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	$ 4,164,855
3	Storage	$ 14,757,101
4	Peaking	$ 2,286,161
5	Total Gross Demand Cost	$ 21,208,117
6		
7	Capacity Assignment Demand Revenue Estimate	$ 2,923,632
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 21,208,117
9	Capacity Assignment as % of Total Gross Demand Cost	13.79%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 574,143
14	Storage	$ 2,034,331
15	Peaking	$ 315,157
16	Total Capacity Assignment Credit	$ 2,923,632
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 3,590,712
21	Storage	$ 12,722,770
22	Peaking	$ 1,971,004
23	Total Net Demand Cost (Less Capacity Assignment)	$ 18,284,486
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	18,356
28	Less 13.79% NH Transp. Capacity Assignment	(2,530)
29	Net Pipeline MDQ	15,826
30		
31	Net Pipeline MDQ	15,826
32	Less: Firm Sales Base Use	3,028
33	Remaining Pipeline MDQ	12,798
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$226.89
37		
38		**Costs**
39	Pipeline & Product Demand	$ 3,590,712
40	Less: Base Pipeline Use	$ 687,045
41	Remaining Pipeline Use	$ 2,903,667

1	**Resource**	
2	Pipeline & Product Demand	Schedule 21, LN 84 + Schedule 21, LN 87
3	Storage	Schedule 21, LN 85
4	Peaking	Schedule 21, LN 86
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Schedule 5B, Page 1
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		
13	Pipeline & Product Demand	LN 2 * LN 9
14	Storage	LN 3 * LN 9
15	Peaking	LN 4 * LN 9
16	Total Capacity Assignment Credit	Sum (LN 13 : LN 15)
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		
20	Pipeline & Product Demand	LN 2 - LN 13
21	Storage	LN 3 - LN 14
22	Peaking	LN 4 - LN 15
23	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 16
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND C**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 13.79% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

All Months	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for All Months	3,230,488	5,158,546	6,758,729	5,587,047	4,021,984	2,015,147
Rank	5	3	1	2	4	6
% Max Month	47.80%	76.32%	100.00%	82.66%	59.51%	29.82%
PR	3.60%	5.61%	17.34%	3.17%	2.93%	2.45%
CumPR	8.00%	16.54%	37.04%	19.71%	10.93%	4.41%

Peak Months Only	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for Peak Months Only	3,230,488	5,158,546	6,758,729	5,587,047	4,021,984	2,015,147
Rank	5	3	1	2	4	6
% Max Month	47.80%	76.32%	100.00%	82.66%	59.51%	29.82%
PR	3.60%	5.61%	17.34%	3.17%	2.93%	4.97%
CumPR	8.57%	17.10%	37.60%	20.27%	11.49%	4.97%

DEMAND COST PR ALLOCATORS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
Pipeline - Remaining	8.00%	16.54%	37.04%	19.71%	10.93%	4.41%
Storage & Peaking	8.00%	16.54%	37.04%	19.71%	10.93%	4.41%
Capacity Release	8.57%	17.10%	37.60%	20.27%	11.49%	4.97%
Interr. Margins & Off Sys Sales	8.57%	17.10%	37.60%	20.27%	11.49%	4.97%

DEMAND COSTS ALLOCATED TO MONTHS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Pipeline - Base	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 57,254
Pipeline - Remaining	$ 232,387	$ 480,159	$ 1,075,580	$ 572,205	$ 317,397	$ 127,961
Total Pipeline	$ 289,641	$ 537,413	$ 1,132,833	$ 629,459	$ 374,651	$ 185,214
Storage & Peaking	$ 1,175,975	$ 2,429,807	$ 5,442,884	$ 2,895,597	$ 1,606,162	$ 647,534
Less Credits to Demand Cost						
Cap Rel Margins, Asset Mgt Credit,	$ 406,168	$ 810,793	$ 1,783,147	$ 961,109	$ 544,994	$ 235,634
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
Total Direct Demand Costs	$ 1,059,448	$ 2,156,427	$ 4,792,570	$ 2,563,947	$ 1,435,819	$ 597,114

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

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

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

45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Annual**	**Winter**	**Summer**
46	Remaining Load for All Months	582,716	105,033	0	18,192	139,110	1,022,278	28,639,269	26,771,941	1,867,328
47	Rank	8	10	12	11	9	7			
48	% Max Month	8.62%	1.55%	0.00%	0.27%	2.06%	15.13%			
49	PR	0.82%	0.13%	0.00%	0.02%	0.06%	0.93%	37.04%		
50	CumPR	1.03%	0.15%	0.00%	0.02%	0.21%	1.96%	100.00%	96.63%	3.37%
51										
52	**Peak Months Only**							**Annual**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only							26,771,941	26,771,941	
54	Rank									
55	% Max Month									
56	PR							37.60%		
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	1.03%	0.15%	0.00%	0.02%	0.21%	1.96%	100.00%	96.63%	3.37%
63	Storage & Peaking	1.03%	0.15%	0.00%	0.02%	0.21%	1.96%	100.00%	96.63%	3.37%
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	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 687,045	$ 343,522	$ 343,522	50.00%	50.00%
70	Pipeline - Remaining	$ 29,891	$ 4,441	$ -	$ 711	$ 6,068	$ 56,868	$ 2,903,667	$ 2,805,688	$ 97,979	96.63%	3.37%
71	Total Pipeline	$ 87,144	$ 61,695	$ 57,254	$ 57,964	$ 63,322	$ 114,122	$ 3,590,712	$ 3,149,210	$ 441,501	87.70%	12.30%
72												
73	Storage & Peaking	$ 151,259	$ 22,475	$ -	$ 3,595	$ 30,707	$ 287,777	$ 14,693,774	$ 14,197,961	$ 495,814	96.63%	3.37%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins, Asset Mgt Credit,	$ -	$ -	$ -	$ -	$ -	$ -	$4,741,845	$ 4,741,845	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 238,404	$ 84,170	$ 57,254	$ 61,560	$ 94,028	$ 401,899	$ 13,542,640	$ 12,605,326	$ 937,315	93.08%	6.92%
81												
82	Indirect Demand Costs/(Credits)											
83	Miscellaneous Overhead							$ 512,686	$ 416,811	$ 95,875	81.30%	18.70%
84	Local Production & Storage							$ 420,658	$ 420,658	$ -	100.00%	0.00%
85	Subtotal							$ 933,344	$ 837,469	$ 95,875	89.73%	10.27%

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

42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**	
43	(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)	
44		
45	**All Months**	
46	Remaining Load for All Months	Schedule 10B, LN 80
47	Rank	Rank LN 46
48	% Max Month	LN 46 / MAX Month LN 46
49	PR	The difference between LN 48 for the month and LN 48 for next highest rank
50	CumPR	Cumulative Values, LN 49
51		
52	**Peak Months Only**	
53	Remaining Load for Peak Months Only	LN 46
54	Rank	Rank LN 53
55	% Max Month	LN 53 / MAX Month LN 53
56	PR	The difference between LN 55 for the month and LN 55 for next highest rank
57	CumPR	Cumulative Values, LN 56
58		
59	**DEMAND COST PR ALLOCATORS**	
60		
61	Pipeline - Base	1/12
62	Pipeline - Remaining	LN 50
63	Storage & Peaking	LN 50
64	Capacity Release	LN 57
65	Interr. Margins & Off Sys Sales	LN 57
66		
67	**DEMAND COSTS ALLOCATED TO MONTHS**	
68		
69	Pipeline - Base	LN 40 * LN 61
70	Pipeline - Remaining	LN 41 * LN 62
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & Peaking	LN 63 * (Sum LN 21 : LN 22)
74		
75	Less Credits to Demand Cost	
76	Cap Rel Margins, Asset Mgt Credit,	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	($5,330,574)	($658,933)	($4,671,641)	Schedule 21, Line 89	Schedule 5B, Page 5*	A - B
2	Capacity Release Revenues	($70,204)	$0	($70,204)	Schedule 21, Line 88		A - B
3	PNGTS Litigation	$0	$0	$0	Schedule 5B, Page 6*	Schedule 5B, Page 5*	A - B
4	Total NH Cap Rel and Asset Management	($5,400,778)	($658,933)	($4,741,845)			Sum (LN1 + LN 2 + LN 5)

*: Provided in the 2013-2014 Winter Period Filing

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	4,389,944	4,550,058	4,574,824	4,008,534	4,412,352	2,914,177	32,209,152	24,849,889
2	New Hampshire Sales Storage	(40,590)	1,534,611	2,617,947	2,210,241	631,773	0	6,953,982	6,953,982
3	New Hampshire Sales Peaking	34,752	13,352	505,629	216,946	152,282	9,743	995,375	932,704
4	Total New Hampshire Firm Sales Sendout	4,384,105	6,098,021	7,698,400	6,435,721	5,196,407	2,923,921	40,158,509	32,736,575
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	4,384,105	6,098,021	7,698,400	6,435,721	5,196,407	2,923,921	40,158,509	32,736,575
9	Total Firm Sales	4,112,314	6,058,317	7,648,394	6,393,843	4,928,858	2,904,612	39,417,643	32,046,338
10	Difference (LAUF & Company Use)	271,791	39,704	50,006	41,878	267,549	19,309	740,865	690,237
11	Percent Difference	6.20%	0.65%	0.65%	0.65%	5.15%	0.66%	1.84%	2.11%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 3,726,464	$ 3,957,000	$ 4,075,082	$ 3,606,995	$ 3,853,450	$ 1,174,663	$ 22,875,022	$ 20,393,655
15	New Hampshire Hedging (Gains) Losses	$ 4,026	$ 6,626	$ 6,805	$ 6,029	$ 4,450	$ -	$ 27,935	$ 27,935
16	New Hampshire Total Storage	$ (22,857)	$ 672,556	$ 1,164,058	$ 980,624	$ 267,232	$ -	$ 3,061,613	$ 3,061,613
17	New Hampshire Total Peaking	$ 28,357	$ 13,499	$ 1,067,041	$ 459,934	$ 288,640	$ 13,849	$ 1,952,181	$ 1,871,318
18	New Hampshire Inventory Finance Charge	$ 752	$ 1,201	$ 1,574	$ 1,301	$ 937	$ 469	$ 6,234	$ 6,234
19	Total New Hampshire Sales Variable Costs	$ 3,736,741	$ 4,650,882	$ 6,314,560	$ 5,054,883	$ 4,414,708	$ 1,188,981	$ 27,922,986	$ 25,360,756
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 3,732,716	$ 4,644,256	$ 6,307,755	$ 5,048,855	$ 4,410,258	$ 1,188,981	$ 27,895,051	$ 25,332,821
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 3,736,741	$ 4,650,882	$ 6,314,560	$ 5,054,883	$ 4,414,708	$ 1,188,981	$ 27,922,986	$ 25,360,756
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.8489	$ 0.8697	$ 0.8908	$ 0.8998	$ 0.8733	$ 0.4031	$ 0.7102	$ 0.8207
27	New Hampshire Hedging (Gains) Losses	$ 0.0009	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0010	$ -	$ 0.0009	$ 0.0011
28	New Hampshire Storage Excld Inventory Finance Costs	$ -	$ 0.4383	$ 0.4446	$ 0.4437	$ 0.4230	$ -	$ 0.4403	$ 0.4403
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.8160	$ 1.0110	$ 2.1103	$ 2.1200	$ 1.8954	$ 1.4213	$ 1.9613	$ 2.0063
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	$ 0.0216	$ 0.0008	$ 0.0005	$ 0.0005	$ 0.0012	$ 0.0482	$ 0.0008	$ 0.0008
31	Weighted Average Cost per Dth Sendout	$ 0.8523	$ 0.7627	$ 0.8202	$ 0.7854	$ 0.8496	$ 0.4066	$ 0.6953	$ 0.7747
32									
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34									
35	**Commodity Costs**								
36	Base Commodity, therms	908,429	938,709	938,709	847,867	938,709	908,429	11,034,355	5,480,852
37	Base Commodity Cost Excld Hedging	$ 771,132	$ 816,357	$ 836,167	$ 762,935	$ 819,806	$ 366,174	$ 6,213,487	$ 4,372,572
38	Base Hedging Commodity Cost	$ 833	$ 1,367	$ 1,396	$ 1,275	$ 947	$ -	$ 5,818	$ 5,818
39	Remaining Commodity Excld Hedging	$ 2,961,584	$ 3,827,899	$ 5,471,588	$ 4,285,920	$ 3,590,452	$ 822,806	$ 21,681,564	$ 20,960,249
40	Remaining Hedging Commodity	$ 3,193	$ 5,259	$ 5,408	$ 4,754	$ 3,503	$ -	$ 22,117	$ 22,117
41	Total Commodity Excld Hedging	$ 3,732,716	$ 4,644,256	$ 6,307,755	$ 5,048,855	$ 4,410,258	$ 1,188,981	$ 27,895,051	$ 25,332,821
42	Total Hedging	$ 4,026	$ 6,626	$ 6,805	$ 6,029	$ 4,450	$ -	$ 27,935	$ 27,935
43	Total Commodity (Incl Hedging)	$ 3,736,741	$ 4,650,882	$ 6,314,560	$ 5,054,883	$ 4,414,708	$ 1,188,981	$ 27,922,986	$ 25,360,756

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Schedule 22, LN 10 * LN 59 * 10
2	New Hampshire Sales Storage	Schedule 22, LN 3 * LN 59 * 10
3	New Hampshire Sales Peaking	Schedule 22, LN 4 * LN 59 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Schedule 22, LN 8 * 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 73
15	New Hampshire Hedging (Gains) Losses	Schedule 22, LN 74
16	New Hampshire Total Storage	Schedule 22, LN 75
17	New Hampshire Total Peaking	Schedule 22, LN 76
18	New Hampshire Inventory Finance Charge	Schedule 22, LN 79
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 41
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

REDACTED

Estimated Delivered City-Gate Commodity Costs and Volumes
November 2014 through April 2015

Denotes Confidential Information

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tenn Zone 4 Spot	[redacted]	112,183	[redacted]
Tennessee Storage		240,061	
Tennessee Production		1,104,186	
TGP Zone 6		42,785	
Niagara		384,052	
Chicago		918,569	
Washington 10 Storage		2,058,071	
Algonquin Receipts		205,774	
Iroquois Receipts		93,130	
PNGTS Receipts		139,523	
Maritimes Delivered		1,175,900	
PNGTS Delivered		1,128,536	
LNG		62,120	
Peaking Contract 1		3,410	
Peaking Contract 2		298,950	
Total Delivered Commodity Cost	$61,138,179	7,967,251	$7.674

Schedule 3

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

			Summer						Winter						
	Sales Revenues								(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
1	Volumes	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
2	Residential Heat & Non Heat								1,893,616	2,789,700	3,521,890	2,944,201	2,269,613	1,337,500	14,756,521
3	Sales HLF Classes								284,142	418,603	528,470	441,786	340,562	200,696	2,214,258
4	Sales LLF Classes								1,934,556	2,850,014	3,598,034	3,007,855	2,318,683	1,366,417	15,075,559
5	Total								4,112,314	6,058,317	7,648,394	6,393,843	4,928,858	2,904,612	32,046,338
6	Rates														
7	Residential Heat & Non Heat CGA								$1.1069	$1.1069	$1.1069	$1.1069	$1.1069	$1.1069	
8	Sales HLF Classes CGA								$1.0092	$1.0092	$1.0092	$1.0092	$1.0092	$1.0092	
9	Sales LLF Classes CGA								$1.1217	$1.1217	$1.1217	$1.1217	$1.1217	$1.1217	
10	Revenues														
11	Residential Heat & Non Heat								$ (2,096,043)	$ (3,087,919)	$ (3,898,381)	$ (3,258,937)	$ (2,512,235)	$ (1,480,478)	$(16,333,993)
12	Sales HLF Classes								$ (286,757)	$ (422,454)	$ (533,332)	$ (445,850)	$ (343,695)	$ (202,542)	$ (2,234,629)
13	Sales LLF Classes								$ (2,169,991)	$ (3,196,861)	$ (4,035,915)	$ (3,373,911)	$ (2,600,866)	$ (1,532,710)	$(16,910,255)
14	Total Sales Revenues								$ (4,552,791)	$ (6,707,234)	$ (8,467,627)	$ (7,078,698)	$ (5,456,797)	$ (3,215,730)	$(35,478,877)
15															

16			Summer						Winter						
17	**Gas Costs and Credits**		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
18			May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
19	Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
20	Pipeline		$ 264,249	$ 264,249	$ 264,249	$ 264,249	$ 264,249	$ 264,249	$ 253,358	$ 253,358	$ 264,249	$ 264,249	$ 264,249	$ 264,249	$ 3,149,210
21	Storage		$ 615,612	$ 615,612	$ 615,612	$ 615,612	$ 615,612	$ 615,612	$ 1,514,140	$ 1,514,140	$ 1,651,757	$ 1,651,757	$ 1,651,757	$ 615,612	$ 12,292,832
22	Peaking		$ 49,674	$ 49,674	$ 49,674	$ 49,674	$ 49,674	$ 49,674	$ 290,359	$ 325,353	$ 325,353	$ 325,353	$ 290,359	$ 49,674	$ 1,904,496
23	Total Demand Costs		$ 929,535	$ 929,535	$ 929,535	$ 929,535	$ 929,535	$ 929,535	$ 2,057,857	$ 2,092,852	$ 2,241,359	$ 2,241,359	$ 2,206,365	$ 929,535	$ 17,346,539
24	NUI Commodity Costs														
25	NUI Total Pipeline Volumes								916,039	947,637	961,402	837,790	928,066	628,089	5,219,022
26	Pipeline Costs Modeled in Sendout™								$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 42,756,455
27	NYMEX Price Used for Forecast								$ 3.9380	$ 4.0180	$ 4.0920	$ 4.0780	$ 4.0090	$ 3.7900	
28	NYMEX Price Used for Update								$ 3.9380	$ 4.0180	$ 4.0920	$ 4.0780	$ 4.0090	$ 3.7900	
29	Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
30	Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
31	Updated Pipeline Costs								$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	
32	Interruptible Volumes - NH								0	0	0	0	0	0	
33	Average Supply Cost ($/MMBtu)								$ 8.49	$ 8.70	$ 8.91	$ 9.00	$ 8.73	$ 4.03	
34	Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
35	Total Updated Pipeline Costs								$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	
36	New Hampshire Allocated Percentage								47.92%	48.01%	47.58%	47.85%	47.54%	46.40%	
37	NH Updated Pipeline Costs								$ 3,726,464	$ 3,957,000	$ 4,075,082	$ 3,606,995	$ 3,853,450	$ 1,174,663	$ 20,393,655
38	Hedging (Gain)/Loss Estimate														
39	Time Triggered NYMEX Contracts (Allocated between ME and NH)														
40	NYMEX Options Contracts														
41	Number of contracts								8	12	13	12	9	0	
42	Option Contract Price								$ 0.0105	$ 0.0115	$ 0.0110	$ 0.1050	$ 0.1040	$ -	
43	Hedging Expense								$8,400	$13,800	$14,300	$12,600	$9,360	$0	
44	NYMEX Option Strike Price								$6	$6	$6	$6	$6	$0	
45	NYMEX Price Used for Forecast								$4	$4	$4	$4	$4	$0	
46	Strike Price Hit								No	No	No	No	No	$0	
47	Option Hedging Gain (Credit)								$0	$0	$0	$0	$0	$0	
48	Total Option Cost								$8,400	$13,800	$14,300	$12,600	$9,360	$0	
49	New Hampshire Allocated Percentage								47.92%	48.01%	47.58%	47.85%	47.54%	46.40%	
50	NH Futures Hedging (Gain)/Loss, Time Triggered								$ 4,026	$ 6,626	$ 6,805	$ 6,029	$ 4,450	$ -	$ 27,935
51	NH Commodity Costs														
52	Pipeline Excl Hedging								$ 3,726,464	$ 3,957,000	$ 4,075,082	$ 3,606,995	$ 3,853,450	$ 1,174,663	$ 20,393,655
53	Hedging (Gain)/Loss Estimate								$ 4,026	$ 6,626	$ 6,805	$ 6,029	$ 4,450	$ -	$ 27,935
54	Storage								$ (22,857)	$ 672,556	$ 1,164,058	$ 980,624	$ 267,232	$ -	$ 3,061,613
55	Peaking								$ 28,357	$ 13,499	$ 1,067,041	$ 459,934	$ 288,640	$ 13,849	$ 1,871,318
56	Total Commodity Costs								$ 3,735,989	$ 4,649,681	$ 6,312,986	$ 5,053,582	$ 4,413,771	$ 1,188,512	$ 25,354,521
57	Inventory Finance Charge		$ 296	$ 384	$ 464	$ 559	$ 614	$ 674	$ 872	$ 799	$ 630	$ 446	$ 274	$ 225	$ 6,234
58	Asset Management and Capacity Release														
59	NUI AMA Revenue								$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	($11,198,056)
60	PNGTS Litigation Cost								$ -	$ -	$ -	$ -	$ -	$ -	$0
61	NUI Capacity Release								$ (24,603)	$ (24,603)	$ (24,603)	$ (24,603)	$ (24,603)	$ (24,603)	$ (147,616)
62	NUI AMA Rev & Cap. Release Subtotal								$ (1,890,945)	$ (1,890,945)	$ (1,890,945)	$ (1,890,945)	$ (1,890,945)	$ (1,890,945)	$(11,345,672)
63	NH AMA Revenue								$ (778,607)	$ (778,607)	$ (778,607)	$ (778,607)	$ (778,607)	$ (778,607)	($4,671,641)

64	NH Capacity Release								$ (11,701)	$ (11,701)	$ (11,701)	$ (11,701)	$ (11,701)	$ (11,701)	($70,204)
65	NH Total Asset Management and Capacity Release								$ (790,308)	$ (790,308)	$ (790,308)	$ (790,308)	$ (790,308)	$ (790,308)	$ (4,741,845)
	Net Demand Costs		$ 929,535	$ 929,535	$ 929,535	$ 929,535	$ 929,535	$ 929,535	$ 1,267,550	$ 1,302,544	$ 1,451,052	$ 1,451,052	$ 1,416,057	$ 139,228	$ 12,604,693
72															
73	**Total Anticipated Direct Cost of Gas**		$ 929,831	$ 929,919	$ 929,999	$ 930,094	$ 930,149	$ 930,209	$ 5,004,410	$ 5,953,024	$ 7,764,667	$ 6,505,080	$ 5,830,103	$ 1,327,964	$ 37,965,449
74			Winter						Summer						
75									(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
76		Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
77	Working Capital														
78	Total Anticipated Direct Cost of Gas		$ 929,831	$ 929,919	$ 929,999	$ 930,094	$ 930,149	$ 930,209	$ 5,004,410	$ 5,953,024	$ 7,764,667	$ 6,505,080	$ 5,830,103	$ 1,327,964	$ 37,965,449
79	Working Capital Percentage		0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.0824%	
80	Working Capital Allowance		$ 766	$ 766	$ 766	$ 766	$ 766	$ 766	$ 4,122	$ 4,903	$ 6,395	$ 5,358	$ 4,802	$ 1,094	$ 31,269
81	Beginning Period Working Capital Balance		$ (1,796)	$ (1,034)	$ (270)	$ 496	$ 1,265	$ 2,035	$ 2,808	$ 6,943	$ 11,872	$ 18,308	$ 23,722	$ 28,595	
82	End of Period Working Capital Allowance		$ (1,030)	$ (268)	$ 496	$ 1,262	$ 2,031	$ 2,802	$ 6,930	$ 11,846	$ 18,267	$ 23,665	$ 28,524	$ 29,689	
83	Interest		$ (4)	$ (2)	$ 0	$ 2	$ 4	$ 7	$ 13	$ 25	$ 41	$ 57	$ 71	$ 79	$ 294
84	End of period with Interest	$ (1,796)	$ (1,034)	$ (270)	$ 496	$ 1,265	$ 2,035	$ 2,808	$ 6,943	$ 11,872	$ 18,308	$ 23,722	$ 28,595	$ 29,768	
85	Bad Debt														
89															$ -
91	Bad Debt Allowance								$ 59,360.49	$ 59,360.49	$ 59,360.49	$ 59,360.49	$ 59,360.49	$ 59,360.49	$ 356,163
92	Beginning Period Bad Debt Balance		$ (118,517)	$ (118,838)	$ (119,160)	$ (119,483)	$ (119,806)	$ (120,131)	$ (120,456)	$ (61,341)	$ (2,067)	$ 57,369	$ 116,965	$ 176,723	
93	End of Period Bad Debt Balance		$ (118,517)	$ (118,838)	$ (119,160)	$ (119,483)	$ (119,806)	$ (120,131)	$ (61,096)	$ (1,981)	$ 57,294	$ 116,729	$ 176,325	$ 236,083	
94	Interest		$ (321)	$ (322)	$ (323)	$ (324)	$ (324)	$ (325)	$ (246)	$ (86)	$ 75	$ 236	$ 397	$ 559	$ (1,004)
95	End of Period Bad Debt Balance with Interest	$ (118,517)	$ (118,838)	$ (119,160)	$ (119,483)	$ (119,806)	$ (120,131)	$ (120,456)	$ (61,341)	$ (2,067)	$ 57,369	$ 116,965	$ 176,723	$ 236,642	
96	Local Production and Storage Capacity								$ 70,110	$ 70,110	$ 70,110	$ 70,110	$ 70,110	$ 70,110	$ 420,658
97	Miscellaneous Overhead								$ 69,469	$ 69,469	$ 69,469	$ 69,469	$ 69,469	$ 69,469	$ 416,811
98	Refunds								$ -	$ -	$ -	$ -	$ -	$ -	$ -
99	Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
100	Beginning Balance Over/Under Collection		$ (3,607,559)	$ (2,686,240)	$ (1,762,336)	$ (835,851)	$ 93,238	$ 1,024,899	$ 1,959,144	$ 2,556,447	$ 1,947,907	$ 1,389,038	$ 958,172	$ 1,474,346	
101	Net Costs - Revenues		$ 929,831	$ 929,919	$ 929,999	$ 930,094	$ 930,149	$ 930,209	$ 591,197	$ (614,632)	$ (563,382)	$ (434,040)	$ 512,885	$ (1,748,187)	
102	Ending Balance before Interest		$ (2,677,728)	$ (1,756,320)	$ (832,337)	$ 94,243	$ 1,023,387	$ 1,955,108	$ 2,550,341	$ 1,941,815	$ 1,384,525	$ 954,998	$ 1,471,056	$ (273,841)	
103	Average Balance		$ (3,142,644)	$ (2,221,280)	$ (1,297,337)	$ (370,804)	$ 558,313	$ 1,490,004	$ 2,254,742	$ 2,249,131	$ 1,666,216	$ 1,172,018	$ 1,214,614	$ 600,252	
104	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%	
105	Interest Expense		$ (8,511)	$ (6,016)	$ (3,514)	$ (1,004)	$ 1,512	$ 4,035	$ 6,107	$ 6,091	$ 4,513	$ 3,174	$ 3,290	$ 1,626	$ 11,302
106	Ending Balance Incl Interest Expense	$ (3,607,559)	$ (2,686,240)	$ (1,762,336)	$ (835,851)	$ 93,238	$ 1,024,899	$ 1,959,144	$ 2,556,447	$ 1,947,907	$ 1,389,038	$ 958,172	$ 1,474,346	$ (272,216)	
107	**Total Over/Under Collection Ending Balance**		$ (2,806,112)	$ (1,881,766)	$ (954,837)	$ (25,303)	$ 906,804	$ 1,841,496	$ 2,502,049	$ 1,957,712	$ 1,464,714	$ 1,098,859	$ 1,679,663	$ (5,806)	
108															$ -
109															
110	**Total Indirect Cost of Gas**	$ (3,727,872)	$ (8,070)	$ (5,574)	$ (3,070)	$ (559)	$ 1,958	$ 4,483	$ 208,934	$ 209,873	$ 209,962	$ 207,763	$ 207,498	$ 202,296	$ (2,492,378)
111															
112	**Total Cost of Gas**	$ (3,727,872)	$ 921,760	$ 924,345	$ 926,929	$ 929,534	$ 932,107	$ 934,692	$ 5,213,345	$ 6,162,896	$ 7,974,630	$ 6,712,843	$ 6,037,601	$ 1,530,260	$ 35,473,071
113															
114	**Total Interest**	$ -	$ (8,836)	$ (6,340)	$ (3,836)	$ (1,325)	$ 1,192	$ 3,717	$ 5,874	$ 6,031	$ 4,628	$ 3,467	$ 3,757	$ 2,264	$ 10,593

Schedule 4

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2014**			
2				
3	Total	$	573,318	Company Analysis
4	Distribution	$	257,587	Company Analysis
5	Distribution (%)		44.93%	
6	Non-Distribution	$	315,731	Company Analysis
7	Non-Distribution(%)		55.07%	LN 6 / LN 3
8				
9	Non-Distribution	$	315,731	LN 6
10	Peak Period	$	291,707	Company Analysis
11	Peak Period (%)		92.39%	LN 10/ LN 9
12	Off-Peak Period	$	24,024	LN 9 - LN 10
13	Off-Peak Period (%)		7.61%	LN 12 / LN 9
14				
15	**Forecast Bad Debt Expense 12 Months Ended December 31, 2015**			
16				
17	Annual Total	$	700,000	Company Forecast
18	Annual Non-Distribution	$	385,495	LN 17* LN 7
19	Winter Non-Distribution	**$**	**356,163**	LN 18* LN 11
20	Summer Non-Distribution	$	29,333	LN 18* LN 13

Schedules 5A & Attachments, 5B, 5C and 5D

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2014 through October 31, 2015			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 9,039,940	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 27,667,462	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,490,461	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 3,271,550	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,345,672)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 33,160,587	Sum Lines 1 through 6.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2014 through October 31, 2015

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 Sch 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 Sch 5A	$ 8,223	$ 98,680
Granite	14-001-FT-NN	FT-NN	No	100,000	NA	NA	$ 3.8633	12	Line 3 of Page 2, Att to Sch 5A	$ 386,330	$ 4,635,960
Iroquois	R181001	RTS-1	No	6,569	Zone 1	Zone 1	$ 6.5971	12	Line 4 of Page 2, Att to Sch 5A	$ 43,336	$ 520,036
PNGTS	1997-003	FT	No	1,100	Pittsburgh	GSGT	$ 40.2456	12	Line 5 of Page 2, Att to Sch 5A	$ 44,270	$ 531,242
PNGTS	1997-004	FT	Yes	33,000	Pittsburgh	GSGT	$ 76.4666	5	Line 6 of Page 2, Att to Sch 5A	$ 2,523,398	$ 12,616,989
Tennessee	5083	FT-A	No	4,605	Zone 0	Zone 6	$ 23.9133	12	Line 7 of Page 2, Att to Sch 5A	$ 110,121	$ 1,321,449
Tennessee	5083	FT-A	No	8,550	Zone L	Zone 6	$ 21.2245	12	Line 8 of Page 2, Att to Sch 5A	$ 181,469	$ 2,177,634
Tennessee	5265	FT-A	No	2,653	Zone 4	Zone 6	$ 8.3778	12	Line 9 of Page 2, Att to Sch 5A	$ 22,226	$ 266,716
Tennessee	5292	FT-A	No	1,406	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att to Sch 5A	$ 10,343	$ 124,110
Tennessee	31861	FT-A	No	2,226	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att to Sch 5A	$ 16,374	$ 196,493
Tennessee	39735	FT-A	No	929	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att to Sch 5A	$ 6,834	$ 82,005
Tennessee	41099	FT-A	No	4,267	Zone 5	Zone 6	$ 7.3560	12	Line 10 of Page 2, Att to Sch 5A	$ 31,388	$ 376,657
Texas Eastern	800384	FT-1	No	965	M3	M3	$ 5.4980	12	Line 11 of Page 2, Att to Sch 5A	$ 5,306	$ 63,667
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 18.9336	2	Line 12 of Page 2, Att to Sch 5A	$ 643,742	$ 1,287,485
TransCanada	33322	FT	No	34,000	Dawn	E. Hereford	$ 29.0954	10	Line 12 of Page 2, Att to Sch 5A	$ 989,244	$ 9,892,436
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 9.3777	2	Line 13 of Page 2, Att to Sch 5A	$ 55,675	$ 111,351
TransCanada	29594	FT	No	5,937	Parkway	Iroquois	$ 14.5540	10	Line 13 of Page 2, Att to Sch 5A	$ 86,407	$ 864,071
Union	M12205	M12	No	6,003	Dawn	Parkway	$ 2.3084	12	Line 14 of Page 2, Att to Sch 5A	$ 13,857	$ 166,288
Vector	CRL-NUI-0725	FT-1	Yes	17,172	Alliance	Dawn	$ 7.6042	12	Line 15 of Page 2, Att to Sch 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 Sch 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 Sch 5A	$ 47,191	$ 566,295
Vector	FT-1-NUI-C0122	FT-1	Yes	6,070	St. Clair	Dawn	$ 0.4480	12	Line 18 of Page 2, Att to Sch 5A	$ 2,719	$ 32,632

Total Annual Demand Costs $ 38,197,864

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2014 through October 31, 2015

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	14-001-FT-NN	100,000	32,321	35,529	32,150	32%	36%	32%	$ 4,635,960	$ 1,498,389	$ 1,647,110	$ 1,490,461
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%	$ 1,321,449	$ 1,321,449	$ -	$ -
Tennessee	5083	8,550	8,550			100%	0%	0%	$ 2,177,634	$ 2,177,634	$ -	$ -
Tennessee	5265	2,653		2,653		0%	100%	0%	$ 266,716	$ -	$ 266,716	$ -
Tennessee	5292	1,406	1,406	-		100%	0%	0%	$ 124,110	$ 124,110	$ -	$ -
Tennessee	31861	2,226	2,226			100%	0%	0%	$ 196,493	$ 196,493	$ -	$ -
Tennessee	39735	929	929	-		100%	0%	0%	$ 82,005	$ 82,005	$ -	$ -
Tennessee	41099	4,267	4,267	-		100%	0%	0%	$ 376,657	$ 376,657	$ -	$ -
Texas Eastern	800384	965	965	-		100%	0%	0%	$ 63,667	$ 63,667	$ -	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 1,287,485	$ -	$ 1,287,485	$ -
TransCanada	33322	34,000		34,000		0%	100%	0%	$ 9,892,436	$ -	$ 9,892,436	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 111,351	$ 111,351	$ -	$ -
TransCanada	29594	5,937	5,937	-		100%	0%	0%	$ 864,071	$ 864,071	$ -	$ -
Union	M12205	6,003	6,003	-		100%	0%	0%	$ 166,288	$ 166,288	$ -	$ -
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%	$ 32,632	$ 32,632	$ -	$ -
Annual Total Demand Costs									$ 38,197,864	$ 9,039,940	$ 27,667,462	$ 1,490,461

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2014 through October 31, 2015

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 Sch 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 Sch 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 Sch 5A	$ 189	$ 1,398	$ 1,587
W-10	01052	Storage	Yes	3,400,000		34,000			12	Line 3 of Page 3, Att to Sch 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, 2014 through October 31, 2015

Denotes Confidential Information

Resource	Supplier	Contract Quantity	Maximum Daily Quantity	Months Per Year	Monthly Fixed Charges	Annual Fixed Charges
LNG Contract	[redacted]	75,000	2,000	5	[redacted]	[redacted]
Peaking Contract 1	[redacted]	300,000	20,000	5	[redacted]	[redacted]
Peaking Contract 2	[redacted]	300,000	20,000	5	[redacted]	[redacted]
Total Peaking Supply Contract Demand Costs						$ 3,271,550

REDACTED

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 1, 2014 through October 31, 2015

Denotes Confidential Information	
Asset Management Agreeement Revenue	
Resources	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin Algonquin Contract #93201A1C (1,251 Dth) Wash 10 via Vector, TCPL, PNGTS Tennessee Niagara Tennessee Long-Haul	[redacted]
Total Asset Management	$ (11,198,056)

Capacity Release Revenue	
Resources	Projected Revenue
Texas Eastern Contract 800384	$ (63,667)
Tennessee 5265	$ (83,950)
Total Capacity Release	$ (147,616)

Total Asset Management and Capacity Release Revenue	$ (11,345,672)

REDACTED

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for September 2, 2014

Denotes Confidential Information

Estimated Adders to NYMEX Last Day Settlement

Line	Supply Source	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
2	Chicago	[redacted]											
3	Iroquois Receipts												
4	PNGTS Delivered												
5	PNGTS Baseload												
6	Maritimes Delivered												
7	Niagara												
8	Tennessee Production (Zone 0)												
9	Tennessee Production (Zone L)												
10	Tennessee Production (Zone 4)												
11	Tenessee Zone 4 Spot												
12	Peaking Supply 1												
13	Peaking Supply 2												
14	LNG												
15	W10 Supply (Injection)												
16	TGP FS Supply (Injection)												
17	W10 AMA Spot Tier I												
18	W10 AMA Spot Tier II												
19	W10 AMA Spot												
20	AGT Receipts												
21													
22	NYMEX Forecast	$3.938	$4.018	$4.092	$4.078	$4.009	$3.790	$3.776	$3.799	$3.828	$3.835	$3.823	$3.859

Northern Utilities, Inc.
Transportation Contract Rates
November 2014 through October 2015
Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Demand Rate Support	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 5	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138	$ 6.1138
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 5	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734	$ 6.5734
3	Granite	FT-NN	N/A	N/A		Page 7	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633	$ 3.8633
4	Iroquois	RTS-1	Zone 1	Zone 1		Page 9	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971	$ 6.5971
5	PNGTS	FT	N/A	N/A		Page 17	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456	$ 40.2456
6	PNGTS	FT (Seasonal)	N/A	N/A		Page 17	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666	$ 76.4666							
7	Tennessee	FT-A	Zone 0	Zone 6		Page 19	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133	$ 23.9133
8	Tennessee	FT-A	Zone L	Zone 6		Page 19	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245	$ 21.2245
9	Tennessee	FT-A	Zone 4	Zone 6		Page 19	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778	$ 8.3778
10	Tennessee	FT-A	Zone 5	Zone 6		Page 19	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560	$ 7.3560
11	Texas Eastern	FT-1/FTS	M3	M3	1	Pages 23, 24	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980	$ 5.4980
12	TransCanada	FT	Dawn	E. Hereford		Page 26	$ 18.9336	$ 18.9336	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954	$ 29.0954
13	TransCanada	FT	Parkway	Iroquois		Page 26	$ 9.3777	$ 9.3777	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540	$ 14.5540
14	Union	M12	Dawn	Parkway		Page 26	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084	$ 2.3084
15	Vector	FT-1	Alliance	Dawn		Page 39	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042	$ 7.6042
16	Vector	FT-1	W-10 Storage	Dawn		Page 40	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625	$ 4.5625							
17	Vector	FT-1	Alliance	St. Clair	2	Pages 36, 37	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745	$ 7.7745
18	Vector Canada	FT-1	St. Clair	Dawn		Page 26	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480	$ 0.4480

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Commodity Rate Support	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
19	Algonquin	AFT-1 (AFT-2)	N/A	N/A	3	Page 5, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
20	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A	3	Page 5, 46	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124
21	Granite	FT-NN	N/A	N/A	3	Page 7, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
22	Iroquois	RTS-1	Zone 1	Zone 1	3	Pages 9, 46	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042
23	LNG Trucking		Everett, MA	LNG Plant		Page 13	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100	$ 1.2100
24	PNGTS	FT	N/A	N/A	3	Page 17, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
25	Tennessee	FT-A	Zone 0	Zone 4	3, 4	Page 20, 21, 46	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926	$ 0.2926
26	Tennessee	FT-A	Zone 0	Zone 6	3, 4	Page 20, 21, 46	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359	$ 0.3359
27	Tennessee	FT-A	Zone L	Zone 4	3, 4	Page 20, 21, 46	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488	$ 0.2488
28	Tennessee	FT-A	Zone L	Zone 6	3, 4	Page 20, 21, 46	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927	$ 0.2927
29	Tennessee	FT-A	Zone 4	Zone 6	3, 4	Page 20, 21, 46	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140
30	Tennessee	FT-A	Zone 5	Zone 6	3, 4	Page 20, 21, 46	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861
31	TransCanada	FT	Dawn	E. Hereford		Page 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	TransCanada	FT	Parkway	Iroquois		Page 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Union	M12	Dawn	Parkway		Page 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Vector	FT-1	Alliance	W-10		Page 37, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
35	Vector	FT-1	Alliance	Dawn		Page 37, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
36	Vector	FT-1	W-10 Storage	Dawn		Page 37, 46	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012

Transportation Fuel Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Notes	Fuel Rate Support	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
37	Algonquin	AFT-1 (AFT-2)	N/A	N/A		Page 6	0.81%	0.91%	0.91%	0.91%	0.91%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
38	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A		Page 6	0.81%	0.91%	0.91%	0.91%	0.91%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
39	Granite	FT-NN	N/A	N/A		Page 7	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
40	Iroquois	RTS-1	Zone 1	Zone 1	5	Page 12	0.40%	0.40%	0.40%	0.40%	0.40%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%
41	PNGTS	FT	N/A	N/A	5	Page 18	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	Tennessee	FT-A	Zone 0	Zone 4		Page 21	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
43	Tennessee	FT-A	Zone 0	Zone 6		Page 21	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%
44	Tennessee	FT-A	Zone L	Zone 4		Page 21	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
45	Tennessee	FT-A	Zone L	Zone 6		Page 21	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
46	Tennessee	FT-A	Zone 4	Zone 6		Page 21	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%
47	Tennessee	FT-A	Zone 5	Zone 6		Page 21	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
48	TransCanada	FT	Dawn	E. Hereford	5	Page 38	2.15%	2.15%	2.15%	2.15%	2.15%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
49	TransCanada	FT	Parkway	Iroquois	5	Page 38	1.10%	1.10%	1.10%	1.10%	1.10%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
50	Union	M12	Dawn	Parkway		Page 35	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	5	Page 42	0.88%	0.88%	0.88%	0.88%	0.88%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
52	Vector	FT-1	Alliance	Dawn	5	Page 42	0.88%	0.88%	0.88%	0.88%	0.88%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
53	Vector	FT-1	W-10 Storage	Dawn	5	Page 42	0.33%	0.33%	0.33%	0.33%	0.33%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%

Note 1 FT-1 Demand Rate = $4.838 plus FT-1 / FTS Rate = $0.66, totals to $5.498.
Note 2 Negotiated Rate Agreement = $8.0908 per Dth (Page 36), which is higher than Maximum Reservation Rate (Page 37), so Maximum Reservation Rate prevails.
Note 3 Variable Rate includes ACA Charge on Page 46.
Note 4 Tennessee Variable Transportation Commodity Rates are calculated by adding the Maximum Commodity Rates found on Page 20 to the applicable EPCR found on page 21.
Note 5 Fuel Rates Estimated based on 12 months historic data.

Northern Utilities, Inc.
Underground Storage Contract Rates
November 2014 through October 2015

Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		Page 22	$ 0.0211	$ 1.5400	$ 0.0087	0.00%	$ 0.0087	1.07%
2	Texas Eastern	SS-1		Page 24	$ 0.1293	$ 5.3400				
3	W-10	Storage	1	Pages 43, 44, 45			$ -	0.40%	$ -	0.90%

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

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Attachment to Schedule 5A
Page 5 of 46

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 2/01/2014

RATE SCHEDULE AFT-1

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
(F-1/WS-1)	$ 6.5734	$0.0112	$0.0112	$0.2273	$0.0112	$0.2161
(F-2/F-3)	$ 6.5734	$0.0112	$0.0112	$0.2273	$0.0112	$0.2161
(F-4)	$ 6.5734	$0.0112	$0.0112	$0.2273	$0.0112	$0.2161
(STB/SS-3)	$ 6.5734	$0.0112	$0.0112	$0.2273	$0.0112	$0.2161
(FTP)	$11.8368	$0.0000	$0.0000	$0.3892	$0.0000	$0.3892
(PSS-T)	$ 9.7854	$0.0000	$0.0000	$0.3217	$0.0000	$0.3217
(AFT-2)	$ 6.1138	$0.0000	$0.0000	$0.2010	$0.0000	$0.2010
(AFT-3)	$10.7554	$0.0000	$0.0000	$0.3536	$0.0000	$0.3536
(AFT-5)	$12.6265	$0.0000	$0.0000	$0.4151	$0.0000	$0.4151
(ITP)	$13.0110	$0.0000	$0.0000	$0.4278	$0.0000	$0.4278
(X-35)	$10.2027	$0.0000	$0.0000	$0.3354	$0.0000	$0.3354
(X-39)	$13.2089	$0.0000	$0.0000	$0.4343	$0.0000	$0.4343
Incremental Surcharges						
Hubline	$ 1.8607	$0.0000	$0.0000	$0.0000	$0.0000	$0.0612
Secondary 1/		$0.0612	$0.0000			
Tiverton	$ 1.6424	$0.0000	$0.0000	$0.0000	$0.0000	$0.0540
Ramapo	$ 7.5608	$0.0000	$0.0000	$0.2486	$0.0000	$0.2486

RATE SCHEDULE AFT-1S

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
(F-1/WS-1)	$ 2.6294	$0.2273	$0.0000	$0.2273	$0.0000	$0.0864
(F-2/F-3)	$ 2.6294	$0.2273	$0.0000	$0.2273	$0.0000	$0.0864
(F-4)	$ 2.6294	$0.2273	$0.0000	$0.2273	$0.0000	$0.0864
(STB/SS-3)	$ 2.6294	$0.2273	$0.0000	$0.2273	$0.0000	$0.0864
(Hubline) 2/		$0.0612	$0.0000			

OTHER FIRM RATE SCHEDULES

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res
AFT-E	$ 6.5734	$0.0112	$0.0112	$0.2273	$0.0112	$0.2161
(Hubline) 2/		$0.0612	$0.0000			
AFT-ES	$ 2.6294	$0.2273	$0.0112	$0.2273	$0.0112	$0.0864
(Hubline) 2/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0039		$0.0581		
AFT-4	$ 3.5211	$0.0013		$0.1171		
AFT-CL:						
Canal	$ 2.0858	$0.0000	$0.0000	$0.0686	$0.0000	$0.0686
Middletown	$ 3.2764	$0.0000	$0.0000	$0.1077	$0.0000	$0.1077
Cleary	$ 1.4529	$0.0000	$0.0000	$0.0478	$0.0000	$0.0478
Lake Road	$ 0.6476	$0.0000	$0.0000	$0.0213	$0.0000	$0.0213
Brayton Pt.	$ 1.2700	$0.0000	$0.0000	$0.0418	$0.0000	$0.0418
Manchester	$ 2.4500	$0.0000	$0.0000	$0.0805	$0.0000	$0.0805
Bellingham	$ 0.9714	$0.0000	$0.0000	$0.0319	$0.0000	$0.0319
Phelps Dodge	$ 0.0000	$0.0166	$0.0000	$0.0166	$0.0000	$0.0000
Cape Cod	$ 9.0501	$0.0000	$0.0000	$0.2975	$0.0000	$0.2975
Northeast Gateway	$ 4.3449	$0.0000	$0.0000	$0.1428	$0.0000	$0.1428
J-2 Facility	$ 4.6346	$0.0000	$0.0000	$0.1524	$0.0000	$0.1524
Kleen Energy	$ 1.2247	$0.0000	$0.0000	$0.0403	$0.0000	$0.0403
X-33	$ 3.0873	$0.0395		$0.1410		

INTERRUPTIBLE SERVICE

	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min
AIT-1	$0.2421	$0.0076	$0.2421	$0.0076
(Hubline 2/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0418	$0.0000	$0.0418	$0.0000
Manchester	$0.0805	$0.0000	$0.0805	$0.0000
Canal	$0.0686	$0.0000	$0.0686	$0.0000
Cape Cod	$0.2975	$0.0000	$0.2975	$0.0000
Northeast Gateway	$0.1428	$0.0000	$0.1428	$0.0000
J-2 Facility	$0.1524	$0.0000	$0.1524	$0.0000
Kleen Energy	$0.0403	$0.0000	$0.0403	$0.0000
PAL	$0.2421	$0.0000	$0.0000	$0.0000

TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions.

FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
System Services 1/		
Winter	Dec 1 - Mar 31	0.91%
Spring, Summer and Fall	Apr 1 - Nov 30	0.81%
Incremental Ramapo Service 1/		
Winter	Dec 1 - Mar 31	2.11%
Spring, Summer and Fall	Apr 1 - Nov 30	1.73%

1/ For all receipt points other than Beverly, Meter No. 00215

Period	Duration	FRP
System Services - Beverly Receipts/Non-Hubline Deliveries		
Winter	Dec 1 - Mar 31	0.62%
Spring, Summer and Fall	Apr 1 - Nov 30	0.54%
Incremental Ramapo Service - Beverly Receipts/Non-Hubline Deliveries		
Winter	Dec 1 - Mar 31	1.67%
Spring, Summer and Fall	Apr 1 - Nov 30	1.38%

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

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

4.2 Rate Schedule FT-NN
Firm Transportation Service
Currently Effective Rates

	$/Dth	
	Base Tariff Rate	ACA Adj.
Reservation Charge:		
Maximum	$3.8633	N/A
Minimum	$0.0000	N/A
Commodity Charge:		
Maximum	$0.0000	a/
Minimum	$0.0000	a/
Authorized Overrun Commodity Charge:		
Maximum	$0.1270	a/
Minimum	$0.0000	a/
Fuel and Losses Percentage	0.35%	N/A
Volumetric Reservation Charge		
Maximum	$0.1270	a/
Minimum	$0.0000	a/

a/ The ACA Adj. Surcharge is revised annually and posted on the FERC website at the web address http://www.fer.gov on the Annual Charges page of the Natural Gas Section. The ACA Adj. Surcharge is incorporated by reference in the Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Section 6.17 of the General Terms and Conditions.

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

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

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

(Footnotes continued on Sheet 4.01)

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

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

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

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

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:
Commodity 1/

MEASUREMENT VARIANCE/FUEL USE FACTOR:

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

1/ The ACA ADJUSTMENT Commoditiy rate shall be the applicable FERC ACA unit charge incorporated by reference pursuant to Section 12.2 in the General Terms and Conditions of Transporter's FERC Gas Tariff.

