0
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	0
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	Annual	
1	Demand	$ 9,127,510	$ 912,730	$ 10,040,239	Schedule 1A, LN 80
2	Commodity	$ 15,579,487	$ 3,173,396	$ 18,752,883	Schedule 1B, LN 43
3	Total	$ 24,706,997	$ 4,086,126	$ 28,793,123	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	27,891,158	6,566,792	34,457,951	Schedule 10B, LN 11
6	Forecasted Residential Sales (Therms)	13,894,351	3,167,323	17,061,674	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Annual**	
8	Average Demand Rate	$0.3273	$0.1390		LN 1 / LN 5
9	Average Commodity Rate	$0.5586	$0.4832		LN 2 / LN 5
10	Average Rate	$0.8858	$0.6222		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Annual**	
13	Demand Costs Allocated To Residential per SMBA	$ 4,634,368	$ 452,259	$ 5,086,627	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 4,546,990	$ 440,258	$ 4,987,248	LN 8 * LN 6
15	**Demand Reallocation:**	$ 87,378	$ 12,001	$ 99,379	LN 13 - LN 14
16	**HLF Allocation**	$ 9,864	$ 3,182	$ 13,046	LN 15 / LN 20
17	**LLF Allocation**	$ 77,513	$ 8,819	$ 86,333	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	11.29%	26.52%		Schedule 10A, LN 173
21	LLF	88.71%	73.48%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 7,761,389	$ 1,530,606	$ 9,291,995	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 7,761,129	$ 1,530,450	$ 9,291,579	LN 9 * LN 6
25	**Commodity Reallocation:**	$ 260	$ 155	$ 415	LN 23 - LN 24
26	**HLF Allocation**	$ 38	$ 65	$ 104	LN 25 * LN 30
27	**LLF Allocation**	$ 222	$ 90	$ 311	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	14.77%	42.15%		Schedule 10C, LN 143
31	LLF	85.23%	57.85%		Schedule 10C, LN 144

Schedule 24

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

Schedule 25

Northern Utilities, Inc., New Hampshire Division
Determination of PNGTS Refund
Effective: November 2013 - October 2014

1	PNGTS Refund - Principal	$540,813	LN 3 - LN 2
2	PNGTS Refund - Interest	$6,816	Schedules 5C & 5B, PG 6
3	Total PNGTS Refund	$547,629	Schedule 5B, PG 6
4	Estimated Interest Expense - Northern	$8,533	PG 2, LN 9
5	Total	$556,163	LN 3 + LN 4
6	Total DTHs: (November 13 - October 14)	34,457,951	FORECAST
7	Demand Refund Rate ($/CCF)	$0.0161	LN 5/ LN 6

Northern Utilities, Inc. New Hampshire Divisio
PNGTS Gas Refund - Demand Portion
Effective: November 2013 - October 2014

		Actual	**Actual**	**Actual**	**Actual**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Estimate**	**Total**	**Total**	**Total**
		May-13	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-13 to Apr-14**	**Apr-14 to Oct-14**	**Nov-13 to Oct-14**
1	Beginning Balance	$0	$548,095	$548,996	$549,928	$550,832	$551,768	$552,705	$495,943	$411,821	$305,237	$216,086	$147,329	$106,823	$85,612	$70,542	$57,382	$43,607	$28,380			
2	PNGTS Refund with Interest	$547,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0			
3	Firm Sales (DTHs)	$0	$0					3,579,105	5,272,786	6,656,691	5,564,807	4,289,774	2,527,995	1,327,606	944,011	823,915	860,734	949,421	1,661,106	27,891,158	6,566,792	34,457,951
4	Refund	$0	$0					$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161			
5	Refund Amount	$0	$0					$57,624	$84,892	$107,173	$89,593	$69,065	$40,701	$21,374	$15,199	$13,265	$13,858	$15,286	$26,744	$449,048	$105,725	$554,773
6	Ending Balance - excl. interest	$547,629	$548,095	$548,996	$549,928	$550,832	$551,768	$495,081	$411,051	$304,648	$215,644	$147,021	$106,629	$85,449	$70,414	$57,277	$43,524	$28,321	$1,637			
7	Average Monthly Balance	$273,815	$548,095	$548,996	$549,928	$550,832	$551,768	$523,893	$453,497	$358,235	$260,441	$181,554	$126,979	$96,136	$78,013	$63,909	$50,453	$35,964	$15,009			
8	Interest Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%			
9	Computed Interest	$465	$901	$933	$904	$936	$937	$861	$770	$589	$442	$308	$195	$163	$128	$105	$83	$59	$25	$6,707	$1,826	$8,533
10	Ending Balance	$548,095	$548,996	$549,928	$550,832	$551,768	$552,705	$495,943	$411,821	$305,237	$216,086	$147,329	$106,823	$85,612	$70,542	$57,382	$43,607	$28,380	$1,661			