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Winter	Summer	Average
Iroquois	Zone 1	Zone 1	0.50%	0.30%	0.40%	0.10%	0.00%	0.20%	0.30%	0.60%	0.50%	0.40%	0.00%	0.00%	0.40%	0.19%	0.28%

REDACTED

Line	Item	Value	Reference
1	LNG Trucking Rate	[redacted]	age 14
2	Diesel Adjustment		
3	Current Diesel Rate per Gallon		age 16
4	Forecast Diesel Rate per Gallon		stimate
5	Diesel Fuel Adjustment per Dth		age 15
6			
7	Average LNG Trucking Cost	$ 1.21	Line 1 plus Line 7

CONFIDENTIAL INFORMATION

REDACTED
LNG TRANSPORTATION RATE AGREEMENT

DATE: October 28, 2013

CONFIDENTIAL

CARRIER:

[redacted]

CONFIDENTIAL INFORMATION

SHIPPER:

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

EFFECTIVE DATE: 11/01/13

EXPIRATION DATE: 10/31/14

ORIGIN	DESTINATION	DATE	COMMODITY RATE
Everett, MA	Lewiston, ME	11/01/13 to 10/31/14	[redacted]

CONFIDENTIAL INFORMATION

OTHER TERMS AND CONDITIONS:

[redacted]

CONFIDENTIAL INFORMATION

[redacted]

SHIPPER: **Northern Utilities Inc.**

By: [signature]

Robert Furino

Its: **Director of Energy Contracts**

REDACTED

EXHIBIT 1

[redacted]

CONFIDENTIAL INFORMATION

If the Price is: (See Note 1)		The Weekly Fuel Surcharge Will Be:	[redacted] (See Note 1)		The Weekly Fuel Surcharge Will Be:
At Least:	But Less Than:		At Least:	But Less Than:	
[redacted]					

CONFIDENTIAL INFORMATION

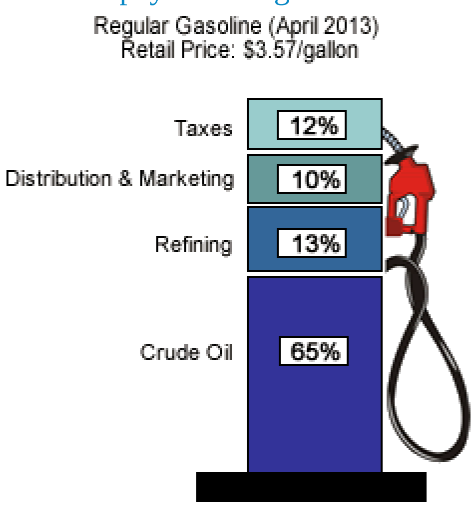
[redacted]

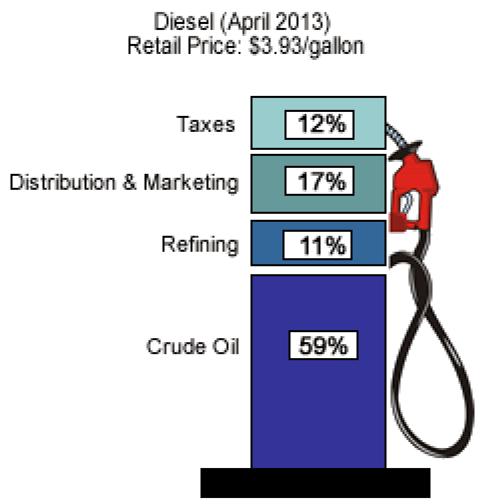
U.S. On-Highway Diesel Fuel Prices* (dollars per gallon)full history

				Change from	
	05/27/13	06/03/13	06/10/13	week ago	year ago
U.S.	3.880	3.869	3.849	-0.020	0.068
East Coast (PADD1)	3.864	3.855	3.839	-0.016	0.021
New England (PADD1A)	3.991	3.984	3.978	-0.006	0.004
Central Atlantic (PADD1B)	3.928	3.920	3.907	-0.013	-0.002
Lower Atlantic (PADD1C)	3.792	3.783	3.762	-0.021	0.041
Midwest (PADD2)	3.916	3.900	3.877	-0.023	0.181
Gulf Coast (PADD3)	3.775	3.770	3.748	-0.022	0.050
Rocky Mountain (PADD4)	3.863	3.866	3.865	-0.001	-0.008
West Coast (PADD5)	3.986	3.968	3.945	-0.023	-0.046
West Coast less California	3.917	3.899	3.870	-0.029	-0.032
California	4.044	4.025	4.008	-0.017	-0.058

**prices include all taxes*

What we pay for in a gallon of:





Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/
FT	Recourse Reservation Rate		
	-- Maximum	$\boxed{\$40.2456}$	---------
	-- Minimum	$00.0000	---------
	Seasonal Recourse Reservation Rate		
	-- Maximum	$\boxed{\$76.4666}$	---------
	-- Minimum	$00.0000	---------
	Recourse Usage Rate		
	-- Maximum	$\boxed{\$00.0000}$	2/
	-- Minimum	$00.0000	2/
FT-FLEX	Recourse Reservation Rate		
	--Maximum	$27.0128	---------
	--Minimum	$00.0000	---------
	Recourse Usage Rate		
	--Maximum	$00.4350	2/
	--Minimum	$00.0000	2/

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

2/ The currently effective ACA unit charge as published on the Commission's website (www.ferc.gov) is incorporated herein by reference.

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Winter	Summer	Average
PNGTS	N/A	N/A	-0.50%	-0.50%	-0.30%	0.00%	0.00%	-0.20%	-0.20%	-0.40%	-0.50%	-0.50%	-0.60%	-0.60%	-0.36%	-0.36%	-0.36%

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7125		$11.9375	$16.0575	$16.3417	$17.9562	$19.0597	$23.9133
L		$5.0714						
1	$8.5997		$8.2435	$10.9704	$15.5407	$15.3052	$17.2607	$21.2245
2	$16.0576		$10.9045	$5.6715	$5.3018	$6.7838	$9.3303	$12.0443
3	$16.3417		$8.6375	$5.7173	$4.1246	$6.3358	$11.4587	$13.2409
4	$20.7484		$19.1282	$7.2895	$11.0779	$5.4225	$5.8643	$8.3778
5	$24.7395		$17.3840	$7.6466	$9.2524	$6.0239	$5.6505	$7.3560
6	$28.6189		$19.9668	$13.7419	$15.1387	$10.6934	$5.6256	$4.8698

Daily Base Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1879		$0.3925	$0.5279	$0.5373	$0.5903	$0.6266	$0.7862
L		$0.1668						
1	$0.2827		$0.2710	$0.3607	$0.5109	$0.5032	$0.5675	$0.6977
2	$0.5279		$0.3585	$0.1865	$0.1743	$0.2230	$0.3068	$0.3960
3	$0.5373		$0.2840	$0.1880	$0.1356	$0.2083	$0.3768	$0.4353
4	$0.6821		$0.6289	$0.2396	$0.3642	$0.1782	$0.1928	$0.2754
5	$0.8133		$0.5716	$0.2513	$0.3042	$0.1981	$0.1857	$0.2419
6	$0.9409		$0.6564	$0.4518	$0.4977	$0.3515	$0.1849	$0.1601

Maximum Reservation Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7125		$11.9375	$16.0575	$16.3417	$17.9562	$19.0597	$23.9133
L		$5.0714						
1	$8.5997		$8.2435	$10.9704	$15.5407	$15.3052	$17.2607	$21.2245
2	$16.0576		$10.9045	$5.6715	$5.3018	$6.7838	$9.3303	$12.0443
3	$16.3417		$8.6375	$5.7173	$4.1246	$6.3358	$11.4587	$13.2409
4	$20.7484		$19.1282	$7.2895	$11.0779	$5.4225	$5.8643	$8.3778
5	$24.7395		$17.3840	$7.6466	$9.2524	$6.0239	$5.6505	$7.3560
6	$28.6189		$19.9668	$13.7419	$15.1387	$10.6934	$5.6256	$4.8698

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

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020

Maximum
Commodity Rates 1/, 2/, 3/

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

Notes:

1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.

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

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

Eighth Revised Sheet No. 32
Superseding
Seventh Revised Sheet No. 32

FUEL AND EPCR

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.64%		1.69%	2.44%	2.96%	3.50%	3.93%	4.63%
L		0.39%						
1	0.77%		1.27%	2.08%	2.47%	2.99%	3.58%	4.06%
2	2.44%		1.34%	0.39%	0.60%	0.99%	1.57%	2.05%
3	3.03%		2.47%	0.60%	0.27%	1.32%	1.84%	2.36%
4	3.61%		2.79%	1.33%	1.56%	0.61%	0.86%	1.39%
5	4.07%		3.58%	1.57%	1.84%	0.86%	0.85%	1.05%
6	4.83%		4.21%	2.08%	2.36%	1.31%	0.71%	0.43%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0018		$0.0070	$0.0109	$0.0135	$0.0163	$0.0186	$0.0223
L		$0.0006						
1	$0.0025		$0.0049	$0.0090	$0.0110	$0.0137	$0.0168	$0.0192
2	$0.0109		$0.0053	$0.0006	$0.0016	$0.0035	$0.0065	$0.0089
3	$0.0135		$0.0110	$0.0016	$0.0000	$0.0052	$0.0077	$0.0102
4	$0.0163		$0.0126	$0.0053	$0.0064	$0.0017	$0.0029	$0.0055
5	$0.0186		$0.0168	$0.0065	$0.0077	$0.0029	$0.0029	$0.0038
6	$0.0223		$0.0192	$0.0089	$0.0102	$0.0051	$0.0022	$0.0008

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.20%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.20%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

Issued: February 28, 2014
Effective: April 1, 2014

Docket No. RP14-563-000
Accepted: March 26, 2014

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.8100	$2.8100 1/		
Space Rate	$0.0286	$0.0286 1/		
Injection Rate	$0.0073	$0.0073	1.07%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.3372	$0.3372 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.5400	$1.5400 1/		
Space Rate	$0.0211	$0.0211 1/		
Injection Rate	$0.0087	$0.0087	1.07%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1848	$0.1848 1/		

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.06%.

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

CURRENTLY EFFECTIVE RATES 2/01/2014

RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.8030	6.5800	2.7210
WLA-AAB	2.8240	2.6010	1.1300
ELA-AAB	2.3740	2.1510	0.9500
ETX-AAB	2.1880	1.9650	0.8750
STX-STX	5.7350	5.5120	2.2920
STX-WLA	5.8940	5.6710	2.3550
STX-ELA	6.8120	6.5890	2.7220
STX-ETX	6.8110	6.5880	2.7210
WLA-WLA	2.0570	1.8340	0.8220
WLA-ELA	2.8310	2.6080	1.1300
WLA-ETX	2.8320	2.6090	1.1300
ELA-ELA	2.3790	2.1560	0.9500
ETX-ETX	2.1930	1.9700	0.8750
ETX-ELA	2.3800	2.1570	0.9500
M1-M1	4.3680	4.1450	1.7440
M1-M2	7.8890	7.6660	3.1500
M1-M3	10.2930	10.0700	4.1110
M2-M2	6.1790	5.9560	2.4680
M2-M3	8.7200	8.4970	3.4830
M3-M3	5.0610	4.8380	2.0210

7(C) RATE SCHEDULES	
FTS	5.3510
FTS-2	7.9590
FTS-4	7.7380
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0110

SCT DEMAND CHARGES	
Access Area	0.0030
M1-M1	0.0040
M1-M2	0.0060
M1-M3	0.0070

USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0168	0.0177	0.0244	0.0243	0.0458	0.0663	0.0819
from WLA	0.0177	0.0130	0.0180	0.0181	0.0395	0.0600	0.0756
from ELA	0.0244	0.0180	0.0180	0.0181	0.0395	0.0600	0.0756
from ETX	0.0243	0.0181	0.0181	0.0180	0.0395	0.0600	0.0756
from M1	0.0458	0.0395	0.0395	0.0395	0.0215	0.0420	0.0576
from M2	0.0663	0.0600	0.0600	0.0600	0.0420	0.0321	0.0467
from M3	0.0819	0.0756	0.0756	0.0756	0.0576	0.0467	0.0257

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0168						
from WLA	0.0177	0.0130					
from ELA	0.0244	0.0180	0.0180				
from ETX	0.0243	0.0181	0.0181	0.0180			
from M1	0.0346	0.0283	0.0283	0.0283	0.0103		
from M2	0.0469	0.0406	0.0406	0.0406	0.0226	0.0166	
from M3	0.0555	0.0492	0.0492	0.0492	0.0312	0.0251	0.0128

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1979	0.2039	0.2408	0.2406	0.3981	0.5342	0.6288
from WLA	0.2039	0.0732	0.1035	0.1037	0.2610	0.3971	0.4917
from ELA	0.2408	0.1035	0.0887	0.0889	0.2462	0.3823	0.4769
from ETX	0.2406	0.1037	0.0889	0.0826	0.2401	0.3762	0.4707
from M1	0.3981	0.2610	0.2462	0.2401	0.1575	0.2936	0.3881
from M2	0.5342	0.3971	0.3823	0.3762	0.2936	0.2276	0.3256
from M3	0.6288	0.4917	0.4769	0.4707	0.3881	0.3256	0.1845

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1979						
from WLA	0.2039	0.0732					
from ELA	0.2408	0.1035	0.0887				
from ETX	0.2406	0.1037	0.0889	0.0826			
from M1	0.3869	0.2498	0.2350	0.2289	0.1463		
from M2	0.5148	0.3777	0.3629	0.3568	0.2742	0.2121	
from M3	0.6024	0.4653	0.4505	0.4443	0.3617	0.3040	0.1716

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3

from STX	0.1980	0.2041	0.2411	0.2409	0.3987	0.5349	0.6296
from WLA	0.2041	0.0733	0.1038	0.1039	0.2615	0.3977	0.4924
from ELA	0.2411	0.1038	0.0890	0.0891	0.2468	0.3830	0.4777
from ETX	0.2409	0.1039	0.0891	0.0828	0.2406	0.3768	0.4715
from M1	0.3987	0.2615	0.2468	0.2406	0.1578	0.2940	0.3887
from M2	0.5349	0.3977	0.3830	0.3768	0.2940	0.2279	0.3260
from M3	0.6296	0.4924	0.4777	0.4715	0.3887	0.3260	0.1848

Backhaul	**STX**	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	0.1980						
from WLA	0.2041	0.0733					
from ELA	0.2411	0.1038	0.0890				
from ETX	0.2409	0.1039	0.0891	0.0828			
from M1	0.3875	0.2503	0.2356	0.2294	0.1466		
from M2	0.5155	0.3783	0.3636	0.3574	0.2746	0.2124	
from M3	0.6032	0.4660	0.4513	0.4451	0.3623	0.3044	0.1719

OTHER TRANSPORTATION SERVICES

	Reservation	**Usage-1**	**Shrinkage**	
			In Path	Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3410 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	0.6600		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	4.4760		0.45%	
FT-1/NC	6.5600		0.00%	
FT-1/RIV	10.4390		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	0.6040 2/		0.00%	
FT-1/TME	11.8880		2.81%	3.84%
FT-1/TME2	20.8320		1.14%	3.84%
FT-1/TME3	22.7390	-0.0318	0.86%	
FT-1/MX	3.1240		0.30%	
FT-1/TME12	15.9860	-0.0289	0.99%	
FT-1/PEP	8.3160		0.03%	
FT-1/NJNY	26.0610		0.58%	
FT-1/MHX	20.8790		0.01%	
MLS-1/FH	0.6240		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270	0.0305 3/	0.01%	
MLS-1/HS	6.1130	0.2010 3/	0.01%	

			Primary Rec Pt	Secondary Rec Pt
FT-1/TMX	19.2800	-0.0060	1.12%	Winter 4.13%/Summer 3.69%

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

STORAGE SERVICES

	RES.	**SPACE**	**INJ.**	**WITH.**
SS	5.2420	0.1293	0.0404	0.0638
SS-1	5.3400	0.1293	0.0404	0.0637
X-28	4.6370	0.1293	0.0404	0.0611
FSS-1	0.8960	0.1293	0.0404	0.0404
ISS-1		0.0323	0.1962	0.0404

SHRINKAGE PERCENTAGES

ASA TRANSPORTATION RATE SCHEDULES

December 1 through March 31 FOR TRANSPORTATION SERVICE

	STX	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	1.30%	1.42%	1.92%	1.92%	3.96%	5.71%	6.87%
from WLA	1.42%	1.77%	1.98%	1.98%	4.02%	5.77%	6.93%
from ELA	1.92%	1.98%	1.98%	1.36%	4.02%	5.77%	6.93%
from ETX	1.92%	1.98%	1.36%	1.36%	3.40%	5.15%	6.31%
from M1	3.96%	4.02%	4.02%	3.40%	2.04%	3.79%	4.95%
from M2	5.71%	5.77%	5.77%	5.15%	3.79%	2.95%	4.13%
from M3	6.87%	6.93%	6.93%	6.31%	4.95%	4.13%	2.39%

December 1 through March 31 FOR TRANSPORTATION SERVICE WITH PARTIAL BACKHAUL PATHS

	STX	**WLA**	**ELA**	**ETX**	**M1**	**M2**	**M3**
from STX	1.30%						
from WLA	1.42%	1.77%					
from ELA	1.92%	1.98%	1.98%				
from ETX	1.92%	1.98%	1.36%	1.36%			

from M1	1.92%	1.98%	1.98%	1.36%	0.00%		
from M2	1.92%	1.98%	1.98%	1.36%	0.00%	0.00%	
from M3	1.92%	1.98%	1.98%	1.36%	0.00%	0.00%	0.00%

April 1 through November 30 FOR TRANSPORTATION SERVICE

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	1.06%	1.34%	1.50%	1.50%	3.56%	4.92%	5.83%
from WLA	1.34%	1.49%	1.55%	1.55%	3.61%	4.97%	5.88%
from ELA	1.50%	1.55%	1.55%	1.24%	3.61%	4.97%	5.88%
from ETX	1.50%	1.55%	1.24%	1.24%	3.30%	4.66%	5.57%
from M1	3.56%	3.61%	3.61%	3.30%	2.06%	3.42%	4.33%
from M2	4.92%	4.97%	4.97%	4.66%	3.42%	2.77%	3.69%
from M3	5.83%	5.88%	5.88%	5.57%	4.33%	3.69%	2.33%

April 1 through November 30 FOR TRANSPORTATION SERVICE WITH PARTIAL BACKHAUL PATHS

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	1.06%						
from WLA	1.34%	1.49%					
from ELA	1.50%	1.55%	1.55%				
from ETX	1.50%	1.55%	1.24%	1.24%			
from M1	1.50%	1.55%	1.55%	1.24%	0.00%		
from M2	1.50%	1.55%	1.55%	1.24%	0.00%	0.00%	
from M3	1.50%	1.55%	1.55%	1.24%	0.00%	0.00%	0.00%

NON-ASA RATE SCHEDULES

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

ASA STORAGE RATE SCHEDULES

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	2.99%	2.97%
FSS-1,ISS-1	0.79%	0.79%
INJECTIONS	0.79%	0.79%
INVENTORY LEVEL	0.07%	0.07%

SURCHARGES

ACA Commodity Surcharge to applicable customers, pursuant to section 15.5 of the General Terms and Conditions

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

Canadian Fixed Transportation Rates

Line	Item	Units	Nov & Dec 2014	Reference	Proposed 2015-2020	Reference
1	Parkway to Iroquois on TCPL					
2	Demand Toll	$CAD / GJ	$ 9.24034	Page 30	$ 14.08109	Page 33
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.43662	Page 28	$ 0.93744	Page 31
4	Total Demand Toll	$CAD / GJ	$ 9.67696	Line 2 plus Line 3	$ 15.01853	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.9185	Page 27	0.9185	Page 27
6	Total Demand Toll	$US / GJ	$ 8.8883	Line 4 times Line 5	$ 13.7945	Line 4 times Line 5
7	GJ per Dth	Ratio	1.055056		1.055056	
8	Total Demand Toll	$US / Dth	$ 9.3777	Line 6 divided by Line 7	$ 14.5540	Line 6 divided by Line 7
9						
10	Union Dawn to East Hereford on TCPL					
11	Demand Toll	$CAD / GJ	$ 18.96846	Page 29	$ 28.90587	Page 32
12	Union Dawn Surcharge	$CAD / GJ	$ 0.13281	Page 28	$ 0.18079	Page 31
13	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.43662	Page 28	$ 0.93744	Page 31
14	Total Demand Toll	$CAD / GJ	$ 19.53789	Sum Lines Above.	$ 30.02410	Sum Lines Above.
15	$CAD to $US	Ratio	0.9185	Page 27	0.9185	Page 27
16	Total Demand Toll	$US / GJ	$ 17.9456	Line 13 times Line 14	$ 27.5771	Line 13 times Line 14
17	GJ per Dth	Ratio	1.055056		1.055056	
18	Total Demand Toll	$US / Dth	$ 18.9336	Line 15 divided by Line 16	$ 29.0954	Line 15 divided by Line 16
19						
20	Dawn to Parkway on Union Pipeline					
21	Total Demand Toll	$CAD / GJ	$ 2.3820	Page 34	$ 2.3820	Page 34
22	$CAD to $US	Ratio	0.9185	Page 27	0.9185	Page 27
23	Total Demand Toll	$US / GJ	$ 2.1879	Line 13 times Line 14	$ 2.1879	Line 13 times Line 14
24	GJ per Dth	Ratio	1.055056		1.055056	
25	Total Demand Toll	$US / Dth	$ 2.3084	Line 15 divided by Line 16	$ 2.3084	Line 15 divided by Line 16
26						
27	St. Clair to Dawn on Vector Canada					
28	Total Demand Toll	$CAD / GJ	$ 0.4623	Page 38	$ 0.4623	Page 38
29	$CAD to $US	Ratio	0.9185	Page 27	0.9185	Page 27
30	Total Demand Toll	$US / GJ	$ 0.4246	Line 13 times Line 14	$ 0.4246	Line 13 times Line 14
31	GJ per Dth	Ratio	1.055056		1.055056	
32	Total Demand Toll	$US / Dth	$ 0.4480	Line 15 divided by Line 16	$ 0.4480	Line 15 divided by Line 16

Canadian Variable Transportation Rates

Line	Item	Units	Value	Reference	Value	Reference
1	Parkway to Iroquois on TCPL					
2	Variable Toll	$CAD / GJ	$ -	Page 30	$ -	Page 33
3	Delivery Pressure Commodity Toll	$CAD / GJ	$ -	Page 28	$ -	Page 31
4	Variable Transportation Rate	$CAD / GJ	$ -	Line 2 plus Line 3	$ -	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.9185	Page 27	0.9185	Page 27
6	Variable Transportation Rate	$US / GJ	$ -	Line 4 times Line 5	$ -	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551		1.0551	
8	Variable Transportation Rate	$US / Dth	$ -	Line 6 divided by Line 7	$ -	Line 6 divided by Line 7
9						
10	Union Dawn to East Hereford on TCPL					
11	Commodity Rate	$CAD / GJ	$ -	Page 29	$ -	Page 32
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ -	Page 28	$ -	Page 31
13	Variable Transportation Rate	$CAD / GJ	$ -	Line 11 plus Line 12	$ -	Line 11 plus Line 12
14	$CAD to $US	Ratio	0.9185	Page 27	0.9185	Page 27
15	Variable Transportation Rate	$US / GJ	$ -	Line 13 times Line 14	$ -	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551		1.0551	
17	Variable Transportation Rate	$US / Dth	$ -	Line 15 divided by Line 16	$ -	Line 15 divided by Line 16

BANK OF CANADA
BANQUE DU CANADA

Daily Currency Converter

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

Currency Converter

Amount:
1.00
From:
Canadian Dollar

To:
U.S. dollar
cash rate
Convert
Answer:
0.92
Exchange Rate:
0.9185
Summary:
On 14 May 2014, 1.00 Canadian Dollar(s) = 0.92 U.S. dollar(s), at an exchange rate of 0.9185 (using nominal rate).

See Also

10-Year Currency Converter (http://www.bankofcanada.ca/rates/exchange/10-year-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.

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 that are denominated in foreign currencies.

Transportation Tolls
Mainline 2013 - 2017 Tolls effective July 1, 2013

System Average Unit Cost of Transportation

Line No.	Particulars	Daily Allocation Base		Adjusted Annual Unit Cost		Adjusted Daily Unit Cost	
	(a)	(b)		(c)		(d)	
1	Energy	4,842,625	GJ	31.2032718304	$/GJ	0.0854884160	$/GJ
2	Energy Distance	4,218,985,129	GJ-KM	0.1866454820	$/GJ-Km	0.0005113575	$/GJ-Km

Storage Transportation Service

Line No.	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
3	Centram MDA	4.82275	0.15856
4	Union WDA	25.55020	0.84001
5	Union NDA	10.88920	0.35800
6	Union EDA	7.61793	0.25045
7	KPUC EDA	7.32723	0.24090
8	GMIT EDA	12.52810	0.41188
9	Enbridge CDA	3.78609	0.12447
10	Enbridge EDA	9.75548	0.32073
11	Cornwall	9.89920	0.32545
12	Philipsburg	12.56045	0.41295

Firm Transportation - Short Notice

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent FT-SN for ST-SN ($/GJ)
	(a)	(b)	(c)
13	Kirkwall to Thorold CDA	4.49081	0.14764
14	Union Parkway Belt to Goreway CDA	3.34364	0.10992
15	Union Parkway Belt to Victoria Square #2 CDA	3.94878	0.12982
16	Union Parkway Belt to Schomberg #2 CDA	3.90927	0.12852

Note: Bid floors for ST-SN may be set at the daily equivalent FT-SN toll or higher.

Delivery Pressure

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)	Fuel Ratio (%)
	(a)	(b)	(c)	(d)
17	Average Delivery Pressure Toll	$\boxed{0.43662}$	0.01435	$\boxed{0.19\%}$

Note: Delivery Pressure toll applies to the following locations: Emerson 1, Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford
The Daily equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

Union Dawn Receipt Point Surcharge

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)	Fuel Ratio (%)
	(a)	(b)	(c)	(d)
18	Union Dawn Receipt Point Surcharge	$\boxed{0.13281}$	0.00437	0.00%

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/MO)	Daily Equivalent FT for IT / STFT ($/GJ)
1	Union Dawn	Nipigon WDA	26.12009	0.8587
2	Union Dawn	Union NDA	14.41835	0.4740
3	Union Dawn	Calstock NDA	20.97568	0.6896
4	Union Dawn	Tunis NDA	16.92547	0.5565
5	Union Dawn	GMIT NDA	13.91581	0.4575
6	Union Dawn	Union SSMDA	12.06507	0.3967
7	Union Dawn	Union NCDA	8.99195	0.2956
8	Union Dawn	Union CDA	6.21000	0.2042
9	Union Dawn	Enbridge CDA	7.16453	0.2356
10	Union Dawn	Union EDA	11.14630	0.3665
11	Union Dawn	Enbridge EDA	13.28433	0.4367
12	Union Dawn	GMIT EDA	16.05695	0.5279
13	Union Dawn	KPUC EDA	10.85607	0.3569
14	Union Dawn	North Bay Junction	11.72039	0.3853
15	Union Dawn	Kirkwall	5.53481	0.1820
16	Union Dawn	Enbridge SWDA	2.60027	0.0855
17	Union Dawn	Union SWDA	2.65611	0.0873
18	Union Dawn	Spruce	29.53850	0.9711
19	Union Dawn	Emerson 1	27.33127	0.8986
20	Union Dawn	Emerson 2	27.33127	0.8986
21	Union Dawn	St. Clair	2.97092	0.0977
22	Union Dawn	Dawn Export	2.60027	0.0855
23	Union Dawn	Niagara Falls	7.26719	0.2389
24	Union Dawn	Chippawa	7.30436	0.2401
25	Union Dawn	Iroquois	12.76919	0.4198
26	Union Dawn	Cornwall	13.42804	0.4415
27	Union Dawn	Napierville	15.81773	0.5200
28	Union Dawn	Philipsburg	16.08930	0.5290
29	Union Dawn	East Hereford	$\boxed{18.96846}$	0.6236
30	Union Dawn	Welwyn	33.73554	1.1091
31	Union EDA	Empress	-	1.6504
32	Union EDA	TransGas SSDA	-	1.4286
33	Union EDA	Centram SSDA	-	1.3377
34	Union EDA	Centram MDA	-	1.2003
35	Union EDA	Centrat MDA	-	1.1398
36	Union EDA	Union WDA	-	0.9028
37	Union EDA	Nipigon WDA	-	0.8055
38	Union EDA	Union NDA	-	0.4208
39	Union EDA	Calstock NDA	-	0.6364
40	Union EDA	Tunis NDA	-	0.5032
41	Union EDA	GMIT NDA	-	0.4043
42	Union EDA	Union SSMDA	-	0.6776
43	Union EDA	Union NCDA	-	0.2948
44	Union EDA	Union CDA	-	0.2658
45	Union EDA	Enbridge CDA	-	0.2365
46	Union EDA	Union EDA	-	0.0855
47	Union EDA	Enbridge EDA	-	0.1758
48	Union EDA	GMIT EDA	-	0.2475
49	Union EDA	KPUC EDA	-	0.1268
50	Union EDA	North Bay Junction	-	0.3321
51	Union EDA	Kirkwall	-	0.2700
52	Union EDA	Enbridge SWDA	-	0.3665
53	Union EDA	Union SWDA	-	0.3683
54	Union EDA	Spruce	-	1.1398
55	Union EDA	Emerson 1	-	1.1646
56	Union EDA	Emerson 2	-	1.1646
57	Union EDA	St. Clair	-	0.3786
58	Union EDA	Dawn Export	-	0.3665
59	Union EDA	Niagara Falls	-	0.3183
60	Union EDA	Chippawa	-	0.3195
61	Union EDA	Iroquois	-	0.1430
62	Union EDA	Cornwall	-	0.1614
63	Union EDA	Napierville	-	0.2399
64	Union EDA	Philipsburg	-	0.2489
65	Union EDA	East Hereford	-	0.3435
66	Union EDA	Welwyn	-	1.3377
67	Union NCDA	Empress	-	1.4953
68	Union NCDA	TransGas SSDA	-	1.2735
69	Union NCDA	Centram SSDA	-	1.1826
70	Union NCDA	Centram MDA	-	1.0459
71	Union NCDA	Centrat MDA	-	0.9828
72	Union NCDA	Union WDA	-	0.7459
73	Union NCDA	Nipigon WDA	-	0.6486

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/MO)	Daily Equivalent FT for IT / STFT ($/GJ)
1	Union Parkway Belt	Calstock NDA	17.44683	0.5736
2	Union Parkway Belt	Tunis NDA	13.39663	0.4404
3	Union Parkway Belt	GMIT NDA	10.38681	0.3415
4	Union Parkway Belt	Union SSMDA	15.59391	0.5127
5	Union Parkway Belt	Union NCDA	5.46310	0.1796
6	Union Parkway Belt	Union CDA	3.06658	0.1008
7	Union Parkway Belt	Enbridge CDA	3.78609	0.1245
8	Union Parkway Belt	Union EDA	7.61793	0.2505
9	Union Parkway Belt	Enbridge EDA	9.75548	0.3207
10	Union Parkway Belt	GMIT EDA	12.52810	0.4119
11	Union Parkway Belt	KPUC EDA	7.32723	0.2409
12	Union Parkway Belt	North Bay Junction	8.19155	0.2693
13	Union Parkway Belt	Kirkwall	3.19458	0.1050
14	Union Parkway Belt	Enbridge SWDA	6.12912	0.2015
15	Union Parkway Belt	Union SWDA	6.18511	0.2034
16	Union Parkway Belt	Spruce	32.75736	1.0770
17	Union Parkway Belt	Emerson 1	30.86011	1.0146
18	Union Parkway Belt	Emerson 2	30.86011	1.0146
19	Union Parkway Belt	St. Clair	6.49976	0.2137
20	Union Parkway Belt	Dawn Export	6.12912	0.2015
21	Union Parkway Belt	Niagara Falls	4.66442	0.1534
22	Union Parkway Belt	Chippawa	4.70159	0.1546
23	Union Parkway Belt	Iroquois	9.24034	0.3038
24	Union Parkway Belt	Cornwall	9.89920	0.3255
25	Union Parkway Belt	Napierville	12.28888	0.4040
26	Union Parkway Belt	Philipsburg	12.56045	0.4130
27	Union Parkway Belt	East Hereford	15.43962	0.5076
28	Union Parkway Belt	Welwyn	37.26438	1.2251
29	Union SSMDA	Empress	-	1.1945
30	Union SSMDA	TransGas SSDA	-	0.9726
31	Union SSMDA	Centram SSDA	-	0.8817
32	Union SSMDA	Centram MDA	-	0.7442
33	Union SSMDA	Centrat MDA	-	0.7438
34	Union SSMDA	Union WDA	-	1.0008
35	Union SSMDA	Nipigon WDA	-	1.0780
36	Union SSMDA	Union NDA	-	0.7852
37	Union SSMDA	Calstock NDA	-	1.0008
38	Union SSMDA	Tunis NDA	-	0.8676
39	Union SSMDA	GMIT NDA	-	0.7687
40	Union SSMDA	Union SSMDA	-	0.0855
41	Union SSMDA	Union NCDA	-	0.6068
42	Union SSMDA	Union CDA	-	0.5153
43	Union SSMDA	Enbridge CDA	-	0.5467
44	Union SSMDA	Union EDA	-	0.6776
45	Union SSMDA	Enbridge EDA	-	0.7479
46	Union SSMDA	GMIT EDA	-	0.8391
47	Union SSMDA	KPUC EDA	-	0.6681
48	Union SSMDA	North Bay Junction	-	0.6965
49	Union SSMDA	Kirkwall	-	0.4931
50	Union SSMDA	Enbridge SWDA	-	0.3967
51	Union SSMDA	Union SWDA	-	0.3948
52	Union SSMDA	Spruce	-	0.7438
53	Union SSMDA	Emerson 1	-	0.6712
54	Union SSMDA	Emerson 2	-	0.6712
55	Union SSMDA	St. Clair	-	0.3845
56	Union SSMDA	Dawn Export	-	0.3967
57	Union SSMDA	Niagara Falls	-	0.5501
58	Union SSMDA	Chippawa	-	0.5513
59	Union SSMDA	Iroquois	-	0.7310
60	Union SSMDA	Cornwall	-	0.7526
61	Union SSMDA	Napierville	-	0.8312
62	Union SSMDA	Philipsburg	-	0.8401
63	Union SSMDA	East Hereford	-	0.9348
64	Union SSMDA	Welwyn	-	0.8817
65	Union WDA	Empress	-	0.8562
66	Union WDA	TransGas SSDA	-	0.6343
67	Union WDA	Centram SSDA	-	0.5434
68	Union WDA	Centram MDA	-	0.4067
69	Union WDA	Centrat MDA	-	0.3437
70	Union WDA	Union WDA	-	0.0855
71	Union WDA	Nipigon WDA	-	0.1864
72	Union WDA	Union NDA	-	0.5674
73	Union WDA	Calstock NDA	-	0.3519

Mainline Transportation Tolls
Effective January 1, 2015 through December 31, 2020

Storage Transportation Service

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
1	Centram MDA	5.39470	0.17736
2	Union WDA	38.93577	1.28008
3	Union NDA	16.59381	0.54555
4	Union EDA	11.60883	0.38166
5	KPUC EDA	11.16596	0.36710
6	GMIT EDA	19.09133	0.62766
7	Enbridge CDA	5.76943	0.18968
8	Enbridge CDA (Amended)	5.93916	0.19526
9	Enbridge EDA	14.86645	0.48876
10	Cornwall	15.08515	0.49595
11	Philipsburg	19.14090	0.62929

Firm Transportation - Short Notice

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
12	Kirkwall to Thorold CDA	6.84345	0.22499
13	Union Parkway Belt to Goreway CDA	5.09510	0.16751
14	Union Parkway Belt to Victoria Square #2 CDA	6.01733	0.19783
15	Union Parkway Belt to Schomberg #2 CDA	5.95710	0.19585

Enhanced Market Balancing Service

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
16	Union Parkway Belt to Union EDA	12.76983	0.41983

Delivery Pressure

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
17	Average Delivery Pressure Toll	0.93744	0.03082

Note: Delivery Pressure toll applies to the following locations: Emerson 1 , Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford.
The Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions, STFT and SSS.

Union Dawn Receipt Point Surcharge

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
18	Union Dawn Receipt Point Surcharge	0.18079	0.00594

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
19	SNB Toll	3.75220	0.12336

Note: This SNB Toll is a representative toll for the Eastern Region.

Energy Deficient Gas Allowance (EDGA) Service

Line No	Particulars	Capacity Charge ($/GJ/D)
	(a)	(b)
20	Western Section	1.57224
21	Eastern Section	0.41040

Note: The EDGA Service capacity charge for the Western Section is the effective Empress to North Bay Junction FT Toll and the capacity charge for the Eastern Section is the effective Parkway to North Bay Junction FT Toll.
The EDGA Service fuel charge for the Western Section includes the effective Empress to North Bay Junction monthly fuel ratio and the fuel charge for the Eastern Section includes the effective Parkway to North Bay Junction monthly fuel ratio.

Enhanced Capacity Release (ECR) Service

Line No	Particulars	Toll ($/GJ/D)
	(a)	(b)
22	ECR Surcharge	0.10106

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/MO)	Daily Equivalent FT for IT / STFT ($/GJ)
1	Union ECDA	Spruce	-	1.6501
2	Union ECDA	St. Clair	-	0.3346
3	Union ECDA	Welwyn	-	1.8759
4	Union ECDA	Dawn Export	-	0.3161
5	Union ECDA	Union Parkway Belt	-	0.1393
6	Union ECDA	Union CDA (Amended)	-	0.1719
7	Union ECDA	Union ECDA	-	0.1303
8	Union ECDA	Enbridge Parkway CDA	-	0.1393
9	Union ECDA	Enbridge CDA (Amended)	-	0.2009
10	Union Dawn	Empress	65.90470	2.1667
11	Union Dawn	TransGas SSDA	55.62205	1.8287
12	Union Dawn	Centram SSDA	51.40903	1.6902
13	Union Dawn	Centram MDA	45.03613	1.4806
14	Union Dawn	Centrat MDA	45.01332	1.4799
15	Union Dawn	Union WDA	43.98311	1.4460
16	Union Dawn	Nipigon WDA	39.80386	1.3086
17	Union Dawn	Union NDA	21.97209	0.7224
18	Union Dawn	Calstock NDA	31.96457	1.0509
19	Union Dawn	Tunis NDA	25.79242	0.8480
20	Union Dawn	GMIT NDA	21.20620	0.6972
21	Union Dawn	Union SSMDA	18.38596	0.6045
22	Union Dawn	Union NCDA	13.70301	0.4505
23	Union Dawn	Union CDA	9.46323	0.3111
24	Union Dawn	Enbridge CDA	10.91806	0.3590
25	Union Dawn	Union EDA	16.98558	0.5584
26	Union Dawn	Enbridge EDA	20.24351	0.6655
27	Union Dawn	KPUC EDA	16.54332	0.5439
28	Union Dawn	GMIT EDA	24.46899	0.8045
29	Union Dawn	Enbridge SWDA	3.96268	0.1303
30	Union Dawn	Union SWDA	4.04755	0.1331
31	Union Dawn	Chippawa	11.13098	0.3660
32	Union Dawn	Cornwall	20.46281	0.6728
33	Union Dawn	East Hereford	$\boxed{28.90587}$	0.9503
34	Union Dawn	Emerson 1	41.64985	1.3693
35	Union Dawn	Emerson 2	41.64985	1.3693
36	Union Dawn	Iroquois	19.45876	0.6397
37	Union Dawn	Kirkwall	8.43454	0.2773
38	Union Dawn	Napierville	24.10430	0.7925
39	Union Dawn	Niagara Falls	11.07440	0.3641
40	Union Dawn	North Bay Junction	17.86067	0.5872
41	Union Dawn	Philipsburg	24.51827	0.8061
42	Union Dawn	Spruce	45.01332	1.4799
43	Union Dawn	St. Clair	4.52722	0.1488
44	Union Dawn	Welwyn	51.40903	1.6902
45	Union Dawn	Dawn Export	3.96268	0.1303
46	Union Dawn	Union Parkway Belt	9.34035	0.3071
47	Union Dawn	Union CDA (Amended)	9.21230	0.3029
48	Union Dawn	Union ECDA	9.61319	0.3161
49	Union Dawn	Enbridge Parkway CDA	9.34035	0.3071
50	Union Dawn	Enbridge CDA (Amended)	11.06558	0.3638
51	Union EDA	Empress	-	2.5151
52	Union EDA	TransGas SSDA	-	2.1770
53	Union EDA	Centram SSDA	-	2.0385
54	Union EDA	Centram MDA	-	1.8291
55	Union EDA	Centrat MDA	-	1.7369
56	Union EDA	Union WDA	-	1.3757
57	Union EDA	Nipigon WDA	-	1.2276
58	Union EDA	Union NDA	-	0.6413
59	Union EDA	Calstock NDA	-	0.9698
60	Union EDA	Tunis NDA	-	0.7669
61	Union EDA	GMIT NDA	-	0.6161
62	Union EDA	Union SSMDA	-	1.0326
63	Union EDA	Union NCDA	-	0.4492
64	Union EDA	Union CDA	-	0.4050

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/MO)	Daily Equivalent FT for IT / STFT ($/GJ)
1	Union Parkway Belt	Enbridge SWDA	9.34035	0.3071
2	Union Parkway Belt	Union SWDA	9.42552	0.3099
3	Union Parkway Belt	Chippawa	7.16465	0.2356
4	Union Parkway Belt	Cornwall	15.08515	0.4960
5	Union Parkway Belt	East Hereford	23.52820	0.7735
6	Union Parkway Belt	Emerson 1	47.02751	1.5461
7	Union Parkway Belt	Emerson 2	47.02751	1.5461
8	Union Parkway Belt	Iroquois	14.08109	0.4629
9	Union Parkway Belt	Kirkwall	4.86819	0.1601
10	Union Parkway Belt	Napierville	18.72693	0.6157
11	Union Parkway Belt	Niagara Falls	7.10807	0.2337
12	Union Parkway Belt	North Bay Junction	12.48300	0.4104
13	Union Parkway Belt	Philipsburg	19.14090	0.6293
14	Union Parkway Belt	Spruce	49.91831	1.6412
15	Union Parkway Belt	St. Clair	9.90488	0.3256
16	Union Parkway Belt	Welwyn	56.78670	1.8670
17	Union Parkway Belt	Dawn Export	9.34035	0.3071
18	Union Parkway Belt	Union Parkway Belt	3.96268	0.1303
19	Union Parkway Belt	Union CDA (Amended)	5.40869	0.1778
20	Union Parkway Belt	Union ECDA	4.23552	0.1393
21	Union Parkway Belt	Enbridge Parkway CDA	3.96268	0.1303
22	Union Parkway Belt	Enbridge CDA (Amended)	5.93916	0.1953
23	Union SSMDA	Empress	-	1.3361
24	Union SSMDA	TransGas SSDA	-	1.0879
25	Union SSMDA	Centram SSDA	-	0.9863
26	Union SSMDA	Centram MDA	-	0.8325
27	Union SSMDA	Centrat MDA	-	0.8319
28	Union SSMDA	Union WDA	-	1.1194
29	Union SSMDA	Nipigon WDA	-	1.2058
30	Union SSMDA	Union NDA	-	0.8783
31	Union SSMDA	Calstock NDA	-	1.1194
32	Union SSMDA	Tunis NDA	-	0.9705
33	Union SSMDA	GMIT NDA	-	0.8598
34	Union SSMDA	Union SSMDA	-	0.0956
35	Union SSMDA	Union NCDA	-	0.7173
36	Union SSMDA	Union CDA	-	0.6092
37	Union SSMDA	Enbridge CDA	-	0.6463
38	Union SSMDA	Union EDA	-	0.8011
39	Union SSMDA	Enbridge EDA	-	0.8842
40	Union SSMDA	KPUC EDA	-	0.7898
41	Union SSMDA	GMIT EDA	-	0.9919
42	Union SSMDA	Enbridge SWDA	-	0.4689
43	Union SSMDA	Union SWDA	-	0.4667
44	Union SSMDA	Chippawa	-	0.6517
45	Union SSMDA	Cornwall	-	0.8898
46	Union SSMDA	East Hereford	-	1.1051
47	Union SSMDA	Emerson 1	-	0.7508
48	Union SSMDA	Emerson 2	-	0.7508
49	Union SSMDA	Iroquois	-	0.8641
50	Union SSMDA	Kirkwall	-	0.5830
51	Union SSMDA	Napierville	-	0.9826
52	Union SSMDA	Niagara Falls	-	0.6503
53	Union SSMDA	North Bay Junction	-	0.7791
54	Union SSMDA	Philipsburg	-	0.9932
55	Union SSMDA	Spruce	-	0.8319
56	Union SSMDA	St. Clair	-	0.4300
57	Union SSMDA	Welwyn	-	0.9863
58	Union SSMDA	Dawn Export	-	0.4689
59	Union SSMDA	Union Parkway Belt	-	0.6061
60	Union SSMDA	Union CDA (Amended)	-	0.6028
61	Union SSMDA	Union ECDA	-	0.6130
62	Union SSMDA	Enbridge Parkway CDA	-	0.6061
63	Union SSMDA	Enbridge CDA (Amended)	-	0.6500
64	Union WDA	Empress	-	0.9577

unionGas

TRANSPORTATION RATES

(A) Applicability

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

Applicable Points

Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).

Dawn as a delivery point: Dawn (Facilities).

(B) Services

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

(C) Rates

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

	Monthly Demand Charge (applied to daily contract demand) Rate/GJ	Commodity and Fuel Charges: Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1)				
Dawn to Parkway	$\boxed{\$2.382}$	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$2.011			
Kirkwall to Parkway	$0.372			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$2.961	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$5.718	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$5.718			
Parkway (TCPL) to Parkway (Cons) (2)		0.153%		

Authorized Overrun (3)

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

Transportation Overrun	If Union supplies fuel Commodity Charge Rate/GJ	Commodity and Fuel Charges: Fuel Ratio %	AND	Commodity Charge Rate/GJ
Dawn to Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.078
Dawn to Kirkwall				$0.066
Kirkwall to Parkway				$0.012
Parkway to Dawn				$0.078
Parkway (TCPL) Overrun (4)	n/a	0.648%		n/a
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.097

Schedule "C"

UNION GAS LIMITED
M12 Monthly Transportation Fuel Ratios and Rates
Firm or Interruptible Transportation Commodity
Effective April 1, 2014

Month	VT1 Easterly Dawn to Parkway (TCPL) With Dawn Compression Fuel Ratio (%)	VT1 Easterly Dawn to Parkway (TCPL) With Dawn Compression Fuel Rate ($/GJ)	VT1 Easterly Dawn to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression Fuel Ratio (%)	VT1 Easterly Dawn to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression Fuel Rate ($/GJ)	VT3 Westerly Parkway to Kirkwall, Dawn Fuel Ratio (%)	VT3 Westerly Parkway to Kirkwall, Dawn Fuel Rate ($/GJ)
April	0.802	0.050	0.533	0.033	0.153	0.009
May	0.567	0.035	0.359	0.022	0.153	0.009
June	0.463	0.029	0.260	0.016	0.357	0.022
July	0.451	0.028	0.248	0.015	0.356	0.022
August	0.355	0.022	0.154	0.010	0.354	0.022
September	0.352	0.022	0.154	0.009	0.351	0.022
October	0.697	0.043	0.463	0.029	0.153	0.009
November	0.840	0.052	0.603	0.037	0.153	0.009
December	0.945	0.058	0.702	0.043	0.153	0.009
January	1.086	0.067	0.831	0.051	0.153	0.009
February	1.033	0.064	0.786	0.048	0.153	0.009
March	0.972	0.060	0.719	0.044	0.153	0.009

Winter Average = 0.98%
Summer Average = 0.53%

Month	M12-X Easterly Kirkwall to Parkway (TCPL) Fuel Ratio (%)	M12-X Easterly Kirkwall to Parkway (TCPL) Fuel Rate ($/GJ)	M12-X Easterly Kirkwall to Lisgar, Parkway (Consumers) Fuel Ratio (%)	M12-X Easterly Kirkwall to Lisgar, Parkway (Consumers) Fuel Rate ($/GJ)	M12-X Westerly Parkway to Kirkwall, Dawn Fuel Ratio (%)	M12-X Westerly Parkway to Kirkwall, Dawn Fuel Rate ($/GJ)
April	0.422	0.026	0.153	0.009	0.268	0.017
May	0.361	0.022	0.153	0.009	0.268	0.017
June	0.357	0.022	0.153	0.009	0.268	0.017
July	0.356	0.022	0.153	0.009	0.268	0.017
August	0.354	0.022	0.153	0.009	0.268	0.017
September	0.351	0.022	0.153	0.009	0.268	0.017
October	0.387	0.024	0.153	0.009	0.268	0.017
November	0.389	0.024	0.153	0.009	0.153	0.009
December	0.396	0.024	0.153	0.009	0.153	0.009
January	0.408	0.025	0.153	0.009	0.153	0.009
February	0.400	0.025	0.153	0.009	0.153	0.009
March	0.406	0.025	0.153	0.009	0.153	0.009

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

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

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

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1

Recourse Rates:

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

Negotiated Rates:

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

Rate Schedule FT-L

Recourse Rates:

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

Negotiated Rates:

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

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

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

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

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s):

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

8. Primary Delivery Point(s):

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

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: D T

Name: DON TUCHFNSKY

Title: ANALYST

Telephone: (508) 836-7259

Fax: ( ) 508 - 870 - 2294

CAPACITY RELEASE TRANSACTIONS
CONFIRMATION LETTER

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

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

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

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

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

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

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

   Washington 10 Interconnect **17,086**

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

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

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DTC

Name: DON JULCHINSKY

Title: ANALYST

Telephone: (___) 508-836 7257

Fax: (___) 508-870-2294

Historic TransCanada Fuel Loss Percentages

	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Winter Fuel Average	Summer Fuel Average	Last 12 Months
Union Parkway Belt - Iroquois	0.92%	0.20%	0.25%	0.19%	0.61%	0.38%	1.18%	0.88%	1.69%	1.35%	0.84%	0.72%	1.10%	0.53%	0.77%
Union Dawn - East Hereford	0.65%	0.66%	0.46%	0.24%	1.00%	1.13%	2.20%	2.11%	2.96%	2.35%	1.85%	1.64%	2.15%	0.93%	1.44%

Historic Fuel Retention Ratios

Pipeline	Receipt	Delivery	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Winter	Summer	Average
Vector	Alliance	W-10	1.05%	1.20%	1.65%	1.41%	1.47%	1.51%	0.90%	1.08%	0.44%	0.45%	0.89%	0.75%	0.88%	1.20%	1.07%
Vector	Alliance	Dawn	1.05%	1.20%	1.65%	1.41%	1.47%	1.51%	0.90%	1.08%	0.44%	0.45%	0.89%	0.75%	0.88%	1.20%	1.07%
Vector	W-10 Storage	Dawn	0.40%	0.40%	0.55%	0.47%	0.49%	0.55%	0.34%	0.47%	0.15%	0.15%	0.30%	0.25%	0.33%	0.41%	0.38%

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

SHIPPER:

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

INVOICES, STATEMENTS AND NOMINATIONS

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

ALL OTHER MATTERS

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

ARTICLE VIII: FURTHER AGREEMENT

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

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

EXHIBIT I

Rates:

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

Service Parameters:

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

Maximum Daily Injection Quantity (MDIQ):

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

Maximum Daily Withdrawal Quantity (MDWQ):

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

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

DTE Energy

Gas Midstream Services

DTE Gas Storage - Non-Critical Notices

Injection Overrun Availability (April 21, 2014)

As with most storage operators in the region, Washington 10 sits at record low inventory coming out of this winter.

More

Long Term Gas Storage Open Season (April 14, 2014)

DTE Gas Storage is conducting an open season for storage services at its Washington 10 facility...

More

Fuel Rates Effective April 1, 2014 (March 19, 2014)

The fuel rate for injections will be reduced from 1.1% to 0.90% for the upcoming injection season beginning April 1, 2014.

The fuel rates for Withdrawals and Wheels-from-Hub will remain unchanged.

Injections: 0.90%
Withdrawals: 0.3%
Wheel-from-hub to DTEGas 0.0%
Wheel-from-hub to Vector 0.5%

As always, we welcome your feedback. Please contact us with your questions or concerns.

Steve Richman (313.235.4275)
Mike Romain (313.235.4213)
Sandy Schmidt (313.235.1148)

Less

Personnel Changes (February 14, 2014)

Mark Bering, Director, Marketing & Optimization has taken a new position as Vice President of Business Development at Millennium Pipeline in Pearl River, New York.

More

New Staff Member Announced (December 20, 2013)

We are pleased to introduce Arlyn Batchelder as Contract & Gas Management Specialist...

More

Instant Messaging Roll Out (December 20, 2013)

You asked for it! Thanks to your responses to our recent customer survey, we are in the process of making some improvements in a number of areas.

More

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2013 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 27, 2013

The annual charges unit charge to be applied to rates in 2013 for recovery of 2012 debit/credit and 2013 current year annual charges is **$0.0012** per Dth. In accordance with 18 CFR § 154.402(a), to recover from its customers the annual charges assessed by the Commission each fiscal year, a natural gas pipeline company must file an annual charge adjustment clause with the Commission to adjust its rates. If you need to correct your ACA surcharge, your tariff filing should reflect a unit charge of **$0.0012** per Dth, as it has been adjusted to include last year's debit/credit factor.

The following calculations were used to determine the 2012 unit charge:

2013 CURRENT:

Estimated Program Cost $59,963,000 divided by 41,997,033,981 Dth	=	0.0014277913

2012 TRUE-UP:

Debit/Credit Cost ($10,060,368) divided by 40,330,657,018 Dth	=	(0.0002494472)
TOTAL UNIT CHARGE	=	0.0011783441

If you have any questions, please contact Norman Richardson at (202)502-6219 or e-mail at Norman.Richardson@ferc.gov.

Schedules 6A and 6B

REDACTED

Denotes Confidential Information

Northern Utilities, Inc.
Commodity Cost by Supply Source
November 2014 through April 2015

Description	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Season
Pipeline Supplies							
Tenn Zone 4 Spot	[redacted]						
Tennessee Production							
Chicago							
Algonquin Receipts							
TGP Zone 6							
Niagara							
Iroquois Receipts							
PNGTS Receipts							
PNGTS Delivered							
Maritimes Delivered							
Total Pipeline	$ 7,849,451	$ 8,328,547	$ 8,665,304	$ 7,626,325	$ 8,186,257	$ 2,531,737	$ 43,187,621
Company Managed Pipeline	$ (73,529)	$ (87,335)	$ (101,497)	$ (87,647)	$ (81,158)	$ -	$ (431,166)
Net Pipeline	$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 42,756,455
Underground Storage							
Tennessee Storage	$ -	$ 203,534	$ 277,139	$ 250,319	$ 148,806	$ -	$ 879,798
Washington 10 Storage	$ 234,501	$ 2,205,041	$ 3,378,553	$ 2,807,049	$ 937,352	$ -	$ 9,562,497
Total Storage	$ 234,501	$ 2,408,575	$ 3,655,692	$ 3,057,368	$ 1,086,158	$ -	$ 10,442,295
Company Managed Storage	$ (282,197)	$ (1,007,848)	$ (1,209,417)	$ (1,007,848)	$ (524,081)	$ -	$ (4,031,390)
Net Storage	$ (47,696)	$ 1,400,728	$ 2,446,275	$ 2,049,521	$ 562,078	$ -	$ 6,410,905
Peaking Supplies							
Peaking Contract 1	[redacted]						
Peaking Contract 2							
LNG							
Total Peaking	$ 59,171	$ 28,114	$ 4,244,360	$ 2,539,665	$ 607,106	$ 29,848	$ 7,508,263
Company Managed Peaking	$ -	$ -	$ (2,001,968)	$ (1,578,395)	$ -	$ -	$ (3,580,363)
Net Peaking	$ 59,171	$ 28,114	$ 2,242,392	$ 961,270	$ 607,106	$ 29,848	$ 3,927,900
Total NUI Commodity	$ 8,143,123	$ 10,765,236	$ 16,565,356	$ 13,223,358	$ 9,879,521	$ 2,561,584	$ 61,138,179
Company-Managed (NH & ME)	$ (355,726)	$ (1,095,182)	$ (3,312,881)	$ (2,673,890)	$ (605,239)	$ -	$ (8,042,918)
Sales Service (NH & ME)	$ 7,787,397	$ 9,670,054	$ 13,252,475	$ 10,549,469	$ 9,274,282	$ 2,561,584	$ 53,095,261
Sales Service Commodity	$ 7,787,397	$ 9,670,054	$ 13,252,475	$ 10,549,469	$ 9,274,282	$ 2,561,584	$ 53,095,261
Off-System Sales	$ (299,837)	$ -	$ -	$ -	$ (545,071)	$ -	$ (844,908)
Net Sales Service	$ 7,487,560	$ 9,670,054	$ 13,252,475	$ 10,549,469	$ 8,729,211	$ 2,561,584	$ 52,250,353

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2014 through April 2015

Description	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Season
Pipeline Supplies							
Tenn Zone 4 Spot	18,407	20,084	0	0	512	73,181	112,183
Tennessee Production	147,397	152,311	186,159	137,571	152,311	328,437	1,104,186
Chicago	174,521	180,219	180,219	162,779	180,219	40,611	918,569
Algonquin Receipts	37,530	38,781	38,781	35,028	38,781	16,873	205,774
TGP Zone 6	0	0	0	0	0	42,785	42,785
Niagara	63,655	65,777	65,777	59,411	65,777	63,655	384,052
Iroquois Receipts	18,410	19,143	19,143	17,291	19,143	0	93,130
PNGTS Receipts	23,916	24,713	24,713	22,322	24,713	19,146	139,523
PNGTS Delivered	224,213	231,686	231,686	209,265	231,686	0	1,128,536
Maritimes Delivered	225,000	232,500	232,500	210,000	232,500	43,400	1,175,900
Total Pipeline	933,049	965,214	978,979	853,666	945,643	628,089	5,304,639
Company Managed Pipeline	-17,010	-17,577	-17,577	-15,876	-17,577	0	-85,617
Net Pipeline	916,039	947,637	961,402	837,790	928,066	628,089	5,219,022
Underground Storage							
Tennessee Storage	0	55,536	75,620	68,302	40,603	0	240,061
Washington 10 Storage	50,470	474,576	727,143	604,142	201,740	0	2,058,071
Total Storage	50,470	530,112	802,763	672,444	242,343	0	2,298,132
Company Managed Storage	-58,940	-210,500	-252,600	-210,500	-109,460	0	-842,000
Net Storage	-8,470	319,612	550,163	461,944	132,883	0	1,456,132
Peaking Supplies							
Peaking Contract 1	0	0	3,410	0	0	0	3,410
Peaking Contract 2	0	0	176,244	102,776	19,930	0	298,950
LNG	7,252	2,781	21,196	16,692	12,100	2,100	62,120
Total Peaking	7,252	2,781	200,849	119,468	32,030	2,100	364,480
Company Managed Peaking	0	0	-94,591	-74,126	0	0	-168,717
Net Peaking	7,252	2,781	106,258	45,342	32,030	2,100	195,763
Total NUI Commodity	990,771	1,498,107	1,982,591	1,645,578	1,220,016	630,189	7,967,251
Company-Managed (NH & ME)	-75,950	-228,077	-364,768	-300,502	-127,037	0	-1,096,334
Sales Service (NH & ME)	914,821	1,270,030	1,617,823	1,345,076	1,092,979	630,189	6,870,917
Sales Service Commodity	914,821	1,270,030	1,617,823	1,345,076	1,092,979	630,189	6,870,917
Off-System Sales	50,708	0	0	0	55,259	0	105,967
Net Sales Service	864,113	1,270,030	1,617,823	1,345,076	1,037,720	630,189	6,764,951

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Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2014 through April 2015

Description	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Season
Pipeline Supplies							
Tenn Zone 4 Spot	[redacted]						
Tennessee Production							
Chicago							
Algonquin Receipts							
TGP Zone 6							
Niagara							
Iroquois Receipts							
PNGTS Receipts							
PNGTS Delivered							
Maritimes Delivered							
Total Pipeline	$ 8.413	$ 8.629	$ 8.851	$ 8.934	$ 8.657	$ 4.031	$ 8.141
Company Managed Pipeline	$ 4.323	$ 4.969	$ 5.774	$ 5.521	$ 4.617		$ 5.036
Net Pipeline	$ 8.489	$ 8.697	$ 8.908	$ 8.998	$ 8.733	$ 4.031	$ 8.192
Underground Storage							
Tennessee Storage		$ 3.665	$ 3.665	$ 3.665	$ 3.665		$ 3.665
Washington 10 Storage	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646		$ 4.646
Total Storage	$ 4.646	$ 4.544	$ 4.554	$ 4.547	$ 4.482		$ 4.544
Company Managed Storage	$ 4.788	$ 4.788	$ 4.788	$ 4.788	$ 4.788		$ 4.788
Net Storage	$ 5.631	$ 4.383	$ 4.446	$ 4.437	$ 4.230		$ 4.403
Peaking Supplies							
Peaking Contract 1	[redacted]						
Peaking Contract 2							
LNG							
Total Peaking	$ 8.160	$ 10.110	$ 21.132	$ 21.258	$ 18.954	$ 14.213	$ 20.600
Company Managed Peaking			$ 21.164	$ 21.293			$ 21.221
Net Peaking	$ 8.160	$ 10.110	$ 21.103	$ 21.200	$ 18.954	$ 14.213	$ 20.065
Total NUI Commodity	$ 8.219	$ 7.186	$ 8.355	$ 8.036	$ 8.098	$ 4.065	$ 7.674
Company-Managed (NH & ME)	$ 4.684	$ 4.802	$ 9.082	$ 8.898	$ 4.764		$ 7.336
Sales Service (NH & ME)	$ 8.512	$ 7.614	$ 8.192	$ 7.843	$ 8.485	$ 4.065	$ 7.728
Sales Service Commodity	$ 8.512	$ 7.614	$ 8.192	$ 7.843	$ 8.485	$ 4.065	$ 7.728
Off-System Sales	$ (5.913)				$ (9.864)		$ (7.973)
Net Sales Service	$ 8.665	$ 7.614	$ 8.192	$ 7.843	$ 8.412	$ 4.065	$ 7.724

REDACTED

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	18,732	20,438	-	-	521	74,473	114,164
2	City Gate Delivered Volume	Line 37	18,407	20,084	-	-	512	73,181	112,183
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Sum Lines 29 and 39	$ 2,128	$ 2,322	$ -	$ -	$ 59	$ 8,460	$ 12,968
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]						
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	18,732	20,438	-	-	521	74,473	114,164
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 3.856
11	NYMEX Cost	Line 9 times Line 10	$ 73,765	$ 82,121	$ -	$ -	$ 2,090	$ 282,252	$ 440,229
12	NYMEX Basis Price	Att to Sch 5A, Line 10 of Page 1	[redacted]						
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]						
14	Total Purchase Price	Line 10 plus Line 12	[redacted]						
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]						
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 2								
19	Tennessee Gas Pipeline (Contract 5265)								
20	Receipt Point: Tennessee FS-MA 300 Leg								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Total Contract Recevied Volume	Sendout Optimization	18,732	76,955	76,955	69,508	41,842	74,473	358,465
23	Received Volume	Line 14	18,732	20,438	-	-	521	74,473	114,164
24	Percentage Allocated	Line 23 divided by Line 22	100.00%	26.56%	0.00%	0.00%	1.25%	100.00%	31.85%
25	Received Volume	Line 9	18,732	20,438	-	-	521	74,473	114,164
26	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.39%	1.39%			1.39%	1.39%	1.39%
27	Delivered Volume	Line 25 times (1 - Line 26)	18,471	20,154	-	-	514	73,438	112,577
28	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1140	$ 0.1140			$ 0.1140	$ 0.1140	$ 0.1140
29	Variable Transportation Costs	Line 27 times Line 28	$ 2,106	$ 2,298	$ -	$ -	$ 59	$ 8,372	$ 12,834
30									
31	Transportation Segment 3								
32	Granite State Gas Transmission (Contract 14-001-FT-NN)								
33	Receipt Point: Pleasant St.								
34	Delivery Point: Northern City Gates								
35	Received Volume	Line 27	18,471	20,154	-	-	514	73,438	112,577
36	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%
37	City Gate Delivered Volume	Line 35 times (1 - Line 36)	18,407	20,084	-	-	512	73,181	112,183
38	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
39	Variable Transportation Costs	Line 37 times Line 38	$ 22	$ 24	$ -	$ -	$ 1	$ 88	$ 135

REDACTED

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
2	City Gate Volumes - Z0	Line 2 of Page 5	-	-	-	-	-	-	-
3	City Gate Volumes - Z1	Line 2 of Page 6	-	-	33,849	-	-	187,599	221,448
4	City Gate Volumes - Z4	Line 2 of Page 7	147,397	152,311	152,311	137,571	152,311	140,838	882,738
5	Total City Gate Volumes	Sum Lines 1 through 3	147,397	152,311	186,159	137,571	152,311	328,437	1,104,186
6	City Gate Delivered Costs - Z0	Line 6 of Page 5	[redacted]						
7	City Gate Delivered Costs - Z1	Line 6 of Page 6	[redacted]						
8	City Gate Delivered Costs - Z4	Line 5 of Page 7	[redacted]						
9	Total City Gate Delivered Costs	Sum Lines 5 through 7	[redacted]						
10	Average Delivered Price	Line 8 divided by Line 4	[redacted]						

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	150,000	155,000	155,000	140,000	155,000	143,325	898,325
2	City Gate Delivered Volume	Line 34	147,397	152,311	152,311	137,571	152,311	140,838	882,738
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 17,039	$ 17,607	$ 17,607	$ 15,903	$ 17,607	$ 16,281	$ 102,045
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Tennessee Zone 4 Supply Costs								
9	Purchased Volumes	Sendout Optimization	150,000	155,000	155,000	140,000	155,000	143,325	898,325
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 3.989
11	NYMEX Cost	Line 9 times Line 10	$ 590,700	$ 622,790	$ 634,260	$ 570,920	$ 621,395	$ 543,201	$ 3,583,266
12	NYMEX Basis Price	Att to Sch 5A, Line 9 of Page 1	[redacted]						
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 2								
19	Tennessee Gas Pipeline (Contract 5083)								
20	Receipt Point: Tennessee Zone 4 200 Leg Pool								
21	Delivery Point: Pleasant St. (Interconnection with Granite)								
22	Received Volume	Line 15	150,000	155,000	155,000	140,000	155,000	143,325	898,325
23	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%
24	Delivered Volume	Line 22 times (1 - Line 23)	147,915	152,846	152,846	138,054	152,846	141,333	885,838
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140
26	Variable Transportation Costs	Line 24 times Line 25	$ 16,862	$ 17,424	$ 17,424	$ 15,738	$ 17,424	$ 16,112	$ 100,986
27									
28	Transportation Segment 3								
29	Granite State Gas Transmission (Contract 14-001-FT-NN)								
30	Receipt Point: Pleasant St.								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	147,915	152,846	152,846	138,054	152,846	141,333	885,838
33	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
34	City Gate Delivered Volume	Line 32 times (1 - Line 33)	147,397	152,311	152,311	137,571	152,311	140,838	882,738
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
36	Variable Transportation Costs	Line 34 times Line 35	$ 177	$ 183	$ 183	$ 165	$ 183	$ 169	$ 1,059

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 23	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 35	-	-	-	-	-	-	-
3	Total Purchase Price	Line 15	[redacted]						
4	Total Purchase Cost	Line 2 times Line 3							
5	Variable Transportation Costs	Sum Lines 27 and 37	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	[redacted]						
7	Average Delivered Price	Line 6 divided by Line 2							
8									
9	Tennessee Zone 0 Supply Costs								
10	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-
11	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Price	Att to Sch 5A, Line 7 of Page 1	[redacted]						
14	NYMEX Basis Costs	Line 9 times Line 12							
15	Total Purchase Price	Line 10 plus Line 12							
16	Total Purchase Cost	Line 11 plus Line 13							
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1A								
20	Tennessee Gas Pipeline (Contract 5083)								
21	Receipt Point: Tennessee Zone 0								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 10	-	-	-	-	-	-	-
24	Fuel Loss Rate	Att to Sch 5A, Line 43 of Page 2							
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	-	-	-	-	-
26	Variable Transportation Rate	Att to Sch 5A, Line 26 of Page 2							
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28									
29	Transportation Segment 2A								
30	Granite State Gas Transmission (Contract 14-001-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	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 23	-	-	35,405	-	-	196,225	231,630
2	City Gate Delivered Volume	Line 35	-	-	33,849	-	-	187,599	221,448
3	Total Purchase Price	Line 15	[redacted]						
4	Total Purchase Cost	Line 2 times Line 3							
5	Variable Transportation Costs	Sum Lines 27 and 37	$ -	$ -	$ 9,983	$ -	$ -	$ 55,328	$ 65,311
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	[redacted]						
7	Average Delivered Price	Line 6 divided by Line 2							
8									
9	Tennessee Zone L Supply Costs								
10	Purchased Volumes	Sendout Optimization	-	-	35,405	-	-	196,225	231,630
11	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 3.836
12	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ 144,877	$ -	$ -	$ 743,693	$ 888,569
13	NYMEX Basis Price	Att to Sch 5A, Line 8 of Page 1	[redacted]						
14	NYMEX Basis Costs	Line 9 times Line 12							
15	Total Purchase Price	Line 10 plus Line 12							
16	Total Purchase Cost	Line 11 plus Line 13							
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1B								
20	Tennessee Gas Pipeline (Contract 5083)								
21	Receipt Point: Tennessee Zone L								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 10	-	-	35,405	-	-	196,225	231,630
24	Fuel Loss Rate	Att to Sch 5A, Line 45 of Page 2			4.06%			4.06%	4.06%
25	Delivered Volume	Line 23 times (1 - Line 24)	-	-	33,967	-	-	188,258	222,226
26	Variable Transportation Rate	Att to Sch 5A, Line 28 of Page 2			$ 0.2927			$ 0.2927	$ 0.2927
27	Variable Transportation Costs	Line 25 times Line 26	$ -	$ -	$ 9,942	$ -	$ -	$ 55,103	$ 65,045
28									
29	Transportation Segment 2B								
30	Granite State Gas Transmission (Contract 14-001-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	-	-	33,967	-	-	188,258	222,226
34	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	-	-	33,849	-	-	187,599	221,448
36	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ 41	$ -	$ -	$ 225	$ 266

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
2	Purchased Volumes	Line 9	183,487	189,603	189,603	171,255	189,603	42,116	965,667
3	City Gate Delivered Volume	Sum Lines 68, 88 and 108	174,521	180,219	180,219	162,779	180,219	40,611	918,569
4	Total Purchase Cost	Line 15	[redacted]						
5	Variable Transportation Costs	Sum Lines 27, 47, 60, 70, 80, 90, 100 and 110	$ 16,241	$ 16,782	$ 16,782	$ 15,158	$ 16,782	$ 3,740	$ 85,487
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
7	Average Delivered Price	Line 5 divided by Line 2							
8									
9	Chicago Supply Costs								
10	Purchased Volumes	Sendout Optimization	183,487	189,603	189,603	171,255	189,603	42,116	965,667
11	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 4.016
12	NYMEX Cost	Line 9 times Line 10	$ 722,572	$ 761,826	$ 775,857	$ 698,376	$ 760,120	$ 159,618	$ 3,878,368
13	NYMEX Basis Price	Att to Sch 5A, Line 1 of Page 1	[redacted]						
14	NYMEX Basis Costs	Line 9 times Line 12							
15	Total Purchase Price	Line 10 plus Line 12							
16	Total Purchase Cost	Line 11 plus Line 13							
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1&2								
20	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
21	Receipt Point: Alliance								
22	Delivery Point: Dawn (Interconnects with Union)								
23	Received Volume	Line 10	183,487	189,603	189,603	171,255	189,603	42,116	965,667
24	Fuel Loss Rate	Att to Sch 5A, Line 52 of Page 2	0.88%	0.88%	0.88%	0.88%	0.88%	1.20%	0.89%
25	Delivered Volume	Line 23 times (1 - Line 24)	181,872	187,935	187,935	169,748	187,935	41,610	957,034
26	Variable Transportation Rate	Att to Sch 5A, Line 35 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
27	Variable Transportation Costs	Line 25 times Line 26	$ 218	$ 226	$ 226	$ 204	$ 226	$ 50	$ 1,148
28									
29	Transportation Segment 3								
30	Union Pipeline (Contract M12205)								
31	Receipt Point: Dawn								
32	Delivery Point: Parkway (Interconnects with TransCanada)								
33	Received Volume	Line 25	181,872	187,935	187,935	169,748	187,935	41,610	957,034
34	Fuel Loss Rate	Att to Sch 5A, Line 50 of Page 2	0.98%	0.98%	0.98%	0.98%	0.98%	0.53%	0.96%
35	Delivered Volume	Line 33 times (1 - Line 34)	180,090	186,093	186,093	168,084	186,093	41,390	947,843
36	Variable Transportation Rate	Att to Sch 5A, Line 33 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	Variable Transportation Costs	Line 35 times Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38									
39	Transportation Segment 4								
40	TransCanada Pipeline (Contract 41235)								
41	Receipt Point: Parkway								
42	Delivery Point: Iroquois								
43	Received Volume	Line 35	180,090	186,093	186,093	168,084	186,093	41,390	947,843
44	Fuel Loss Rate	Att to Sch 5A, Line 49 of Page 2	1.10%	1.10%	1.10%	1.10%	1.10%	0.53%	1.08%
45	Delivered Volume	Line 43 times (1 - Line 44)	178,109	184,046	184,046	166,235	184,046	41,170	937,652
46	Variable Transportation Rate	Att to Sch 5A, Line 32 of Page 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	Variable Transportation Costs	Line 45 times Line 46	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48									
49	Transportation Segment 5								
50	Iroquois Pipeline (Contract R181001)								
51	Receipt Point: Waddington								
52	Delivery Point: Wright (Interconnection with Tennessee)								
53	Total Contract Recevied Volume	Sendout Optimization	196,898	203,596	203,596	183,893	203,596	41,170	1,032,747
54	Received Volume	Line 45	178,109	184,046	184,046	166,235	184,046	41,170	937,652
55	Percentage Allocated	Line 54 divided by Line 53	90.46%	90.40%	90.40%	90.40%	90.40%	100.00%	91%
56	Received Volume	Line 45	178,109	184,046	184,046	166,235	184,046	41,170	937,652
57	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.40%	0.40%	0.40%	0.40%	0.40%	0.19%	0.39%
58	Delivered Volume	Line 56 times (1 - Line 57)	177,397	183,310	183,310	165,570	183,310	41,092	933,988
59	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ -
60	Variable Transportation Costs	Line 58 times Line 59	$ 745	$ 770	$ 770	$ 695	$ 770	$ 173	$ -
61									
62	Transporation Segment 6A								
63	Tennessee Gas Pipeline (Contract 95196)								
64	Receipt Point: Wright								
65	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
66	Received Volume	Line 58	37,902	39,139	39,139	35,352	39,139	26,749	217,420
67	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
68	City Gate Delivered Volume	Line 66 times (1 - Line 67)	37,504	38,728	38,728	34,980	38,728	26,468	215,137
69	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861
70	Variable Transportation Costs	Line 68 times Line 69	$ 3,229	$ 3,335	$ 3,335	$ 3,012	$ 3,335	$ 2,279	$ 18,523
71									
72	Transportation Segment 6B								
73	Tennessee Gas Pipeline (Contract 95196)								
74	Receipt Point: Wright								
75	Delivery Point: Pleasant St. (Interconnection with Granite)								
76	Received Volume	Line 68	23,147	23,903	23,903	21,590	23,903	14,343	130,787
77	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
78	Delivered Volume	Line 76 times (1 - Line 77)	22,904	23,652	23,652	21,363	23,652	14,192	129,414
79	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861
80	Variable Transportation Costs	Line 78 times Line 79	$ 1,972	$ 2,036	$ 2,036	$ 1,839	$ 2,036	$ 1,222	$ 11,143
81									
82	Transportation Segment 7B								
83	Granite State Gas Transmission (Contract 14-001-FT-NN)								
84	Receipt Point: Pleasant St.								
85	Delivery Point: Northern City Gates								
86	Received Volume	Line 78	22,904	23,652	23,652	21,363	23,652	14,192	129,414
87	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%
88	City Gate Delivered Volume	Line 86 times (1 - Line 87)	22,824	23,569	23,569	21,288	23,569	14,143	128,961
89	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
90	Variable Transportation Costs	Line 88 times Line 89	$ 27	$ 28	$ 28	$ 26	$ 28	$ 17	$ 155
91									
92	Transportation Segment 6C								
93	Tennessee Gas Pipeline (Contract 41099)								
94	Receipt Point: Wright								
95	Delivery Point: Mendon (Interconnection with Algonquin)								
96	Received Volume	Line 58	116,348	120,268	120,268	108,629	120,268	-	585,781
97	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%		1.05%
98	Delivered Volume	Line 96 times (1 - Line 97)	115,126	119,005	119,005	107,488	119,005	-	579,630
99	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861		$ 0.0861
100	Variable Transportation Costs	Line 98 times Line 99	$ 9,912	$ 10,246	$ 10,246	$ 9,255	$ 10,246	$ -	$ 49,906
101									
102	Transportation Segment 7C								
103	Algonquin Gas Transmission (Contract 93200F)								
104	Receipt Point: Mendon								
105	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
106	Received Volume	Line 98	115,126	119,005	119,005	107,488	119,005	-	579,630
107	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2	0.81%	0.91%	0.91%	0.91%	0.91%		0.89%
108	City Gate Delivered Volume	Line 106 times (1 - Line 107)	114,194	117,922	117,922	106,510	117,922	-	574,471
109	Variable Transportation Rate	Att to Sch 5A, Line 19 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012		$ 0.0012
110	Variable Transportation Costs	Line 108 times Line 109	$ 137	$ 142	$ 142	$ 128	$ 142	$ -	$ 689

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	37,836	39,137	39,137	35,350	39,137	17,011	207,609
2	City Gate Delivered Volume	Sum Lines 24	37,530	38,781	38,781	35,028	38,781	16,873	205,774
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Sum Lines 26	$ 465	$ 481	$ 481	$ 434	$ 481	$ 209	$ 2,552
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Algonquin Receipts Supply Costs								
9	Purchased Volumes	Sendout Optimization	37,836	39,137	39,137	35,350	39,137	17,011	207,609
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 4.007
11	NYMEX Cost	Line 9 times Line 10	$ 149,000	$ 157,253	$ 160,149	$ 144,156	$ 156,901	$ 64,472	$ 831,932
12	NYMEX Basis Price	Att to Sch 5A, Line 19 of Page 1	[redacted]						
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	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	37,836	39,137	39,137	35,350	39,137	17,011	207,609
23	Fuel Loss Rate	Att to Sch 5A, Line 38 of Page 2	0.81%	0.91%	0.91%	0.91%	0.91%	0.81%	1.20%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	37,530	38,781	38,781	35,028	38,781	16,873	205,774
25	Variable Transportation Rate	Att to Sch 5A, Line 20 of Page 2	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0124
26	Variable Transportation Costs	Line 24 times Line 25	$ 465	$ 481	$ 481	$ 434	$ 481	$ 209	$ 2,552

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	-	-	-	-	-	42,936	42,936
2	City Gate Delivered Volume	Line 24	-	-	-	-	-	42,785	42,785
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Line 26	$ -	$ -	$ -	$ -	$ -	$ 51	$ 51
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Tennessee Zone 6 Supply								
9	Purchased Volumes	Sendout Optimization	-	-	-	-	-	42,936	42,936
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 3.790
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ 162,726	$ 162,726
12	NYMEX Basis Price	Att to Sch 5A, Line 18 of Page 1	[redacted]						
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 14-001-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	-	-	-	42,936	42,936
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	-	-	-	42,785	42,785
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ -	$ -	$ -	$ 51	$ 51

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
2	Purchased Volumes	Line 9	64,556	66,708	66,708	60,253	66,708	64,556	389,491
3	City Gate Delivered Volume	Line 45	63,655	65,777	65,777	59,411	65,777	63,655	384,052
4	Total Purchase Cost	Line 15	[redacted]						
5	Variable Transportation Costs	Sum Lines 27, 37 and 47	$ 5,576	$ 5,762	$ 5,762	$ 5,205	$ 5,762	$ 5,576	$ 33,644
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
7	Average Delivered Price	Line 5 divided by Line 2	[redacted]						
8									
9	Niagara Supply Costs								
10	Purchased Volumes	Sendout Optimization	64,556	66,708	66,708	60,253	66,708	64,556	389,491
11	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 3.987
12	NYMEX Cost	Line 9 times Line 10	$ 254,223	$ 268,034	$ 272,970	$ 245,710	$ 267,434	$ 244,669	$ 1,553,041
13	NYMEX Basis Price	Att to Sch 5A, Line 6 of Page 1	[redacted]						
14	NYMEX Basis Costs	Line 9 times Line 12	[redacted]						
15	Total Purchase Price	Line 10 plus Line 12	[redacted]						
16	Total Purchase Cost	Line 11 plus Line 13	[redacted]						
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 1A								
20	Tennessee Gas Pipeline (Contract 5292)								
21	Receipt Point: Niagara								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 9	38,872	40,168	40,168	36,281	40,168	38,872	234,528
24	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
25	Delivered Volume	Line 23 times (1 - Line 24)	38,464	39,746	39,746	35,900	39,746	38,464	232,066
26	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861
27	Variable Transportation Costs	Line 25 times Line 26	$ 3,312	$ 3,422	$ 3,422	$ 3,091	$ 3,422	$ 3,312	$ 19,981
28									
29	Transportation Segment 1B								
30	Tennessee Gas Pipeline (Contract 39375)								
31	Receipt Point: Niagara								
32	Delivery Point: Pleasant St. (Interconnection with Granite)								
33	Received Volume	Line 9	25,684	26,540	26,540	23,972	26,540	25,684	154,962
34	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
35	Delivered Volume	Line 33 times (1 - Line 34)	25,415	26,262	26,262	23,720	26,262	25,415	153,335
36	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861
37	Variable Transportation Costs	Line 35 times Line 36	$ 2,188	$ 2,261	$ 2,261	$ 2,042	$ 2,261	$ 2,188	$ 13,202
38									
39	Transportation Segment 2B								
40	Granite State Gas Transmission (Contract 14-001-FT-NN)								
41	Receipt Point: Pleasant St.								
42	Delivery Point: Northern City Gates								
43	Received Volume	Line 35	63,879	66,008	66,008	59,620	66,008	63,879	385,401
44	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%
45	City Gate Delivered Volume	Line 43 times (1 - Line 44)	63,655	65,777	65,777	59,411	65,777	63,655	384,052
46	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
47	Variable Transportation Costs	Line 45 times Line 46	$ 76	$ 79	$ 79	$ 71	$ 79	$ 76	$ 461

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
2	Purchased Volumes	Line 9	18,789	19,550	19,550	17,658	19,550	-	95,095
3	City Gate Delivered Volume	Line 38	18,410	19,143	19,143	17,291	19,143	-	93,130
4	Total Purchase Cost	Line 15	[redacted]						
5	Variable Transportation Costs	Sum Lines 30, 40, 50, 60, 70 and 80	$ 1,690	$ 1,759	$ 1,759	$ 1,589	$ 1,759	$ -	$ 8,555
6	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
7	Average Delivered Price	Line 5 divided by Line 2							
8									
9	Irgoquois Receipts Supply Costs								
10	Purchased Volumes	Sendout Optimization	18,789	19,550	19,550	17,658	19,550	-	95,095
11	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 4.027
12	NYMEX Cost	Line 9 times Line 10	$ 73,990	$ 78,550	$ 79,997	$ 72,008	$ 78,374	$ -	$ 382,919
13	NYMEX Basis Price	Att to Sch 5A, Line 2 of Page 1	[redacted]						
14	NYMEX Basis Costs	Line 9 times Line 12							
15	Total Purchase Price	Line 10 plus Line 12							
16	Total Purchase Cost	Line 11 plus Line 13							
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 5								
20	Iroquois Pipeline (Contract R181001)								
21	Receipt Point: Waddington								
22	Delivery Point: Wright (Interconnection with Tennessee)								
23	Total Contract Recevied Volume	Sendout Optimization	196,898	203,596	203,596	183,893	203,596	41,170	1,032,747
24	Received Volume	Line 10	18,789	19,550	19,550	17,658	19,550	-	95,095
25	Percentage Allocated	Line 24 divided by Line 23	9.54%	9.60%	9.60%	9.60%	9.60%	0.00%	9%
26	Received Volume	Line 15	18,789	19,550	19,550	17,658	19,550	-	95,095
27	Fuel Loss Rate	Att to Sch 5A, Line 40 of Page 2	0.40%	0.40%	0.40%	0.40%	0.40%		0.40%
28	Delivered Volume	Line 26 times (1 - Line 27)	18,713	19,471	19,471	17,587	19,471	-	94,715
29	Variable Transportation Rate	Att to Sch 5A, Line 22 of Page 2	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042	$ 0.0042		$ -
30	Variable Transportation Costs	Line 28 times Line 29	$ 79	$ 82	$ 82	$ 74	$ 82	$ -	$ -
31									
32	Transporation Segment 6A								
33	Tennessee Gas Pipeline (Contract 95196)								
34	Receipt Point: Wright								
35	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
36	Received Volume	Line 28	3,998	4,157	4,157	3,755	4,157	-	20,226
37	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%		1.05%
38	City Gate Delivered Volume	Line 36 times (1 - Line 37)	3,956	4,114	4,114	3,716	4,114	-	20,013
39	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861		$ 0.0861
40	Variable Transportation Costs	Line 38 times Line 39	$ 341	$ 354	$ 354	$ 320	$ 354	$ -	$ 1,723
41									
42	Transportation Segment 6B								
43	Tennessee Gas Pipeline (Contract 95196)								
44	Receipt Point: Wright								
45	Delivery Point: Pleasant St. (Interconnection with Granite)								
46	Received Volume	Line 38	2,442	2,539	2,539	2,293	2,539	-	12,352
47	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%		1.05%
48	Delivered Volume	Line 46 times (1 - Line 47)	2,416	2,512	2,512	2,269	2,512	-	12,222
49	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861		$ 0.0861
50	Variable Transportation Costs	Line 48 times Line 49	$ 208	$ 216	$ 216	$ 195	$ 216	$ -	$ 1,052
51									
52	Transportation Segment 7B								
53	Granite State Gas Transmission (Contract 14-001-FT-NN)								
54	Receipt Point: Pleasant St.								
55	Delivery Point: Northern City Gates								
56	Received Volume	Line 48	2,416	2,512	2,512	2,269	2,512	-	12,222
57	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%
58	City Gate Delivered Volume	Line 56 times (1 - Line 57)	2,408	2,504	2,504	2,261	2,504	-	12,179
59	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
60	Variable Transportation Costs	Line 58 times Line 59	$ 3	$ 3	$ 3	$ 3	$ 3	$ -	$ 15
61									
62	Transportation Segment 6C								
63	Tennessee Gas Pipeline (Contract 41099)								
64	Receipt Point: Wright								
65	Delivery Point: Mendon (Interconnection with Algonquin)								
66	Received Volume	Line 28	12,273	12,775	12,775	11,539	12,775	-	62,137
67	Fuel Loss Rate	Att to Sch 5A, Line 47 of Page 2	1.05%	1.05%	1.05%	1.05%	1.05%		1.05%
68	Delivered Volume	Line 66 times (1 - Line 67)	12,145	12,641	12,641	11,418	12,641	-	61,485
69	Variable Transportation Rate	Att to Sch 5A, Line 30 of Page 2	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861	$ 0.0861		$ 0.0861
70	Variable Transportation Costs	Line 68 times Line 69	$ 1,046	$ 1,088	$ 1,088	$ 983	$ 1,088	$ -	$ 5,294
71									
72	Transportation Segment 7C								
73	Algonquin Gas Transmission (Contract 93200F)								
74	Receipt Point: Mendon								
75	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
76	Received Volume	Line 68	12,145	12,641	12,641	11,418	12,641	-	61,485
77	Fuel Loss Rate	Att to Sch 5A, Line 37 of Page 2	0.81%	0.91%	0.91%	0.91%	0.91%		0.89%
78	City Gate Delivered Volume	Line 76 times (1 - Line 77)	12,046	12,526	12,526	11,314	12,526	-	60,937
79	Variable Transportation Rate	Att to Sch 5A, Line 19 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012		$ 0.0012
80	Variable Transportation Costs	Line 78 times Line 79	$ 14	$ 15	$ 15	$ 14	$ 15	$ -	$ 73

REDACTED

Source of Supply: PNGTS (Pittsburg, NH)
Delivered to Northern via PNGTS and Granite Pipelines

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	24,000	24,800	24,800	22,400	24,800	19,213	140,013
2	City Gate Delivered Volume	Line 34	23,916	24,713	24,713	22,322	24,713	19,146	139,523
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Sum Lines 26 and 36	$ 57	$ 59	$ 59	$ 54	$ 59	$ 46	$ 335
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Portland Supply Costs								
9	Purchased Volumes	Sendout Optimization	24,000	24,800	24,800	22,400	24,800	19,213	140,013
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 3.994
11	NYMEX Cost	Line 9 times Line 10	$ 94,512	$ 99,646	$ 101,482	$ 91,347	$ 99,423	$ 72,818	$ 559,229
12	NYMEX Basis Price	Att to Sch 5A, Line 4 of Page 1	[redacted]						
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	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	24,000	24,800	24,800	22,400	24,800	19,213	140,013
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)	24,000	24,800	24,800	22,400	24,800	19,213	140,013
25	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
26	Variable Transportation Costs	Line 24 times Line 25	$ 29	$ 30	$ 30	$ 27	$ 30	$ 23	$ 168
27									
28	Transportation Segment 2								
29	Granite State Gas Transmission (Contract 14-001-FT-NN)								
30	Receipt Point: Granite (Westbrook)								
31	Delivery Point: Northern City Gates								
32	Received Volume	Line 24	24,000	24,800	24,800	22,400	24,800	19,213	140,013
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)	23,916	24,713	24,713	22,322	24,713	19,146	139,523
35	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
36	Variable Transportation Costs	Line 34 times Line 35	$ 29	$ 30	$ 30	$ 27	$ 30	$ 23	$ 167

REDACTED

Source of Supply: Maritimes Baseload Supply
City-Gate Delivered Supply

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	225,000	232,500	232,500	210,000	232,500	43,400	1,175,900
2	City Gate Delivered Volume	Line 1	225,000	232,500	232,500	210,000	232,500	43,400	1,175,900
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Maritimes Supply Costs								
9	Purchased Volumes	Sendout Optimization	225,000	232,500	232,500	210,000	232,500	43,400	1,175,900
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 4.018
11	NYMEX Cost	Line 9 times Line 10	$ 886,050	$ 934,185	$ 951,390	$ 856,380	$ 932,093	$ 164,487	$ 4,724,585
12	NYMEX Basis Price	Att to Sch 5A, Line 5 of Page 1	[redacted]						
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							

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	225,000	232,500	232,500	210,000	232,500	-	1,132,500
2	City Gate Delivered Volume	Line 24	224,213	231,686	231,686	209,265	231,686	-	1,128,536
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Line 26	$ 269	$ 278	$ 278	$ 251	$ 278	$ -	$ 1,354
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Portland Supply Costs								
9	Purchased Volumes	Sendout Optimization	225,000	232,500	232,500	210,000	232,500	-	1,132,500
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 4.027
11	NYMEX Cost	Line 9 times Line 10	$ 886,050	$ 934,185	$ 951,390	$ 856,380	$ 932,093	$ -	$ 4,560,098
12	NYMEX Basis Price	Att to Sch 5A, Line 3 of Page 1	[redacted]						
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 14-001-FT-NN)								
20	Receipt Point: Granite (Westbrook)								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	225,000	232,500	232,500	210,000	232,500	-	1,132,500
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	224,213	231,686	231,686	209,265	231,686	-	1,128,536
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
26	Variable Transportation Costs	Line 24 times Line 25	$ 269	$ 278	$ 278	$ 251	$ 278	$ -	$ 1,354

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

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Gross Withdrawn Volume	Line 9	52,140	490,280	751,204	624,133	208,415	-	2,126,172
2	City Gate Delivered Volume	Line 68	50,470	474,576	727,143	604,142	201,740	-	2,058,071
3	Total Withdrawal Costs	Line 16	$ 234,318	$ 2,203,316	$ 3,375,910	$ 2,804,853	$ 936,619	$ -	$ 9,555,017
4	Variable Transportation Costs	Sum Lines 27, 37, 47, 60 and 70	$ 183	$ 1,725	$ 2,643	$ 2,196	$ 733	$ -	$ 7,481
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 234,501	$ 2,205,041	$ 3,378,553	$ 2,807,049	$ 937,352	$ -	$ 9,562,497
6	Average Delivered Price	Line 5 divided by Line 2	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646		$ 4.646
7									
8	<u>Washington 10 Withdrawn Inventory (Segment 1)</u>								
9	Gross Withdrawn Volume	Sendout Optimization	52,140	490,280	751,204	624,133	208,415	-	2,126,172
10	Withdrawal Rate	Att to Sch 5A, Line 3 of Page 3	$ -	$ -	$ -	$ -	$ -		$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8	$ 4.4940	$ 4.4940	$ 4.4940	$ 4.4940	$ 4.4940		$ 4.4940
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 234,318	$ 2,203,316	$ 3,375,910	$ 2,804,853	$ 936,619	$ -	$ 9,555,017
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 3 of Page 3 times Line	209	1,961	3,005	2,497	834	-	8,505
15	Net Withdrawn Volume	Line 9 minus Line 14	51,932	488,318	748,199	621,636	207,582	-	2,117,667
16	Total Withdrawal Costs	Line 11 plus Line 13	$ 234,318	$ 2,203,316	$ 3,375,910	$ 2,804,853	$ 936,619	$ -	$ 9,555,017
17									
18	<u>Transportation Fuel Losses and Variable Charges</u>								
19	Transportation Segment 2A								
20	Vector Pipeline (Contract CRL-NUI-0725)								
21	Receipt Point: Washington 10 Withdrawal Meter								
22	Delivery Point: Dawn (Interconnects with TransCanada)								
23	Received Volume	Line 15	27,501	250,983	350,649	320,079	127,119	-	1,076,331
24	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2	0.33%	0.33%	0.33%	0.33%	0.33%		0.33%
25	Delivered Volume	Line 23 times (1 - Line 24)	27,410	250,155	349,492	319,022	126,700	-	1,072,779
26	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012		$ 0.0012
27	Variable Transportation Costs	Line 25 times Line 26	$ 33	$ 300	$ 419	$ 383	$ 152	$ -	$ 1,287
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	24,430	237,335	397,550	301,558	80,462	-	1,041,336
34	Fuel Loss Rate	Att to Sch 5A, Line 53 of Page 2	0.33%	0.33%	0.33%	0.33%	0.33%		0.33%
35	Delivered Volume	Line 33 times (1 - Line 34)	24,350	236,552	396,238	300,563	80,197	-	1,037,900
36	Variable Transportation Rate	Att to Sch 5A, Line 36 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012		$ 0.0012
37	Variable Transportation Costs	Line 35 times Line 36	$ 29	$ 284	$ 475	$ 361	$ 96	$ -	$ 1,245
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	51,760	486,707	745,730	619,585	206,897	-	2,110,679
44	Fuel Loss Rate	Att to Sch 5A, Line 48 of Page 2	2.15%	2.15%	2.15%	2.15%	2.15%		2.15%
45	Delivered Volume	Line 43 times (1 - Line 44)	50,647	476,243	729,697	606,264	202,448	-	2,065,299
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	Total Contract Recevied Volume	Sendout Optimization	50,647	476,243	729,697	606,264	202,448	-	2,065,299
54	Received Volume	Line 45	50,647	476,243	729,697	606,264	202,448	-	2,065,299
55	Percentage Allocated	Line 54 divided by Line 53	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	100.00%
56	Total Contract Recevied Volume	Sendout Optimization	50,647	476,243	729,697	606,264	202,448	-	2,065,299
57	Fuel Loss Rate	Att to Sch 5A, Line 41 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
58	Delivered Volume	Line 56 times (1 - Line 57)	50,647	476,243	729,697	606,264	202,448	-	2,065,299
59	Variable Transportation Rate	Att to Sch 5A, Line 24 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012		$ 0.0012
60	Variable Transportation Costs	Line 58 times Line 59	$ 61	$ 571	$ 876	$ 728	$ 243	$ -	$ 2,478
61									
62	Transportation Segment 5								
63	Granite State Gas Transmission (Contract 14-001-FT-NN)								
64	Receipt Point: Westbrook, Newington, Eliot								
65	Delivery Point: Northern City Gates								
66	Received Volume	Line 58	50,647	476,243	729,697	606,264	202,448	-	2,065,299
67	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%
68	City Gate Delivered Volume	Line 66 times (1 - Line 67)	50,470	474,576	727,143	604,142	201,740	-	2,058,071
69	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
70	Variable Transportation Costs	Line 68 times Line 69	$ 61	$ 569	$ 873	$ 725	$ 242	$ -	$ 2,470

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

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Gross Withdrawn Volume	Line 9	-	56,517	76,955	69,508	41,320	-	244,300
2	City Gate Delivered Volume	Line 38	-	55,536	75,620	68,302	40,603	-	240,061
3	Total Withdrawal Costs	Line 16	$ -	$ 197,114	$ 268,397	$ 242,423	$ 144,112	$ -	$ 852,046
4	Variable Transportation Costs	Sum Lines 30 and 40	$ -	$ 6,420	$ 8,742	$ 7,896	$ 4,694	$ -	$ 27,751
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ 203,534	$ 277,139	$ 250,319	$ 148,806	$ -	$ 879,798
6	Average Delivered Price	Line 5 divided by Line 2		$ 3.665	$ 3.665	$ 3.665	$ 3.665		$ 3.665
7									
8	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	-	56,517	76,955	69,508	41,320	-	244,300
10	Withdrawal Rate	Att to Sch 5A, Line 1 of Page 3		$ 0.0087	$ 0.0087	$ 0.0087	$ 0.0087		$ 0.0087
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ 492	$ 670	$ 605	$ 359	$ -	$ 2,125
12	Inventory Rate	FXW-8		$ 3.4790	$ 3.4790	$ 3.4790	$ 3.4790		$ 3.4790
13	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ 196,622	$ 267,727	$ 241,818	$ 143,753	$ -	$ 849,921
14	Withdrawal Fuel Losses	Att to Sch 5A, Line 1 of Page 3 times Line	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	-	56,517	76,955	69,508	41,320	-	244,300
16	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ 197,114	$ 268,397	$ 242,423	$ 144,112	$ -	$ 852,046
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 2								
20	Tennessee Gas Pipeline (Contract 5265)								
21	Receipt Point: Tennessee FS-MA Withdrawal Meter								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Total Contract Recevied Volume	Sendout Optimization	18,732	76,955	76,955	69,508	41,842	74,473	358,465
24	Received Volume	Line 15	-	56,517	76,955	69,508	41,320	-	244,300
25	Percentage Allocated	Line 24 divided by Line 23	0.00%	73.44%	100.00%	100.00%	98.75%	0.00%	68.15%
26	Received Volume	Line 10	-	56,517	76,955	69,508	41,320	-	244,300
27	Fuel Loss Rate	Att to Sch 5A, Line 46 of Page 2		1.39%	1.39%	1.39%	1.39%		1.39%
28	Delivered Volume	Line 26 times (1 - Line 27)	-	55,731	75,886	68,542	40,746	-	240,905
29	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2		$ 0.1140	$ 0.1140	$ 0.1140	$ 0.1140		$ 0.1140
30	Variable Transportation Costs	Line 28 times Line 29	$ -	$ 6,353	$ 8,651	$ 7,814	$ 4,645	$ -	$ 27,463
31									
32	Transportation Segment 3								
33	Granite State Gas Transmission (Contract 14-001-FT-NN)								
34	Receipt Point: Pleasant St.								
35	Delivery Point: Northern City Gates								
36	Received Volume	Line 28	-	55,731	75,886	68,542	40,746	-	240,905
37	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%
38	City Gate Delivered Volume	Line 36 times (1 - Line 37)	-	55,536	75,620	68,302	40,603	-	240,061
39	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
40	Variable Transportation Costs	Line 38 times Line 39	$ -	$ 67	$ 91	$ 82	$ 49	$ -	$ 288

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	-	-	3,422	-	-	-	3,422
2	City Gate Delivered Volume	Line 24	-	-	3,410	-	-	-	3,410
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Line 26	$ -	$ -	$ 4	$ -	$ -	$ -	$ 4
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Peaking Contract 1 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	3,422	-	-	-	3,422
10	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	$ 3.790	$ 4.092
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ 14,001	$ -	$ -	$ -	$ 14,001
12	NYMEX Basis Price	Att to Sch 5A, Line 11 of Page 1	[redacted]						
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 14-001-FT-NN)								
20	Receipt Point: Pleasant St.								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	3,422	-	-	-	3,422
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	3,410	-	-	-	3,410
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ 4	$ -	$ -	$ -	$ 4

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Purchased Volumes	Line 9	-	-	176,863	103,137	20,000	-	300,000
2	City Gate Delivered Volume	Line 24	-	-	176,244	102,776	19,930	-	298,950
3	Total Purchase Cost	Line 15	[redacted]						
4	Variable Transportation Costs	Line 26	$ -	$ -	$ 211	$ 123	$ 24	$ -	$ 359
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]						
7									
8	Peaking Supply 2 Costs								
9	Purchased Volumes	Sendout Optimization	-	-	176,863	103,137	20,000	-	300,000
10	Monthly Commodity Price	Att to Sch 5A, Line 21 of Page 1	$ 21.670	$ 21.670	$ 21.670	$ 21.670	$ 21.670		$ 21.670
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ 3,832,614	$ 2,234,986	$ 433,400	$ -	$6,501,000
12	NYMEX Basis Price	Att to Sch 5A, Line 12 of Page 1	[redacted]						
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]						
14	Total Purchase Price	Line 10 plus Line 12	[redacted]						
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]						
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	Granite State Gas Transmission (Contract 14-001-FT-NN)								
20	Receipt Point: Newington or Westbrook								
21	Delivery Point: Northern City Gates								
22	Received Volume	Line 9	-	-	176,863	103,137	20,000	-	300,000
23	Fuel Loss Rate	Att to Sch 5A, Line 39 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	176,244	102,776	19,930	-	298,950
25	Variable Transportation Rate	Att to Sch 5A, Line 21 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ 211	$ 123	$ 24	$ -	$ 359

REDACTED

Source of Supply: Northern LNG Inventory
On-System Storage

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	2014-2015 Peak
1	Gross Withdrawn Volume	Line 9	7,252	2,781	21,196	16,692	12,100	2,100	62,120
2	City Gate Delivered Volume	Line 15	7,252	2,781	21,196	16,692	12,100	2,100	62,120
3	Total Withdrawal Costs	Line 16	[redacted]						
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	[redacted]						
6	Average Delivered Price	Line 5 divided by Line 2							
7									
8	Northern LNG Withdrawn Inventory								
9	Gross Withdrawn Volume	Sendout Optimization	7,252	2,781	21,196	16,692	12,100	2,100	62,120
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	FXW-8	[redacted]						
13	Withdrawn Inventory Value	Line 9 times Line 12							
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	7,252	2,781	21,196	16,692	12,100	2,100	62,120
16	Total Withdrawal Costs	Line 11 plus Line 13	[redacted]						

REDACTED

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

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference		Nov-14		Dec-14		Jan-15		Feb-15		Mar-15		Apr-15		2014-2015 Peak
1	Purchased Volumes	Line 22		7,382		3,761		20,086		16,692		13,350		850		62,120
2	Storage Delivered Volume	Line 24		7,382		3,761		20,086		16,692		13,350		850		62,120
3	Total Purchase Price	Line 15	[redacted]													
4	Total Purchase Cost	Line 10 times Line 12														
5	Variable Transportation Costs	Line 26														
6	Total Storage Delivered Costs	Line 13 plus Line 14														
7	Average Delivered Price	Line 15 divided by Line 11														
8																
9	LNG Supply Costs															
10	Purchased Volumes	Sendout Optimization		7,382		3,761		20,086		16,692		13,350		850		62,120
11	Monthly NYMEX Price	Att to Sch 5A, Line 21 of Page 1	$	3.938	$	4.018	$	4.092	$	4.078	$	4.009	$	3.790	$	4.043
12	NYMEX Costs	Line 9 times Line 10	$	29,069	$	15,111	$	82,192	$	68,068	$	53,520	$	3,222	$	251,182
13	NYMEX Basis Price	Att to Sch 5A, Line 14 of Page 1	[redacted]													
14	NYMEX Basis Costs	Line 9 times Line 12														
15	Total Purchase Price	Line 10 plus Line 12														
16	Total Purchase Cost	Line 11 plus Line 13														
17																
18	Transportation Segment 3															
19	Trucking Contract															
20	Receipt Point: Distrigas Terminal															
21	Delivery Point: Northern LNG Facility (Lewiston, ME)															
22	Received Volume	Line 19 minus Line 31		7,382		3,761		20,086		16,692		13,350		850		62,120
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)		7,382		3,761		20,086		16,692		13,350		850		62,120
25	Variable Transportation Rate	Att to Sch 5A, Line 29 of Page 2	[redacted]													
26	Variable Transportation Costs	Line 24 times Line 25														

Schedule 7

Northern Utilities, Inc.
Hedging Expense and Option Contract Value - Maine Division
November 2014 through March 2015
As of 9/2/2014

Description	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Winter
NYMEX Options Contracts	8	12	13	12	9	54
Option Contract Price	$ 0.105	$ 0.115	$ 0.110	$ 0.105	$ 0.104	
Hedging Expense	$ 8,400	$ 13,800	$ 14,300	$ 12,600	$ 9,360	$ 58,460

Description	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Winter
NYMEX Options Contracts	8	12	13	12	9	54
NYMEX Option Strike Price	$ 5.800	$ 6.100	$ 5.900	$ 5.750	$ 5.850	
Futures Price (9/2/2014)	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009	
Trade Equity as of 9/2/2014[1]	$ -	$ -	$ -	$ -	$ -	$ -

[1] If Futures Price exceeds Strike Price upon contract settlement, then value upon expiration equals the difference between the Futures Price and Strike Price. If Futures Price is below the Strike Price upon contract settlement, then the option will expire with no value.

Schedule 8

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 771 therms/year

Comparison of Winter 2014-2015 vs. Winter 2013-2014

Line			Rate	Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		55	97	139	142	119	81	633	44	25	16	15	15	23	138	771
3	**Winter 2014 - 2015**																	
4	Customer Charge	units @	$ 20.01	$20.01	$20.01	$20.01	$20.01	$20.01	$20.01	$120.06								
5	First	50 units @	$0.5844	$29.22	$29.22	$29.22	$29.22	$29.22	$29.22	$175.32								
6	Over	50 units @	$0.4780	$2.39	$22.47	$42.54	$43.98	$32.98	$14.82	$159.17								
7		COG 1	$1.1069	$60.88						$60.88								
8		COG 2	$1.1069		$107.37					$107.37								
9		COG 3	$1.1069			$153.86				$153.86								
10		COG 4	$1.1069				$157.18			$157.18								
11		COG 5	$1.1069					$131.72		$131.72								
12		COG 6	$1.1069						$89.66	$89.66								
13		LDAC	$0.0649	$3.57	$6.30	$9.02	$9.22	$7.72	$5.26	$41.08								
14	**Summer 2014**																	
15	Customer Charge	units @	$ 20.01								$ 20.01	$20.01	$20.01	$20.01	$ 20.01	$20.01	$120.06	
16	First	50 units @	$0.5104								$22.46	$12.76	$8.17	$7.66	$7.66	$11.74	$70.44	
17	Over	50 units @	$0.5104								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
18		COG 1	$0.6833								$30.07						$30.07	
19		COG 2	$0.6833									$17.08					$17.08	
20		COG 3	$0.6153										$9.84				$9.84	
21		COG 4	$0.6153											$9.23			$9.23	
22		COG 5	$0.6153												$9.23		$9.23	
23		COG 6	$0.6153													$14.15	$14.15	
24	Summer Period 2014 Weighted Avg. COG		$0.6493															
25		LDAC	$ 0.0551								$2.42	$1.38	$0.88	$0.83	$0.83	$1.27	$7.60	
26			**TOTAL**	$116.07	$185.36	$254.65	$259.60	$221.66	$158.96	**$1,196.30**	$74.96	$51.23	$38.90	$37.72	$37.72	$47.17	$287.70	$1,484.01
27				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
28		Typical Usage: therms		55	97	139	142	119	81	633	44	25	16	15	15	23	138	771
29	**Winter 2013 - 2014**																	
30	Customer Charge	units @	$ 13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38								
31	First	50 units @	$0.4831	$24.16	$24.16	$24.16	$24.16	$24.16	$24.16	$144.93								
32	Over	50 units @	$0.4250	$2.13	$19.98	$37.83	$39.10	$29.33	$13.18	$141.53								
33		COG 1	$0.8530	$46.92						$46.92								
34		COG 2	$0.8530		$82.74					$82.74								
35		COG 3	$0.9569			$133.01				$133.01								
36		COG 4	$0.9569				$135.88			$135.88								
37		COG 5	$0.9569					$113.87		$113.87								
38		COG 6	$0.7196						$58.29	$58.29								
39	Winter Period 13-14 Weighted Avg. COG		$0.9016															
40		LDAC	$ 0.0489	$2.69	$4.74	$6.80	$6.94	$5.82	$3.96	$30.95								
41	**Summer 2013**																	
42	Customer Charge	units @	$ 13.73								$13.73	$13.73	$13.73	$13.73	$13.73	$13.73	$82.38	
43	First	50 units @	$0.4410								$19.40	$11.03					$30.43	
44	First (Temp)	50 units @	$0.4831										$7.73	$7.25	$7.25	$11.11	$33.33	
45	Over	50 units @	$0.4410								$0.00	$0.00					$0.00	
46	Over (Temp	50 units @	$0.4831										$0.00	$0.00	$0.00	$0.00	$0.00	
47		COG 1	$0.5553								$24.43						$24.43	
48		COG 2	$0.5858									$14.65					$14.65	
49		COG 3	$0.5858										$9.37				$9.37	
50		COG 4	$0.5858											$8.79			$8.79	
51		COG 5	$0.5858												$8.79		$8.79	
52		COG 6	$0.5858													$13.47	$13.47	
53	Summer Period 2013 Wighted Avg. COG		$0.5761															
54		LDAC	$ 0.0551								$2.42	$1.38	$0.88	$0.83	$0.83	$1.27	$7.60	
55			**TOTAL**	$89.61	$145.34	$215.52	$219.81	$186.90	$113.31	**$970.49**	$59.99	$40.78	$31.71	$30.59	$30.59	$39.58	$233.25	$1,203.74
56			**Change**	$26.45	$40.02	$39.14	$39.79	$34.76	$45.66	**$225.81**	$14.97	$10.45	$7.19	$7.13	$7.13	$7.59	**$54.46**	$280.27
57			**% Chg**	29.52%	27.53%	18.16%	18.10%	18.60%	40.29%	**23.27%**	24.95%	25.63%	22.67%	23.31%	23.31%	19.17%	**23.35%**	23.28%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 1,846 therms/year

Comparison of Winter 2014-2015 vs. Winter 2013-2014

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
2		Typical Usage: therms		118	238	369	381	322	192	1,620	92	40	21	19	18	36	226	1,846
3	**Winter 2014 - 2015**																	
4	Customer Charge	units @	$ 63.18	$63.18	$63.18	$63.18	$63.18	$63.18	$63.18	$379.08								
5	First	75 units @	$0.1513	$11.35	$11.35	$11.35	$11.35	$11.35	$11.35	$68.09								
6	Over	75 units @	$0.1513	$6.51	$24.66	$44.48	$46.30	$37.37	$17.70	$177.02								
7		COG 1	$1.1217	$132.36						$132.36								
8		COG 2	$1.1217		$266.96					$266.96								
9		COG 3	$1.1217			$413.91				$413.91								
10		COG 4	$1.1217				$427.37			$427.37								
11		COG 5	$1.1217					$361.19		$361.19								
12		COG 6	$1.1217						$215.37	$215.37								
13		LDAC	$0.0437	$5.16	$10.40	$16.13	$16.65	$14.07	$8.39	$70.79								
14	**Summer 2014**																	
15	Customer Charge	units @	$ 63.18								$ 63.18	$63.18	$63.18	$63.18	$ 63.18	$63.18	$379.08	
16	First	75 units @	$0.1513								$11.35	$6.05	$3.18	$2.87	$2.72	$5.45	$31.62	
17	Over	75 units @	$0.1513								$2.57	$0.00	$0.00	$0.00	$0.00	$0.00	$2.57	
18		COG 1	$0.7209								$66.32						$66.32	
19		COG 2	$0.7209									$28.84					$28.84	
20		COG 3	$0.6529										$13.71				$13.71	
21		COG 4	$0.6529											$12.41			$12.41	
22		COG 5	$0.6529												$11.75		$11.75	
23		COG 6	$0.6529													$23.50	$23.50	
24	Summer Period 2013 Weighted Avg. COG		$0.6926															
25		LDAC	$ 0.0430								$3.96	$1.72	$0.90	$0.82	$0.77	$1.55	$9.72	
26		**TOTAL**		$218.55	$376.55	$549.04	$564.84	$487.16	$315.99	**$2,512.13**	$147.38	$99.79	$80.97	$79.28	$78.43	$93.68	$579.52	$3,091.66
27				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
28		Typical Usage: therms		118	238	369	381	322	192	1,620	92	40	21	19	18	36	226	1,846
29	**Winter 2013 - 2014**																	
30	Customer Charge	units @	$ 31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40								
31	First	75 units @	$0.3122	$23.42	$23.42	$23.42	$23.42	$23.42	$23.42	$140.49								
32	Over	75 units @	$0.2647	$11.38	$43.15	$77.82	$81.00	$65.38	$30.97	$309.70								
33		COG 1	$0.8664	$102.24						$102.24								
34		COG 2	$0.8664		$206.20					$206.20								
35		COG 3	$0.9703			$358.04				$358.04								
36		COG 4	$0.9703				$369.68			$369.68								
37		COG 5	$0.9703					$312.44		$312.44								
38		COG 6	$0.7330						$140.74	$140.74								
39	Winter Period 12-13 Weighted Avg. COG		$0.9193															
40		LDAC	$ 0.0227	$2.68	$5.40	$8.38	$8.65	$7.31	$4.36	$36.77								
41	**Summer 2013**																	
42	Customer Charge	units @	$ 31.40								$31.40	$31.40	$31.40	$31.40	$31.40	$31.40	$188.40	
43	First	75 units @	$0.2701								$20.26	$10.80					$31.06	
44	First (Temp)	75 units @	$0.3122										$6.56	$5.93	$5.62	$11.24	$29.35	
45	Over	75 units @	$0.2226								$3.78	$0.00					$3.78	
46	Over (Temp	75 units @	$0.2647										$0.00	$0.00	$0.00	$0.00	$0.00	
47		COG 1	$0.5780								$53.18						$53.18	
48		COG 2	$0.6085									$24.34					$24.34	
49		COG 3	$0.6085										$12.78				$12.78	
50		COG 4	$0.6085											$11.56			$11.56	
51		COG 5	$0.6085												$10.95		$10.95	
52		COG 6	$0.6085													$21.91	$21.91	
53	Summer Period 2012 Wighted Avg. COG		$0.5961															
54		LDAC	$ 0.0266								$2.45	$1.06	$0.56	$0.51	$0.48	$0.96	$6.01	
55		**TOTAL**		$171.11	$309.57	$499.05	$514.15	$439.94	$230.88	**$2,164.70**	$111.06	$67.61	$51.29	$49.40	$48.45	$65.50	$393.32	$2,558.02
56		**Change**		$47.44	$66.99	$49.99	$50.70	$47.22	$85.11	**$347.44**	$36.31	$32.18	$29.68	$29.88	$29.98	$28.18	**$186.20**	$533.64
57		**% Chg**		27.72%	21.64%	10.02%	9.86%	10.73%	36.86%	**16.05%**	32.70%	47.60%	57.86%	60.48%	61.87%	43.02%	**47.34%**	20.86%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 19,587 therms/year

Comparison of Winter 2014-2015 vs. Winter 2013-2014

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		1,405	2,384	3,842	3,633	3,430	1,851	16,545	1,027	604	202	307	303	599	3,042	19,587
3	**Winter 2014 - 2015**																	
4	Customer Charge	units @	$ 184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$1,105.56								
5	All	units @	$0.1965	$276.08	$468.46	$754.95	$713.88	$674.00	$363.72	$3,251.09								
6		COG 1	$1.1217	$1,575.99						$1,575.99								
7		COG 2	$1.1217		$2,674.13					$2,674.13								
8		COG 3	$1.1217			$4,309.57				$4,309.57								
9		COG 4	$1.1217				$4,075.14			$4,075.14								
10		COG 5	$1.1217					$3,847.43		$3,847.43								
11		COG 6	$1.1217						$2,076.27	$2,076.27								
12		LDAC	$0.0437	$61.40	$104.18	$167.90	$158.76	$149.89	$80.89	$723.02								
13	**Summer 2014**																	
14	Customer Charge	units @	$ 184.26								$ 184.26	$184.26	$184.26	$184.26	$ 184.26	$184.26	$1,105.56	
15	All	units @	$0.1519								$156.00	$91.75	$30.68	$46.63	$46.03	$90.99	$462.08	
##		COG 1	$0.7209								$740.36						$740.36	
##		COG 2	$0.7209									$435.42					$435.42	
##		COG 3	$0.6529										$131.89				$131.89	
##		COG 4	$0.6529											$200.44			$200.44	
##		COG 5	$0.6529												$197.83		$197.83	
##		COG 6	$0.6529													$391.09	$391.09	
##	Summer Period 2013 Weighted Avg. COG		$0.6894															
##		LDAC	$ 0.0430								$44.16	$25.97	$8.69	$13.20	$13.03	$25.76	$130.81	
##		TOTAL		$2,097.73	$3,431.03	$5,416.68	$5,132.04	$4,855.58	$2,705.14	**$23,638.20**	$1,124.79	$737.40	$355.52	$444.53	$441.14	$692.09	$3,795.48	$27,433.67
26				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
27		Typical Usage: therms		1,405	2,384	3,842	3,633	3,430	1,851	16,545	1,027	604	202	307	303	599	3,042	19,587
28	**Winter 2013 - 2014**																	
29	Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
30	All	units @	$0.2437	$342.40	$580.98	$936.30	$885.36	$835.89	$451.09	$4,032.02								
31		COG 1	$0.8664	$1,217.29						$1,217.29								
32		COG 2	$0.8664		$2,065.50					$2,065.50								
33		COG 3	$0.9703			$3,727.89				$3,727.89								
34		COG 4	$0.9703				$3,525.10			$3,525.10								
35		COG 5	$0.9703					$3,328.13		$3,328.13								
36		COG 6	$0.7330						$1,356.78	$1,356.78								
37	Winter Period 12-13 Weighted Avg. COG		$0.9200															
38		LDAC	$ 0.0227	$31.89	$54.12	$87.21	$82.47	$77.86	$42.02	$375.57								
39	**Summer 2013**																	
40	Customer Charge	units @	$ 94.21								$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26	
41	All	units @	$0.1557								$159.90	$94.04					$253.95	
42	All (Temp)	units @	$0.1978										$39.96	$60.72	$59.93	$118.48	$279.10	
43		COG 1	$0.5780								$593.61						$593.61	
44		COG 2	$0.6085									$367.53					$367.53	
45		COG 3	$0.6085										$122.92				$122.92	
46		COG 4	$0.6085											$186.81			$186.81	
47		COG 5	$0.6085												$184.38		$184.38	
48		COG 6	$0.6085													$364.49	$364.49	
49	Summer Period 2012 Wighted Avg. COG		$0.5982															
50		LDAC	$ 0.0266								$27.32	$16.07	$5.37	$8.17	$8.06	$15.93	$80.92	
51		**TOTAL**		$1,685.79	$2,794.81	$4,845.61	$4,587.14	$4,336.09	$1,944.10	**$20,193.54**	$875.04	$571.85	$262.46	$349.91	$346.58	$593.12	$2,998.95	$23,192.50
52		**Change**		$411.94	$636.22	$571.07	$544.90	$519.49	$761.04	**$3,444.65**	$249.75	$165.55	$93.06	$94.62	$94.56	$98.98	**$796.52**	$4,241.18
53		**% Chg**		24.44%	22.76%	11.79%	11.88%	11.98%	39.15%	**17.06%**	28.54%	28.95%	35.46%	27.04%	27.29%	16.69%	**26.56%**	18.29%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 15,232 therms/year

Comparison of Winter 2014-2015 vs. Winter 2013-2014

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms		1,298	1,367	1,686	1,693	1,557	1,366	8,967	1,286	994	862	1,016	1,043	1,064	6,265	15,232
3	**Winter 2014 - 2015**																	
4	Customer Charge	units @	$ 184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$184.26	$1,105.56								
5	First	1,300 units @	$0.1424	$184.84	$185.12	$185.12	$185.12	$185.12	$185.12	$1,110.44								
6	Over	1,300 units @	$0.1160	$0.00	$7.77	$44.78	$45.59	$29.81	$7.66	$135.60								
7		COG 1	$1.0063	$1,306.18						$1,306.18								
8		COG 2	$1.0063		$1,375.61					$1,375.61								
9		COG 3	$1.0063			$1,696.62				$1,696.62								
10		COG 4	$1.0063				$1,703.67			$1,703.67								
11		COG 5	$1.0063					$1,566.81		$1,566.81								
12		COG 6	$1.0063						$1,374.61	$1,374.61								
13		LDAC	$0.0437	$56.72	$59.74	$73.68	$73.98	$68.04	$59.69	$391.86								
14	**Summer 2014**																	
15	Customer Charge	units @	$ 184.26								$ 184.26	$184.26	$184.26	$184.26	$ 184.26	$184.26	$1,105.56	
16	First	1,000 units @	$0.1108								$110.80	$110.14	$95.51	$110.80	$110.80	$110.80	$648.84	
17	Over	1,000 units @	$0.0897								$25.65	$0.00	$0.00	$1.44	$3.86	$5.74	$36.69	
18		COG 1	$0.6318								$812.49						$812.49	
19		COG 2	$0.5638									$560.42					$560.42	
20		COG 3	$0.5638										$486.00				$486.00	
21		COG 4	$0.5638											$572.82			$572.82	
22		COG 5	$0.5638												$588.04		$588.04	
23		COG 6	$0.5638													$599.88	$599.88	
24	Summer Period 2014 Weighted Avg. COG		$0.5778															
25		LDAC	$ 0.0430								$55.30	$42.74	$37.07	$43.69	$44.85	$45.75	$269.40	
26			**TOTAL**	$1,732.00	$1,812.50	$2,184.46	$2,192.62	$2,034.04	$1,811.34	**$11,766.95**	$1,188.51	$897.55	$802.83	$913.00	$931.81	$946.44	$5,680.14	$17,447.09
27				**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**	**May**	**June**	**July**	**August**	**Sept**	**October**	**Summer**	**Annual**
28		Typical Usage: therms		1,298	1,367	1,686	1,693	1,557	1,366	8,967	1,286	994	862	1,016	1,043	1,064	6,265	15,232
29	**Winter 2013 - 2014**																	
30	Customer Charge	units @	$ 94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26								
31	First	1,300 units @	$0.2270	$294.65	$295.10	$295.10	$295.10	$295.10	$295.10	$1,770.15								
32	Over	1,300 units @	$0.1903	$0.00	$12.75	$73.46	$74.79	$48.91	$12.56	$222.46								
33		COG 1	$0.7762	$1,007.51						$1,007.51								
34		COG 2	$0.7762		$1,061.07					$1,061.07								
35		COG 3	$0.8801			$1,483.85				$1,483.85								
36		COG 4	$0.8801				$1,490.01			$1,490.01								
37		COG 5	$0.8801					$1,370.32		$1,370.32								
38		COG 6	$0.6428						$878.06	$878.06								
39	Winter Period 13-14 Weighted Avg. COG		$0.8131															
40		LDAC	$ 0.0227	$29.46	$31.03	$38.27	$38.43	$35.34	$31.01	$203.55								
41	**Summer 2013**																	
42	Customer Charge	units @	$ 94.21								$94.21	$94.21	$94.21	$94.21	$94.21	$94.21	$565.26	
43	First	1,000 units @	$0.1325								$132.50	$131.71					$264.21	
44	First (Temp)	1,000 units @	$0.1746										$150.51	$174.60	$174.60	$174.60	$674.31	
45	Over	1,000 units @	$0.1011								$28.91	$0.00					$28.91	
46	Over (Temp)	1,000 units @	$0.1432										$0.00	$2.29	$6.16	$9.16	$17.61	
47		COG 1	$0.5180								$666.15						$666.15	
48		COG 2	$0.5485									$545.21					$545.21	
49		COG 3	$0.5485										$472.81				$472.81	
50		COG 4	$0.5485											$557.28			$557.28	
51		COG 5	$0.5485												$572.09		$572.09	
52		COG 6	$0.5485													$583.60	$583.60	
53	Summer Period 2013 Wighted Avg. COG		$0.5422															
54		LDAC	$ 0.0266								$34.21	$26.44	$22.93	$27.03	$27.74	$28.30	$166.65	
55			**TOTAL**	$1,425.83	$1,494.16	$1,984.89	$1,992.54	$1,843.88	$1,310.94	**$10,052.23**	$955.98	$797.56	$740.45	$855.40	$874.80	$889.88	$5,114.08	$15,166.31
56			**Change**	$306.17	$318.35	$199.57	$200.08	$190.17	$500.39	**$1,714.72**	$232.53	$99.99	$62.38	$57.60	$57.01	$56.55	**$566.07**	$2,280.79
57			**% Chg**	21.47%	21.31%	10.05%	10.04%	10.31%	38.17%	**17.06%**	24.32%	12.54%	8.42%	6.73%	6.52%	6.36%	**11.07%**	15.04%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Winter 2014-2015 vs. Actual Winter 2013-2014

Residential Heating	Winter 2013-2014	Winter 2014- 2015
Customer Charge	$13.73	$20.01
First 50 Therms	$0.4831	$0.5844
Over 50 therms	$0.4250	$0.4780
LDAC	$0.0489	$0.0649
CGA	$0.9016	$1.1069

	Usage (Therms)	Winter 2013-2014 Bill Amount	Winter 2014-2015 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$20.90	$28.79	$7.89	37.8%	$0.51	2.4%	$1.03	4.9%	$0.08	0.4%
	10	$28.07	$37.57	$9.51	33.9%	$1.01	3.6%	$2.05	7.3%	$0.16	0.6%
	20	$42.40	$55.13	$12.73	30.0%	$2.03	4.8%	$4.11	9.7%	$0.32	0.8%
	25	$49.57	$63.92	$14.35	28.9%	$2.53	5.1%	$5.13	10.3%	$0.40	0.8%
	30	$56.74	$72.70	$15.96	28.1%	$3.04	5.4%	$6.16	10.9%	$0.48	0.8%
	45	$78.24	$99.04	$20.80	26.6%	$4.56	5.8%	$9.24	11.8%	$0.72	0.9%
Average Monthly	50	$85.41	$107.82	$22.41	26.2%	$5.07	5.9%	$10.27	12.0%	$0.80	0.9%
	75	$119.80	$149.07	$29.27	24.4%	$7.60	6.3%	$15.40	12.9%	$1.20	1.0%
	125	$188.57	$231.56	$42.98	22.8%	$12.67	6.7%	$25.66	13.6%	$2.00	1.1%
	150	$222.96	$272.80	$49.84	22.4%	$15.20	6.8%	$30.80	13.8%	$2.40	1.1%
	200	$291.73	$355.29	$63.56	21.8%	$20.27	6.9%	$41.06	14.1%	$3.20	1.1%

Schedule 9

Northern Utilities New Hampshire Division
Period Covered: May 1, 2015 - October 30, 2015
Variance Analysis

		2013-2014 Winter (6 months actual)			Forecast Winter 2014-2015 (6 months proposed)			Variance		
1	Therm Sales	32,687,745			32,046,338			-641,407		
2				EFFECT			EFFECT			EFFECT
3		THERM		ON COST	THERM		ON COST	THERM		ON COST
4		SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS	SENDOUT	COSTS	OF GAS
5										
6	Demand Charges		$ 15,075,562	$ 0.4612		$ 17,347,171	$ 0.5413		$ 2,271,609	$ 0.0801
7										
8	Purchased Gas		19,002,567	0.5813		20,393,655	0.6364		$ 1,391,088	$ 0.0550
9										
10	Storage & Peaking Gas		2,694,229	0.0824		4,932,932	0.1539		$ 2,238,703	$ 0.0715
11										
12	Hedging (Gain)/Loss		(403,749)	(0.0124)		27,935	0.0009		431,684	0.0132
13										
14										
15	Total Volumes and Cost		$ 36,368,609	$ 1.1126	$ -	$ 42,701,692	$ 1.3325	$ -	$ 6,333,083	$ 0.2199
16										
17	Prior Period Balance		(2,258,251)	$ (0.0691)		$ (3,607,559)	$ (0.1126)		$ (1,349,308)	$ (0.0435)
18							$ -			
19	Interest		$ (44,733)	$ (0.0014)		10,648	$ 0.0003		55,381	$ 0.0017
20	Refunds from Suppliers		103,007	$ 0.0032		-	$ -		(103,007)	$ (0.0032)
21	Off-system Sales		(2,569,121)	$ (0.0786)			$ -		2,569,121	$ 0.0786
22	Prior Period Adjustment									
23	Interruptible Revenues					-	$ -		-	$ -
24	Capacity Release & Asset Management		(6,007,433)	$ (0.1875)		$ (4,741,845)	$ (0.1480)		1,265,588	$ 0.0395
25	Working Capital Allowance		(1,796)	$ (0.0001)		29,474	$ 0.0009		31,270	$ 0.0010
26	Bad Debt Allowance		(118,517)	$ (0.0036)		$ 237,646	$ 0.0074		356,163	$ 0.0110
27	Fuel Inventory Financing		5,031	$ 0.0002		6,234	$ 0.0002		1,203	$ 0.0000
28	Local Production and Storage		441,308	$ 0.0135		420,658	$ 0.0131		-	$ -
29	Misc Overhead		420,658	$ 0.0129		416,811	$ 0.0130		(3,847)	$ 0.0001
30										
31	Total Anticipated Indirect Cost of Gas		($10,029,848)	$ (0.3068)		(7,227,933)	$ (0.2255)		2,801,915	$ 0.0813
32	Total Adjusted Cost		26,338,761	$ 0.8058		35,473,759	$ 1.1069		9,134,998	$ 0.3011

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**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	**Winter**	
2	**Total Therms**									
3	Res Heat	396,159	409,365	409,365	369,749	409,365	396,159	4,812,004	2,390,161	Schedule 10B, LN 52
4	Res General	11,746	12,137	12,137	10,963	12,137	11,746	142,670	70,865	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	72,578	74,998	74,998	67,740	74,998	72,578	881,584	437,890	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	144,190	148,996	148,996	134,577	148,996	144,190	1,751,425	869,946	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	98,474	101,757	101,757	91,909	101,757	98,474	1,196,133	594,129	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	148,593	153,546	153,546	138,687	153,546	148,593	1,804,907	896,511	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	17,179	17,751	17,751	16,033	17,751	17,179	208,663	103,644	Schedule 10B, LN 58
10	G42 High Annual-High Winter	19,509	20,159	20,159	18,208	20,159	19,509	236,970	117,705	Schedule 10B, LN 59
11	Total Firm Sales	908,429	938,709	938,709	847,867	938,709	908,429	11,034,355	5,480,852	Sum LN 3 : LN 10
12										
13	**% of Total**									
14	Res Heat	43.61%	43.61%	43.61%	43.61%	43.61%	43.61%			LN 3 / LN 11
15	Res General	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%			LN 4 / LN 11
16	G50 Low Annual-Low Winter	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%			LN 5 / LN 11
17	G40 Low Annual-High Winter	15.87%	15.87%	15.87%	15.87%	15.87%	15.87%			LN 6 / LN 11
18	G51 Med Annual-Low Winter	10.84%	10.84%	10.84%	10.84%	10.84%	10.84%			LN 7 / LN 11
19	G41 Med Annual-High Winter	16.36%	16.36%	16.36%	16.36%	16.36%	16.36%			LN 8 / LN 11
20	G52 High Annual-Low Winter	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%			LN 9 / LN 11
21	G42 High Annual-High Winter	2.15%	2.15%	2.15%	2.15%	2.15%	2.15%			LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			LN 11 / LN 11
23										
24	**PIPELINE BASE DEMAND COSTS**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	**Winter**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 57,254	$ 687,045	$ 343,522	Schedule 1A, LN 69
26	Res Heat	$ 24,968	$ 24,968	$ 24,968	$ 24,968	$ 24,968	$ 24,968	$ 299,615	$ 149,808	LN 25 * LN 14
27	Res General	$ 740	$ 740	$ 740	$ 740	$ 740	$ 740	$ 8,883	$ 4,442	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 4,574	$ 4,574	$ 4,574	$ 4,574	$ 4,574	$ 4,574	$ 54,891	$ 27,446	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 9,088	$ 9,088	$ 9,088	$ 9,088	$ 9,088	$ 9,088	$ 109,051	$ 54,525	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 6,206	$ 6,206	$ 6,206	$ 6,206	$ 6,206	$ 6,206	$ 74,476	$ 37,238	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 9,365	$ 9,365	$ 9,365	$ 9,365	$ 9,365	$ 9,365	$ 112,381	$ 56,190	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 12,992	$ 6,496	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 1,230	$ 1,230	$ 1,230	$ 1,230	$ 1,230	$ 1,230	$ 14,755	$ 7,377	LN 25 * LN 21
34										
35	Residential	$ 25,708	$ 25,708	$ 25,708	$ 25,708	$ 25,708	$ 25,708	$ 308,499	$ 154,249	LN 26 + LN 27
36	SALES HLF CLASSES	$ 11,863	$ 11,863	$ 11,863	$ 11,863	$ 11,863	$ 11,863	$ 142,359	$ 71,180	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 19,682	$ 19,682	$ 19,682	$ 19,682	$ 19,682	$ 19,682	$ 236,187	$ 118,093	LN 29 + LN 31 + LN 33
38										

Remaining Capacity Costs

LN		Column A Design Day Demand (MMBtu)	Column B Avg Daily Base Use Load (MMBtu)	Column C Remaining Design Day Demand (MMBtu)	Column D % of Total Remaining Design Day Demand	
39						
40	Res Heat	18,499	1,536	16,963	45.13%	Company Analysis
41	Res General	227	56	171	0.45%	Company Analysis
42	G50 Low Annual-Low Winter	984	324	660	1.76%	Company Analysis
43	G40 Low Annual-High Winter	10,253	512	9,741	25.92%	Company Analysis
44	G51 Med Annual-Low Winter	1,249	384	864	2.30%	Company Analysis
45	G41 Med Annual-High Winter	8,726	631	8,094	21.54%	Company Analysis
46	G52 High Annual-Low Winter	186	19	167	0.44%	Company Analysis
47	G42 High Annual-High Winter	980	54	926	2.46%	Company Analysis
48	TOTAL	41,103	3,517	37,586	100.00%	Sum LN 40 : LN 47

49

50 **REMAINING PIPELINE DEMAND**

LN		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
51										
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 232,387	$ 480,159	$ 1,075,580	$ 572,205	$ 317,397	$ 127,961	$ 2,903,667	$ 2,805,688	Schedule 1A, LN 70
53										
54	Res Heat	$ 104,878	$ 216,699	$ 485,415	$ 258,239	$ 143,243	$ 57,749	$ 1,310,442	$ 1,266,223	LN 40 Col D * LN 52
55	Res General	$ 1,054	$ 2,179	$ 4,881	$ 2,596	$ 1,440	$ 581	$ 13,176	$ 12,731	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 4,080	$ 8,431	$ 18,886	$ 10,047	$ 5,573	$ 2,247	$ 50,984	$ 49,264	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 60,227	$ 124,441	$ 278,754	$ 148,296	$ 82,259	$ 33,163	$ 752,533	$ 727,140	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 5,344	$ 11,043	$ 24,736	$ 13,160	$ 7,300	$ 2,943	$ 66,779	$ 64,526	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 50,045	$ 103,403	$ 231,628	$ 123,225	$ 68,352	$ 27,557	$ 625,310	$ 604,210	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 1,032	$ 2,132	$ 4,775	$ 2,540	$ 1,409	$ 568	$ 12,891	$ 12,456	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 5,726	$ 11,832	$ 26,504	$ 14,100	$ 7,821	$ 3,153	$ 71,552	$ 69,137	LN 47 Col D * LN 52
62	TOTAL	$ 232,387	$ 480,159	$ 1,075,580	$ 572,205	$ 317,397	$ 127,961	$ 2,903,667	$ 2,805,688	Sum LN 54 : LN 61
63										
64	Residential	$ 105,932	$ 218,877	$ 490,296	$ 260,836	$ 144,683	$ 58,330	$ 1,323,618	$ 1,278,955	LN 54 + LN 55
65	SALES HLF CLASSES	$ 10,457	$ 21,606	$ 48,397	$ 25,747	$ 14,282	$ 5,758	$ 130,655	$ 126,246	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 115,998	$ 239,676	$ 536,886	$ 285,622	$ 158,432	$ 63,873	$ 1,449,394	$ 1,400,487	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

LN		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
69										
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 1,175,975	$ 2,429,807	$ 5,442,884	$ 2,895,597	$ 1,606,162	$ 647,534	$ 14,693,774	$ 14,197,961	Schedule 1A, LN 73
71										
72	Res Heat	$ 530,724	$ 1,096,586	$ 2,456,405	$ 1,306,800	$ 724,870	$ 292,236	$ 6,631,386	$ 6,407,622	LN 40 Col D * LN 70
73	Res General	$ 5,336	$ 11,026	$ 24,698	$ 13,139	$ 7,288	$ 2,938	$ 66,675	$ 64,426	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 20,648	$ 42,664	$ 95,569	$ 50,843	$ 28,202	$ 11,370	$ 258,002	$ 249,296	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 304,773	$ 629,725	$ 1,410,613	$ 750,442	$ 416,263	$ 167,819	$ 3,808,133	$ 3,679,635	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 27,045	$ 55,881	$ 125,177	$ 66,594	$ 36,939	$ 14,892	$ 337,931	$ 326,529	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 253,248	$ 523,263	$ 1,172,134	$ 623,572	$ 345,890	$ 139,448	$ 3,164,329	$ 3,057,555	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 5,221	$ 10,788	$ 24,165	$ 12,855	$ 7,131	$ 2,875	$ 65,236	$ 63,034	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 28,978	$ 59,875	$ 134,122	$ 71,353	$ 39,579	$ 15,956	$ 362,081	$ 349,863	LN 47 Col D * LN 70
80	TOTAL	$ 1,175,975	$ 2,429,807	$ 5,442,884	$ 2,895,597	$ 1,606,162	$ 647,534	$ 14,693,774	$ 14,197,961	Sum LN 72 : LN 79
81										
82	Residential	$ 536,061	$ 1,107,612	$ 2,481,103	$ 1,319,939	$ 732,159	$ 295,174	$ 6,698,061	$ 6,472,048	LN 72 + LN 73
83	SALES HLF CLASSES	$ 52,915	$ 109,333	$ 244,911	$ 130,292	$ 72,272	$ 29,137	$ 661,169	$ 638,859	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 587,000	$ 1,212,863	$ 2,716,870	$ 1,445,366	$ 801,732	$ 323,223	$ 7,334,543	$ 7,087,053	LN 75 + LN 77 + LN 79

85

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

Ln		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
87		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ (406,168)	$ (810,793)	$ (1,783,147)	$ (961,109)	$ (544,994)	$ (235,634)	$ (4,741,845)	$ (4,741,845)	Schedule 1A, LN 76
89										
90	Res Heat	$ (183,306)	$ (365,916)	$ (804,745)	$ (433,754)	$ (245,959)	$ (106,343)	$ (2,140,023)	$ (2,140,023)	LN 40 Col D * LN 88
91	Res General	$ (1,843)	$ (3,679)	$ (8,091)	$ (4,361)	$ (2,473)	$ (1,069)	$ (21,517)	$ (21,517)	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ (7,132)	$ (14,236)	$ (31,310)	$ (16,876)	$ (9,569)	$ (4,137)	$ (83,260)	$ (83,260)	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ (105,265)	$ (210,130)	$ (462,132)	$ (249,087)	$ (141,244)	$ (61,068)	$ (1,228,927)	$ (1,228,927)	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ (9,341)	$ (18,647)	$ (41,009)	$ (22,104)	$ (12,534)	$ (5,419)	$ (109,054)	$ (109,054)	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ (87,469)	$ (174,606)	$ (384,004)	$ (206,976)	$ (117,365)	$ (50,744)	$ (1,021,165)	$ (1,021,165)	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ (1,803)	$ (3,600)	$ (7,917)	$ (4,267)	$ (2,420)	$ (1,046)	$ (21,052)	$ (21,052)	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ (10,009)	$ (19,979)	$ (43,940)	$ (23,683)	$ (13,430)	$ (5,806)	$ (116,848)	$ (116,848)	LN 47 Col D * LN 88
98	TOTAL	$ (406,168)	$ (810,793)	$ (1,783,147)	$ (961,109)	$ (544,994)	$ (235,634)	$ (4,741,845)	$ (4,741,845)	Sum LN 90 : LN 97
99										
100	Residential	$ (185,149)	$ (369,595)	$ (812,836)	$ (438,115)	$ (248,432)	$ (107,412)	$ (2,161,539)	$ (2,161,539)	LN 90 + LN 91
101	SALES HLF CLASSES	$ (18,276)	$ (36,483)	$ (80,235)	$ (43,247)	$ (24,523)	$ (10,603)	$ (213,367)	$ (213,367)	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ (202,743)	$ (404,716)	$ (890,076)	$ (479,747)	$ (272,039)	$ (117,619)	$ (2,366,939)	$ (2,366,939)	LN 93 + LN 95 + LN 97

103

104 **INTERRUPTIBLE MARGINS BY CLASS**

Ln		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
105		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 77
107										
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117										
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115

121

122 **REMAINING RE-ENTRY FEE CREDIT**

LN		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
123		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
124	NH DIVISION - RE-ENTRY FEE CREDITS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 78
125										
126	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 124
127	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 124
128	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 124
129	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 124
130	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 124
131	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 124
132	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 124
133	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 124
134	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 126 : LN 133
135										
136	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 126 + LN 127
137	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 128 + LN 130 + LN 132
138	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 129 + LN 131 + LN 133

139

140 **TOTAL NON-BASE CAPACITY COSTS**

LN		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
141		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
142	Res Heat	$ 452,296	$ 947,369	$ 2,137,076	$ 1,131,285	$ 622,155	$ 243,642	$ 5,801,805	$ 5,533,823	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 4,548	$ 9,525	$ 21,487	$ 11,375	$ 6,255	$ 2,450	$ 58,334	$ 55,640	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 17,597	$ 36,859	$ 83,146	$ 44,014	$ 24,206	$ 9,479	$ 225,726	$ 215,300	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 259,735	$ 544,035	$ 1,227,235	$ 649,651	$ 357,278	$ 139,914	$ 3,331,739	$ 3,177,848	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 23,049	$ 48,277	$ 108,904	$ 57,650	$ 31,705	$ 12,416	$ 295,657	$ 282,000	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 215,824	$ 452,061	$ 1,019,759	$ 539,821	$ 296,876	$ 116,260	$ 2,768,474	$ 2,640,600	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 4,449	$ 9,320	$ 21,023	$ 11,129	$ 6,120	$ 2,397	$ 57,075	$ 54,438	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 24,696	$ 51,727	$ 116,687	$ 61,769	$ 33,970	$ 13,303	$ 316,785	$ 302,153	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 1,002,194	$ 2,099,173	$ 4,735,317	$ 2,506,693	$ 1,378,565	$ 539,861	$ 12,855,595	$ 12,261,803	Sum LN 142 : LN 149
151										
152	Residential	$ 456,844	$ 956,894	$ 2,158,563	$ 1,142,660	$ 628,410	$ 246,092	$ 5,860,140	$ 5,589,463	LN 142 + LN 143
153	SALES HLF CLASSES	$ 45,095	$ 94,456	$ 213,073	$ 112,793	$ 62,031	$ 24,292	$ 578,458	$ 551,739	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 500,255	$ 1,047,823	$ 2,363,680	$ 1,251,241	$ 688,125	$ 269,477	$ 6,416,998	$ 6,120,601	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
157		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter	
158	Res Heat	$ 477,264	$ 972,337	$ 2,162,044	$ 1,156,253	$ 647,122	$ 268,610	$ 6,101,421	$ 5,683,631	LN 142 + LN 26
159	Res General	$ 5,288	$ 10,266	$ 22,228	$ 12,115	$ 6,996	$ 3,190	$ 67,218	$ 60,082	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 22,171	$ 41,433	$ 87,720	$ 48,588	$ 28,780	$ 14,053	$ 280,617	$ 242,746	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 268,823	$ 553,123	$ 1,236,323	$ 658,738	$ 366,365	$ 149,001	$ 3,440,790	$ 3,232,374	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 29,255	$ 54,484	$ 115,110	$ 63,856	$ 37,911	$ 18,622	$ 370,133	$ 319,238	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 225,189	$ 461,426	$ 1,029,124	$ 549,186	$ 306,241	$ 125,625	$ 2,880,855	$ 2,696,791	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 5,532	$ 10,402	$ 22,106	$ 12,212	$ 7,203	$ 3,479	$ 70,067	$ 60,934	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 25,925	$ 52,957	$ 117,916	$ 62,999	$ 35,200	$ 14,533	$ 331,540	$ 309,530	LN 149 + LN 33
166	TOTAL	$ 1,059,448	$ 2,156,427	$ 4,792,570	$ 2,563,947	$ 1,435,819	$ 597,114	$ 13,542,640	$ 12,605,326	Sum LN 158 : LN 165
167										
168	Residential	$ 482,552	$ 982,603	$ 2,184,272	$ 1,168,368	$ 654,118	$ 271,800	$ 6,168,638	$ 5,743,713	LN 158 + LN 159
169	SALES HLF CLASSES	$ 56,959	$ 106,319	$ 224,936	$ 124,656	$ 73,894	$ 36,155	$ 720,817	$ 622,919	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 519,937	$ 1,067,505	$ 2,383,363	$ 1,270,923	$ 707,807	$ 289,159	$ 6,653,185	$ 6,238,694	LN 161 + LN 163 + LN 165
171										
172	% ALLOCATION BETWEEN SALES HLF AND LLF									
173	SALES HLF CLASSES								9.08%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES								90.92%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Normal Winter	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	Winter
1	Res Heat	1,868,718	2,753,021	3,475,584	2,905,490	2,239,772	1,319,914	658,894	438,844	398,587	414,345	453,609	849,300	17,776,077	14,562,498
2	Res General	24,898	36,680	46,307	38,711	29,842	17,586	19,546	13,018	11,824	12,292	13,456	25,195	289,355	194,024
3	**Total Residential**	**1,893,616**	**2,789,700**	**3,521,890**	**2,944,201**	**2,269,613**	**1,337,500**	**678,440**	**451,862**	**410,412**	**426,637**	**467,066**	**874,495**	**18,065,432**	**14,756,521**
4	G50 Low Annual-Low Winter	108,395	159,689	201,601	168,533	129,918	76,562	120,779	80,442	73,063	75,952	83,149	155,682	1,433,766	844,699
5	G40 Low Annual-High Winter	1,005,941	1,481,966	1,870,926	1,564,041	1,205,682	710,517	239,949	159,813	145,153	150,892	165,191	309,289	9,009,361	7,839,073
6	G51 Med Annual-Low Winter	147,015	216,585	273,430	228,580	176,207	103,840	163,873	109,144	99,132	103,051	112,817	211,229	1,944,904	1,145,658
7	G41 Med Annual-High Winter	829,848	1,222,543	1,543,414	1,290,251	994,623	586,139	247,276	164,694	149,586	155,500	170,235	318,734	7,672,841	6,466,817
8	G52 High Annual-Low Winter	28,732	42,328	53,438	44,673	34,437	20,294	28,587	19,040	17,293	17,977	19,681	36,848	363,328	223,902
9	G42 High Annual-High Winter	98,767	145,505	183,694	153,563	118,378	69,761	32,465	21,623	19,639	20,416	22,351	41,847	928,010	769,669
10	**Total C&I**	**2,218,698**	**3,268,617**	**4,126,504**	**3,449,641**	**2,659,245**	**1,567,112**	**832,930**	**554,757**	**503,868**	**523,788**	**573,423**	**1,073,629**	**21,352,211**	**17,289,817**
11	**Total Sales**	**4,112,314**	**6,058,317**	**7,648,394**	**6,393,843**	**4,928,858**	**2,904,612**	**1,511,370**	**1,006,619**	**914,279**	**950,425**	**1,040,489**	**1,948,123**	**39,417,643**	**32,046,338**
12															
13	Residential Heat & Non Heat	1,893,616	2,789,700	3,521,890	2,944,201	2,269,613	1,337,500	678,440	451,862	410,412	426,637	467,066	874,495	18,065,432	14,756,521
14	SALES HLF CLASSES	284,142	418,603	528,470	441,786	340,562	200,696	313,239	208,627	189,489	196,980	215,647	403,758	3,741,998	2,214,258
15	SALES LLF CLASSES	1,934,556	2,850,014	3,598,034	3,007,855	2,318,683	1,366,417	519,691	346,130	314,379	326,808	357,776	669,870	17,610,213	15,075,559
16	**Total Firm Sales**	**4,112,314**	**6,058,317**	**7,648,394**	**6,393,843**	**4,928,858**	**2,904,612**	**1,511,370**	**1,006,619**	**914,279**	**950,425**	**1,040,489**	**1,948,123**	**39,417,643**	**32,046,338**
17															
18	**ESTIMATED SENDOUT BY CLASS - Therms**														
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)														
20	Normal Winter	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Winter**
21	Res Heat	1,881,294	2,771,440	3,498,789	2,924,920	2,254,823	1,328,870	663,476	441,970	401,430	417,299	456,827	855,162	17,896,299	14,660,135
22	Res General	25,054	36,908	46,594	38,951	30,028	17,697	19,672	13,104	11,902	12,372	13,544	25,355	291,180	195,231
23	G50 Low Annual-Low Winter	109,073	160,681	202,850	169,579	130,729	77,045	121,554	80,969	73,544	76,451	83,692	156,673	1,442,840	849,956
24	G40 Low Annual-High Winter	1,012,230	1,491,166	1,882,511	1,573,745	1,213,207	715,004	241,490	160,859	146,109	151,884	166,269	311,260	9,065,734	7,887,863
25	G51 Med Annual-Low Winter	147,934	217,930	275,123	229,998	177,307	104,496	164,925	109,859	99,785	103,729	113,553	212,575	1,957,214	1,152,788
26	G41 Med Annual-High Winter	835,036	1,230,133	1,552,971	1,298,255	1,000,831	589,840	248,864	165,771	150,571	156,522	171,347	320,765	7,720,905	6,507,066
27	G52 High Annual-Low Winter	28,912	42,591	53,769	44,950	34,652	20,422	28,771	19,165	17,407	18,095	19,809	37,083	365,625	225,295
28	G42 High Annual-High Winter	99,384	146,408	184,832	154,516	119,117	70,202	32,674	21,765	19,769	20,550	22,496	42,114	933,827	774,459
29	**Subtotal**														
30	Residential	1,906,348	2,808,347	3,545,382	2,963,871	2,284,851	1,346,566	683,147	455,073	413,332	429,671	470,372	880,517	18,187,480	14,855,366
31	SALES HLF CLASSES	285,919	421,201	531,742	444,527	342,688	201,963	315,250	209,992	190,737	198,275	217,055	406,331	3,765,679	2,228,039
32	SALES LLF CLASSES	1,946,650	2,867,707	3,620,314	3,026,516	2,333,155	1,375,046	523,028	348,395	316,449	328,955	360,112	674,139	17,720,466	15,169,388
33	**Total Firm Sales**	4,138,917	6,097,256	7,697,438	6,434,914	4,960,694	2,923,575	1,521,425	1,013,461	920,518	956,901	1,047,538	1,960,987	39,673,625	32,252,793

Northern Utilities - NEW HAMPSHIRE DIV

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 &	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

DAILY BASE GAS ENTITLEMENT - Therms/day	
Res Heat	13,205
Res General	392
G50 Low Annual-Low Winter	2,419
G40 Low Annual-High Winter	4,806
G51 Med Annual-Low Winter	3,282
G41 Med Annual-High Winter	4,953
G52 High Annual-Low Winter	573
G42 High Annual-High Winter	650
Subtotal	
Residential	13,597
SALES HLF CLASSES	6,274
SALES LLF CLASSES	10,410
Total Firm Sales	**30,281**

BASE SENDOUT BY CLASS - Therms														
Days per Month	30	31	31	28	31	30	31	30	31	31	30	31		
	Nov-14	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Winter**
Res Heat	396,159	409,365	409,365	369,749	409,365	396,159	409,365	396,159	401,430	409,365	396,159	409,365	4,812,004	2,390,161
Res General	11,746	12,137	12,137	10,963	12,137	11,746	12,137	11,746	11,902	12,137	11,746	12,137	142,670	70,865
G50 Low Annual-Low Winter	72,578	74,998	74,998	67,740	74,998	72,578	74,998	72,578	73,544	74,998	72,578	74,998	881,584	437,890
G40 Low Annual-High Winter	144,190	148,996	148,996	134,577	148,996	144,190	148,996	144,190	146,109	148,996	144,190	148,996	1,751,425	869,946
G51 Med Annual-Low Winter	98,474	101,757	101,757	91,909	101,757	98,474	101,757	98,474	99,785	101,757	98,474	101,757	1,196,133	594,129
G41 Med Annual-High Winter	148,593	153,546	153,546	138,687	153,546	148,593	153,546	148,593	150,571	153,546	148,593	153,546	1,804,907	896,511
G52 High Annual-Low Winter	17,179	17,751	17,751	16,033	17,751	17,179	17,751	17,179	17,407	17,751	17,179	17,751	208,663	103,644
G42 High Annual-High Winter	19,509	20,159	20,159	18,208	20,159	19,509	20,159	19,509	19,769	20,159	19,509	20,159	236,970	117,705
Subtotal														
Residential	407,905	421,502	421,502	380,711	421,502	407,905	421,502	407,905	413,332	421,502	407,905	421,502	4,954,674	2,461,027
SALES HLF CLASSES	188,231	194,506	194,506	175,683	194,506	188,231	194,506	188,231	190,737	194,506	188,231	194,506	2,286,380	1,135,663
SALES LLF CLASSES	312,292	322,702	322,702	291,473	322,702	312,292	322,702	312,292	316,449	322,702	312,292	322,702	3,793,302	1,884,163
Total Firm Sales	908,429	938,709	938,709	847,867	938,709	908,429	938,709	908,429	920,518	938,709	908,429	938,709	11,034,355	5,480,852

REMAINING SENDOUT BY CLASS - Therms														
	Nov-14	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Annual**	**Winter**
Res Heat	1,485,135	2,362,075	3,089,424	2,555,171	1,845,458	932,710	254,111	45,811	-	7,934	60,668	445,798	13,084,296	12,269,974
Res General	13,308	24,770	34,457	27,989	17,891	5,951	7,534	1,358	-	235	1,799	13,218	148,510	124,366
G50 Low Annual-Low Winter	36,494	85,683	127,852	101,839	55,731	4,467	46,557	8,391	-	1,453	11,114	81,676	561,256	412,066
G40 Low Annual-High Winter	868,040	1,342,170	1,733,514	1,439,167	1,064,211	570,814	92,493	16,669	-	2,887	22,079	162,264	7,314,309	7,017,916
G51 Med Annual-Low Winter	49,460	116,173	173,367	138,089	75,550	6,021	63,168	11,384	-	1,972	15,079	110,818	761,081	558,660
G41 Med Annual-High Winter	686,443	1,076,587	1,399,425	1,159,568	847,285	441,247	95,318	17,178	-	2,975	22,753	167,219	5,915,998	5,610,555
G52 High Annual-Low Winter	11,733	24,840	36,017	28,916	16,901	3,243	11,020	1,986	-	344	2,630	19,332	156,963	121,651
G42 High Annual-High Winter	79,875	126,249	164,672	136,307	98,958	50,693	12,514	2,255	-	391	2,987	21,954	696,856	656,754
Subtotal														
Residential	1,498,443	2,386,845	3,123,881	2,583,160	1,863,349	938,662	261,646	47,168	-	8,170	62,467	459,016	13,232,806	12,394,340
SALES HLF CLASSES	97,687	226,695	337,236	268,844	148,182	13,732	120,745	21,761	-	3,769	28,823	211,825	1,479,300	1,092,377
SALES LLF CLASSES	1,634,358	2,545,005	3,297,612	2,735,043	2,010,453	1,062,754	200,326	36,103	-	6,253	47,820	351,437	13,927,164	13,285,225
Total Firm Sales	3,230,488	5,158,546	6,758,729	5,587,047	4,021,984	2,015,147	582,716	105,033	-	18,192	139,110	1,022,278	28,639,269	26,771,941

Northern Utilities - NEW HAMPSHIRE DIV
Sendout by Class - Allocation between B Remaining Sendout

LN		
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
Billed Distribution Service Volumes and Meter Counts

	Total Division Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	666,556	626,941	39,615	6.3%	13,959	25,656	511,721	154,835	30.3%	22,744	132,091
Dec	899,446	846,547	52,898	6.2%	18,850	34,048	801,556	97,890	12.2%	37,094	60,795
Jan	1,197,339	1,126,289	71,049	6.3%	25,093	45,957	1,046,910	150,429	14.4%	49,006	101,423
Feb	1,196,059	1,125,318	70,741	6.3%	25,071	45,670	1,076,904	119,155	11.1%	50,577	68,578
Mar	1,066,133	1,003,409	62,724	6.3%	22,344	40,379	956,164	109,969	11.5%	45,800	64,169
Apr	789,010	743,126	45,884	6.2%	16,559	29,325	700,207	88,803	12.7%	31,500	57,302
May	555,928	523,415	32,513	6.2%	11,650	20,864	493,031	62,897	12.8%	22,153	40,744
Jun	429,229	404,212	25,017	6.2%	8,997	16,020	380,854	48,375	12.7%	17,113	31,262
Jul	350,230	330,053	20,178	6.1%	7,348	12,830	311,193	39,037	12.5%	13,986	25,052
Aug	357,240	336,541	20,699	6.2%	7,503	13,196	317,208	40,032	12.6%	14,277	25,755
Sep	364,504	343,111	21,394	6.2%	7,645	13,748	323,141	41,363	12.8%	14,536	26,827
Oct	461,920	434,798	27,122	6.2%	9,707	17,415	409,469	52,450	12.8%	18,456	33,994
Peak	5,814,542	5,471,630	342,912	6.3%	121,878	221,034	5,093,461	721,081	14.2%	235,483	485,598
Off-Peak	2,519,052	2,372,129	146,922	6.2%	52,849	94,073	2,234,898	284,154	12.7%	100,523	183,631
Annual	8,333,594	7,843,760	489,834	6.2%	174,727	315,107	7,328,359	1,005,235	13.7%	334,210	671,026

Note 1 Company Forecast
Note 2 Pages 2 - 4; Sum of Column 2 of Billed Deliveries table. Actual Data through March 2014 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						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	30,713	30,044	669	2.2%	29,406	1,307	4.4%
Dec	30,870	30,198	672	2.2%	29,505	1,365	4.6%
Jan	30,973	30,298	675	2.2%	29,588	1,385	4.7%
Feb	31,000	30,324	676	2.2%	29,609	1,391	4.7%
Mar	31,052	30,376	676	2.2%	29,633	1,419	4.8%
Apr	31,063	30,386	677	2.2%	29,726	1,337	4.5%
May	30,992	30,317	675	2.2%	29,659	1,333	4.5%
Jun	30,934	30,261	674	2.2%	29,604	1,330	4.5%
Jul	30,846	30,174	672	2.2%	29,519	1,327	4.5%
Aug	30,881	30,208	673	2.2%	29,551	1,330	4.5%
Sep	30,940	30,265	674	2.2%	29,608	1,332	4.5%
Oct	31,182	30,501	681	2.2%	29,837	1,345	4.5%
Peak	30,945	30,271	674	2.2%	29,578	1,367	4.6%
Off-Peak	30,962	30,288	675	2.2%	29,630	1,333	4.5%
Annual	30,954	30,279	675	2.2%	29,604	1,350	4.6%

Note 1 Company Forecast
Note 2 Actual data through March 2014. Forecast data beginning April 2014. 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						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	21.70	20.87	0.84	4.0%	17.40	4.30	24.7%
Dec	29.14	28.03	1.10	3.9%	27.17	1.97	7.2%
Jan	38.66	37.17	1.48	4.0%	35.38	3.27	9.3%
Feb	38.58	37.11	1.47	4.0%	36.37	2.21	6.1%
Mar	34.33	33.03	1.30	3.9%	32.27	2.07	6.4%
Apr	25.40	24.46	0.94	3.9%	23.56	1.84	7.8%
May	17.94	17.26	0.67	3.9%	16.62	1.31	7.9%
Jun	13.88	13.36	0.52	3.9%	12.86	1.01	7.9%
Jul	11.35	10.94	0.42	3.8%	10.54	0.81	7.7%
Aug	11.57	11.14	0.43	3.8%	10.73	0.83	7.8%
Sep	11.78	11.34	0.44	3.9%	10.91	0.87	7.9%
Oct	14.81	14.26	0.56	3.9%	13.72	1.09	7.9%
Peak	187.90	180.75	7.14	4.0%	172.21	15.67	9.1%
Off-Peak	81.36	78.32	3.04	3.9%	75.43	5.93	7.9%
Annual	269.23	259.05	10.18	3.9%	247.55	21.60	8.7%

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
Billed Distribution Service Volumes and Meter Counts

	Residential Non-Heat Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	2,247	2,414	-167	-6.9%	75	-242	2,213	34	1.5%	224	-190
Dec	2,915	3,132	-217	-6.9%	98	-314	3,475	-560	-16.1%	363	-923
Jan	3,914	4,205	-291	-6.9%	131	-422	4,486	-572	-12.8%	479	-1,051
Feb	3,954	4,248	-294	-6.9%	132	-426	4,777	-823	-17.2%	482	-1,306
Mar	3,537	3,800	-263	-6.9%	118	-381	4,044	-507	-12.5%	416	-923
Apr	2,835	3,046	-211	-6.9%	95	-306	3,273	-437	-13.4%	207	-644
May	2,154	2,314	-160	-6.9%	72	-232	2,486	-332	-13.4%	157	-490
Jun	2,427	2,608	-180	-6.9%	81	-262	2,802	-374	-13.4%	177	-552
Jul	730	784	-54	-6.9%	24	-79	842	-113	-13.4%	53	-166
Aug	1,376	1,478	-102	-6.9%	46	-148	1,588	-212	-13.4%	100	-313
Sep	1,352	1,453	-101	-6.9%	45	-146	1,561	-209	-13.4%	99	-307
Oct	1,494	1,605	-111	-6.9%	50	-161	1,725	-230	-13.4%	109	-340
Peak	19,402	20,845	-1,443	-6.9%	650	-2,092	22,268	-2,866	-12.9%	2,148	-5,014
Off-Peak	9,533	10,242	-709	-6.9%	319	-1,028	11,003	-1,470	-13.4%	696	-2,167
Annual	28,935	31,087	-2,151	-6.9%	969	-3,120	33,272	-4,336	-13.0%	2,640	-6,976

Note 1 Company Forecast
Note 2 Actual, weather normalized data through March 2014. Forecast data beginning April 2014.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data through March 2014. Forecast data beginning April 2014.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1,604	1,556	48	3.1%	1,457	147	10.1%
Dec	1,602	1,554	48	3.1%	1,451	151	10.4%
Jan	1,598	1,550	48	3.1%	1,444	154	10.7%
Feb	1,594	1,546	48	3.1%	1,448	146	10.1%
Mar	1,602	1,554	48	3.1%	1,453	149	10.3%
Apr	1,577	1,529	48	3.1%	1,483	94	6.3%
May	1,607	1,558	49	3.1%	1,511	96	6.3%
Jun	1,602	1,554	48	3.1%	1,507	95	6.3%
Jul	1,597	1,549	48	3.1%	1,502	95	6.3%
Aug	1,730	1,678	52	3.1%	1,627	103	6.3%
Sep	1,703	1,652	51	3.1%	1,602	101	6.3%
Oct	1,671	1,621	51	3.1%	1,572	99	6.3%
Peak	1,596	1,548	48	3.1%	1,456	140	9.6%
Off-Peak	1,652	1,602	50	3.1%	1,554	98	6.3%
Annual	1,624	1,575	49	3.1%	1,505	119	7.9%

Note 1 Company Forecast
Note 2 Actual data through March 2014. Forecast data beginning April 2014.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1.40	1.55	-0.15	-9.7%	1.52	-0.12	-7.8%
Dec	1.82	2.02	-0.20	-9.7%	2.40	-0.58	-24.0%
Jan	2.45	2.71	-0.26	-9.7%	3.11	-0.66	-21.2%
Feb	2.48	2.75	-0.27	-9.7%	3.30	-0.82	-24.8%
Mar	2.21	2.45	-0.24	-9.7%	2.78	-0.58	-20.7%
Apr	1.80	1.99	-0.19	-9.7%	2.21	-0.41	-18.5%
May	1.34	1.49	-0.14	-9.7%	1.65	-0.30	-18.5%
Jun	1.51	1.68	-0.16	-9.7%	1.86	-0.34	-18.5%
Jul	0.46	0.51	-0.05	-9.7%	0.56	-0.10	-18.5%
Aug	0.80	0.88	-0.09	-9.7%	0.98	-0.18	-18.5%
Sep	0.79	0.88	-0.09	-9.7%	0.97	-0.18	-18.5%
Oct	0.89	0.99	-0.10	-9.7%	1.10	-0.20	-18.5%
Peak	12.15	13.46	-1.31	-9.7%	15.29	-3.16	-20.6%
Off-Peak	5.77	6.39	-0.62	-9.7%	7.08	-1.32	-18.6%
Annual	17.82	19.74	-1.92	-9.7%	22.11	-4.47	-20.2%

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

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

	Residential Heat Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	126,151	121,210	4,941	4.1%	2,811	2,130	90,867	35,285	38.8%	4,001	31,283
Dec	221,684	213,001	8,683	4.1%	4,939	3,743	203,629	18,055	8.9%	9,258	8,797
Jan	318,582	306,105	12,478	4.1%	7,098	5,380	283,638	34,945	12.3%	12,891	22,054
Feb	325,933	313,167	12,766	4.1%	7,262	5,504	305,876	20,057	6.6%	13,806	6,250
Mar	274,426	263,678	10,748	4.1%	6,114	4,634	253,039	21,387	8.5%	11,729	9,658
Apr	189,473	182,052	7,421	4.1%	4,222	3,199	174,921	14,551	8.3%	8,206	6,345
May	103,615	99,557	4,058	4.1%	2,309	1,750	95,658	7,958	8.3%	4,488	3,470
Jun	58,985	56,675	2,310	4.1%	1,314	996	54,455	4,530	8.3%	2,555	1,975
Jul	36,782	35,342	1,441	4.1%	820	621	33,957	2,825	8.3%	1,593	1,232
Aug	33,792	32,469	1,324	4.1%	753	571	31,197	2,595	8.3%	1,464	1,132
Sep	34,615	33,259	1,356	4.1%	771	584	31,956	2,658	8.3%	1,499	1,159
Oct	53,568	51,470	2,098	4.1%	1,194	905	49,454	4,114	8.3%	2,320	1,794
Peak	1,456,250	1,399,214	57,036	4.1%	32,446	24,590	1,311,970	144,280	11.0%	59,777	84,503
Off-Peak	321,358	308,772	12,586	4.1%	7,160	5,426	296,678	24,680	8.3%	13,919	10,761
Annual	1,777,608	1,707,985	69,622	4.1%	39,606	30,016	1,608,648	168,960	10.5%	74,382	94,578

Note 1 Company Forecast
Note 2 Actual, weather normalized data through March 2014. Forecast data beginning April 2014.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data through March 2014. Forecast data beginning April 2014.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	22,394	21,886	508	2.3%	21,449	945	4.4%
Dec	22,520	22,010	510	2.3%	21,541	979	4.5%
Jan	22,586	22,074	512	2.3%	21,604	982	4.5%
Feb	22,607	22,095	512	2.3%	21,631	976	4.5%
Mar	22,646	22,133	513	2.3%	21,643	1,003	4.6%
Apr	22,739	22,224	515	2.3%	21,720	1,019	4.7%
May	22,689	22,175	514	2.3%	21,672	1,017	4.7%
Jun	22,656	22,143	513	2.3%	21,641	1,015	4.7%
Jul	22,601	22,089	512	2.3%	21,588	1,013	4.7%
Aug	22,504	21,994	510	2.3%	21,496	1,008	4.7%
Sep	22,546	22,035	511	2.3%	21,536	1,010	4.7%
Oct	22,738	22,223	515	2.3%	21,719	1,019	4.7%
Peak	22,582	22,070	512	2.3%	21,598	984	4.6%
Off-Peak	22,622	22,110	513	2.3%	21,609	1,014	4.7%
Annual	22,602	22,090	512	2.3%	21,603	999	4.6%

Note 1 Company Forecast
Note 2 Actual data through March 2014. Forecast data beginning April 2014.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	5.63	5.54	0.10	1.7%	4.24	1.40	33.0%
Dec	9.84	9.68	0.17	1.7%	9.45	0.39	4.1%
Jan	14.11	13.87	0.24	1.7%	13.13	0.98	7.4%
Feb	14.42	14.17	0.24	1.7%	14.14	0.28	2.0%
Mar	12.12	11.91	0.20	1.7%	11.69	0.43	3.6%
Apr	8.33	8.19	0.14	1.7%	8.05	0.28	3.5%
May	4.57	4.49	0.08	1.7%	4.41	0.15	3.5%
Jun	2.60	2.56	0.04	1.7%	2.52	0.09	3.5%
Jul	1.63	1.60	0.03	1.7%	1.57	0.05	3.5%
Aug	1.50	1.48	0.03	1.7%	1.45	0.05	3.5%
Sep	1.54	1.51	0.03	1.7%	1.48	0.05	3.5%
Oct	2.36	2.32	0.04	1.7%	2.28	0.08	3.5%
Peak	64.49	63.40	1.09	1.7%	60.74	3.75	6.2%
Off-Peak	14.21	13.97	0.24	1.7%	13.73	0.48	3.5%
Annual	78.65	77.32	1.33	1.7%	74.46	4.22	5.7%

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
Billed Distribution Service Volumes and Meter Counts

	Total Division C&I Metered Deliveries (Dth)										
	2014-2015	2014-2015 Compared to 2013-2014					2014-2015 Compared to 2012-2013				
	Forecast	2013-2014 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2012-2013 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	538,158	503,317	34,841	6.9%	8,612	26,229	418,642	119,516	28.5%	13,845	105,671
Dec	674,846	630,414	44,432	7.0%	10,797	33,635	594,452	80,394	13.5%	21,414	58,980
Jan	874,843	815,980	58,863	7.2%	14,041	44,821	758,786	116,056	15.3%	28,872	87,185
Feb	866,173	807,903	58,270	7.2%	13,911	44,359	766,250	99,922	13.0%	31,456	68,466
Mar	788,169	735,931	52,239	7.1%	12,627	39,612	699,081	89,089	12.7%	28,529	60,560
Apr	596,702	558,028	38,674	6.9%	9,600	29,074	522,013	74,689	14.3%	17,961	56,728
May	450,159	421,544	28,615	6.8%	7,171	21,444	394,887	55,272	14.0%	13,430	41,841
Jun	367,817	344,929	22,887	6.6%	5,866	17,021	323,597	44,219	13.7%	11,003	33,217
Jul	312,718	293,927	18,791	6.4%	5,003	13,788	276,393	36,325	13.1%	9,406	26,919
Aug	322,072	302,594	19,478	6.4%	5,146	14,332	284,423	37,649	13.2%	9,670	27,978
Sep	328,537	308,399	20,138	6.5%	5,248	14,890	289,624	38,913	13.4%	9,854	29,059
Oct	406,858	381,723	25,135	6.6%	6,601	18,534	358,291	48,567	13.6%	12,392	36,175
Peak	4,338,890	4,051,572	287,318	7.1%	69,588	217,730	3,759,223	579,667	15.4%	139,995	439,672
Off-Peak	2,188,161	2,053,116	135,045	6.6%	35,037	100,008	1,927,216	260,945	13.5%	65,736	195,208
Annual	6,527,051	6,104,688	422,363	6.9%	104,625	317,738	5,686,440	840,611	14.8%	202,902	637,709

Note 1 Company Forecast
Note 2 Actual, weather normalized data through March 2014. Forecast data beginning April 2014.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data through March 2014. Forecast data beginning April 2014.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	6,715	6,602	113	1.7%	6,500	215	3.3%
Dec	6,748	6,634	114	1.7%	6,513	235	3.6%
Jan	6,789	6,674	115	1.7%	6,540	249	3.8%
Feb	6,798	6,683	115	1.7%	6,530	268	4.1%
Mar	6,804	6,689	115	1.7%	6,537	267	4.1%
Apr	6,747	6,633	114	1.7%	6,523	224	3.4%
May	6,696	6,584	112	1.7%	6,476	220	3.4%
Jun	6,676	6,564	112	1.7%	6,456	220	3.4%
Jul	6,648	6,537	111	1.7%	6,429	219	3.4%
Aug	6,647	6,535	111	1.7%	6,428	219	3.4%
Sep	6,690	6,578	112	1.7%	6,470	220	3.4%
Oct	6,772	6,657	115	1.7%	6,546	226	3.5%
Peak	6,767	6,653	114	1.7%	6,524	243	3.7%
Off-Peak	6,688	6,576	112	1.7%	6,468	221	3.4%
Annual	6,727	6,614	113	1.7%	6,496	232	3.6%

Note 1 Company Forecast
Note 2 Actual data through March 2014. Forecast data beginning April 2014.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2014-2015	Compared to 2013-2014			Compared to 2012-2013		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	80.14	76.24	3.91	5.1%	64.41	15.74	24.4%
Dec	100.01	95.03	4.98	5.2%	91.27	8.74	9.6%
Jan	128.86	122.26	6.60	5.4%	116.02	12.84	11.1%
Feb	127.41	120.89	6.53	5.4%	117.34	10.07	8.6%
Mar	115.84	110.02	5.82	5.3%	106.94	8.90	8.3%
Apr	88.43	84.13	4.31	5.1%	80.03	8.41	10.5%
May	67.23	64.02	3.20	5.0%	60.98	6.25	10.2%
Jun	55.10	52.55	2.55	4.9%	50.12	4.98	9.9%
Jul	47.04	44.97	2.07	4.6%	42.99	4.05	9.4%
Aug	48.46	46.30	2.16	4.7%	44.25	4.21	9.5%
Sep	49.11	46.88	2.23	4.7%	44.76	4.34	9.7%
Oct	60.08	57.34	2.74	4.8%	54.73	5.34	9.8%
Peak	641.20	609.03	32.18	5.3%	576.23	64.70	11.2%
Off-Peak	327.17	312.22	14.95	4.8%	297.98	29.17	9.8%
Annual	970.21	922.96	47.25	5.1%	875.42	93.87	10.7%

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
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
Nov-14	2,490	186,872	100,594	10,840	82,985	14,702	9,877	2,873	0	411,231
Dec-14	3,668	275,302	148,197	15,969	122,254	21,659	14,550	4,233	0	605,832
Jan-15	4,631	347,558	187,093	20,160	154,341	27,343	18,369	5,344	0	764,839
Feb-15	3,871	290,549	156,404	16,853	129,025	22,858	15,356	4,467	0	639,384
Mar-15	2,984	223,977	120,568	12,992	99,462	17,621	11,838	3,444	0	492,886
Apr-15	1,759	131,991	71,052	7,656	58,614	10,384	6,976	2,029	0	290,461
May-15	1,955	65,889	23,995	12,078	24,728	16,387	3,247	2,859	0	151,137
Jun-15	1,302	43,884	15,981	8,044	16,469	10,914	2,162	1,904	0	100,662
Jul-15	1,182	39,859	14,515	7,306	14,959	9,913	1,964	1,729	0	91,428
Aug-15	1,229	41,435	15,089	7,595	15,550	10,305	2,042	1,798	0	95,043
Sep-15	1,346	45,361	16,519	8,315	17,024	11,282	2,235	1,968	0	104,049
Oct-15	2,519	84,930	30,929	15,568	31,873	21,123	4,185	3,685	0	194,812
Peak	19,402	1,456,250	783,907	84,470	646,682	114,566	76,967	22,390	0	3,204,634
Off-Peak	9,533	321,358	117,029	58,907	120,602	79,925	15,834	13,943	0	737,130
Total	28,935	1,777,608	900,936	143,377	767,284	194,490	92,801	36,333	0	3,941,764

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
Nov-14	2,490	186,872	122,649	15,423	155,506	46,918	58,015	128,155	79,888	795,914
Dec-14	3,668	275,302	174,042	21,340	207,236	59,410	70,960	151,042	93,614	1,056,614
Jan-15	4,631	347,558	216,690	26,311	251,661	70,575	82,968	173,466	107,205	1,281,064
Feb-15	3,871	290,549	183,102	22,401	216,813	61,856	73,629	156,124	96,706	1,105,051
Mar-15	2,984	223,977	145,792	18,233	182,401	54,465	66,891	146,723	91,364	932,830
Apr-15	1,759	131,991	91,268	11,857	125,088	39,914	51,100	116,865	73,226	643,069
May-15	1,955	65,889	30,835	17,243	47,334	42,994	32,199	126,435	94,525	459,409
Jun-15	1,302	43,884	22,401	12,891	37,683	35,882	29,331	117,869	88,703	389,947
Jul-15	1,182	39,859	20,483	11,812	34,680	33,124	27,221	109,535	82,461	360,358
Aug-15	1,229	41,435	21,277	12,268	35,999	34,373	28,232	113,585	85,507	373,904
Sep-15	1,346	45,361	22,916	13,145	38,163	36,162	29,309	117,527	88,392	392,321
Oct-15	2,519	84,930	38,658	21,404	57,415	51,184	36,896	143,308	106,799	543,113
Peak	19,402	1,456,250	933,543	115,565	1,138,705	333,138	403,563	872,374	542,002	5,814,542
Off-Peak	9,533	321,358	156,569	88,764	251,274	233,720	183,187	728,260	546,386	2,519,052
Total	28,935	1,777,608	1,090,112	204,329	1,389,978	566,858	586,751	1,600,634	1,088,389	8,333,594

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-14	100%	100%	82%	70%	53%	31%	17%	2%	0%	52%
Dec-14	100%	100%	85%	75%	59%	36%	21%	3%	0%	57%
Jan-15	100%	100%	86%	77%	61%	39%	22%	3%	0%	60%
Feb-15	100%	100%	85%	75%	60%	37%	21%	3%	0%	58%
Mar-15	100%	100%	83%	71%	55%	32%	18%	2%	0%	53%
Apr-15	100%	100%	78%	65%	47%	26%	14%	2%	0%	45%
May-15	100%	100%	78%	70%	52%	38%	10%	2%	0%	33%
Jun-15	100%	100%	71%	62%	44%	30%	7%	2%	0%	26%
Jul-15	100%	100%	71%	62%	43%	30%	7%	2%	0%	25%
Aug-15	100%	100%	71%	62%	43%	30%	7%	2%	0%	25%
Sep-15	100%	100%	72%	63%	45%	31%	8%	2%	0%	27%
Oct-15	100%	100%	80%	73%	56%	41%	11%	3%	0%	36%
Peak	100%	100%	84%	73%	57%	34%	19%	3%	0%	55%
Off-Peak	100%	100%	75%	66%	48%	34%	9%	2%	0%	29%
Total	100%	100%	83%	70%	55%	34%	16%	2%	0%	47%

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
Nov-14	2,247	126,151	56,552	10,980	52,774	16,288	8,427	5,798		279,218
Dec-14	2,915	221,684	112,753	12,563	90,325	17,710	12,949	2,954		473,854
Jan-15	3,914	318,582	176,567	16,939	150,268	21,504	16,868	3,195		707,838
Feb-15	3,954	325,933	182,550	17,406	144,925	21,589	16,155	3,320		715,832
Mar-15	3,537	274,426	154,877	15,861	136,451	19,702	13,233	3,401		621,488
Apr-15	2,835	189,473	100,608	10,721	71,938	17,773	9,334	3,722		406,405
May-15	2,154	103,615	47,377	9,698	39,931	16,980	4,347	2,760		226,863
Jun-15	2,427	58,985	20,521	10,129	23,325	13,130	3,024	1,706		133,248
Jul-15	730	36,782	10,917	9,425	7,883	11,301	1,752	2,820		81,610
Aug-15	1,376	33,792	9,611	10,064	12,539	12,702	2,313	1,752		84,149
Sep-15	1,352	34,615	9,508	10,300	12,393	12,829	785	2,441		84,225
Oct-15	1,494	53,568	19,094	9,292	24,531	12,982	3,613	2,463		127,036
Peak	19,402	1,456,250	783,907	84,470	646,682	114,566	76,967	22,390	0	3,204,634
Off-Peak	9,533	321,358	117,029	58,907	120,602	79,925	15,834	13,943	0	737,130
Total	28,935	1,777,608	900,936	143,377	767,284	194,490	92,801	36,333	0	3,941,764

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
Nov-14	2,247	126,151	71,081	15,164	104,296	45,967	55,159	155,171	91,320	666,556
Dec-14	2,915	221,684	137,767	17,288	169,184	50,919	69,364	139,671	90,653	899,446
Jan-15	3,914	318,582	209,433	22,626	258,042	63,794	86,184	150,613	84,150	1,197,339
Feb-15	3,954	325,933	215,976	23,092	248,026	65,176	76,743	152,975	84,184	1,196,059
Mar-15	3,537	274,426	181,720	21,040	219,601	59,803	67,044	143,154	95,806	1,066,133
Apr-15	2,835	189,473	117,565	16,355	139,556	47,478	49,069	130,790	95,889	789,010
May-15	2,154	103,615	57,819	14,777	79,338	44,330	33,701	130,317	89,876	555,928
Jun-15	2,427	58,985	28,631	15,613	45,429	38,339	34,477	118,375	86,953	429,229
Jul-15	730	36,782	15,688	14,187	25,147	33,669	26,740	106,605	90,683	350,230
Aug-15	1,376	33,792	16,449	15,019	25,392	36,274	30,299	108,194	90,445	357,240
Sep-15	1,352	34,615	13,780	15,322	27,817	40,834	19,516	123,801	87,467	364,504
Oct-15	1,494	53,568	24,203	13,845	48,149	40,275	38,456	140,968	100,963	461,920
Peak	19,402	1,456,250	933,543	115,565	1,138,705	333,138	403,563	872,374	542,002	5,814,542
Off-Peak	9,533	321,358	156,569	88,764	251,274	233,720	183,187	728,260	546,386	2,519,052
Total	28,935	1,777,608	1,090,112	204,329	1,389,978	566,858	586,751	1,600,634	1,088,389	8,333,594

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-14	100%	100%	80%	72%	51%	35%	15%	4%	0%	42%
Dec-14	100%	100%	82%	73%	53%	35%	19%	2%	0%	53%
Jan-15	100%	100%	84%	75%	58%	34%	20%	2%	0%	59%
Feb-15	100%	100%	85%	75%	58%	33%	21%	2%	0%	60%
Mar-15	100%	100%	85%	75%	62%	33%	20%	2%	0%	58%
Apr-15	100%	100%	86%	66%	52%	37%	19%	3%	0%	52%
May-15	100%	100%	82%	66%	50%	38%	13%	2%	0%	41%
Jun-15	100%	100%	72%	65%	51%	34%	9%	1%	0%	31%
Jul-15	100%	100%	70%	66%	31%	34%	7%	3%	0%	23%
Aug-15	100%	100%	58%	67%	49%	35%	8%	2%	0%	24%
Sep-15	100%	100%	69%	67%	45%	31%	4%	2%	0%	23%
Oct-15	100%	100%	79%	67%	51%	32%	9%	2%	0%	28%
Peak	100%	100%	84%	73%	57%	34%	19%	3%	0%	55%
Off-Peak	100%	100%	75%	66%	48%	34%	9%	2%	0%	29%
Total	100%	100%	83%	70%	55%	34%	16%	2%	0%	47%

Northern Utilities, Inc.
New Hampshire Division
Estimation of Northern - New Hampshire City-Gate Sendout Requirement

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-14	795,914	0.02%	159	279,218	132,014	411,231	411,391	0.63%	2,608	413,999	34,804	448,803
Dec-14	1,056,614	0.02%	211	473,854	131,977	605,832	606,043	0.63%	3,842	609,885	81,127	691,012
Jan-15	1,281,064	0.02%	256	707,838	57,002	764,839	765,096	0.63%	4,850	769,946	122,398	892,344
Feb-15	1,105,051	0.02%	221	715,832	-76,448	639,384	639,605	0.63%	4,055	643,660	101,808	745,468
Mar-15	932,830	0.02%	187	621,488	-128,602	492,886	493,072	0.63%	3,126	496,198	50,623	546,821
Apr-15	643,069	0.02%	129	406,405	-115,943	290,461	290,590	0.63%	1,842	292,432		292,432
May-15	459,409	0.02%	92	226,863	-75,726	151,137	151,229	0.63%	959	152,188		152,188
Jun-15	389,947	0.02%	78	133,248	-32,586	100,662	100,740	0.63%	639	101,379		101,379
Jul-15	360,358	0.02%	72	81,610	9,818	91,428	91,500	0.63%	580	92,080		92,080
Aug-15	373,904	0.02%	75	84,149	10,894	95,043	95,117	0.63%	603	95,720		95,720
Sep-15	392,321	0.02%	78	84,225	19,824	104,049	104,127	0.63%	660	104,787		104,787
Oct-15	543,113	0.02%	109	127,036	67,776	194,812	194,921	0.63%	1,236	196,157		196,157
Peak	5,814,542	0.02%	1,163	3,204,634	0	3,204,634	3,205,797	0.63%	20,323	3,226,120	390,760	3,616,880
Off-Peak	2,519,052	0.02%	504	737,130	0	737,130	737,634	0.63%	4,677	742,311	0	742,311
Annual	8,333,594	0.02%	1,667	3,941,764	0	3,941,764	3,943,431	0.63%	25,000	3,968,431	390,760	4,359,191

	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
BTU Factor	1.039	1.033	1.036	1.039	1.041	1.039	1.039	1.046	1.049	1.048	1.041
GSG Meter Throughput (Mcf)	265,598	249,025	269,606	273,645	427,825	569,708	849,169	1,045,428	914,419	780,093	493,361
Salem Meter (Mcf)	9,904	9,385	9,959	10,496	18,586	31,154	57,324	67,178	57,567	45,512	25,940
Total Throughput IN (MCF)	275,503	258,411	279,566	284,142	446,412	600,863	906,494	1,112,607	971,987	825,606	519,302
GSG Meter Throughput (Dth)	275,956	257,243	279,312	284,317	445,366	591,927	882,287	1,093,518	959,226	817,537	513,589
Salem Meter (Dth)	10,290	9,695	10,318	10,905	19,348	32,369	59,560	70,268	60,388	47,697	27,004
Total Throughput IN (Dth)	286,247	266,938	289,629	295,222	464,714	624,296	941,846	1,163,786	1,019,613	865,234	540,592
Total Billed Units (MCF)	293,685	263,021	273,467	283,785	341,331	501,994	754,087	1,025,592	1,045,825	886,534	679,479
Company Use (MCF)	6	2	2	5	16	36	82	139	135	99	73
Current Month Unbilled Units (MCF)	93,201	89,302	109,507	131,638	205,743	284,516	489,204	531,639	405,881	527,570	309,655
Prior Month Unbilled Units (MCF)	-108,958	-93,201	-89,302	-109,507	-131,638	-205,743	-284,516	-489,204	-531,639	-405,881	-527,570
Total Throughput OUT (MCF)	277,934	259,124	293,674	305,921	415,452	580,803	958,857	1,068,166	920,202	1,008,322	461,637
Total Billed Units (Dth)	305,139	271,701	283,312	294,853	355,325	521,571	783,495	1,072,769	1,097,070	929,087	707,337
Company Use (Dth)	7	2	2	6	17	37	85	145	141	104	76
Current Month Unbilled Units (Dth)	96,836	92,248	113,449	136,772	214,178	295,613	508,283	556,095	425,769	552,893	322,351
Prior Month Unbilled Units (Dth)	-113,098	-96,836	-92,248	-113,449	-136,772	-214,178	-295,613	-508,283	-556,095	-425,769	-552,893
Total Throughput OUT (Dth)	288,884	267,115	304,514	318,182	432,747	603,043	996,250	1,120,725	966,885	1,056,314	476,871
Total Throughput IN (Dth)	286,247	266,938	289,629	295,222	464,714	624,296	941,846	1,163,786	1,019,613	865,234	540,592
Total Throughput OUT (Dth)	288,884	267,115	304,514	318,182	432,747	603,043	996,250	1,120,725	966,885	1,056,314	476,871
LAUF	-2,637	-178	-14,885	-22,959	31,966	21,252	-54,404	43,060	52,728	-191,080	63,721
Company Use (Dth)	7	2	2	6	17	37	85	145	141	104	76
Company Gas Allowance	-2,631	-176	-14,883	-22,954	31,983	21,289	-54,319	43,205	52,869	-190,977	63,797
LAUF %	-0.92%	-0.07%	-5.14%	-7.78%	6.88%	3.40%	-5.78%	3.70%	5.17%	-22.08%	11.79%
Company Use %	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Company Gas Allowance %	-0.92%	-0.07%	-5.14%	-7.78%	6.88%	3.41%	-5.77%	3.71%	5.19%	-22.07%	11.80%

	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12
BTU Factor	1.027	1.043	1.039	1.038	1.041	1.042	1.047	1.037	1.032	1.03
GSG Meter Throughput (Mcf)	356,512	270,436	244,612	266,618	284,943	411,448	528,465	774,469	924,402	771,024
Salem Meter (Mcf)	16,128	11,573	9,849	10,962	11,554	20,294	28,517	46,797	58,942	47,478
Total Throughput IN (MCF)	372,641	282,010	254,462	277,581	296,498	431,743	556,983	821,267	983,345	818,503
GSG Meter Throughput (Dth)	366,138	282,065	254,152	276,749	296,626	428,729	553,303	803,124	953,983	794,155
Salem Meter (Dth)	16,563	12,071	10,233	11,379	12,028	21,146	29,857	48,528	60,828	48,902
Total Throughput IN (Dth)	382,701	294,135	264,385	288,128	308,653	449,875	583,160	851,653	1,014,811	843,057
Total Billed Units (MCF)	438,668	326,626	267,428	267,015	293,619	328,407	504,624	638,201	916,302	878,239
Company Use (MCF)	30	28	21	20	27	98	111	160	266	301
Current Month Unbilled Units (MCF)	215,425	181,909	126,082	159,356	163,781	276,999	360,970	515,648	516,679	512,139
Prior Month Unbilled Units (MCF)	-309,655	-215,425	-181,909	-126,082	-159,356	-163,781	-276,999	-360,970	-515,648	-516,679
Total Throughput OUT (MCF)	344,468	293,138	211,622	300,309	298,071	441,723	588,706	793,039	917,599	874,000
Total Billed Units (Dth)	450,512	340,671	277,859	277,161	305,657	342,200	528,341	661,814	945,625	904,587
Company Use (Dth)	31	29	22	21	28	102	116	166	274	310
Current Month Unbilled Units (Dth)	221,241	189,731	130,999	165,412	170,496	288,633	377,937	534,727	533,212	527,504
Prior Month Unbilled Units (Dth)	-322,351	-221,241	-189,731	-130,999	-165,412	-170,496	-288,633	-377,937	-534,727	-533,212
Total Throughput OUT (Dth)	349,433	309,190	219,149	311,595	310,769	460,439	617,760	818,769	944,385	899,188
Total Throughput IN (Dth)	382,701	294,135	264,385	288,128	308,653	449,875	583,160	851,653	1,014,811	843,057
Total Throughput OUT (Dth)	349,433	309,190	219,149	311,595	310,769	460,439	617,760	818,769	944,385	899,188
LAUF	33,268	-15,055	45,236	-23,467	-2,116	-10,563	-34,600	32,884	70,426	-56,131
Company Use (Dth)	31	29	22	21	28	102	116	166	274	310
Company Gas Allowance	33,299	-15,026	45,258	-23,446	-2,088	-10,462	-34,484	33,049	70,700	-55,821
LAUF %	8.69%	-5.12%	17.11%	-8.14%	-0.69%	-2.35%	-5.93%	3.86%	6.94%	-6.66%
Company Use %	0.01%	0.01%	0.01%	0.01%	0.01%	0.02%	0.02%	0.02%	0.03%	0.04%
Company Gas Allowance %	8.70%	-5.11%	17.12%	-8.14%	-0.68%	-2.33%	-5.91%	3.88%	6.97%	-6.62%

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
BTU Factor	1.035	1.028	1.029	1.031	1.032	1.031	1.029	1.031	1.027	1.031
GSG Meter Throughput (Mcf)	625,991	456,655	353,621	305,807	274,541	291,876	300,897	396,348	685,674	783,117
Salem Meter (Mcf)	34,494	21,251	14,628	11,332	10,022	10,329	11,898	18,768	39,103	52,707
Total Throughput IN (MCF)	660,486	477,907	368,250	317,140	284,564	302,206	312,796	415,117	724,778	835,825
GSG Meter Throughput (Dth)	647,901	469,441	363,876	315,287	283,326	300,924	309,623	408,635	704,187	807,394
Salem Meter (Dth)	35,701	21,846	15,052	11,683	10,343	10,649	12,243	19,350	40,159	54,341
Total Throughput IN (Dth)	683,602	491,287	378,928	326,970	293,669	311,573	321,866	427,985	744,346	861,735
Total Billed Units (MCF)	773,119	555,475	417,161	337,685	290,872	293,154	294,789	350,450	535,061	778,077
Company Use (MCF)	240	173	87	67	75	148	166	107	111	211
Current Month Unbilled Units (MCF)	406,368	230,049	148,767	117,991	126,762	132,561	163,165	202,483	332,362	638,798
Prior Month Unbilled Units (MCF)	-512,139	-406,368	-230,049	-148,767	-117,991	-126,762	-132,561	-163,165	-202,483	-332,362
Total Throughput OUT (MCF)	667,588	379,329	335,966	306,976	299,718	299,101	325,559	389,875	665,051	1,084,724
Total Billed Units (Dth)	800,178	571,029	429,260	348,153	300,179	302,241	303,338	361,315	549,507	802,198
Company Use (Dth)	248	178	90	69	77	153	171	110	114	218
Current Month Unbilled Units (Dth)	420,590	236,491	153,081	121,649	130,819	136,670	167,896	208,760	341,336	658,601
Prior Month Unbilled Units (Dth)	-527,504	-420,590	-236,491	-153,081	-121,649	-130,819	-136,670	-167,896	-208,760	-341,336
Total Throughput OUT (Dth)	693,512	387,108	345,939	316,790	309,426	308,245	334,736	402,289	682,197	1,119,680
Total Throughput IN (Dth)	683,602	491,287	378,928	326,970	293,669	311,573	321,866	427,985	744,346	861,735
Total Throughput OUT (Dth)	693,512	387,108	345,939	316,790	309,426	308,245	334,736	402,289	682,197	1,119,680
LAUF	-9,910	104,179	32,989	10,180	-15,757	3,328	-12,870	25,696	62,149	-257,946
Company Use (Dth)	248	178	90	69	77	153	171	110	114	218
Company Gas Allowance	-9,662	104,357	33,078	10,249	-15,680	3,482	-12,699	25,806	62,263	-257,728
LAUF %	-1.45%	21.21%	8.71%	3.11%	-5.37%	1.07%	-4.00%	6.00%	8.35%	-29.93%
Company Use %	0.04%	0.04%	0.02%	0.02%	0.03%	0.05%	0.05%	0.03%	0.02%	0.03%
Company Gas Allowance %	-1.41%	21.24%	8.73%	3.13%	-5.34%	1.12%	-3.95%	6.03%	8.36%	-29.91%

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13
BTU Factor	1.034	1.026	1.024	1.025	1.029	1.028	1.025	1.022	1.028	1.034	1.028
GSG Meter Throughput (Mcf)	1,020,632	899,906	809,744	554,200	384,902	317,797	297,037	312,639	329,270	441,664	721,172
Salem Meter (Mcf)	66,624	58,701	49,074	27,692	15,702	11,992	10,261	11,661	12,337	21,451	43,060
Total Throughput IN (MCF)	1,087,257	958,608	858,819	581,893	400,605	329,790	307,299	324,301	341,608	463,116	764,233
GSG Meter Throughput (Dth)	1,055,333	923,304	829,178	568,055	396,064	326,695	304,463	319,517	338,490	456,681	741,365
Salem Meter (Dth)	68,889	60,227	50,252	28,384	16,157	12,328	10,518	11,918	12,682	22,180	44,266
Total Throughput IN (Dth)	1,124,223	983,531	879,430	596,439	412,222	339,023	314,980	331,435	351,172	478,861	785,630
Total Billed Units (MCF)	968,852	1,048,986	906,050	697,596	470,411	366,747	302,982	313,495	319,318	383,503	627,612
Company Use (MCF)	254	313	279	205	104	105	100	167	118	80	115
Current Month Unbilled Units (MCF)	733,208	542,597	560,743	335,281	217,281	162,805	147,117	182,728	237,453	364,926	446,781
Prior Month Unbilled Units (MCF)	-638,798	-733,208	-542,597	-560,743	-335,281	-217,281	-162,805	-147,117	-182,728	-237,453	-364,926
Total Throughput OUT (MCF)	1,063,516	858,688	924,475	472,339	352,515	312,376	287,394	349,273	374,161	511,056	709,582
Total Billed Units (Dth)	1,001,792	1,076,260	927,794	715,036	484,053	377,016	310,556	320,392	328,259	396,543	645,185
Company Use (Dth)	263	321	286	210	107	108	103	171	121	83	118
Current Month Unbilled Units (Dth)	758,136	556,705	574,201	343,664	223,581	167,363	150,794	186,748	244,102	377,334	459,291
Prior Month Unbilled Units (Dth)	-658,601	-758,136	-556,705	-574,201	-343,664	-223,581	-167,363	-150,794	-186,748	-244,102	-377,334
Total Throughput OUT (Dth)	1,101,591	875,150	945,576	484,710	364,077	320,906	294,090	356,517	385,734	529,858	727,260
Total Throughput IN (Dth)	1,124,223	983,531	879,430	596,439	412,222	339,023	314,980	331,435	351,172	478,861	785,630
Total Throughput OUT (Dth)	1,101,591	875,150	945,576	484,710	364,077	320,906	294,090	356,517	385,734	529,858	727,260
LAUF	22,632	108,381	-66,146	111,729	48,145	18,117	20,891	-25,082	-34,562	-50,997	58,370
Company Use (Dth)	263	321	286	210	107	108	103	171	121	83	118
Company Gas Allowance	22,895	108,702	-65,860	111,940	48,252	18,225	20,994	-24,911	-34,441	-50,914	58,488
LAUF %	2.01%	11.02%	-7.52%	18.73%	11.68%	5.34%	6.63%	-7.57%	-9.84%	-10.65%	7.43%
Company Use %	0.02%	0.03%	0.03%	0.04%	0.03%	0.03%	0.03%	0.05%	0.03%	0.02%	0.02%
Company Gas Allowance %	2.04%	11.05%	-7.49%	18.77%	11.71%	5.38%	6.67%	-7.52%	-9.81%	-10.63%	7.44%

	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	**48-Month**
BTU Factor	1.03	1.037	1.033	1.03	1.031	1.033	**1.034**
GSG Meter Throughput (Mcf)	1,011,103	1,101,964	945,004	960,102	585,094	400,652	**26,538,215**
Salem Meter (Mcf)	66,847	78,114	66,670	63,835	30,968	16,158	**1,480,778**
Total Throughput IN (MCF)	1,077,951	1,180,079	1,011,675	1,023,938	616,063	416,811	**28,019,043**
GSG Meter Throughput (Dth)	1,041,436	1,142,737	976,189	988,905	603,232	413,874	**27,445,411**
Salem Meter (Dth)	68,852	81,004	68,870	65,750	31,928	16,691	**1,531,641**
Total Throughput IN (Dth)	1,110,289	1,223,741	1,045,059	1,054,655	635,160	430,565	**28,977,052**
Total Billed Units (MCF)	900,731	1,151,467	1,126,362	1,070,253	782,448	512,252	**27,782,837**
Company Use (MCF)	218	307	327	295	229	113	**6,371**
Current Month Unbilled Units (MCF)	695,490	701,044	471,018	549,823	426,886	166,710	**15,648,041**
Prior Month Unbilled Units (MCF)	-446,781	-695,490	-701,044	-471,018	-549,823	-426,886	**-15,590,289**
Total Throughput OUT (MCF)	1,149,658	1,157,328	896,663	1,149,353	659,740	252,189	**27,846,960**
Total Billed Units (Dth)	927,753	1,194,071	1,163,532	1,102,360	806,704	529,156	**28,729,946**
Company Use (Dth)	225	318	338	304	236	117	**6,576**
Current Month Unbilled Units (Dth)	716,354	726,983	486,561	566,317	440,120	172,212	**16,180,738**
Prior Month Unbilled Units (Dth)	-459,291	-716,354	-726,983	-486,561	-566,317	-440,120	**-16,121,624**
Total Throughput OUT (Dth)	1,185,041	1,205,019	923,448	1,182,420	680,742	261,366	**28,795,637**
Total Throughput IN (Dth)	1,110,289	1,223,741	1,045,059	1,054,655	635,160	430,565	**28,977,052**
Total Throughput OUT (Dth)	1,185,041	1,205,019	923,448	1,182,420	680,742	261,366	**28,795,637**
LAUF	-74,752	18,722	121,611	-127,765	-45,582	169,199	**181,415**
Company Use (Dth)	225	318	338	304	236	117	**6,576**
Company Gas Allowance	-74,527	19,041	121,949	-127,461	-45,347	169,316	**187,991**
LAUF %	-6.73%	1.53%	11.64%	-12.11%	-7.18%	39.30%	**0.63%**
Company Use %	0.02%	0.03%	0.03%	0.03%	0.04%	0.03%	**0.02%**
Company Gas Allowance %	-6.71%	1.56%	11.67%	-12.09%	-7.14%	39.32%	**0.65%**

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	**Winter**
2	**Total Therms**								
3	Res Heat	396,159	409,365	409,365	369,749	409,365	396,159	4,812,004	2,390,161
4	Res General	11,746	12,137	12,137	10,963	12,137	11,746	142,670	70,865
5	G50 Low Annual-Low Winter	72,578	74,998	74,998	67,740	74,998	72,578	881,584	437,890
6	G40 Low Annual-High Winter	144,190	148,996	148,996	134,577	148,996	144,190	1,751,425	869,946
7	G51 Med Annual-Low Winter	98,474	101,757	101,757	91,909	101,757	98,474	1,196,133	594,129
8	G41 Med Annual-High Winter	148,593	153,546	153,546	138,687	153,546	148,593	1,804,907	896,511
9	G52 High Annual-Low Winter	17,179	17,751	17,751	16,033	17,751	17,179	208,663	103,644
10	G42 High Annual-High Winter	19,509	20,159	20,159	18,208	20,159	19,509	236,970	117,705
11	Total Firm Sales	908,429	938,709	938,709	847,867	938,709	908,429	11,034,355	5,480,852
12	**% of Total**								
13	Res Heat	43.61%	43.61%	43.61%	43.61%	43.61%	43.61%		
14	Res General	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%		
15	G50 Low Annual-Low Winter	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%		
16	G40 Low Annual-High Winter	15.87%	15.87%	15.87%	15.87%	15.87%	15.87%		
17	G51 Med Annual-Low Winter	10.84%	10.84%	10.84%	10.84%	10.84%	10.84%		
18	G41 Med Annual-High Winter	16.36%	16.36%	16.36%	16.36%	16.36%	16.36%		
19	G52 High Annual-Low Winter	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%		
20	G42 High Annual-High Winter	2.15%	2.15%	2.15%	2.15%	2.15%	2.15%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

22	**BASE COMMODITY COSTS Excld Hedging**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	**Winter**
23	TOTAL BASE COMMODITY Excld Hedging	$ 771,132	$ 816,357	$ 836,167	$ 762,935	$ 819,806	$ 366,174	$ 6,213,487	$ 4,372,572
24	Res Heat	$ 336,285	$ 356,008	$ 364,647	$ 332,711	$ 357,511	$ 159,686	$ 2,709,657	$ 1,906,848
25	Res General	$ 9,970	$ 10,555	$ 10,811	$ 9,864	$ 10,600	$ 4,735	$ 80,338	$ 56,536
26	G50 Low Annual-Low Winter	$ 61,609	$ 65,222	$ 66,805	$ 60,954	$ 65,498	$ 29,255	$ 496,423	$ 349,344
27	G40 Low Annual-High Winter	$ 122,398	$ 129,576	$ 132,720	$ 121,097	$ 130,123	$ 58,121	$ 986,234	$ 694,035
28	G51 Med Annual-Low Winter	$ 83,591	$ 88,494	$ 90,641	$ 82,703	$ 88,868	$ 39,694	$ 673,547	$ 473,990
29	G41 Med Annual-High Winter	$ 126,135	$ 133,533	$ 136,773	$ 124,794	$ 134,097	$ 59,896	$ 1,016,350	$ 715,228
30	G52 High Annual-Low Winter	$ 14,582	$ 15,438	$ 15,812	$ 14,427	$ 15,503	$ 6,924	$ 117,499	$ 82,687
31	G42 High Annual-High Winter	$ 16,561	$ 17,532	$ 17,957	$ 16,385	$ 17,606	$ 7,864	$ 133,439	$ 93,904
32									
33	Residential	$ 346,256	$ 366,563	$ 375,458	$ 342,575	$ 368,111	$ 164,421	$ 2,789,996	$ 1,963,384
34	SALES HLF CLASSES	$ 159,783	$ 169,154	$ 173,258	$ 158,084	$ 169,868	$ 75,873	$ 1,287,469	$ 906,021
35	SALES LLF CLASSES	$ 265,094	$ 280,641	$ 287,451	$ 262,276	$ 281,826	$ 125,880	$ 2,136,022	$ 1,503,167

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**							**Annual**	**Winter**
37	TOTAL BASE HEDGING COMMODITY	$ 833	$ 1,367	$ 1,396	$ 1,275	$ 947	$ -	$ 5,818	$ 5,818
38	Res Heat	$ 363	$ 596	$ 609	$ 556	$ 413	$ -	$ 2,537	$ 2,537
39	Res General	$ 11	$ 18	$ 18	$ 16	$ 12	$ -	$ 75	$ 75
40	G50 Low Annual-Low Winter	$ 67	$ 109	$ 112	$ 102	$ 76	$ -	$ 465	$ 465
41	G40 Low Annual-High Winter	$ 132	$ 217	$ 222	$ 202	$ 150	$ -	$ 923	$ 923
42	G51 Med Annual-Low Winter	$ 90	$ 148	$ 151	$ 138	$ 103	$ -	$ 631	$ 631
43	G41 Med Annual-High Winter	$ 136	$ 224	$ 228	$ 209	$ 155	$ -	$ 952	$ 952
44	G52 High Annual-Low Winter	$ 16	$ 26	$ 26	$ 24	$ 18	$ -	$ 110	$ 110
45	G42 High Annual-High Winter	$ 18	$ 29	$ 30	$ 27	$ 20	$ -	$ 125	$ 125
46									
47	Residential	$ 374	$ 614	$ 627	$ 573	$ 425	$ -	$ 2,612	$ 2,612
48	SALES HLF CLASSES	$ 173	$ 283	$ 289	$ 264	$ 196	$ -	$ 1,206	$ 1,206
49	SALES LLF CLASSES	$ 286	$ 470	$ 480	$ 438	$ 325	$ -	$ 2,000	$ 2,000

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

Base Commodity Costs

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

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

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

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

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	**Winter**
51	**Total Therms**								
52	Res Heat	1,485,135	2,362,075	3,089,424	2,555,171	1,845,458	932,710	13,084,296	12,269,974
53	Res General	13,308	24,770	34,457	27,989	17,891	5,951	148,510	124,366
54	G50 Low Annual-Low Winter	36,494	85,683	127,852	101,839	55,731	4,467	561,256	412,066
55	G40 Low Annual-High Winter	868,040	1,342,170	1,733,514	1,439,167	1,064,211	570,814	7,314,309	7,017,916
56	G51 Med Annual-Low Winter	49,460	116,173	173,367	138,089	75,550	6,021	761,081	558,660
57	G41 Med Annual-High Winter	686,443	1,076,587	1,399,425	1,159,568	847,285	441,247	5,915,998	5,610,555
58	G52 High Annual-Low Winter	11,733	24,840	36,017	28,916	16,901	3,243	156,963	121,651
59	G42 High Annual-High Winter	79,875	126,249	164,672	136,307	98,958	50,693	696,856	656,754
60	Total Firm Sales	3,230,488	5,158,546	6,758,729	5,587,047	4,021,984	2,015,147	28,639,269	26,771,941
61	**% of Total**								
62	Res Heat	45.97%	45.79%	45.71%	45.73%	45.88%	46.28%		
63	Res General	0.41%	0.48%	0.51%	0.50%	0.44%	0.30%		
64	G50 Low Annual-Low Winter	1.13%	1.66%	1.89%	1.82%	1.39%	0.22%		
65	G40 Low Annual-High Winter	26.87%	26.02%	25.65%	25.76%	26.46%	28.33%		
66	G51 Med Annual-Low Winter	1.53%	2.25%	2.57%	2.47%	1.88%	0.30%		
67	G41 Med Annual-High Winter	21.25%	20.87%	20.71%	20.75%	21.07%	21.90%		
68	G52 High Annual-Low Winter	0.36%	0.48%	0.53%	0.52%	0.42%	0.16%		
69	G42 High Annual-High Winter	2.47%	2.45%	2.44%	2.44%	2.46%	2.52%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	**Winter**
72	REMAINING COMMODITY Excld Hedging	$ 2,961,584	$ 3,827,899	$ 5,471,588	$ 4,285,920	$ 3,590,452	$ 822,806	$ 21,681,564	$ 20,960,249
73	Res Heat	$ 1,361,513	$ 1,752,778	$ 2,501,070	$ 1,960,116	$ 1,647,453	$ 380,836	$ 9,918,325	$ 9,603,765
74	Res General	$ 12,200	$ 18,381	$ 27,895	$ 21,471	$ 15,971	$ 2,430	$ 107,674	$ 98,347
75	G50 Low Annual-Low Winter	$ 33,457	$ 63,581	$ 103,504	$ 78,122	$ 49,752	$ 1,824	$ 387,868	$ 330,239
76	G40 Low Annual-High Winter	$ 795,785	$ 995,957	$ 1,403,382	$ 1,104,010	$ 950,028	$ 233,070	$ 5,596,722	$ 5,482,231
77	G51 Med Annual-Low Winter	$ 45,343	$ 86,206	$ 140,350	$ 105,930	$ 67,444	$ 2,459	$ 525,924	$ 447,732
78	G41 Med Annual-High Winter	$ 629,303	$ 798,881	$ 1,132,917	$ 889,525	$ 756,377	$ 180,166	$ 4,505,156	$ 4,387,169
79	G52 High Annual-Low Winter	$ 10,756	$ 18,432	$ 29,158	$ 22,182	$ 15,087	$ 1,324	$ 110,581	$ 96,941
80	G42 High Annual-High Winter	$ 73,227	$ 93,683	$ 133,312	$ 104,564	$ 88,340	$ 20,698	$ 529,314	$ 513,824
81									
82	Residential	$ 1,373,713	$ 1,771,158	$ 2,528,965	$ 1,981,586	$ 1,663,424	$ 383,266	$ 10,025,999	$ 9,702,113
83	SALES HLF CLASSES	$ 89,556	$ 168,219	$ 273,013	$ 206,235	$ 132,283	$ 5,607	$ 1,024,373	$ 874,912
84	SALES LLF CLASSES	$ 1,498,315	$ 1,888,521	$ 2,669,611	$ 2,098,098	$ 1,794,745	$ 433,934	$ 10,631,192	$ 10,383,224

85	**REMAINING COMMODITY HEDGING COSTS**							**Annual**	**Winter**
86	TOTAL REMAINING COMMODITY HEDGING	$ 3,193	$ 5,259	$ 5,408	$ 4,754	$ 3,503	$ -	$ 22,117	$ 22,117
87	Res Heat	$ 1,468	$ 2,408	$ 2,472	$ 2,174	$ 1,607	$ -	$ 10,129	$ 10,129
88	Res General	$ 13	$ 25	$ 28	$ 24	$ 16	$ -	$ 105	$ 105
89	G50 Low Annual-Low Winter	$ 36	$ 87	$ 102	$ 87	$ 49	$ -	$ 361	$ 361
90	G40 Low Annual-High Winter	$ 858	$ 1,368	$ 1,387	$ 1,224	$ 927	$ -	$ 5,765	$ 5,765
91	G51 Med Annual-Low Winter	$ 49	$ 118	$ 139	$ 117	$ 66	$ -	$ 489	$ 489
92	G41 Med Annual-High Winter	$ 678	$ 1,098	$ 1,120	$ 987	$ 738	$ -	$ 4,620	$ 4,620
93	G52 High Annual-Low Winter	$ 12	$ 25	$ 29	$ 25	$ 15	$ -	$ 105	$ 105
94	G42 High Annual-High Winter	$ 79	$ 129	$ 132	$ 116	$ 86	$ -	$ 542	$ 542
95								$ -	$ -
96	Residential	$ 1,481	$ 2,433	$ 2,500	$ 2,198	$ 1,623	$ -	$ 10,235	$ 10,235
97	SALES HLF CLASSES	$ 97	$ 231	$ 270	$ 229	$ 129	$ -	$ 955	$ 955
98	SALES LLF CLASSES	$ 1,615	$ 2,595	$ 2,639	$ 2,327	$ 1,751	$ -	$ 10,927	$ 10,927

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

Remaining Commodity Costs

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

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

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

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**							**Annual**	**Winter**
100	TOTAL COMMODITY Excld Hedging	$ 3,732,716	$ 4,644,256	$ 6,307,755	$ 5,048,855	$ 4,410,258	$ 1,188,981	$ 27,895,051	$ 25,332,821
101	Res Heat	$ 1,697,798	$ 2,108,785	$ 2,865,717	$ 2,292,826	$ 2,004,965	$ 540,522	$ 12,627,982	$ 11,510,613
102	Res General	$ 22,171	$ 28,936	$ 38,706	$ 31,335	$ 26,571	$ 7,164	$ 188,012	$ 154,883
103	G50 Low Annual-Low Winter	$ 95,066	$ 128,803	$ 170,309	$ 139,077	$ 115,250	$ 31,079	$ 884,292	$ 679,583
104	G40 Low Annual-High Winter	$ 918,182	$ 1,125,533	$ 1,536,102	$ 1,225,106	$ 1,080,151	$ 291,190	$ 6,582,956	$ 6,176,266
105	G51 Med Annual-Low Winter	$ 128,934	$ 174,700	$ 230,992	$ 188,633	$ 156,311	$ 42,152	$ 1,199,470	$ 921,722
106	G41 Med Annual-High Winter	$ 755,439	$ 932,414	$ 1,269,690	$ 1,014,319	$ 890,474	$ 240,062	$ 5,521,506	$ 5,102,397
107	G52 High Annual-Low Winter	$ 25,339	$ 33,870	$ 44,970	$ 36,609	$ 30,590	$ 8,249	$ 228,080	$ 179,627
108	G42 High Annual-High Winter	$ 89,787	$ 111,215	$ 151,269	$ 120,948	$ 105,946	$ 28,562	$ 662,753	$ 607,728
109									
110	Residential	$ 1,719,969	$ 2,137,721	$ 2,904,423	$ 2,324,161	$ 2,031,535	$ 547,686	$ 12,815,995	$ 11,665,496
111	SALES HLF CLASSES	$ 249,339	$ 337,373	$ 446,271	$ 364,319	$ 302,151	$ 81,480	$ 2,311,842	$ 1,780,933
112	SALES LLF CLASSES	$ 1,763,408	$ 2,169,162	$ 2,957,061	$ 2,360,374	$ 2,076,571	$ 559,814	$ 12,767,214	$ 11,886,391
113	**TOTAL HEDGING COMMODITY COSTS**							**Annual**	**Winter**
114	TOTAL HEDGING COMMODITY	$ 4,026	$ 6,626	$ 6,805	$ 6,029	$ 4,450	$ -	$ 27,935	$ 27,935
115	Res Heat	$ 1,831	$ 3,004	$ 3,081	$ 2,730	$ 2,020	$ -	$ 12,667	$ 12,667
116	Res General	$ 24	$ 43	$ 46	$ 40	$ 28	$ -	$ 181	$ 181
117	G50 Low Annual-Low Winter	$ 103	$ 197	$ 214	$ 189	$ 124	$ -	$ 826	$ 826
118	G40 Low Annual-High Winter	$ 990	$ 1,585	$ 1,609	$ 1,427	$ 1,077	$ -	$ 6,688	$ 6,688
119	G51 Med Annual-Low Winter	$ 139	$ 267	$ 290	$ 256	$ 168	$ -	$ 1,120	$ 1,120
120	G41 Med Annual-High Winter	$ 815	$ 1,321	$ 1,348	$ 1,195	$ 893	$ -	$ 5,572	$ 5,572
121	G52 High Annual-Low Winter	$ 27	$ 51	$ 55	$ 49	$ 33	$ -	$ 215	$ 215
122	G42 High Annual-High Winter	$ 97	$ 158	$ 162	$ 143	$ 107	$ -	$ 667	$ 667
123									
124	Residential	$ 1,855	$ 3,047	$ 3,127	$ 2,770	$ 2,048	$ -	$ 12,847	$ 12,847
125	SALES HLF CLASSES	$ 269	$ 514	$ 559	$ 493	$ 325	$ -	$ 2,161	$ 2,161
126	SALES LLF CLASSES	$ 1,902	$ 3,065	$ 3,119	$ 2,765	$ 2,077	$ -	$ 12,927	$ 12,927
127	TOTAL COMMODITY	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	**Winter**
128	Res Heat	$ 1,699,629	$ 2,111,789	$ 2,868,798	$ 2,295,556	$ 2,006,985	$ 540,522	$ 12,640,649	$ 11,523,280
129	Res General	$ 22,195	$ 28,979	$ 38,752	$ 31,376	$ 26,599	$ 7,164	$ 188,193	$ 155,064
130	G50 Low Annual-Low Winter	$ 95,168	$ 129,000	$ 170,523	$ 139,265	$ 115,374	$ 31,079	$ 885,117	$ 680,409
131	G40 Low Annual-High Winter	$ 919,172	$ 1,127,119	$ 1,537,711	$ 1,226,533	$ 1,081,229	$ 291,190	$ 6,589,644	$ 6,182,955
132	G51 Med Annual-Low Winter	$ 129,074	$ 174,966	$ 231,282	$ 188,889	$ 156,480	$ 42,152	$ 1,200,590	$ 922,842
133	G41 Med Annual-High Winter	$ 756,253	$ 933,735	$ 1,271,038	$ 1,015,514	$ 891,367	$ 240,062	$ 5,527,078	$ 5,107,969
134	G52 High Annual-Low Winter	$ 25,366	$ 33,921	$ 45,026	$ 36,658	$ 30,623	$ 8,249	$ 228,295	$ 179,842
135	G42 High Annual-High Winter	$ 89,884	$ 111,373	$ 151,431	$ 121,092	$ 106,053	$ 28,562	$ 663,420	$ 608,394
136	Total Firm Sales	$ 3,736,741	$ 4,650,882	$ 6,314,560	$ 5,054,883	$ 4,414,708	$ 1,188,981	$ 27,922,986	$ 25,360,756
137									
138	Residential	$ 1,721,824	$ 2,140,769	$ 2,907,550	$ 2,326,932	$ 2,033,584	$ 547,686	$ 12,828,842	$ 11,678,344
139	SALES HLF CLASSES	$ 249,608	$ 337,887	$ 446,830	$ 364,812	$ 302,476	$ 81,480	$ 2,314,003	$ 1,783,094
140	SALES LLF CLASSES	$ 1,765,310	$ 2,172,226	$ 2,960,180	$ 2,363,139	$ 2,078,648	$ 559,814	$ 12,780,141	$ 11,899,318
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								13.03%
144	SALES LLF CLASSES								86.97%

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	
100	TOTAL COMMODITY Excld Hedging	Schedule 1B, LN 41
101	Res Heat	LN 24 + LN 73
102	Res General	LN 25 + LN 74
103	G50 Low Annual-Low Winter	LN 26 + LN 75
104	G40 Low Annual-High Winter	LN 27 + LN 76
105	G51 Med Annual-Low Winter	LN 28 + LN 77
106	G41 Med Annual-High Winter	LN 29 + LN 78
107	G52 High Annual-Low Winter	LN 30 + LN 79
108	G42 High Annual-High Winter	LN 31 + LN 80
109		
110	Residential	LN 101 + LN 102
111	SALES HLF CLASSES	LN 103 + LN 105 + LN 107
112	SALES LLF CLASSES	LN 104 + LN 106 + LN 108
113	**TOTAL HEDGING COMMODITY COSTS**	
114	TOTAL HEDGING COMMODITY	Schedule 1B, LN 42
115	Res Heat	LN 38 + LN 87
116	Res General	LN 39 + LN 88
117	G50 Low Annual-Low Winter	LN 40 + LN 89
118	G40 Low Annual-High Winter	LN 41 + LN 90
119	G51 Med Annual-Low Winter	LN 42 + LN 91
120	G41 Med Annual-High Winter	LN 43 + LN 92
121	G52 High Annual-Low Winter	LN 44 + LN 93
122	G42 High Annual-High Winter	LN 45 + LN 94
123		
124	Residential	LN 115 + LN 116
125	SALES HLF CLASSES	LN 117 + LN 119 + LN 121
126	SALES LLF CLASSES	LN 118 + LN 120 + LN 122
127	**TOTAL COMMODITY**	
128	Res Heat	LN 101 + LN 115
129	Res General	LN 102 + LN 116
130	G50 Low Annual-Low Winter	LN 103 + LN 117
131	G40 Low Annual-High Winter	LN 104 + LN 118
132	G51 Med Annual-Low Winter	LN 105 + LN 119
133	G41 Med Annual-High Winter	LN 106 + LN 120
134	G52 High Annual-Low Winter	LN 107 + LN 121
135	G42 High Annual-High Winter	LN 108 + LN 122
136	Total Firm Sales	Sum LN 128 : LN 135
137		
138	Residential	LN 128 + LN 129
139	SALES HLF CLASSES	LN 130 + LN 132 + LN 134
140	SALES LLF CLASSES	LN 131 + LN 133 + LN 135
141		
142	% ALLOCATION BETWEEN SALES HLF AND LLF	
143	SALES HLF CLASSES	LN 139 / (LN 139 + LN 140)
144	SALES LLF CLASSES	LN 140 / (LN 139 + LN 140)

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

Northern Utilities, Inc. Normal Winter Weather - Sales Service & Company Managed Sendout Commodity Volumes by Supply Source (Dth) November 2014 through April 2015							
Description	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Season
Pipeline Supplies							
Tennessee Production	147,397	152,311	186,159	137,571	152,311	328,437	1,104,186
Chicago	174,521	180,219	180,219	162,779	180,219	40,611	918,569
Algonquin Receipts	37,530	38,781	38,781	35,028	38,781	16,873	205,774
TGP Zone 6	0	0	0	0	0	42,785	42,785
Niagara	63,655	65,777	65,777	59,411	65,777	63,655	384,052
Iroquois Receipts	18,410	19,143	19,143	17,291	19,143	0	93,130
PNGTS Receipts	23,916	24,713	24,713	22,322	24,713	19,146	139,523
PNGTS Delivered	224,213	231,686	231,686	209,265	231,686	0	1,128,536
Maritimes Delivered	225,000	232,500	232,500	210,000	232,500	43,400	1,175,900
Subtotal Pipeline	914,642	945,130	978,979	853,666	945,130	554,908	5,192,456
Underground Storage							
Tenn Zone 4 Spot	18,407	20,084	0	0	512	73,181	112,183
Tennessee Storage	0	55,536	75,620	68,302	40,603	0	240,061
Tennesse Storage Path	18,407	75,620	75,620	68,302	41,116	73,181	352,245
W10 AMA Spot	0	0	0	0	0	0	0
Washington 10 Storage	50,470	474,576	727,143	604,142	201,740	0	2,058,071
W10 Storage Path	50,470	474,576	727,143	604,142	201,740	0	2,058,071
Subtotal Storage	68,877	550,196	802,763	672,444	242,855	73,181	2,410,316
Peaking Supplies							
Peaking Contract 1	0	0	3,410	0	0	0	3,410
Peaking Contract 2	0	0	176,244	102,776	19,930	0	298,950
LNG	7,252	2,781	21,196	16,692	12,100	2,100	62,120
Subtotal Peaking	7,252	2,781	200,849	119,468	32,030	2,100	364,480
Total Delivered (Dth)	990,771	1,498,107	1,982,591	1,645,578	1,220,016	630,189	7,967,251

Northern Utilities, Inc. Design Cold Winter Weather - Planning Load Sendout Commodity Volumes by Supply Source (Dth) November 2014 through April 2015							
Description	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Season
Pipeline Supplies							
Tennessee Production	147,397	152,311	183,953	137,571	159,650	369,886	1,150,768
Chicago	134,140	138,652	138,652	125,234	138,652	5,009	680,337
Algonquin Receipts	37,530	38,781	38,781	35,028	38,781	30,753	219,654
TGP Zone 6	0	0	0	0	0	94,393	94,393
Niagara	69,805	72,132	72,132	65,151	72,132	69,805	421,156
Iroquois Receipts	58,791	60,711	60,711	54,836	60,711	43,595	339,354
PNGTS Receipts	32,885	33,981	33,981	30,692	33,981	32,885	198,403
PNGTS Delivered	224,213	231,686	231,686	209,265	231,686	0	1,128,536
Maritimes Delivered	225,000	232,500	232,500	210,000	232,500	60,000	1,192,500
Subtotal Pipeline	929,760	960,753	992,395	867,776	968,092	706,326	5,425,103
Underground Storage							
Tenn Zone 4 Spot	78,249	81,955	0	0	14,645	78,428	253,278
Tennessee Storage	0	0	81,955	74,024	67,310	0	223,289
Tennesse Storage Path	78,249	81,955	81,955	74,024	81,955	78,428	476,567
W10 AMA Spot	0	0	0	0	0	0	0
Washington 10 Storage	235,853	766,685	852,284	740,526	445,533	0	3,040,880
W10 Storage Path	235,853	766,685	852,284	740,526	445,533	0	3,040,880
Subtotal Storage	314,101	848,640	934,239	814,550	527,488	78,428	3,517,447
Peaking Supplies							
Peaking Contract 1	0	0	625	0	0	0	625
Peaking Contract 2	0	8,707	162,653	127,590	0	0	298,950
LNG	2,100	15,504	18,507	11,687	12,222	2,100	62,120
Subtotal Peaking	2,100	24,211	181,784	139,277	12,222	2,100	361,695
Total Delivered (Dth)	1,245,962	1,833,604	2,108,419	1,821,603	1,507,803	786,854	9,304,245

Northern Utilities, Inc.
Normal Winter Weather - Sales Service & Company Managed Sendout
Capacity Utilization by Supply Source
November 2014 through April 2015

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Tennessee Production	1,104,186	2,163,668	51%
Chicago and Iroquois	1,011,699	1,164,554	87%
Algonquin Receipts	205,774	226,431	91%
TGP Zone 6	42,785	0	
Niagara	384,052	421,187	91%
PNGTS Receipts	139,523	180,897	77%
PNGTS Delivered	1,128,536	1,128,536	100%
Maritimes Delivered	1,175,900	1,175,900	100%
Subtotal Pipeline	5,192,456	6,461,173	80%
Underground Storage			
Tenn Zone 4 Spot	112,183		
Tennessee Storage	240,061		
Tennesse Storage Path	352,245	441,522	80%
W10 AMA Spot	0		
Washington 10 Storage	2,058,071		
W10 Storage Path	2,058,071	4,965,635	41%
Subtotal Storage	2,410,316	5,407,157	45%
Peaking Supplies			
Peaking Contract 1	3,410	298,950	1%
Peaking Contract 2	298,950	298,950	100%
LNG	62,120	75,000	83%
Subtotal Peaking	364,480	672,900	54%
Total Delivered (Dth)	7,967,251	12,541,231	64%

Northern Utilities, Inc.
Design Cold Winter Weather - Planning Load Sendout
Capacity Utilization by Supply Source
November 2014 through April 2015

Description	Projected Volume (Dth)	Maximum Volume (Dth)	Capacity Utilization
Pipeline Supplies			
Tennessee Production	1,150,768	2,372,729	48%
Chicago and Iroquois	1,011,699	1,164,554	87%
Algonquin Receipts	219,654	226,431	97%
TGP Zone 6	94,393	0	
Niagara	421,156	421,187	100%
PNGTS Receipts	198,403	198,376	100%
PNGTS Delivered	1,128,536	1,128,536	100%
Maritimes Delivered	1,192,500	1,192,500	100%
Subtotal Pipeline	5,417,110	6,704,313	81%
Underground Storage			
Tenn Zone 4 Spot	253,278		
Tennessee Storage	223,289		
Tennesse Storage Path	476,567	478,512	100%
W10 AMA Spot	0		
Washington 10 Storage	3,040,880		
W10 Storage Path	3,040,880	4,965,635	61%
Subtotal Storage	3,517,447	5,444,147	65%
Peaking Supplies			
Peaking Contract 1	625	298,950	0%
Peaking Contract 2	298,950	298,950	100%
LNG	62,120	75,000	83%
Subtotal Peaking	361,695	672,900	54%
Total Delivered (Dth)	9,304,245	12,821,361	73%

Northern Utilities Inc.
Forecast of Upcoming Winter Period Design Day Report
2014 / 2015 Winter Period
(Therms)

Demand	
NH Firm Sales	411,015
NH Non-Capacity Exempt Transportation	100,568
NH Capacity Exempt Transportation	127,602
NH Interruptible Sales	0
NH Interruptible Transportation	0
NH Design Day Demand	639,185
ME Firm Sales	416,119
ME Non-Capacity Exempt Transportation	148,015
ME Capacity Exempt Transportation	273,240
ME Interruptible Sales	0
ME Interruptible Transportation	0
ME Design Day Demand	837,374
Total Firm Sales	827,134
Total Non-Capacity Exempt Transportation	248,583
Total Capacity Exempt Transportation	400,842
Total Interruptible Sales	0
Total Interruptible Transportation	0
Total Design Day Demand	1,476,559
Supplies	
Capacity Exempt Transportation	400,842
Pipeline	391,650
Storage	355,290
On-System LNG	100,000
Off-System Peaking	398,870
On-System Propane	0
Total	1,646,652

Effective Degree Day	
New Hampshire	81
Maine	79
Probability	1 in 30

Report Prepared By	Francis X. Wells
Title	Manager, Energy Planning
Signature	

Northern Utilities Inc.
New Hampshire 7 Day Cold Snap Analysis
Winter 2014-2015

Coldest 7 Consecutive Days
Based on historic Portsmouth weather data

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

Maximum Projected Design Week Demand (Dth)

Daily Baseload	5,276
Weekly Baseload	36,933
Heating Increment*	577
Effective Degree Days	479
Total Heat Load	276,530
Projected Cold Snap Demand	313,464

** Based on PR Allocator Loads prepared for COG filing.*

New Hampshire Allocation **47.77%**
Based on the latest demand cost allocator in the Winter COG filing.

Maximum Supply Capability (Dth)

Amount to be Supplied by Natural Gas Pipelines	
Tennessee Production	13,109
Chicago City-Gates Supply	6,434
Algonquin Receipt Points Supply	1,251
Niagara	2,327
PNGTS	1,096
PNGTS Delivered	7,474
Maritimes Delivered	7,474
Tennessee Firm Storage	2,644
Washington 10 Storage	32,885
Peaking Supply 1	19,930
Peaking Supply 2	19,957
Total Daily Pipeline	114,581
Pipeline for 7 days	802,067
New Hampshire Allocation	383,147

Available LNG Storage

Facility	Gallons	Dth
Lewiston LNG	145,134	12,140
Total	145,134	12,140
New Hampshire Allocation - 7 Days		5,799

LNG Delivery Contract

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

The storage credit for LNG is calculated as follows:

Number of Days	5
Number of Loads	4
Delivery Reliability	70%
Assumed Number of LNG Deliveries	14
Dth Per Load	900
Total Storage Credit	12,600
NH Storage Credit - 7 Days	6,019

Summary	
Maximum projected design week demand	313,464
Amount to be furnished by natural gas pipeline	383,147
Remaining Balance	-69,684
Storage available	5,799
Credit from LNG delivery supply contract	6,019
Total available storage and propane deliveries	11,818
Net Surplus/(Deficiency)	**81,502**

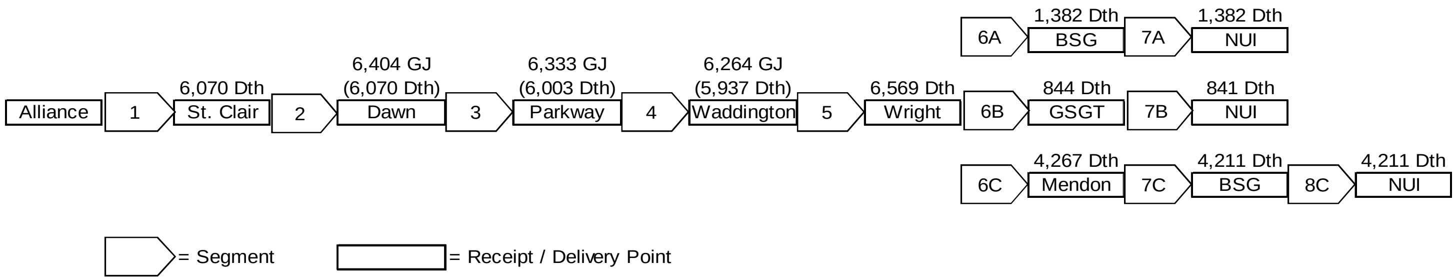
Report Prepared By	Francis X. Wells
Title	Manager, Energy Planning
Signature	

Schedule 12

Northern Capacity by Supply Source (Dth per Day)		
Supply Source	Nov 2014 through Mar 2015	Apr 2015 through Oct 2015
Chicago City-Gates Supply	6,434	6,434
PNGTS Receipts	1,096	1,096
Tennessee Niagara	2,327	2,327
Tennessee Production	13,109	13,109
Algonquin Receipt Points Supply	1,251	1,251
Maritimes Delivered Baseload Supply	7,474	0
PNGTS Delivered Baseload Supply	7,474	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Contract 1	19,930	0
Peaking Contract 2	19,957	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**124,581**	**36,861**

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Chicago City-Gate

Capacity Path Diagram

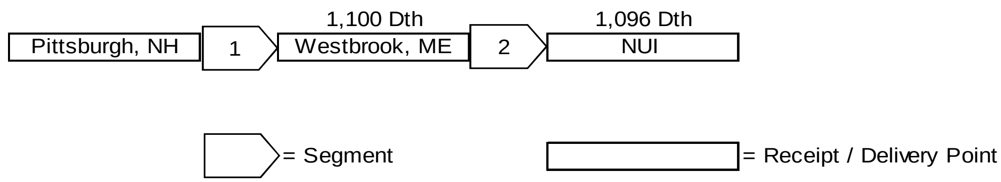


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	Union
3	Transportation	Union	M12205	M12	10/31/2017	6,333	GJ	Year-Round	Dawn	Parkway	TransCanada
4	Transportation	TransCanada	41235	FT	10/31/2017	6,264	GJ	Year-Round	Parkway	Waddington	Iroquois
5	Transportation	Iroquois	R181001	RTS-1	10/31/2017	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
6A	ME Assignable Storage	0	#DIV/0!	FT-A	10/31/2017	1,382	Dth	Year-Round	Wright	Bay State City Gate	
7A	ME Assignable Peaking	0	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
6B	ME Assignable Capacity	0	95196	FT-A	10/31/2017	844	Dth	Year-Round	Wright	Pleasant St.	Granite
7B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	841	Dth	Year-Round	Granite	Northern City Gates	
6C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
7C	Transportation	Algonquin	93200F	AFT-1	10/31/2015	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
8C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,434	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: PNGTS Receipts

Capacity Path Diagram

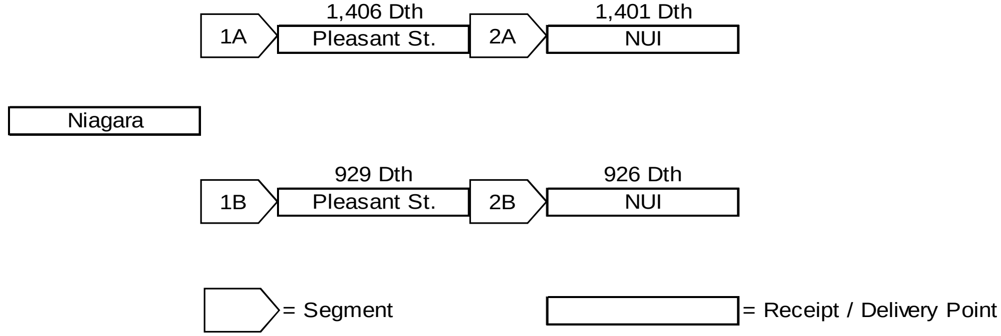


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	1,096	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						1,096	Dth				

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

Capacity Path Diagram

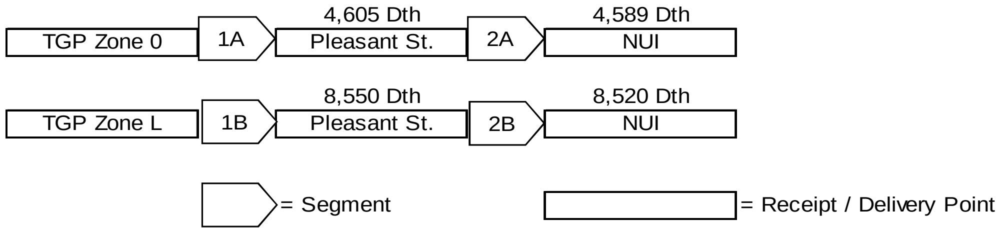


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2020	1,406	Dth	Year-Round	Niagara	Pleasant St.	Granite
2A	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	1,401	Dth	Year-Round	Granite	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2020	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	ME Assignable Storage	0	#DIV/0!	FT-NN	10/31/2014	926	Dth	Year-Round	Granite	Northern City Gates	
Total Path	ME Assignable Peaking	0				2,327	Dth				

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

Capacity Path Diagram



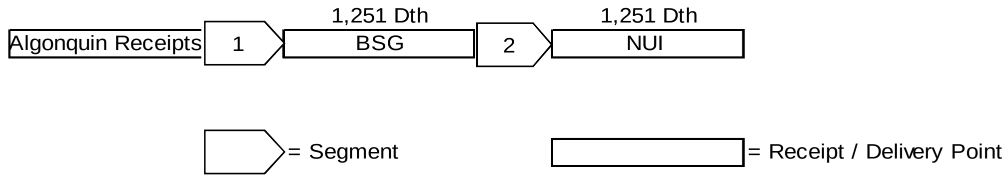
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	Dth				

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

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

Capacity Path Diagram

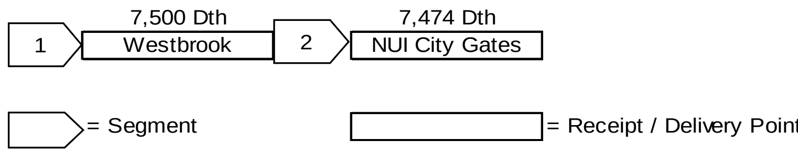


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2015	1,251	Dth	Year-Round	Algonquin Receipt Points	Bay State City Gate	
2	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,251	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						1,251	Dth				

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

Capacity Path Diagram

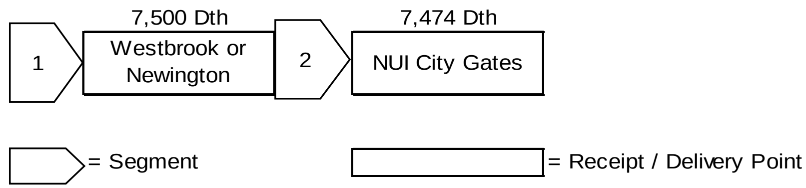


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Delivered Supply	Confidential	NA	NA	3/31/2015	7,500	Dth	Winter Only (Nov - Mar)	NA	Westbrook	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	7,474	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						7,474	Dth				

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

Capacity Path Diagram

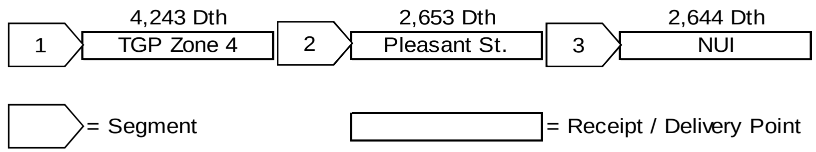


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Delivered Supply	Confidential	NA	NA	3/31/2015	7,500	Dth	Winter Only (Nov - Mar)	NA	Westbrook or Newington	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	7,474	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						7,474	Dth				

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

Capacity Path Diagram



Capacity Path Detail

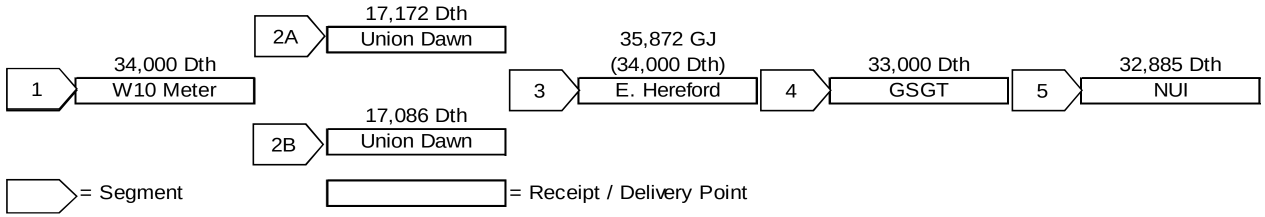
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	3/31/2020	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2020	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

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

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

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

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-0725	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-0727	FT	3/31/2017	17,086	Dth	Winter Only (Nov - Mar)	W10 Withdrawal Meter	Union Dawn	TransCanada
3	Transportation	TransCanada	33322	FT	3/31/2018	35,872	GJ	Year-Round	Union Dawn	East Hereford	PNGTS
4	Transportation	PNGTS	1997-004	FT	3/9/2019	33,000	Dth	Winter Only (Nov - Mar)	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	32,885	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,885	Dth				

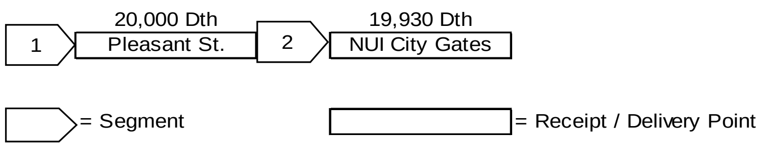
ME Assignable St(0 #DIV/0!

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

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

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

Capacity Path Diagram



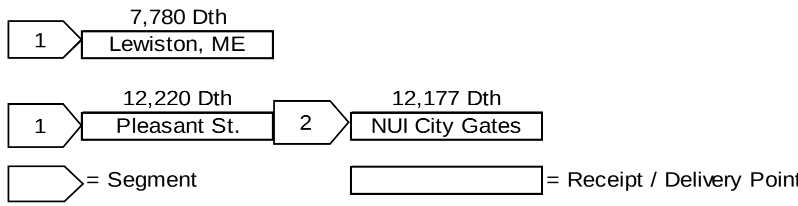
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2014	20,000	Dth	Winter Only (Nov - Mar)	NA	Pleasant St.	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	19,930	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						19,930	Dth				

Note 1: Peaking Contract 1 allows Northern to nominate up to 20,000 Dth per Day and up to 300,000 Dth from November 2014 through March 2015.

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

Capacity Path Diagram



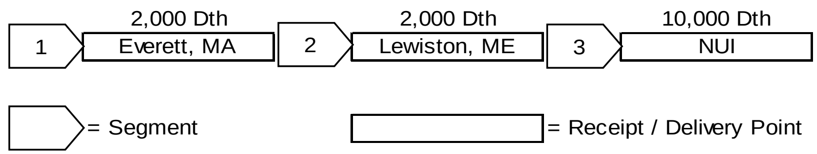
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2014	7,780	Dth	Winter Only (Nov - Mar)	NA	Northern City Gates	
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2014	12,220	Dth	Winter Only (Nov - Mar)	NA	Maritimes / Granite Westbrook	Northern or Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2014	12,177	Dth	Year-Round	Maritimes Westbrook	Northern City Gates	
Total Path Deliverable						19,957	Dth				

Note 1: Peaking Contract 2 allows Northern to nominate up to 20,000 Dth per Day and 300,000 Dth from November 2014 through March 2015.

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

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	LNG Contract	Confidential	NA	NA	10/31/2015	2,000	Dth	Year-Round	NA	Everett, MA	NA
2	LNG Trucking Contract	Confidential			10/31/2015	2,000	Dth	Year-Round	Everett, MA	Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	10,000	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						10,000	Dth				

Note 1: The LNG Contract allows Northern to nominate up to 2,000 Dth per day with an annual maximum take is 75,000 Dth.

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.
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-14	259,337	-	-	259,337	$ 902,233	$ 3.48	NA	$ -	$ 3.48	$ -	$ 902,233	2.19%	$ 1,644	$ 902,233	$ -
Dec-14	259,337	-	56,517	202,820	$ 902,233	$ 3.48	NA	$ -	$ 3.48	$ 196,622	$ 705,611	2.19%	$ 1,465	$ 705,611	$ 196,622
Jan-15	202,820	-	76,955	125,865	$ 705,611	$ 3.48	NA	$ -	$ 3.48	$ 267,727	$ 437,884	2.19%	$ 1,042	$ 437,884	$ 267,727
Feb-15	125,865	-	69,508	56,357	$ 437,884	$ 3.48	NA	$ -	$ 3.48	$ 241,818	$ 196,065	2.19%	$ 578	$ 196,065	$ 241,818
Mar-15	56,357	-	41,320	15,037	$ 196,065	$ 3.48	NA	$ -	$ 3.48	$ 143,753	$ 52,312	2.19%	$ 226	$ 52,312	$ 143,753
Apr-15	15,037	29,679	-	44,716	$ 52,312	$ 3.48	$ 2.99	$ 88,817	$ 3.16	$ -	$ 141,129	2.19%	$ 176	$ 141,129	$ -
May-15	44,716	30,668	-	75,384	$ 141,129	$ -	$ 2.98	$ 91,343	$ 3.08	$ -	$ 232,472	2.19%	$ 340	$ 232,472	$ -
Jun-15	75,384	29,679	-	105,063	$ 232,472	$ 3.08	$ 3.00	$ 89,086	$ 3.06	$ -	$ 321,559	2.19%	$ 505	$ 321,559	$ -
Jul-15	105,063	30,668	-	135,731	$ 321,559	$ 3.06	$ 3.03	$ 92,955	$ 3.05	$ -	$ 414,513	2.19%	$ 671	$ 414,513	$ -
Aug-15	135,731	30,668	-	166,400	$ 414,513	$ 3.05	$ 3.04	$ 93,172	$ 3.05	$ -	$ 507,685	2.19%	$ 840	$ 507,684	$ -
Sep-15	166,400	29,679	-	196,079	$ 507,685	$ 3.05	$ 3.03	$ 89,805	$ 3.05	$ -	$ 597,490	2.19%	$ 1,007	$ 597,489	$ -
Oct-15	196,079	30,668	-	226,747	$ 597,490	$ 3.05	$ 3.06	$ 93,909	$ 3.05	$ -	$ 691,399	2.19%	$ 1,174	$ 691,398	$ -

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-14	3,400,000	-	52,140	3,347,860	$15,279,600	$ 4.49	NA	$ -	$ 4.49	$ 234,318	$ 15,045,282	2.19%		$ 15,045,282	$ 234,318
Dec-14	3,347,860	-	490,280	2,857,580	$15,045,282	$ 4.49	NA	$ -	$ 4.49	$2,203,316	$ 12,841,966	2.19%		$ 12,841,966	$2,203,316
Jan-15	2,857,580	-	751,204	2,106,376	$12,841,966	$ 4.49	NA	$ -	$ 4.49	$3,375,910	$ 9,466,056	2.19%		$ 9,466,056	$3,375,910
Feb-15	2,106,376	-	624,133	1,482,244	$ 9,466,056	$ 4.49	NA	$ -	$ 4.49	$2,804,853	$ 6,661,202	2.19%		$ 6,661,202	$2,804,853
Mar-15	1,482,243	-	208,415	1,273,828	$ 6,661,202	$ 4.49	NA	$ -	$ 4.49	$ 936,619	$ 5,724,583	2.19%		$ 5,724,583	$ 936,619
Apr-15	1,273,828	-	-	1,273,828	$ 5,724,583	$ 4.49	NA		$ 4.49	$ -	$ 5,724,583	2.19%		$ 5,724,583	$ -
May-15	1,273,828	522,257	-	1,796,085	$ 5,724,583	$ 4.49	$ 3.87	$2,023,716	$ 4.31	$ -	$ 7,748,300	2.19%		$ 7,748,300	$ -
Jun-15	1,796,085	505,410	-	2,301,495	$ 7,748,300	$ 4.31	$ 3.84	$1,941,390	$ 4.21	$ -	$ 9,689,690	2.19%		$ 9,689,690	$ -
Jul-15	2,301,495	522,257	-	2,823,752	$ 9,689,690	$ 4.21	$ 3.86	$2,015,171	$ 4.15	$ -	$ 11,704,860	2.19%		$ 11,704,860	$ -
Aug-15	2,823,752	-	-	2,823,752	$11,704,860	$ 4.15	NA	$ -	$ 4.15	$ -	$ 11,704,860	2.19%		$ 11,704,860	$ -
Sep-15	2,823,752	505,410	-	3,329,162	$11,704,860	$ 4.15	$ 3.90	$1,971,802	$ 4.11	$ -	$ 13,676,663	2.19%		$ 13,676,663	$ -
Oct-15	3,329,162	70,838	-	3,400,000	$13,676,663	$ 4.11	$ 3.93	$ 278,438	$ 4.10	$ -	$ 13,955,100	2.19%		$ 13,955,100	$ -

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-14	11,250	7,382	7,252	11,380	$ 99,450	$ 8.84	$ 7.12	$ 52,579	$ 8.16	$ 59,171	$ 92,858	2.19%	$ 175	$ 92,858	$ 59,171
Dec-14	11,380	3,761	2,781	12,360	$ 92,858	$ 8.16	$16.01	$ 60,214	$ 10.11	$ 28,114	$ 124,958	2.19%	$ 198	$ 124,958	$ 28,114
Jan-15	12,360	20,086	21,196	11,250	$ 124,958	$ 10.11	$20.19	$ 405,576	$ 16.35	$ 346,582	$ 183,952	2.19%	$ 281	$ 183,952	$ 346,582
Feb-15	11,250	16,692	16,692	11,250	$ 183,952	$ 16.35	$19.52	$ 325,871	$ 18.25	$ 304,556	$ 205,268	2.19%	$ 355	$ 205,268	$ 304,556
Mar-15	11,250	13,350	12,100	12,500	$ 205,268	$ 18.25	$11.07	$ 147,838	$ 14.35	$ 173,682	$ 179,423	2.19%	$ 350	$ 179,423	$ 173,682
Apr-15	12,500	850	2,100	11,250	$ 179,423	$ 14.35	$12.14	$ 10,323	$ 14.21	$ 29,848	$ 159,899	2.19%	$ 309	$ 159,899	$ 29,848
May-15	11,250	2,170	2,170	11,250	$ 159,899	$ 14.21	$10.66	$ 23,124	$ 13.64	$ 29,595	$ 153,428	2.19%	$ 285	$ 153,428	$ 29,595
Jun-15	11,250	2,100	2,100	11,250	$ 153,428	$ 13.64	$11.99	$ 25,177	$ 13.38	$ 28,095	$ 150,510	2.19%	$ 277	$ 150,510	$ 28,095
Jul-15	11,250	2,170	2,170	11,250	$ 150,510	$ 13.38	$11.38	$ 24,701	$ 13.06	$ 28,331	$ 146,879	2.19%	$ 271	$ 146,879	$ 28,331
Aug-15	11,250	2,170	2,170	11,250	$ 146,879	$ 13.06	$11.08	$ 24,044	$ 12.74	$ 27,638	$ 143,285	2.19%	$ 264	$ 143,285	$ 27,638
Sep-15	11,250	2,100	2,100	11,250	$ 143,285	$ 12.74	$10.70	$ 22,466	$ 12.42	$ 26,073	$ 139,678	2.19%	$ 258	$ 139,678	$ 26,073
Oct-15	11,250	2,170	2,170	11,250	$ 139,678	$ 12.42	$11.02	$ 23,922	$ 12.19	$ 26,454	$ 137,146	2.19%	$ 252	$ 137,146	$ 26,454

Schedule 15

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF WINTER PERIOD BALANCE
May 2013 - April 2014

	AMOUNT	
Winter Period Beg. Balance	($2,128,249)	SCHEDULE 2
Less: May 1, 2013 Adjustment	($130,002)	SCHEDULE 2
Less: Reported Collections	($30,066,634)	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$28,659,051	SCHEDULE 4
Add: Interest	($44,733)	SCHEDULE 2
Add: April 20, 2014 Adjustment	$103,007	SCHEDULE 2
Winter Period Ending Balance	($3,607,559)	

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED WINTER PERIOD ACCOUNTS
May 2013 - April 2014
Acct 191.20

	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
WINTER PERIOD													
Initial Winter Period Account Beginning Balance	$ (2,128,249)												
Reconciliation Adjustment (1)	**$ (130,002)**												
Revised Winter Period Account Beginning Balance	$ (2,258,251)	$ (1,641,768)	$(1,437,389)	$(1,202,790)	$ (988,347)	$ (779,527)	$ (556,547)	$ 258,088	$ 209,661	$ (1,688,817)	$ (2,317,555)	$ (3,409,624)	$ (2,258,251)
Plus: Cost of Firm Gas (Schedule 4)	$ 316,557	$ 225,746	$ 213,639	$ 216,553	$ 211,472	$ 225,040	$ 3,562,125	$ 5,169,092	$ 5,650,404	$ 5,397,617	$ 5,679,490	$ 1,791,316	$ 28,659,051
Less: Reported Collections (Schedule 3)	$ 305,200	$ (17,203)	$ 24,530	$ 853	$ (261)	$ (253)	$ (2,747,086)	$ (5,218,152)	$ (7,546,882)	$ (6,020,936)	$ (6,763,815)	$ (2,082,628)	$ (30,066,634)
Winter Period Account Ending Balance	$ (1,636,494)	$ (1,433,225)	$ (1,199,220)	$ (985,384)	$ (777,136)	$ (554,740)	$ 258,492	$ 209,029	$ (1,686,817)	$ (2,312,137)	$ (3,401,879)	$ (3,700,937)	$ (3,665,833)
Month's Average Balance	$ (1,947,372)	$ (1,537,497)	$ (1,318,304)	$ (1,094,087)	$ (882,742)	$ (667,134)	$ (149,028)	$ 233,559	$ (738,578)	$ (2,000,477)	$ (2,859,717)	$ (3,555,281)	
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	$ (5,274)	$ (4,164)	$ (3,570)	$ (2,963)	$ (2,391)	$ (1,807)	$ (404)	$ 633	$ (2,000)	$ (5,418)	$ (7,745)	$ (9,629)	$ (44,733)
Reconciliation Adjustment (2)												$ 103,007	$ 103,007
Winter Period Account Ending Balance w/int	**$ (1,641,768)**	**$ (1,437,389)**	**$ (1,202,790)**	**$ (988,347)**	**$ (779,527)**	**$ (556,547)**	**$ 258,088**	**$ 209,661**	**$ (1,688,817)**	**$ (2,317,555)**	**$ (3,409,624)**	**$ (3,607,559)**	**$ (3,607,559)**

Reconciliation Adjustment (1): $130,002 - Final outstanding balance of Tennessee Gas Pipeline refund due customers ($13,143.78). Transferred from Supplier Refund Account (SRA) on May 1, 2013 plus ($116, 857.73) transferred from SRA to off-set PNGTS refund to marketers being flowed through company managed account. This adjustment is required to make sales customers whole.

Reconciliation Adjustment (2): $103,007 - Outstanding balance of PNGTS refund transferred from SRA because PNGTS refund due customers has been exceeded at April 30, 2014 (see Attachment F).

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
May 2013 - April 2014

FORM III
Schedule 3

	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
Accrued Revenue	$ (955,992)		$ -	$ -	$ -	$ -	$ 1,682,974	$ 886,729	$ 1,108,290	$ (728,739)	$ 458,585	$(1,806,216)	$ 645,631
Billed Revenue	$ 650,792	$ 17,203	$ (24,530)	$ (853)	$ 261	$ 253	$ 1,064,112	$ 4,331,423	$ 6,438,593	$ 6,749,675	$ 6,305,230	$ 3,888,844	$ 29,421,003
Calendarized Revenue	**$ (305,200)**	**$ 17,203**	**$ (24,530)**	**$ (853)**	**$ 261**	**$ 253**	**$ 2,747,086**	**$ 5,218,152**	**$ 7,546,882**	**$ 6,020,936**	**$ 6,763,815**	**$ 2,082,628**	**$ 30,066,634**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2013 - April 2014

Commodity Costs:	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Total Winter**
Anadarko	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,518	$ 9,049	$ -	**$ 29,567**
Cargill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,149	$ 81,853	$ 90,742	$ 98,352	$ 104,646	**$ 458,742**
Chesapeake	$ 411,523	$ -	$ -	$ -	$ -	$ -	$ -	$ 96,486	$ -	$ -	$ -	$ -	**$ 508,009**
DTE	$ 145,024	$ -	$ -	$ -	$ -	$ -	$ -	$ 270,795	$ 277,005	$ 319,799	$ 498,755	$ 405,072	**$ 1,916,450**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,148,021	$ 1,142,490	$ 1,316,255	$ 1,621,110	$ 2,041,633	**$ 7,269,509**
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Repsol	$ 130,762	$ -	$ -	$ -	$ -	$ -	$ -	$ 193,192	$ 632,517	$ 2,520,403	$ 1,147,093	$ 668,857	**$ 5,292,823**
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 247,215	$ 966,153	$ 674,516	$ 359,815	$ 357,850	**$ 2,605,549**
South Jersey	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,257	**$ 92,257**
Tenaska	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,413	$ -	**$ 14,413**
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 173	$ -	$ -	**$ 173**
Subtotal - Commodiity Supply	$ 687,309	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,038,857	$ 3,100,017	$ 4,942,407	$ 3,748,585	$ 3,670,316	**$ 18,187,492**
Transportation Costs:													
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 284	$ 619	$ 734	$ 573	$ 540	$ 176	**$ 2,925**
Portland	$ 53	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,690	$ 93,885	$ 72,763	$ 22,260	$ 19,395	**$ 241,045**
Tennessee	$ 14,353	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,658	$ 11,798	$ 21,959	$ 15,178	$ 12,912	**$ 87,858**
Subtotal - Commodity Transportation	$ 14,406	$ -	$ -	$ -	$ -	$ -	$ 284	$ 44,967	$ 106,416	$ 95,296	$ 37,977	$ 32,483	**$ 331,829**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,083,176	$ 3,255,238	$ 5,037,301	$ 3,786,262	$ 3,702,760	$ 1,185,088	**$ 19,049,825**
Commodity Cost Reversals	$ (701,842)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,083,176)	$ (3,255,238)	$ (5,037,301)	$ (3,786,262)	$ (3,702,760)	**$ (18,566,579)**
Subtotal - Supply	$ (127)	$ -	$ -	$ -	$ -	$ -	$ 2,083,460	$ 3,255,886	$ 4,988,497	$ 3,786,663	$ 3,703,061	$ 1,185,127	**$ 19,002,567**
Withdrawal - Underground Storage	$ 127	$ -	$ -	$ -	$ -	$ -	$ 425,790	$ 1,188,552	$ 1,648,303	$ 1,582,547	$ 1,059,576	$ (306)	**$ 5,904,590**
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,502	$ (159,704)	$ (419,680)	$ (232,436)	$ (107,665)	$ 15,641	**$ (898,344)**
Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (407,790)	$ (23,667)	$ (888,877)	$ (1,248,788)	$ -	**$ (2,569,121)**
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ (709)	$ (9,309)	$ (1,754)	$ (50,863)	$ 16,871	$ (16,125)	**$ (61,889)**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (166,940)	$ (658,185)	$ (1,247,369)	$ (675,188)	$ (580,713)	**$ (3,328,394)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,103	$ 7,882	$ 22,886	$ 39,882	$ 63,181	$ 24,109	**$ 164,043**
Transportation Charges	$ 24,492	$ (70,026)	$ -	$ -	$ -	$ -	$ -	$ (40,495)	$ (46,031)	$ 791,839	$ 149,125	$ 105,319	**$ 914,222**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,114	$ 27,962	$ (38,769)	$ (202,366)	$ (174,049)	$ (48,642)	**$ (403,749)**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Inventory Finance Charage	$ 179	$ 336	$ 440	$ 538	$ 640	$ 589	$ 573	$ 516	$ 426	$ 291	$ 258	$ 244	**$ 5,031**
Prior Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal - Other Commodity	$ 24,798	$ (69,690)	$ 440	$ 538	$ 640	$ 589	$ 469,374	$ 440,675	$ 483,529	$ (207,351)	$ (916,681)	$ (500,472)	**$ (273,611)**
Off System Sales Estimates	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (574,666)**	**$ (672,983)**	**$ (2,136,246)**	**$ (1,923,976)**	**$ (580,713)**	**$ -**	**$ (5,888,584)**
Off System Sales Reversals	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 574,666**	**$ 672,983**	**$ 2,136,246**	**$ 1,923,976**	**$ 580,713**	**$ 5,888,584**
Subtotal Estimates/Reversals	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (574,666)**	**$ (98,317)**	**$ (1,463,263)**	**$ 212,270**	**$ 1,343,263**	**$ 580,713**	**$ -**
Total Commodity Costs	$ 24,672	$ (69,690)	$ 440	$ 538	$ 640	$ 589	$ 1,978,168	$ 3,598,244	$ 4,008,762	$ 3,791,583	$ 4,129,643	$ 1,265,368	**$ 18,728,957**

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2013 - April 2014

Demand Costs	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total Winter
Pipeline Reservation													
Alberta Northeast	$ 6,538	$ 7,313	$ 9,872	$ 8,535	$ 8,412	$ 8,974	$ 9,080	$ 7,710	$ 8,458	$ 9,148	$ 7,647	$ 7,775	**$ 99,462**
Algonquin	$ 15,757	$ 15,761	$ 15,761	$ 15,737	$ 15,761	$ 15,760	$ 15,761	$ 16,047	$ 16,046	$ 16,035	$ 16,007	$ 16,018	**$ 190,452**
DTE Energy	$ 443,017	$ 440,065	$ 445,703	$ 310,988	$ 319,388	$ 314,964	$ 311,973	$ 314,364	$ 301,950	$ 302,419	$ 298,843	$ 303,388	**$ 4,107,061**
Emera	$ 38,778	$ 38,146	$ 38,759	$ 33,613	$ 34,474	$ 34,023	$ 33,700	$ 34,085	$ 33,614	$ 32,683	$ 32,683	$ 32,431	**$ 416,987**
Granite State	$ 152,716	$ 152,716	$ 152,716	$ 163,170	$ 163,170	$ 163,170	$ 166,124	$ 166,124	$ 166,124	$ 166,124	$ 166,124	$ 166,124	**$ 1,944,405**
Iroquois	$ 20,108	$ 20,108	$ 20,108	$ 20,108	$ 20,108	$ 20,108	$ 20,108	$ 20,472	$ 20,472	$ 20,472	$ 20,472	$ 20,472	**$ 243,117**
Portland	$ 20,541	$ 20,541	$ 20,541	$ 20,541	$ 20,541	$ 20,541	$ 20,541	$ 1,212,966	$ 1,212,966	$ 1,212,966	$ 1,212,966	$ 1,212,966	**$ 6,208,621**
Tennessee	$ 179,232	$ 179,232	$ 179,232	$ 179,232	$ 179,232	$ 175,742	$ 175,742	$ 178,924	$ 178,924	$ 178,924	$ 178,924	$ 178,924	**$ 2,142,264**
Texas Eastern	$ 2,479	$ 2,479	$ 2,479	$ 2,479	$ 2,457	$ 2,457	$ 2,457	$ 2,502	$ 2,502	$ 2,502	$ 2,506	$ 2,506	**$ 29,806**
Union	$ (370)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ (370)**
Vector	$ 83,850	$ 83,848	$ 83,817	$ 83,832	$ 83,828	$ 83,826	$ 83,806	$ 122,138	$ 122,098	$ 122,094	$ 122,082	$ 122,095	**$ 1,197,315**
Total Pipeline Reservation	$ 962,646	$ 960,211	$ 968,989	$ 838,236	$ 847,373	$ 839,567	$ 839,293	$ 2,075,331	$ 2,063,153	$ 2,063,367	$ 2,058,254	$ 2,062,700	**$ 16,579,120**
Product Demand													
Alberta Northeast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
BG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,700	$ 55,113	$ 55,113	$ 55,113	$ 13,700	**$ 192,739**
DTE Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,086	$ 7,086	$ 7,086	$ 7,086	$ 7,086	**$ 35,430**
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,860	$ 73,222	$ 73,222	$ 66,136	$ 73,222	**$ 356,662**
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,440	$ 7,440	$ 7,440	$ 7,440	$ 7,440	**$ 37,202**
Total Product Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 99,086	$ 142,862	$ 142,862	$ 135,776	$ 101,448	**$ 622,033**
Storage Pipeline Transportation and Demand Reservation													
Tennessee	$ 5,571	$ 5,571	$ 5,571	$ 5,571	$ 5,571	$ 5,571	$ 5,571	$ 5,672	$ 5,672	$ 5,672	$ 5,672	$ 5,672	**$ 67,355**
Texas Eastern	$ 68	$ 80	$ 80	$ 80	$ 79	$ 79	$ 80	$ 81	$ 82	$ 81	$ 81	$ 81	**$ 953**
Wash 10	$ 111,747	$ 111,747	$ 111,747	$ 111,747	$ 111,747	$ 111,747	$ 111,747	$ 113,770	$ 113,770	$ 113,770	$ 113,770	$ 113,770	**$ 1,351,075**
Company Managed	$ (150,969)	$ (99,506)	$ (97,253)	$ (70,783)	$ (68,434)	$ (69,902)	$ (69,774)	$ (347,938)	$ (356,916)	$ (356,916)	$ (342,336)	$ (331,404)	**$ (2,362,130)**
Total Storage and Demand Reservation	$ (33,584)	$ 17,892	$ 20,144	$ 46,614	$ 48,963	$ 47,495	$ 47,624	$ (228,416)	$ (237,393)	$ (237,393)	$ (222,814)	$ (211,881)	**$ (942,747)**
Demand Cost Estimates	$ 823,162	$ 818,945	$ 723,414	$ 737,562	$ 724,273	$ 732,639	$ 1,797,033	$ 1,790,417	$ 1,831,865	$ 1,836,171	$ 1,781,667	$ 727,752	**$ 14,324,900**
Demand Cost Reversals	$ (781,605)	$ (823,162)	$ (818,945)	$ (723,414)	$ (737,562)	$ (724,273)	$ (732,639)	$ (1,797,033)	$ (1,790,417)	$ (1,831,865)	$ (1,836,171)	$ (1,781,667)	**$ (14,378,753)**
Subtotal	$ 41,557	$ (4,217)	$ (95,531)	$ 14,148	$ (13,289)	$ 8,366	$ 1,064,394	$ (6,616)	$ 41,448	$ 4,306	$ (54,504)	$ (1,053,915)	**$ (53,853)**
Total Direct Demand Costs	$ 970,619	$ 973,885	$ 893,603	$ 898,998	$ 883,047	$ 895,428	$ 1,951,311	$ 1,939,385	$ 2,010,070	$ 1,973,141	$ 1,916,712	$ 898,352	**$ 16,204,552**
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,831	$ 3,831	$ 3,831	$ 3,831	$ 3,831	$ 3,831	**$ 22,988**
Capacity Release	$ (492,818)	$ (493,441)	$ (493,610)	$ (502,276)	$ (505,019)	$ (493,774)	$ (494,449)	$ (506,421)	$ (506,982)	$ (506,707)	$ (505,664)	$ (506,274)	**$ (6,007,433)**
Capacity Mitigation	$ (10,100)	$ (10,100)	$ (10,100)	$ (10,100)	$ (9,536)	$ (9,536)	$ (8,937)	$ (4,549)	$ (4,549)	$ (4,549)	$ (4,549)	$ (4,056)	**$ (90,659)**
Production and Storage	$ -	$ -	$ 6,585	$ 6,585	$ 6,585	$ 6,585	$ 69,161	$ 69,161	$ 69,161	$ 69,161	$ 69,161	$ 69,161	**$ 441,308**
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,110	$ 70,110	$ 70,110	$ 70,110	$ 70,110	$ 70,110	**$ 420,658**
Total Indirect Demand Costs	$ (502,917)	$ (503,540)	$ (497,124)	$ (505,790)	$ (507,970)	$ (496,725)	$ (360,284)	$ (367,867)	$ (368,429)	$ (368,153)	$ (367,111)	$ (367,227)	**$ (5,213,139)**
Demand Cost Estimates - Capacity Release	$ (498,075)	$ (497,993)	$ (506,281)	$ (508,483)	$ (497,736)	$ (496,997)	$ (504,066)	$ (504,736)	$ (504,736)	$ (503,690)	$ (503,444)	$ (508,621)	**$ (6,034,858)**
Demand Cost Reversals - Capacity Release	$ 497,250	$ 498,075	$ 497,993	$ 506,281	$ 508,483	$ 497,736	$ 496,997	$ 504,066	$ 504,736	$ 504,736	$ 503,690	$ 503,444	**$ 6,023,487**
Subtotal	$ (825)	$ 82	$ (8,288)	$ (2,202)	$ 10,747	$ 739	$ (7,069)	$ (670)	$ -	$ 1,046	$ 246	$ (5,177)	**$ (11,371)**
Total Demand Costs	**$ 466,877**	**$ 470,427**	**$ 388,191**	**$ 391,006**	**$ 385,824**	**$ 399,442**	**$ 1,583,958**	**$ 1,570,848**	**$ 1,641,641**	**$ 1,606,034**	**$ 1,549,847**	**$ 525,948**	$ 10,980,043
Demand Costs Transferred to Summer	$ (174,991)	$ (174,991)	$ (174,991)	$ (174,991)	$ (174,991)	$ (174,991)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (1,049,948)**
Net Demand Costs For Winter Period	**$ 291,885**	**$ 295,436**	**$ 213,199**	**$ 216,015**	**$ 210,832**	**$ 224,451**	**$ 1,583,958**	**$ 1,570,848**	**$ 1,641,641**	**$ 1,606,034**	**$ 1,549,847**	**$ 525,948**	$ 9,930,095
Total Gas Costs	**$ 316,557**	**$ 225,746**	**$ 213,639**	**$ 216,553**	**$ 211,472**	**$ 225,040**	**$ 3,562,125**	**$ 5,169,092**	**$ 5,650,404**	**$ 5,397,617**	**$ 5,679,490**	**$ 1,791,316**	$ 28,659,051

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
May 2013 - April 2014

Commodity Volumes:	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total Winter
Anadarko	[redacted]												
Cargill													
Chesapeake													
DTE													
Emera Energy													
Granite													
Hess													
Repsol													
Shell													
South Jersey													
Tenaska													
Tennessee													
Subtotal - Commodity Supply													
Transportation Volumes													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation													
Off System Sales													
Net OBA Adjustment													
Company Managed													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Prior Period Adjustment													
Subtotal - Other Commodity													
Off System & Company Managed Estimates													
Off System & Company Managed Reversals													
Total Commodity Volumes													

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
May 2013 - April 2014

Commodity Costs:	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total Winter
Anadarko	[redacted]												
Cargill													
Chesapeake													
DTE													
Emera Energy													
Granite													
Hess													
Repsol													
Shell													
South Jersey													
Tenaska													
Tennessee													
Subtotal - Commodity Supply													
Transportation Costs:													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Cost Estimates													
Commodity Cost Reversals													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
Company Managed													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Prior Period Adjustments													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Total Commodity Costs													

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
May 2013 - April 2014

Commodity Costs:	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total Winter
Anadarko	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,210	$ 10,791	$ -	$ 37,001
Cargill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,270	$ 108,370	$ 115,913	$ 117,285	$ 114,508	$ 548,346
Chesapeake	$ 385,230	$ -	$ -	$ -	$ -	$ -	$ -	$ 107,071	$ -	$ -	$ -	$ -	$ 492,301
DTE	$ 135,758	$ -	$ -	$ -	$ -	$ -	$ -	$ 300,502	$ 366,744	$ 408,507	$ 594,766	$ 443,247	$ 2,249,523
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,273,965	$ 1,512,611	$ 1,681,365	$ 1,933,176	$ 2,234,038	$ 8,635,155
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Repsol	$ 122,408	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,386	$ 837,427	$ 3,219,526	$ 1,367,910	$ 731,891	$ 6,493,547
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 274,335	$ 1,279,148	$ 861,617	$ 429,080	$ 391,575	$ 3,235,755
South Jersey	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,951	$ 100,951
Tenaska	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,187	$ -	$ 17,187
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 221	$ -	$ -	$ 221
Subtotal - Commodity Supply	$ 643,396	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,262,529	$ 4,104,299	$ 6,313,359	$ 4,470,194	$ 4,016,210	$ 21,809,987
Transportation Costs:													
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 315	$ 687	$ 937	$ 684	$ 591	$ 184	$ 3,398
Portland	$ 50	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,276	$ 124,300	$ 92,946	$ 26,545	$ 21,223	$ 301,339
Tennessee	$ 13,436	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,937	$ 15,620	$ 28,051	$ 18,099	$ 14,129	$ 102,272
Subtotal - Commodity Transportation	$ 13,486	$ -	$ -	$ -	$ -	$ -	$ 315	$ 49,900	$ 140,857	$ 121,681	$ 45,235	$ 35,536	$ 407,009
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,311,710	$ 4,309,806	$ 6,434,576	$ 4,515,124	$ 4,051,711	$ 1,241,382	$ 22,864,309
Commodity Cost Reversals	$ (657,001)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,311,710)	$ (4,309,806)	$ (6,434,576)	$ (4,515,124)	$ (4,051,711)	$ (22,279,928)
Subtotal - Supply	$ (119)	$ -	$ -	$ -	$ -	$ -	$ 2,312,025	$ 4,310,525	$ 6,369,926	$ 4,515,588	$ 4,052,016	$ 1,241,417	$ 22,801,377
Withdrawal - Underground Storage	$ 119	$ -	$ -	$ -	$ -	$ -	$ 472,502	$ 1,573,596	$ 2,105,524	$ 1,887,219	$ 1,159,453	$ (314)	$ 7,198,098
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,106	$ (208,103)	$ (532,856)	$ (277,181)	$ (117,812)	$ 16,383	$ (1,113,462)
Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (452,526)	$ (31,334)	$ (1,135,438)	$ (1,489,182)	$ -	$ (3,108,480)
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ (786)	$ (12,324)	$ (2,241)	$ (60,655)	$ 18,460	$ (16,890)	$ (74,436)
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (338,599)	$ (1,583,348)	$ (1,973,036)	$ (1,582,690)	$ (678,826)	$ (6,156,499)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,772	$ 10,435	$ 29,235	$ 47,560	$ 69,135	$ 25,254	$ 188,391
Transportation Charges	$ 22,927	$ (68,640)	$ -	$ -	$ -	$ -	$ -	$ (44,937)	$ (60,944)	$ 1,011,484	$ 177,831	$ 115,244	$ 1,152,966
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 35,637	$ 37,021	$ (49,523)	$ (241,322)	$ (190,451)	$ (50,952)	$ (459,590)
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 420	$ 531	$ 1,006	$ 1,061	$ 772	$ 1,086	$ 4,877
Inventory Finance Charage	$ 176	$ 293	$ 412	$ 490	$ 554	$ 604	$ 636	$ 684	$ 544	$ 347	$ 282	$ 255	$ 5,278
Prior Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Other Commodity	$ 23,222	$ (68,346)	$ 412	$ 490	$ 554	$ 604	$ 521,286	$ 565,775	$ (123,936)	$ (739,960)	$ (1,954,201)	$ (588,759)	$ (2,362,858)
Off System Sales Estimates	-	-	-	-	-	-	(791,054)	(1,614,681)	(3,108,474)	(3,071,872)	(678,826)	-	(9,264,907)
Off System Sales Reversals	-	-	-	-	-	-	-	791,054	1,614,681	3,108,474	3,071,872	678,826	9,264,907
Subtotal Estimates/Reversals	-	-	-	-	-	-	(791,054)	(823,627)	(1,493,793)	36,602	2,393,046	678,826	-
Total Commodity Costs	$ 23,103	$ (68,346)	$ 412	$ 490	$ 554	$ 604	$ 2,042,257	$ 4,052,674	$ 4,752,197	$ 3,812,230	$ 4,490,862	$ 1,331,484 #	**$ 20,438,519**

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN DOLLARS
May 2013 - April 2014

Demand Costs	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total Winter
Pipeline Reservation													
Alberta Northeast	$ 7,552	$ 8,448	$ 11,404	$ 9,859	$ 9,718	$ 10,367	$ 10,489	$ 8,610	$ 9,446	$ 10,217	$ 8,541	$ 8,683	$ 113,335
Algonquin	$ 18,202	$ 18,207	$ 18,207	$ 18,179	$ 18,207	$ 18,206	$ 18,207	$ 17,922	$ 17,921	$ 17,909	$ 17,877	$ 17,890	$ 216,933
DTE Energy	$ 511,761	$ 508,351	$ 514,864	$ 359,245	$ 368,948	$ 363,838	$ 360,382	$ 351,097	$ 337,232	$ 337,756	$ 333,762	$ 338,839	$ 4,686,077
Freepoint	$ 44,795	$ 44,065	$ 44,773	$ 38,829	$ 39,823	$ 39,303	$ 38,929	$ 38,067	$ 37,541	$ 36,502	$ 36,502	$ 36,220	$ 475,350
Granite State	$ 176,414	$ 176,414	$ 176,414	$ 188,490	$ 188,490	$ 188,490	$ 185,536	$ 185,536	$ 185,536	$ 185,536	$ 185,536	$ 185,536	$ 2,207,925
Iroquois	$ 23,228	$ 23,228	$ 23,228	$ 23,228	$ 23,228	$ 23,228	$ 23,228	$ 22,864	$ 22,864	$ 22,864	$ 22,864	$ 22,864	$ 276,919
Portland	$ 23,729	$ 23,729	$ 23,729	$ 23,729	$ 23,729	$ 23,729	$ 23,729	$ 1,354,702	$ 1,354,702	$ 1,354,702	$ 1,354,702	$ 1,354,702	$ 6,939,610
Tennessee	$ 207,044	$ 207,044	$ 207,044	$ 207,044	$ 207,044	$ 203,013	$ 203,013	$ 199,831	$ 199,831	$ 199,831	$ 199,831	$ 199,831	$ 2,440,401
Texas Eastern	$ 2,863	$ 2,863	$ 2,863	$ 2,863	$ 2,839	$ 2,839	$ 2,839	$ 2,794	$ 2,795	$ 2,795	$ 2,799	$ 2,799	$ 33,951
Union	$ (427)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (427)
Vector	$ 96,861	$ 96,859	$ 96,824	$ 96,841	$ 96,836	$ 96,833	$ 96,810	$ 136,410	$ 136,365	$ 136,360	$ 136,348	$ 136,361	$ 1,359,709
Total Pipeline Reservation	$1,112,022	$1,109,209	$1,119,350	$968,307	$978,862	$969,845	$963,162	$2,317,834	$2,304,233	$2,304,472	$2,298,761	$2,303,727	$18,749,782
Product Demand													
Alberta Northeast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,300	$ 61,553	$ 61,553	$ 61,553	$ 15,300	$ 215,261
DTE Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,914	$ 7,914	$ 7,914	$ 7,914	$ 7,914	$ 39,570
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 79,140	$ 81,778	$ 81,778	$ 73,864	$ 81,778	$ 398,338
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,310	$ 8,310	$ 8,310	$ 8,310	$ 8,310	$ 41,549
Total Product Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,664	$ 159,555	$ 159,555	$ 151,641	$ 113,302 #	$ 694,717
Storage Pipeline Transportation and Demand Reservation													
Tennessee	$ 6,435	$ 6,435	$ 6,435	$ 6,435	$ 6,435	$ 6,435	$ 6,435	$ 6,334	$ 6,334	$ 6,334	$ 6,334	$ 6,334	$ 76,720
Texas Eastern	$ 105	$ 93	$ 92	$ 92	$ 92	$ 92	$ 92	$ 91	$ 91	$ 91	$ 91	$ 91	$ 1,112
Wash 10	$ 129,087	$ 129,087	$ 129,087	$ 129,087	$ 129,087	$ 129,087	$ 129,087	$ 127,064	$ 127,064	$ 127,064	$ 127,064	$ 127,064	$ 1,538,925
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (745,571)	$ (739,246)	$ (734,102)	$ (709,699)	$ (702,242)	$ (3,630,860)
Total Storage and Demand Reservation	$ 135,627	$ 135,615	$ 135,614	$ 135,614	$ 135,614	$ 135,614	$ 135,614	$ (612,082)	$ (605,757)	$ (600,613)	$ (576,210)	$ (568,753)	$ (2,014,103)
Demand Cost Estimates	$ 1,065,841	$ 1,058,366	$ 917,435	$ 931,065	$ 917,410	$ 927,000	$ 1,650,040	$ 1,659,003	$ 1,710,437	$ 1,723,366	$ 1,657,741	$ 957,249	$ 15,174,953
Demand Cost Reversals	$ (1,077,283)	$ (1,065,841)	$ (1,058,366)	$ (917,435)	$ (931,065)	$ (917,410)	$ (927,000)	$ (1,650,040)	$ (1,659,003)	$ (1,710,437)	$ (1,723,366)	$ (1,657,741)	$ (15,294,987)
Subtotal Estimates/Reversals	$ (11,442)	$ (7,475)	$ (140,931)	$ 13,630	$ (13,655)	$ 9,590	$ 723,040	$ 8,963	$ 51,434	$ 12,929	$ (65,625)	$ (700,492)	$ (120,034)
Totall Direct Demand Costs	$ 1,236,207	$ 1,237,349	$ 1,114,033	$ 1,117,551	$ 1,100,820	$ 1,115,048	$ 1,821,816	$ 1,825,379	$ 1,909,465	$ 1,876,343	$ 1,808,567	$ 1,147,784	$ 17,310,363
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,063	$ 4,769	$ 10,152	$ 4,282	$ 2,856	$ 1,025	$ 25,147
Capacity Release	$ (535,110)	$ (534,769)	$ (534,784)	$ (542,550)	$ (547,329)	$ (533,092)	$ (533,187)	$ (524,119)	$ (526,402)	$ (527,783)	$ (528,404)	$ (528,632)	$ (6,396,160)
Capacity Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Production and Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ 73,588	$ 73,588	$ 135,298	$ 135,298	$ 135,298	$ 135,298	$ 688,368
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,790	$ 52,790	$ 61,951	$ 61,951	$ 61,951	$ 61,951	$ 353,385
Total Indirect Demand Costs	$ (535,110)	$ (534,769)	$ (534,784)	$ (542,550)	$ (547,329)	$ (533,092)	$ (404,747)	$ (392,972)	$ (319,000)	$ (326,251)	$ (328,299)	$ (330,357)	$ (5,329,259)
Demand Cost Estimates - Capacity Release	$ (530,231)	$ (530,136)	$ (539,332)	$ (542,526)	$ (530,112)	$ (530,205)	$ (521,804)	$ (521,896)	$ (521,896)	$ (521,620)	$ (521,896)	$ (528,076)	$ (6,339,730)
Demand Cost Reversals - Capacity Release	$ 530,136	$ 530,231	$ 530,136	$ 539,332	$ 542,526	$ 530,112	$ 530,205	$ 521,804	$ 521,896	$ 521,896	$ 521,620	$ 521,896	$ 6,341,790
Subtotal	$ (95)	$ 95	$ (9,196)	$ (3,194)	$ 12,414	$ (93)	$ 8,401	$ (92)	$ -	$ 276	$ (276)	$ (6,180)	$ 2,060
Total Demand Costs	$ 701,002	$ 702,675	$ 570,053	$ 571,807	$ 565,905	$ 581,864	$ 1,425,470	$ 1,432,314	$ 1,590,465	$ 1,550,368	$ 1,479,992	$ 811,247	$ 11,983,163
Demand Costs Transferred to Summer	$ (172,313)	$ (172,313)	$ (172,313)	$ (172,313)	$ (172,313)	$ (172,313)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,033,876)
Net Demand Costs For Winter Period	**$ 528,690**	**$ 530,362**	**$ 397,741**	**$ 399,495**	**$ 393,593**	**$ 409,551**	**$ 1,425,470**	**$ 1,432,314**	**$ 1,590,465**	**$ 1,550,368**	**$ 1,479,992**	**$ 811,247**	**$ 10,949,287**
Total Gas Costs	**$ 551,792**	**$ 462,016**	**$ 398,153**	**$ 399,985**	**$ 394,147**	**$ 410,155**	**$ 3,467,728**	**$ 5,484,988**	**$ 6,342,662**	**$ 5,362,598**	**$ 5,970,854**	**$ 2,142,731**	**$ 31,387,807**

REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
May 2013 - April 2014

Commodity Volumes:	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Total Winter**
Anadarko	[redacted]												
Cargill													
Chesapeake													
DTE													
Emera Energy													
Granite													
Hess													
Repsol													
Shell													
South Jersey													
Tenaska													
Tennessee													
Subtotal - Commodity Costs													
Transportation Volumes													
Granite													
Portland													
Tennessee													
Subtotal- Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation													
Off System Sales													
Net OBA Adjustment													
Company Managed													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Prior Period Adjustment													
Subtotal - Other Commodity													
Off System & Company Managed Estimates													
Off System & Company Managed Reversals													
Total Commodity Volumes													

REDACTED

NORTHERN UTILITIES, INC. - MAINE DIVISION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
May 2013 - April 2014

Commodity Costs:	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total Winter
Anadarko	[redacted]												
Cargill													
Chesapeake													
DTE													
Emera Energy													
Granite													
Hess													
Repsol													
Shell													
South Jersey													
Tenaska													
Tennessee													
Subtotal - Commodity Supply													
Transportation Costs:													
Granite													
Portland													
Tennessee													
Subtotal - Commoditty Transportation													
Commodity Cost Estimates													
Commodity Cost Reversals													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
Company Managed													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Inventory Finance Charge													
Prior Period Adjustments													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Total Commodity Costs													

NORTHERN UTILITIES, INC. - BOTH DIVISIONs
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2013 - April 2014

Commodity Costs:	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**		**Total Winter**
Anadarko	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,728	$ 19,840	$ -	#	$ 66,568
Cargill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,419	$ 190,222	$ 206,655	$ 215,636	$ 219,155	#	$ 1,007,087
Chesapeake	$ 796,753	$ -	$ -	$ -	$ -	$ -	$ -	$ 203,557	$ -	$ -	$ -	$ -	#	$ 1,000,310
DTE	$ 280,782	$ -	$ -	$ -	$ -	$ -	$ -	$ 571,297	$ 643,749	$ 728,306	$ 1,093,520	$ 848,319	#	$ 4,165,973
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,421,986	$ 2,655,101	$ 2,997,621	$ 3,554,286	$ 4,275,672	#	$ 15,904,665
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	#	$ -
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	#	$ -
Repsol	$ 253,170	$ -	$ -	$ -	$ -	$ -	$ -	$ 407,577	$ 1,469,944	$ 5,739,928	$ 2,515,003	$ 1,400,748	#	$ 11,786,371
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 521,550	$ 2,245,301	$ 1,536,134	$ 788,894	$ 749,425	#	$ 5,841,304
South Jersey	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 193,208	#	$ 193,208
Tenaska	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,600	$ -	#	$ 31,600
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 394	$ -	$ -	#	$ 394
Subtotal - Commodity Supply	$ 1,330,705	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,301,387	$ 7,204,317	$ 11,255,766	$ 8,218,780	$ 7,686,526	#	$ 39,997,480
Transportation Costs:														
Granite	$ -	$ -	$ -	$ -	$ -	$ -	$ 599	$ 1,305	$ 1,671	$ 1,257	$ 1,131	$ 360		$ 6,323
Portland	$ 103	$ -	$ -	$ -	$ -	$ -	$ -	$ 68,966	$ 218,184	$ 165,709	$ 48,804	$ 40,618		$ 542,385
Tennessee	$ 27,789	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,595	$ 27,417	$ 50,010	$ 33,277	$ 27,042		$ 190,130
Subtotal - Commodity Transporation	$ 27,892	$ -	$ -	$ -	$ -	$ -	$ 599	$ 94,866	$ 247,273	$ 216,976	$ 83,213	$ 68,019		$ 738,838
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,394,886	$ 7,565,044	$ 11,471,877	$ 8,301,386	$ 7,754,471	$ 2,426,470		$ 41,914,134
Commodity Cost Reversals	$ (1,358,843)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,394,886)	$ (7,565,044)	$ (11,471,877)	$ (8,301,386)	$ (7,754,471)		$ (40,846,507)
Subtotal - Supply	$ (246)	$ -	$ -	$ -	$ -	$ -	$ 4,395,485	$ 7,566,411	$ 11,358,422	$ 8,302,251	$ 7,755,077	$ 2,426,544		$ 41,803,945
Withdrawal - Underground Storage	$ 246	$ -	$ -	$ -	$ -	$ -	$ 898,292	$ 2,762,148	$ 3,753,827	$ 3,469,766	$ 2,219,029	$ (620)		$ 13,102,689
Withdrawal - LNG Vaporization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
ATV Reconciliation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,609	$ (367,808)	$ (952,536)	$ (509,617)	$ (225,477)	$ 32,024		$ (2,011,805)
Off System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (860,316)	$ (55,000)	$ (2,024,315)	$ (2,737,970)	$ -		$ (5,677,602)
Net OBA Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,495)	$ (21,633)	$ (3,995)	$ (111,518)	$ 35,331	$ (33,015)		$ (136,325)
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (505,540)	$ (2,241,534)	$ (3,220,404)	$ (2,257,877)	$ (1,259,539)		$ (9,484,894)
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,875	$ 18,317	$ 52,121	$ 87,442	$ 132,315	$ 49,364		$ 352,434
Transportation Charges	$ 47,419	$ (138,666)	$ -	$ -	$ -	$ -	$ -	$ (85,432)	$ (106,975)	$ 1,803,323	$ 326,956	$ 220,564		$ 2,067,189
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,750	$ 64,983	$ (88,291)	$ (443,687)	$ (364,500)	$ (99,594)		$ (863,340)
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ 420	$ 531	$ 1,006	$ 1,061	$ 772	$ 1,086		$ 4,877
Inventory Finance Charage	$ 355	$ 630	$ 852	$ 1,028	$ 1,194	$ 1,193	$ 1,210	$ 1,200	$ 969	$ 639	$ 540	$ 499		$ 10,308
Prior Period Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Subtotal- Other Commodity	$ 48,020	$ (138,036)	$ 852	$ 1,028	$ 1,194	$ 1,193	$ 990,660	$ 1,006,450	$ 359,593	$ (947,310)	$ (2,870,881)	$ (1,089,231)		$ (2,636,469)
Off System Sales Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,365,720)	$ (2,287,664)	$ (5,244,720)	$ (4,995,848)	$ (1,259,539)	$ -		$ (15,153,491)
Off System Sales Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,365,720	$ 2,287,664	$ 5,244,720	$ 4,995,848	$ 1,259,539		$ 15,153,491
Subtotal Estimates/Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ (791,054)	$ (248,961)	$ (820,810)	$ 2,172,848	$ 4,317,022	$ 1,259,539		$ 5,888,584
Total Commodity Costs	$ 47,774	$ (138,036)	$ 852	$ 1,028	$ 1,194	$ 1,193	$ 4,020,425	$ 7,650,918	$ 8,760,959	$ 7,603,813	$ 8,620,505	$ 2,596,852		$ 39,167,476

NORTHERN UTILITIES, INC. - BOTH DIVISIONs
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO WINTER PERIOD
May 2013 - April 2014

Demand Costs	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total Winter
Pipeline Reservation													
Alberta Northeast	$ 14,090	$ 15,762	$ 21,276	$ 18,394	$ 18,130	$ 19,341	$ 19,569	$ 16,320	$ 17,903	$ 19,365	$ 16,188	$ 16,458	$ 212,797
Algonquin	$ 33,958	$ 33,969	$ 33,969	$ 33,915	$ 33,969	$ 33,966	$ 33,969	$ 33,969	$ 33,967	$ 33,944	$ 33,883	$ 33,908	$ 407,385
DTE Energy	$ 954,777	$ 948,416	$ 960,568	$ 670,234	$ 688,335	$ 678,802	$ 672,355	$ 665,461	$ 639,182	$ 640,175	$ 632,605	$ 642,228	$ 8,793,138
Freepoint	$ 83,572	$ 82,211	$ 83,531	$ 72,442	$ 74,297	$ 73,326	$ 72,629	$ 72,152	$ 71,155	$ 69,185	$ 69,185	$ 68,651	$ 892,336
Granite State	$ 329,130	$ 329,130	$ 329,130	$ 351,660	$ 351,660	$ 351,660	$ 351,660	$ 351,660	$ 351,660	$ 351,660	$ 351,660	$ 351,660	$ 4,152,330
Iroquois	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 43,336	$ 520,036
Portland	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 44,270	$ 2,567,668	$ 2,567,668	$ 2,567,668	$ 2,567,668	$ 2,567,668	$ 13,148,231
Tennessee	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 386,276	$ 378,755	$ 378,755	$ 378,755	$ 378,755	$ 378,755	$ 378,755	$ 378,755	$ 4,582,665
Texas Eastern	$ 5,342	$ 5,342	$ 5,342	$ 5,342	$ 5,296	$ 5,296	$ 5,296	$ 5,296	$ 5,297	$ 5,297	$ 5,306	$ 5,306	$ 63,758
Union	$ (797)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (797)
Vector	$ 180,711	$ 180,707	$ 180,641	$ 180,673	$ 180,664	$ 180,659	$ 180,616	$ 258,549	$ 258,463	$ 258,454	$ 258,430	$ 258,456	$ 2,557,024
Total Pipeline Reservation	$ 2,074,667	$ 2,069,420	$ 2,088,339	$ 1,806,543	$ 1,826,234	$ 1,809,412	$ 1,802,456	$ 4,393,165	$ 4,367,387	$ 4,367,838	$ 4,357,015	$ 4,366,427	$ 35,328,902
Product Demand													
Alberta Northeast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,000	$ 116,667	$ 116,667	$ 116,667	$ 29,000	$ 408,000
DTE Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 75,000
Repsol	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 150,000	$ 155,000	$ 155,000	$ 140,000	$ 155,000	$ 755,000
Shell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,750	$ 15,750	$ 15,750	$ 15,750	$ 15,750	$ 78,750
Total Product Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 209,750	$ 302,417	$ 302,417	$ 287,417	$ 214,750	$ 1,316,750
Storage Pipeline Transportation and Demand Reservation													
Tennessee	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 12,006	$ 144,075
Texas Eastern	$ 173	$ 173	$ 172	$ 172	$ 171	$ 171	$ 172	$ 172	$ 173	$ 172	$ 172	$ 172	$ 2,065
Wash 10	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 240,833	$ 2,890,000
Company Managed	$ (150,969)	$ (99,506)	$ (97,253)	$ (70,783)	$ (68,434)	$ (69,902)	$ (69,774)	$ (1,093,510)	$ (1,096,162)	$ (1,091,017)	$ (1,052,036)	$ (1,033,645)	$ (5,992,990)
Total Storage and Demand Reservation	$ 102,044	$ 153,506	$ 155,759	$ 182,229	$ 184,577	$ 183,109	$ 183,238	$ (840,498)	$ (843,150)	$ (838,006)	$ (799,024)	$ (780,634)	$ (2,956,850)
Demand Cost Estimates	$ 1,889,003	$ 1,877,311	$ 1,640,849	$ 1,668,627	$ 1,641,683	$ 1,659,639	$ 3,447,073	$ 3,449,420	$ 3,542,302	$ 3,559,537	$ 3,439,408	$ 1,685,001	$ 29,499,853
Demand Cost Reversals	$ (1,858,888)	$ (1,889,003)	$ (1,877,311)	$ (1,640,849)	$ (1,668,627)	$ (1,641,683)	$ (1,659,639)	$ (3,447,073)	$ (3,449,420)	$ (3,542,302)	$ (3,559,537)	$ (3,439,408)	$ (29,673,740)
Subtotal	$ 30,115	$ (11,692)	$ (236,462)	$ 27,778	$ (26,944)	$ 17,956	$ 1,787,434	$ 2,347	$ 92,882	$ 17,235	$ (120,129)	$ (1,754,407)	$ (173,887)
Total Direct Demand Costs	$ 2,206,826	$ 2,211,234	$ 2,007,636	$ 2,016,549	$ 1,983,867	$ 2,010,477	$ 3,773,128	$ 3,764,764	$ 3,919,535	$ 3,849,484	$ 3,725,279	$ 2,046,136	$ 33,514,915
Amortization of PNGTS Rate Case Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,894	$ 8,600	$ 13,983	$ 8,113	$ 6,687	$ 4,856	$ 48,135
Capacity Release	$ (1,027,928)	$ (1,028,209)	$ (1,028,393)	$ (1,044,825)	$ (1,052,348)	$ (1,026,866)	$ (1,027,637)	$ (1,030,539)	$ (1,033,384)	$ (1,034,489)	$ (1,034,069)	$ (1,034,906)	$ (12,403,593)
Capacity Mitigation	$ (10,100)	$ (10,100)	$ (10,100)	$ (10,100)	$ (9,536)	$ (9,536)	$ (8,937)	$ (4,549)	$ (4,549)	$ (4,549)	$ (4,549)	$ (4,056)	$ (90,659)
Production and Storage	$ -	$ -	$ 6,585	$ 6,585	$ 6,585	$ 6,585	$ 142,749	$ 142,749	$ 204,460	$ 204,460	$ 204,460	$ 204,460	$ 1,129,676
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,900	$ 122,900	$ 132,061	$ 132,061	$ 132,061	$ 132,061	$ 774,043
Total Indirect Demand Costs	$ (1,038,027)	$ (1,038,309)	$ (1,031,908)	$ (1,048,340)	$ (1,055,299)	$ (1,029,817)	$ (765,031)	$ (760,839)	$ (687,429)	$ (694,404)	$ (695,409)	$ (697,584)	$ (10,542,398)
Demand Cost Estimates - Capacity Release	$ (1,028,306)	$ (1,028,129)	$ (1,045,613)	$ (1,051,009)	$ (1,027,848)	$ (1,027,202)	$ (1,025,870)	$ (1,026,632)	$ (1,026,632)	$ (1,025,310)	$ (1,025,340)	$ (1,036,697)	$ (12,374,588)
Demand Cost Reversals - Capacity Release	$ 1,027,386	$ 1,028,306	$ 1,028,129	$ 1,045,613	$ 1,051,009	$ 1,027,848	$ 1,027,202	$ 1,025,870	$ 1,026,632	$ 1,026,632	$ 1,025,310	$ 1,025,340	$ 12,365,277
Subtotal	$ (920)	$ 177	$ (17,484)	$ (5,396)	$ 23,161	$ 646	$ 1,332	$ (762)	$ -	$ 1,322	$ (30)	$ (11,357)	$ (9,311)
Total Demand Costs	$ 1,167,879	$ 1,173,102	$ 958,244	$ 962,813	$ 951,729	$ 981,306	$ 3,009,428	$ 3,003,162	$ 3,232,106	$ 3,156,402	$ 3,029,839	$ 1,337,195	$ 22,963,206
Demand Costs Transferred to Summer Period	$ (347,304)	$ (347,304)	$ (347,304)	$ (347,304)	$ (347,304)	$ (347,304)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,083,824)
Net Demand Costs For Winter Period	$ 820,575	$ 825,798	$ 610,940	$ 615,509	$ 604,425	$ 634,002	$ 3,009,428	$ 3,003,162	$ 3,232,106	$ 3,156,402	$ 3,029,839	$ 1,337,195	$ 20,879,382
Total Gas Costs	$ 868,350	$ 687,761	$ 611,792	$ 616,537	$ 605,619	$ 635,195	$ 7,029,853	$ 10,654,080	$ 11,993,066	$ 10,760,214	$ 11,650,344	$ 3,934,047	$ 60,046,858

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
May 2013 - April 2014

Commodity Volumes:	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Total Winter**
Anadarko	[redacted]												
Cargill													
Chesapeake													
DTE													
Emera Energy													
Granite													
Hess													
Repsol													
Shell													
South Jersey													
Tenaska													
Tennessee													
Subtotal - Commodity Supply													
Transportation Volumes													
Granite													
Portland													
Tennessee													
Subtotal - Commodity Transportation													
Commodity Volume Estimates													
Commodity Volume Reversals													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation													
Off System Sales													
Net OBA Adjustment													
Company Managed													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Prior Period Adjustment													
Subtotal - Other Commodity													
Off System & Company Managed Estimates													
Off System & Company Managed Reversals													
Total Commodity Volumes													

REDACTED

NORTHERN UTILITIES, INC. - BOTH DIVISIONS
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
May 2013 - April 2014

Commodity Volumes:	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total Winter
Anadarko	[redacted]												
Cargill													
Chesapeake													
DTE													
Emera Energy													
Granite													
Hess													
Repsol													
Shell													
South Jersey													
Tenaska													
Tennessee													
Subtotal - Commodity Supply													
Transportation Costs:													
Granite													
Portland													
Tennessee													
Subtotal- Commodity Transportation													
Commodity Cost Estimates													
Commodity Cost Reversals													
Subtotal - Supply													
Withdrawal - Underground Storage													
Withdrawal - LNG Vaporization													
ATV Reconciliation Charges													
Off System Sales													
Net OBA Adjustment													
Company Managed													
LNG Boiloff													
Transportation Charges													
Hedging Costs													
Propane													
Inventory Finance Charage													
Prior Period Adjustments													
Subtotal - Other Commodity													
Off System Sales Estimates													
Off System Sales Reversals													
Total Commodity Costs													

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 WINTER PERIOD RECONCILIATION
SCHEDULE 5: SALES AND TRANSPORTATION VOLUMES
May 2013 - April 2014

New Hampshire	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
Throughput IN													
BTU Factor	1.029	1.028	1.025	1.022	1.028	1.034	1.028	1.030	1.037	1.033	1.030	1.031	
GST Meter Throughput (MCF)	384,902	317,797	297,308	312,850	329,531	442,456	721,172	1,011,103	1,101,964	945,004	960,102	585,094	7,409,283
Salem Meter (MCF)	15,702	11,992	10,261	11,661	12,337	21,451	43,060	66,847	78,114	66,670	63,835	30,968	432,898
GST Meter Throughput (DTH)	396,064	326,695	304,741	319,733	338,758	457,500	741,365	1,041,436	1,142,737	976,189	988,905	603,232	7,637,354
Salem Meter (DTH)	16,157	12,328	10,518	11,918	12,682	22,180	44,266	68,852	81,004	68,870	65,750	31,928	446,453
LNG/Propane													
Total Throughput	412,222	339,023	315,258	331,650	351,440	479,680	785,630	1,110,289	1,223,741	1,045,059	1,054,655	635,160	8,083,807
Throughput OUT													
Residential Gas													
Charged	95,039	55,928	34,579	33,886	35,282	46,731	129,897	244,069	333,579	330,531	301,458	210,141	1,851,120
Uncharged Current	41,554	27,276	21,954	28,336	50,467	86,052	126,803	214,603	223,191	146,825	164,281	123,599	1,254,942
Uncharged Prior	-85,733	-41,554	-27,276	-21,954	-28,336	-50,467	-86,052	-126,803	-214,603	-223,191	-146,825	-164,281	-1,217,075
Total Residential Gas	**50,860**	**41,650**	**29,257**	**40,268**	**57,413**	**82,316**	**170,648**	**331,870**	**342,166**	**254,166**	**318,914**	**169,459**	1,888,987
Interruptible	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
Commercial/Industrial Gas													
Charged	103,907	61,002	42,826	45,170	45,494	57,832	145,309	256,463	374,634	364,492	348,407	229,795	2,075,330
Uncharged Current	47,498	34,080	26,636	35,900	46,976	76,149	124,134	220,474	245,771	163,453	194,330	139,537	1,354,940
Uncharged Prior	-96,076	-47,498	-34,080	-26,636	-35,900	-46,976	-76,149	-124,134	-220,474	-245,771	-163,453	-194,330	-1,311,479
Total C/I Gas	**55,329**	**47,583**	**35,382**	**54,433**	**56,570**	**87,006**	**193,294**	**352,803**	**399,931**	**282,174**	**379,284**	**175,002**	2,118,791
Transportation													
Charged	285,107	260,086	233,151	241,336	247,483	291,980	369,979	427,221	485,858	468,509	452,495	366,768	4,129,974
Uncharged Current	134,529	106,007	102,203	122,512	146,659	215,133	208,354	281,276	258,021	176,282	207,706	176,984	2,135,668
Uncharged Prior	-161,856	-134,529	-106,007	-102,203	-122,512	-146,659	-215,133	-208,354	-281,276	-258,021	-176,282	-207,706	-2,120,540
Total Transportation	**257,780**	**231,564**	**229,347**	**261,645**	**271,630**	**360,454**	**363,200**	**500,143**	**462,603**	**386,770**	**483,919**	**336,046**	**4,145,102**
Company Use	**107**	**108**	**103**	**171**	**121**	**83**	**118**	**225**	**318**	**338**	**304**	**236**	**2,232**
Total Throughput OUT	**364,077**	**320,906**	**294,090**	**356,517**	**385,733**	**529,859**	**727,260**	**1,185,041**	**1,205,019**	**923,448**	**1,182,420**	**680,742**	**8,155,112**
Total Throughput IN	**412,222**	**339,023**	**315,258**	**331,650**	**351,440**	**479,680**	**785,630**	**1,110,289**	**1,223,741**	**1,045,059**	**1,054,655**	**635,160**	**8,083,807**
Difference IN/OUT	48,145	18,117	21,169	-24,867	-34,293	-50,179	58,370	-74,752	18,722	121,611	-127,765	-45,582	-71,304
%													-0.88%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED WINTER PERIOD WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending April 30, 2014

PEAK PERIOD - Acct 182.11

		BEGINNING BALANCE	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 * (J / 12)	J = F + I
May 2013	$	(1,852)	261	0.0824%	41	302	(1,550)	(1,701)	3.25%	(5)	(1,555)
June	$	(1,555)	186	0.0824%	(9)	177	(1,378)	(1,466)	3.25%	(4)	(1,382)
July	$	(1,382)	171	0.0824%	8	179	(1,203)	(1,292)	3.25%	(3)	(1,206)
August	$	(1,206)	173	0.0824%	1	174	(1,033)	(1,119)	3.25%	(3)	(1,036)
September	$	(1,036)	169	0.0824%	(0)	169	(867)	(951)	3.25%	(3)	(870)
October	$	(870)	180	0.0824%	(0)	180	(690)	(780)	3.25%	(2)	(692)
November	$	(692)	2,908	0.0824%	(2,250)	659	(33)	(362)	3.25%	(1)	(34)
December	$	(34)	4,233	0.0824%	(4,234)	(2)	(36)	(35)	3.25%	(0)	(36)
January 2014	$	(36)	4,629	0.0824%	(5,539)	(910)	(946)	(491)	3.25%	(1)	(947)
February	$	(947)	4,421	0.0824%	(4,333)	88	(859)	(903)	3.25%	(2)	(861)
March	$	(861)	4,653	0.0824%	(4,887)	(234)	(1,096)	(978)	3.25%	(3)	(1,098)
April	$	(1,098)	1,449	0.0824%	(2,143)	(694)	(1,792)	(1,445)	3.25%	(4)	(1,796)
Totals			23,433		(23,346)					(31)	

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Sch 4, page 2 of 12, and multiplying by (9.25/365)*Interest Rate.

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
WINTER PERIOD BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending April 30, 2014

PEAK PERIOD - Acct 182.16

	REVISED BALANCE	BAD DEBT ALLOWANCE (1)	BAD DEBT COLLECTIONS	DEFERRED BALANCE	ENDING BALANCE	BAD DEBT 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
May 2013	(71,949)	20,972	387	21,359	(50,590)	(61,269)	3.25%	(166)	(50,756)
June	(50,756)	20,800	(101)	20,700	(30,056)	(40,406)	3.25%	(109)	(30,165)
July	(30,165)	40,576	168	40,744	10,579	(9,793)	3.25%	(27)	10,552
August	10,552	25,373	6	25,379	35,931	23,242	3.25%	63	35,994
September	35,994	9,094	(2)	9,092	45,086	40,540	3.25%	110	45,196
October	45,196	18,393	(2)	18,391	63,587	54,392	3.25%	147	63,735
November	63,735	10,555	(22,264)	(11,709)	52,026	57,881	3.25%	157	52,183
December	52,183	10,141	(41,733)	(31,593)	20,590	36,387	3.25%	99	20,689
January 2014	20,689	3,442	(54,592)	(51,150)	(30,461)	(4,886)	3.25%	(13)	(30,474)
February	(30,474)	3,048	(42,689)	(39,641)	(70,115)	(50,294)	3.25%	(136)	(70,251)
March	(70,251)	6,617	(48,176)	(41,559)	(111,810)	(91,030)	3.25%	(247)	(112,056)
April	(112,056)	15,013	(21,162)	(6,149)	(118,205)	(115,131)	3.25%	(312)	(118,517)
Totals		184,025	(230,159)					(434)	

(1) Per Docket No. DG 11-69, Bad Debt based on actual write-offs

Attachment C

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Costs
June 2013 - October 2014

		Beginning Balance		Firm Sales and Transportation (therms)	ERC Recovery/Passback Rate		Current ERC Recoveries/ Passbacks		Ending Balance
May 2013	(act)	$ 56,494		2,949,527	$ 0.0044		$ 17,567		$ 38,927
June 2013	(act)	$ 38,927		2,249,655	$ 0.0044		$ 12,978		$ 25,949
July 2013	(act)	$ 25,949		2,350,175	$ 0.0044		$ 9,890		$ 16,058
August 2013	(act)	$ 16,058		2,456,910	$ 0.0044		$ 10,342		$ 5,716
September 2013	(act)	$ 5,716		3,012,769	$ 0.0044		$ 10,808		$ (5,092)
October 2013	(act)	$ 165,302	(1)	5,564,254	$ 0.0038	(2)	$ 13,253		$ 152,049
November 2013	(act)	$ 152,049		8,395,061	$ 0.0031		$ (4,781)	(3)	$ 156,830
December 2013	(act)	$ 156,830		11,121,715	$ 0.0031		$ 26,024		$ 130,805
January 2014	(act)	$ 130,805		10,816,631	$ 0.0031		$ 34,485		$ 96,321
February 2014	(act)	$ 96,321		10,090,691	$ 0.0031		$ 33,509		$ 62,811
March 2014	(act)	$ 62,811		7,101,834	$ 0.0031		$ 31,283		$ 31,526
April 2014	(act)	$ 31,526		4,432,890	$ 0.0031		$ 22,017		$ 9,509
May 2014	(act)	$ 9,509		2,858,677	$ 0.0031		$ 13,740		$ (4,231)
June 2014	(est)	$ (4,231)		2,487,452	$ 0.0031		$ 7,711		$ (11,943)
July 2014	(est)	$ (11,943)		2,444,040	$ 0.0031		$ 7,577		$ (19,519)
August 2014	(est)	$ (19,519)		2,525,244	$ 0.0031		$ 7,828		$ (27,347)
September 2014	(est)	$ (27,347)		1,973,826	$ 0.0031		$ 6,119		$ (33,466)
October 2014	(est)	$ (33,466)		3,911,290	$ 0.0031		$ 12,125		$ (45,591)

(1) November Beginning Balance includes $170,394 amortization from all prior years at 1/7 of annual costs. (See Section 4.7 of Tariff.)

(2) November Current ERC Recoveries/Passbacks reflect an Average ERC Rate based on actual Firm Sales and Transportation (therms) at $0.0044 and actual Firm Sales and Transportation (therms) at $0.0031.

Attachment D

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
RLIARA Reconciliation
May 2013 - October 2014

		Beginning Balance	**Program Costs**	**Regulatory Assessments**	**RLIARA Recoveries**	**Ending Balance**	**Average Monthly Balance**	**Interest Rate**	**Interest**	**Ending Balance w/Interest**
		A	B	C	D	E = A + B +C - D	F = (A +E) / 2	G	H = F * (G / 12)	I = E + H
May 2013	Actual	$ (89,556)	$ 22,767	$ 14,734	$ 41,527	$ (93,582)	$ (91,569)	3.25%	$ (253)	$ (93,835)
June 2013	Actual	$ (93,835)	$ 15,692	$ 14,734	$ 30,672	$ (94,080)	$ (93,957)	3.25%	$ (251)	$ (94,331)
July 2013	Actual	$ (94,331)	$ 13,262	$ 14,734	$ 23,402	$ (89,737)	$ (92,034)	3.25%	$ (254)	$ (89,991)
August 2013	Actual	$ (89,991)	$ 12,787	$ (7,095)	$ 24,440	$ (108,740)	$ (99,366)	3.25%	$ (308)	$ (109,048)
September 2013	Actual	$ (109,048)	$ 12,694	$ 3,820	$ 25,553	$ (118,087)	$ (113,568)	3.25%	$ (303)	$ (118,391)
October 2013	Actual	$ (118,391)	$ 13,568	$ 10,995	$ 31,332	$ (125,159)	$ (121,775)	3.25%	$ (336)	$ (125,495)
November 2013	Actual	$ (125,495)	$ 11,196	$ 10,995	$ 44,956	$ (148,260)	$ (136,878)	3.25%	$ (366)	$ (148,626)
December 2013	Actual	$ (148,626)	$ 35,446	$ 10,995	$ 54,570	$ (156,755)	$ (152,690)	3.25%	$ (421)	$ (157,176)
January 2014	Actual	$ (157,177)	$ 45,851	$ 10,765	$ 72,313	$ (172,873)	$ (165,026)	3.25%	$ (442)	$ (173,315)
February 2014	Actual	$ (173,315)	$ 44,937	$ 10,765	$ 70,306	$ (187,919)	$ (180,617)	3.25%	$ (489)	$ (188,408)
March 2014	Actual	$ (188,408)	$ 48,554	$ 10,765	$ 65,591	$ (194,679)	$ (191,544)	3.25%	$ (519)	$ (195,198)
April 2014	Actual	$ (195,198)	$ 36,868	$ 10,765	$ 46,156	$ (193,721)	$ (194,460)	3.25%	$ (527)	$ (194,248)
May 2014	Actual	$ (194,248)	$ 28,018	$ 10,765	$ 28,812	$ (184,276)	$ (189,262)	3.25%	$ (513)	$ (184,789)
June 2014	Actual	$ (184,789)	$ 20,907	$ 10,765	$ 21,117	$ (174,233)	$ (179,511)	3.25%	$ (486)	$ (174,719)
July 2014	Est.	$ (174,719)	$ 13,262	$ 10,765	$ 16,168	$ (166,860)	$ (170,789)	3.25%	$ (463)	$ (167,323)
August 2014	Est.	$ (167,323)	$ 12,787	$ 10,765	$ 15,886	$ (159,657)	$ (163,490)	3.25%	$ (443)	$ (160,100)
September 2014	Est.	$ (160,100)	$ 12,694	$ 10,765	$ 16,414	$ (153,055)	$ (156,577)	3.25%	$ (424)	$ (153,479)
October 2014	Est.	$ (153,479)	$ 13,568	$ 10,765	$ 12,830	$ (141,975)	$ (147,727)	3.25%	$ (400)	$ (142,376)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2013 - 2014

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	TOTAL
Forecast Calendar Month Sales	357,911	527,279	665,669	556,481	428,977	252,899	2,789,216
Actual Sales	275,205	500,532	708,214	695,023	649,864	439,937	3,268,775
Difference	(82,706)	(26,747)	42,545	138,542	220,887	187,038	479,559
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	262,219	443,074	660,194	667,908	579,574	393,810	3,006,778
Actual Sales	275,205	500,532	708,214	695,023	649,864	439,937	3,268,775
Weather Variance	(12,986)	(57,458)	(48,020)	(27,115)	(70,290)	(46,126)	(261,997)
Total Variance Excluding Weather	(95,692)	(84,205)	(5,475)	111,427	150,597	140,911	217,562
(excl weather effect)							
Variance-difference due to meter count							(63,288)
-difference in load pattern							542,947
SALES							479,659

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
WINTER 2013 - 2014

	NORMAL MMBtu			METERS		
	2013-14 Forecast	2013-14 Actual	Difference	2013-14 Forecast	2013-14 Actual	Difference
Res Heat	1,365,577	1,527,473	161,896	134,421	129,588	(4,833)
Res General	23,858	22,202	(1,656)	9,240	8,736	(504)
Total Res	1,389,435	1,549,675	160,240	143,661	138,324	(5,337)
G-40	670,283	762,156	91,873	26,794	26,448	(346)
G-50	76,315	90,600	14,285	4,695	4,621	(74)
G-41	443,661	652,657	208,996	2,253	2,228	(25)
G-51	110,042	117,626	7,584	883	940	57
G-42	78,339	74,162	(4,177)	60	55	(5)
G-52	21,041	21,901	860	48	51	3
Total C & I	1,399,681	1,719,100	319,419	34,733	34,343	(390)
Total Company	2,789,116	3,268,775	479,659	178,394	172,667	(5,727)

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2013-14 Forecast	2013-14 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	10.16	11.79	1.63	(49,096)	210,991	161,896	11.86%
Res General	2.58	2.54	(0.04)	(1,301)	(354)	(1,656)	-6.94%
Total Res	12.74	14.33	1.59	(50,397)	210,637	160,240	11.53%
G-40	25.02	28.82	3.80	(8,656)	100,528	91,873	13.71%
G-50	16.25	19.61	3.35	(1,203)	15,487	14,285	18.72%
G-41	196.92	292.93	96.01	(4,923)	213,919	208,996	47.11%
G-51	124.62	125.13	0.51	7,104	480	7,584	6.89%
G-42	1,305.65	1,348.39	42.74	(6,528)	2,351	(4,177)	-5.33%
G-52	438.35	429.42	(8.93)	1,315	(455)	860	4.09%
Total C & I	40.30	50.06	9.76	(12,891)	332,310	319,419	22.82%
Total Company	15.63	18.93	3.30	(63,288)	542,947	479,659	17.20%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2013-2014 ANNUAL RECONCILIATION
SUPPLIER REFUNDS
Period Ending April 30, 2014

WINTER SEASON DEMAND - Acct 242.90.10

	BEGINNING BALANCE	REFUND COLLECTIONS	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C = A + B	D = (A + C) / 2	E	F = D * (E / 12)	G = C + F
May 2013	$ (492,950)	0	(492,950)	(492,950)	3.25%	(1,335)	(494,285)
June	$ (494,285)	0	(494,285)	(494,285)	3.25%	(1,339)	(495,624)
July	$ (495,624)	0	(495,624)	(495,624)	3.25%	(1,342)	(496,966)
August	$ (496,966)	0	(496,966)	(496,966)	3.25%	(1,346)	(498,312)
September	$ (498,312)	0	(498,312)	(498,312)	3.25%	(1,350)	(499,661)
October	$ (499,661)	0	(499,661)	(499,661)	3.25%	(1,353)	(501,015)
November	$ (501,015)	24,061	(476,953)	(488,984)	3.25%	(1,324)	(478,278)
December	$ (478,278)	97,575	(380,703)	(429,490)	3.25%	(1,163)	(381,866)
January 2014	$ (381,866)	138,086	(243,780)	(312,823)	3.25%	(847)	(244,627)
February	$ (244,627)	135,566	(109,062)	(176,845)	3.25%	(479)	(109,541)
March	$ (109,541)	126,719	17,178	(46,181)	3.25%	(125)	17,053
April	$ 17,053	85,791	102,844	59,949	3.25%	162	103,007
Totals		607,798				(11,841)	

WINTER SEASON COMMODITY - Acct 242.90.01

	BEGINNING BALANCE	REFUND COLLECTIONS	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C = A + B	D = (A + C) / 2	E	F = D * (E / 12)	G = C + F
May 2013	$ -	0	0	0	3.25%	0	0
June	$ 0	0	0	0	3.25%	0	0
July	$ 0	0	0	0	3.25%	0	0
August	$ 0	0	0	0	3.25%	0	0
September	$ 0	0	0	0	3.25%	0	0
October	$ 0	0	0	0	3.25%	0	0
November	$ 0	0	0	0	3.25%	0	0
December	$ 0	0	0	0	3.25%	0	0
January 2014	$ 0	0	0	0	3.25%	0	0
February	$ 0	0	0	0	3.25%	0	0
March	$ 0	0	0	0	3.25%	0	0
April	$ 0	0	0	0	3.25%	0	0
Totals		0				0	

Schedule 16

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

		Customer Charge	First Block	Last Block	Total
1	**Peak Period**				
2	R-5 Base Rates	$20.01	$0.5844	$0.4780	
3	R-10 Rate at 40% of R5	$8.00	$0.2338	$0.1912	
4	Program Subsidy	$12.01	$0.3506	$0.2868	
5	Average Annual Therms		209	424	633
6					
7	Peak Period Subsidy	$72.04	$73.25	$121.63	$266.92
8					
9	**Off Peak Period**				
10	R-5 Base Rates	$20.01	$0.5104	$0.5104	
11	R10 Rate at 40% of R5	$8.00	$0.2041	$0.2041	
12	Program Subsidy	$12.01	$0.3063	$0.3063	
13	Average Annual Therms		110	28	138
14					
15	Off Peak Period Subsidy	$72.04	$33.82	$8.45	$114.31
16					
17	Estimated Annual Subsidy				$381.23
18					
19	Number of Estimated 2014/15 Participants				1,146
20					
21	Annual Subsidy times Number of Participants (Ln 17 *Ln 19)				$436,791
22	Prior Year Ending Balance 10/31/2014 - RLIARA Page 2				($163,833)
23	Estimated Annual Administrative Costs				$0
24	Estimated Non-Distribution Regulatory Assessment (Based off of NHPUC invoice dated August 13, 2014)				$211,607
25	Total Program Costs				$484,564
26					
27	Estimated weather normalized firm therms billed for				
28	the twelve months ended 10/31/15 sales and transportation				62,481,365
29	(Attachment 2 to Schedule 10B, Revised Page 1 of 3, Line 41, "Total Division"				
30	subtract Line 41 "Special Contracts").				
31	**Total Residential Low Income Assistance and Regulatory Assessment Costs Charge**				**$0.0078**

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
NOVEMBER 2013 THROUGH OCTOBER 2014
RESIDENTIAL LOW INCOME ASSISTANCE AND REGULATORY ASSESSMENT COSTS (RLIARA) RECONCILIATION

											(Estimate)	(Estimate)	(Estimate)	(Estimate)
1	**FOR THE MONTH OF:**	**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	**DAYS IN MONTH**	30	31	31	28	31	30	31	30	31	31	30	31	365
3														**Average**
4	RLIA Participant Count	985	1,110	1,185	1,171	1,351	1,292	1,271	1,135	1,103	1,089	1,056	1,001	1,146
5														**Total**
6	Beginning Balance	($125,495)	($148,626)	($157,176)	($173,314)	($188,407)	($195,197)	($194,247)	($184,788)	($174,718)	($161,581)	($162,387)	($164,389)	($125,495)
7														
8	Add: Actual Costs	$11,196	$35,446	$45,851	$44,937	$48,554	$36,868	$28,018	$20,907	$18,099	$12,787	$12,694	$13,568	$328,926
9														
10	Add: Regulatory Assessments	$10,995	$10,995	$10,765	$10,765	$10,765	$10,765	$10,765	$10,765	$11,293	$11,293	$11,293	$18,772	$139,234
11														
12	Less: Collected Revenue	$44,956	$54,570	$72,313	$70,306	$65,591	$46,156	$28,812	$21,117	$15,799	$24,440	$25,553	$31,332	($500,945)
13														
14	Add: Administrative and Start Up Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15														
16	Ending Balance Pre-Interest	($148,260)	($156,755)	($172,872)	($187,918)	($194,678)	($193,720)	($184,275)	($174,232)	($161,125)	($161,941)	($163,953)	($163,381)	
17														
18	Month's Average Balance	($136,878)	($152,690)	($165,024)	($180,616)	($191,543)	($194,459)	($189,261)	($179,510)	($168,185)	($161,761)	($163,170)	($163,885)	
19														
20	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
21														
22	Interest Applied	($365.63)	($421.47)	($441.98)	($489.17)	($518.76)	($526.66)	($512.58)	($486.17)	($455.50)	($446.50)	($435.87)	($452.37)	($5,553)
23														
24	Ending Balance	($148,626)	($157,176)	($173,314)	($188,407)	($195,197)	($194,247)	($184,788)	($174,718)	($161,581)	($162,387)	($164,389)	**($163,833)**	($163,833)

Note- January 2014 Interest Applied line items includes true ups for Regulatory Assessment Costs.
() Over Collection

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
Calculation of Distribution and Non-Distribution Revenues of the NHPUC Annual Regulatory Assessment
NHPUC Assessment Invoice dated August 13, 2014

	July 2014	August 2014	September 2014	October 2014	November 2014	December 2014	January 2015	February 2015	March 2015	April 2015	May 2015	June 2015	Total Fiscal Year	
Distribution	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$7,589.60	$91,075.17	1
Non-Distribution	$11,293.07	$11,293.07	$11,293.07	$18,771.73	$18,771.73	$18,771.73	$19,535.40	$19,535.40	$19,535.40	$20,935.40	$20,935.40	$20,935.40	$211,606.83	2
Total	$18,882.67	$18,882.67	$18,882.67	$26,361.33	$26,361.33	$26,361.33	$27,125.00	$27,125.00	$27,125.00	$28,525.00	$28,525.00	$28,525.00	$302,682.00	

(1) The $91,075.17 for Distribution represents the amount included in the test year in Docket DG 13-086.
(2) Total Invoice amount minus Distribution amount.

Northern Utilities, Inc. -- New Hampshire Division

DSM Budget

	Residential	Low-Income	Gen Service	Total
August-14	$64,604	$30,116	$88,564	$183,284
September-14	$34,604	$15,058	$116,248	$165,910
October-14	$32,302	$15,058	$69,966	$117,326
November-14	$32,302	$15,058	$59,042	$106,402
December-14	$160,351	$72,279	$61,042	$293,672
January-15	$31,001	$10,865	$33,113	$74,979
February-15	$37,118	$13,038	$44,012	$94,168
March-15	$45,485	$15,211	$34,613	$95,309
April-15	$43,235	$15,211	$54,910	$113,357
May-15	$31,001	$10,865	$33,113	$74,979
June-15	$106,655	$36,941	$78,208	$221,804
July-15	$24,884	$8,692	$22,214	$55,791
August-15	$61,586	$21,730	$65,809	$149,125
September-15	$33,251	$10,865	$67,309	$111,425
October-15	$31,001	$10,865	$33,113	$74,979
Total	$769,382	$301,852	$861,277	$1,932,511

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

	Residential	Low-Income	Gen Service	Total
August-14	$68,904	0	$114,380	$183,284
September-14	$36,873	0	$129,037	$165,910
October-14	$34,796	0	$82,530	$117,326
November-14	$35,663	0	$70,739	$106,402
December-14	$180,423	0	$113,250	$293,672
January-15	$34,149	0	$40,830	$74,979
February-15	$40,987	0	$53,181	$94,168
March-15	$49,843	0	$45,467	$95,309
April-15	$47,456	0	$65,901	$113,357
May-15	$33,467	0	$41,512	$74,979
June-15	$113,283	0	$108,521	$221,804
July-15	$26,141	0	$29,650	$55,791
August-15	$64,451	0	$84,675	$149,125
September-15	$34,662	0	$76,763	$111,425
October-15	$32,659	0	$42,321	$74,979
Total	$833,755	$0	$1,098,757	$1,932,511

DSM Charge Factor Calculation

DSM Charge Factors for Residential Customers

DSM Reconciliation Adjustment	($115,128)	Schedule 16 DSM Page 3 Nov '14 - Oct '15 Totals- November 2014 Beginning Balance
DSM Costs	$637,873	Schedule 16 DSM Page 3 Nov '14 - Oct '15 Totals- Column 2
DSM Share Holder Incentive	$49,737	Schedule 16 DSM Page 3 Nov '14 - Oct '15 Totals- Column 3
DSM Low-Income Costs	$55,309	Schedule 16 DSM Page 3 Nov '14 - Oct '15 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$3,840	Schedule 16 DSM Page 3 Nov '14 - Oct '15 Totals- Column 5
Total	$631,630	
Forecasted Annual Throughput Volumes for Residential Customers	18,065,432	Schedule 16 DSM Page 3 Nov '14 - Oct '15 Totals- Column 6
Conservation Charge Factor for Residential Customers	**$0.0350**	

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

DSM Reconciliation Adjustment	($80,731)	Schedule 16 DSM Page 4 Nov '14 - Oct '15 Totals- November 2014 Beginning Balance
DSM Costs	$586,499	Schedule 16 DSM Page 4 Nov '14 - Oct '15 Totals- Column 2
DSM Share Holder Incentive	$44,559	Schedule 16 DSM Page 4 Nov '14 - Oct '15 Totals- Column 3
DSM Low-Income Costs	$186,311	Schedule 16 DSM Page 4 Nov '14 - Oct '15 Totals- Column 4
DSM Allocated Low-Income Share Holder Incentive	$13,744	Schedule 16 DSM Page 4 Nov '14 - Oct '15 Totals- Column 5
Total	$750,382	
Forecasted Annual Throughput Volumes for C&I Customers	54,386,623	Schedule 16 DSM Page 4 Nov '14 - Oct '15 Totals- Column 6
Conservation Charge Factor for C&I Customers	**$0.0138**	

Northern Utilities, Inc.

New Hampshire Division

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

To Be Effective November 1, 2014 through October 31, 2015

Residential Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Costs	DSM SHI	Allocated Low Income Costs	Allocated Low Income SHI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-13	Actual	($18,277)	$0.0403	$13,657	$30,762	$3,643	$579	$50	$3,101	($7,588)	3.25%	($21)	$3,080	338,859	31
September-13	Actual	$3,080	$0.0403	$14,216	$33,233	$3,643	$3,350	$291	$29,382	$16,231	3.25%	$43	$29,425	352,818	30
October-13	Actual	$29,425	$0.0403	$18,833	$23,015	$3,643	$2,323	$202	$39,775	$34,600	3.25%	$96	$39,870	467,314	31
November-13	Actual	$39,870	$0.0393	$51,805	$36,216	$3,643	$774	$67	$28,766	$34,318	3.25%	$92	$28,857	1,298,969	30
December-13	Actual	$28,857	$0.0393	$95,919	$65,779	$657	$9,117	$793	$9,284	$19,071	3.25%	($98)	$9,186	2,440,685	31
January-14	Actual	$9,186	$0.0393	$131,098	$25,313	$3,913	$1,244	$108	($91,333)	($41,073)	3.25%	($113)	($91,446)	3,335,797	31
February-14	Actual	($91,446)	$0.0393	$129,898	$20,336	$3,913	$1,500	$130	($195,464)	($143,455)	3.25%	($358)	($195,822)	3,305,306	28
March-14	Actual	($195,822)	$0.0393	$118,473	$48,466	$3,913	$1,761	$153	($260,002)	($227,912)	3.25%	($629)	($260,631)	3,014,577	31
April-14	Actual	($260,631)	$0.0393	$82,588	$15,651	$3,913	$1,759	$153	($321,743)	($291,187)	3.25%	($778)	($322,521)	2,101,417	30
May-14	Actual	($322,521)	$0.0393	$43,146	$17,404	$3,913	$1,431	$124	($342,794)	($332,657)	3.25%	($918)	($343,712)	1,097,754	31
June-14	Actual	($343,712)	$0.0393	$22,107	$27,034	$3,913	$833	$72	($333,967)	($338,840)	3.25%	($905)	($334,872)	562,599	30
July-14	Actual	($334,872)	$0.0393	$14,842	$129,250	$3,913	$1,431	$124	($214,994)	($274,933)	3.25%	($759)	($215,753)	377,672	31
August-14	Forecast	($215,753)	$0.0393	$13,953	$64,604	$3,913	$4,300	$221	($156,668)	($186,211)	3.25%	($514)	($157,182)	355,042	31
September-14	Forecast	($157,180)	$0.0393	$15,287	$34,604	$3,913	$2,269	$233	($131,448)	($144,314)	3.25%	($385)	($131,833)	388,974	30
October-14	Forecast	($131,833)	$0.0393	$21,921	$32,302	$3,913	$2,494	$256	($114,788)	($123,311)	3.25%	($340)	($115,128)	557,777	31
November-14	Forecast	**($115,128)**	$0.0350	$44,892	$32,302	$3,913	$3,361	$345	($120,099)	($117,614)	3.25%	($314)	($120,413)	1,283,979	30
December-14	Forecast	($120,413)	$0.0350	$78,528	$160,351	$3,913	$20,072	$430	($14,175)	($67,294)	3.25%	($186)	($14,361)	2,245,994	31
January-15	Forecast	($14,361)	$0.0350	$112,756	$31,001	$4,191	$3,148	$420	($88,357)	($51,359)	3.25%	($142)	($88,499)	3,224,962	31
February-15	Forecast	($88,499)	$0.0350	$115,340	$37,118	$4,191	$3,868	$430	($158,231)	($123,365)	3.25%	($308)	($158,539)	3,298,866	28
March-15	Forecast	($158,539)	$0.0350	$97,186	$45,485	$4,191	$4,357	$415	($201,276)	($179,908)	3.25%	($497)	($201,773)	2,779,638	31
April-15	Forecast	($201,773)	$0.0350	$67,238	$43,235	$4,191	$4,220	$402	($216,962)	($209,368)	3.25%	($559)	($217,522)	1,923,082	30
May-15	Forecast	($217,522)	$0.0350	$36,981	$31,001	$4,191	$2,466	$329	($216,515)	($217,019)	3.25%	($599)	($217,115)	1,057,693	31
June-15	Forecast	($217,115)	$0.0350	$21,472	$106,655	$4,191	$6,628	$260	($120,853)	($168,984)	3.25%	($451)	($121,304)	614,125	30
July-15	Forecast	($121,304)	$0.0350	$13,115	$24,884	$4,191	$1,256	$209	($103,878)	($112,591)	3.25%	($311)	($104,189)	375,119	31
August-15	Forecast	($104,189)	$0.0350	$12,296	$61,586	$4,191	$2,864	$191	($47,652)	($75,921)	3.25%	($210)	($47,862)	351,681	31
September-15	Forecast	($47,862)	$0.0350	$12,575	$33,251	$4,191	$1,411	$188	($21,396)	($34,629)	3.25%	($93)	($21,488)	359,672	30
October-15	Forecast	($21,488)	$0.0350	$19,252	$31,001	$4,191	$1,657	$221	($3,669)	($12,579)	3.25%	($35)	($3,704)	550,621	31
Nov 14 thru Oct 15 Totals				$631,632	$637,873	$49,737	$55,309	$3,840						18,065,432	

Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 1 of 3, Lines 26 through 41 filed on September 15, 2014 in this Cost of Gas Docket.

Northern Utilities, Inc.

New Hampshire Division

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

To Be Effective November 1, 2014 through October 31, 2015

General Service Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Costs	DSM SHI	Allocated Low Income Costs	Allocated Low Income SHI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-13	Actual	($220,339)	$0.0118	$23,733	$16,435	$3,589	$3,439	$299	($220,399)	($220,369)	3.25%	($608)	($220,978)	2,011,316	31
September-13	Actual	($220,978)	$0.0118	$24,828	$53,115	$3,589	$19,981	$1,737	($167,382)	($194,180)	3.25%	($519)	($167,901)	2,104,091	30
October-13	Actual	($167,901)	$0.0118	$30,036	$57,790	$3,589	$12,655	$1,100	($122,802)	($145,352)	3.25%	($401)	($123,203)	2,545,455	31
November-13	Actual	($123,203)	$0.0131	$53,930	$59,522	$3,589	$2,325	$437	($111,260)	($117,232)	3.25%	($313)	($111,573)	4,262,285	30
December-13	Actual	($111,573)	$0.0131	$78,001	$107,420	$6,398	$22,058	$2,060	($51,637)	($81,605)	3.25%	($100)	($51,738)	5,954,374	31
January-14	Actual	($51,738)	$0.0131	$101,989	$13,045	$3,750	$2,904	$252	($133,776)	($92,757)	3.25%	($256)	($134,032)	7,785,918	31
February-14	Actual	($134,032)	$0.0131	$98,400	$13,064	$3,750	$3,408	$296	($211,915)	($172,973)	3.25%	($431)	($212,346)	7,511,325	28
March-14	Actual	($212,346)	$0.0131	$92,697	$13,386	$3,750	$4,133	$359	($283,414)	($247,880)	3.25%	($684)	($284,098)	7,076,114	31
April-14	Actual	($284,098)	$0.0131	$65,506	$22,465	$3,750	$4,185	$364	($318,840)	($301,469)	3.25%	($805)	($319,645)	5,000,417	30
May-14	Actual	($319,645)	$0.0131	$43,691	$22,151	$3,750	$4,347	$378	($332,711)	($326,178)	3.25%	($900)	($333,611)	3,335,135	31
June-14	Actual	($333,611)	$0.0131	$35,196	$14,630	$3,750	$3,977	$346	($346,106)	($339,859)	3.25%	($908)	($347,014)	2,686,577	30
July-14	Actual	($347,014)	$0.0131	$26,910	$16,397	$3,750	$7,784	$677	($345,317)	($346,165)	3.25%	($956)	($346,272)	2,054,188	31
August-14	Forecast	($346,272)	$0.0131	$27,366	$88,564	$3,750	$25,816	$1,326	($254,182)	($300,227)	3.25%	($829)	($255,011)	2,088,998	31
September-14	Forecast	($255,011)	$0.0131	$27,985	$116,248	$3,750	$12,789	$1,314	($148,895)	($201,953)	3.25%	($539)	($149,435)	2,136,271	30
October-14	Forecast	($149,435)	$0.0131	$18,550	$69,966	$3,750	$12,564	$1,291	($80,414)	($114,924)	3.25%	($317)	($80,731)	1,416,049	31
November-14	Forecast	**($80,731)**	$0.0138	$61,651	$59,042	$3,750	$11,697	$1,202	($66,691)	($73,711)	3.25%	($197)	($66,888)	4,468,377	30
December-14	Forecast	($66,888)	$0.0138	$80,602	$61,042	$3,750	$52,207	$1,117	($29,374)	($48,131)	3.25%	($133)	($29,507)	5,841,935	31
January-15	Forecast	($29,507)	$0.0138	$109,093	$33,113	$3,706	$7,717	$1,029	($93,034)	($61,270)	3.25%	($169)	($93,203)	7,906,924	31
February-15	Forecast	($93,203)	$0.0138	$107,892	$44,012	$3,706	$9,170	$1,019	($143,189)	($118,196)	3.25%	($295)	($143,484)	7,819,885	28
March-15	Forecast	($143,484)	$0.0138	$95,527	$34,613	$3,706	$10,854	$1,034	($188,804)	($166,144)	3.25%	($459)	($189,263)	6,923,629	31
April-15	Forecast	($189,263)	$0.0138	$69,098	$54,910	$3,706	$10,991	$1,047	($187,707)	($188,485)	3.25%	($503)	($188,210)	5,008,125	30
May-15	Forecast	($188,210)	$0.0138	$49,709	$33,113	$3,706	$8,399	$1,120	($191,581)	($189,896)	3.25%	($524)	($192,105)	3,602,832	31
June-15	Forecast	($192,105)	$0.0138	$38,751	$78,208	$3,706	$30,313	$1,189	($117,440)	($154,773)	3.25%	($413)	($117,853)	2,808,634	30
July-15	Forecast	($117,853)	$0.0138	$30,635	$22,214	$3,706	$7,436	$1,240	($113,893)	($115,873)	3.25%	($320)	($114,213)	2,220,358	31
August-15	Forecast	($114,213)	$0.0138	$31,958	$65,809	$3,706	$18,865	$1,258	($56,532)	($85,373)	3.25%	($236)	($56,768)	2,316,273	31
September-15	Forecast	($56,768)	$0.0138	$33,261	$67,309	$3,706	$9,454	$1,261	($8,299)	($32,534)	3.25%	($87)	($8,386)	2,410,697	30
October-15	Forecast	($8,386)	$0.0138	$42,205	$33,113	$3,706	$9,208	$1,228	($3,336)	($5,861)	3.25%	($16)	($3,352)	3,058,951	31
Nov 14 thru Oct 15 Totals				$750,379	$586,499	$44,559	$186,311	$13,744						54,386,622	

Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 1 of 3, Lines 26 through 41 filed on September 15, 2014 in this Cost of Gas Docket. Does not include Special Contracts.
Note- January 2014 DSM SHI includes a LI Allocation adjustment for 2013 trueup.

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE
November 1, 2014 through October 31, 2015

Total ERC Costs for the Period	$149,548	
Less Current Over Collection (Estimated)	($37,340)	(See page 2 of 2)
Total ERC Cost to be Recovered	$112,208	
Forcasted Firm Sales & Firm Transportation Volumes (Attachment 2 to Schedule 10B, Revised Page 1 of 3, Line 41, "Total Division" subtract Line 41 "Special Contracts").	62,481,366	
ERC Recovery Rate	**$0.0018**	

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

Month	Actual or Forecast	Beginning Balance (Over)/Under	Revenue	New ERC Costs To be recovered	DG 13-257 RCE and RPC Final Recon.	Ending Balance
August	Actual	$16,058	$10,342			$5,716
September	Actual	$5,716	$10,808			($5,092)
October	Actual	($5,092)	$13,253			($18,345)
November-'13	Actual	($18,345)	$20,178	$170,394	$24,959	$156,830
December	Actual	$156,830	$26,024		.	$130,806
January- '14	Actual	$130,806	$34,485			$96,321
February	Actual	$96,321	$33,509			$62,812
March	Actual	$62,812	$31,283			$31,529
April	Actual	$31,529	$22,017			$9,512
May	Actual	$9,512	$13,743			($4,231)
June	Actual	($4,231)	$10,075			($14,306)
July	Actual	($14,306)	$7,539			($21,846)
August	Est.	($21,846)	$4,377			($26,224)
September	Est.	($26,224)	$4,762			($30,986)
October	Est.	($30,986)	$6,353			($37,340)

Schedule 17

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDIATION ADJUSTMENT CLAUSE COMPLIANE FILING
2013-2014 ENVIORMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES

Line	Description	Total	11/08 - 10/09	11/09 - 10/10	11/10 - 10/11	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14 10/15	11/15-10/16	11/16-10/17	11/17-10/18	11/18-10/19	11/19-10/20
	ENVIRONMENTAL RESPONSE COST (ERC)													
1	July 07 - June 08 Expenses Amortization (1/7)	$ 232,960	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280					
2	July 08 - June 09 Expenses Amortization (1/7)	$ 127,728		$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247				
3	July 09 - June 10 Expenses Amortization (1/7)	$ 189,634			$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091	$ 27,091			
4	July 10 - June 11 Expenses Amortization (1/7)	$ 121,209				$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316		
5	July 11 - June 12 Expenses Amortization (1/7)	$ 159,020					$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	
6	July 12 - June 13 Expenses Amortization (1/7)	$ 175,406						$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058
7	July 13 - June 14 Expenses Amortization (1/7)	$ 40,881							$ 5,840	$ 5,840	$ 5,840	$ 5,840	$ 5,840	$ 5,840
8	Subtotal (Line 1 through Line 7)	$ 1,046,838	$ 33,280	$ 51,527	$ 78,617	$ 95,933	$ 118,650	$ 143,708	$ 149,548	$ 116,268	$ 98,021	$ 70,931	$ 53,615	$ 30,898
9	Add: Excess amortization from prior years (from schedule 5, Line 10)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Less: Excess amortization to be deferred (from schedule 5, Line 9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total Enviromental Response cost to be recovered (ERC)	$ 1,046,838	$ 33,281	$ 51,527	$ 78,617	$ 95,933	$ 118,650	$ 143,708	$ 149,548	$ 116,268	$ 98,021	$ 70,931	$ 53,615	$ 30,898
14	July 2007 - June 2008 Unamortized beginning balance		$ 232,960	$ 199,680	$ 166,400	$ 133,120	$ 99,840	$ 66,560	$ 33,280					
15	July 2008 - June 2009 Unamortized beginning balance			$ 127,728	$ 109,481	$ 91,234	$ 72,987	$ 54,741	$ 36,494	$ 18,247				
16	July 2009 - June 2010 Unamortized beginning balance				$ 189,634	$ 162,544	$ 135,453	$ 108,362	$ 81,272	$ 54,181	$ 27,091			
17	July 2010 - June 2011 Unamortized beginning balance					$ 121,209	$ 103,893	$ 86,578	$ 69,262	$ 51,947	$ 34,631	$ 17,316		
18	July 2011 - June 2012 Unamortized beginning balance						$ 159,020	$ 136,303	$ 113,586	$ 90,869	$ 68,151	$ 45,434	$ 22,717	
19	July 2012 - June 2013 Unamortized beginning balance							$ 175,406	$ 152,689	$ 129,972	$ 107,255	$ 84,537	$ 61,820	$ 39,103
20	July 2013 - June 2014 Unamortized beginning balance								$ 40,881	$ 35,041	$ 29,201	$ 23,361	$ 17,521	$ 11,680
20	Total Unamortized beginning balance		$ 232,960	$ 327,408	$ 465,515	$ 508,107	$ 571,194	$ 452,544	$ 486,582	$ 345,215	$ 237,128	$ 147,287	$ 84,537	$ 39,103
21	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)													
22	INSURANCE/3RD PARTY RECOVERIES (IR)													
23	UNDER/OVER Recovery from previous year													
24	**Total of Lines 15, 16, 17, 18**		$ 232,960	$ 327,408	$ 465,515	$ 508,107	$ 571,194	$ 452,544	$ 486,582	$ 345,215	$ 237,128	$ 147,287	$ 84,537	$ 39,103

Schedule 18

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

November 2014 through October 2015

		MDQ	Max Swing	% MDQ
1	New Hampshire Underground	16,996	3,532	20.78%
2	LNG	0	0	0.00%
3	Propane	0	0	0.00%

		% MDQ	Costs	Balancing Costs	% Allocated	Allocated Costs
4	New Hampshire Underground					
5	Del., Res., and Transp.	20.78%	$13,229,204	$2,749,218	0.20%	$5,468
6	Capacity	20.78%	$1,408,965	$292,803	35.64%	$104,350
7	LNG	0.00%	$316,739	$0	0.00%	$0
8	Propane	0.00%	$0	$0	0.00%	$0
9	Total		$14,954,908	$3,042,021		$109,818
10	Annual Sum of Absolute Swings					142,624
11	Balancing Rate Per MMBtu Swing					**$0.77**

Note: LNG and LP MDQ allocated based on NH's current PR-Allocator percentage. 47.67%

Northern Utilities, Inc.
Calculation of Balancing Charge
Costs of Balancing Resources
November 2014 through October 2015

1	**Maine**		Northern	Division			
2		Type	Capacity	Allocated	Rate	Months	Costs
3	**El Paso FS Storage**						
4	Capacity	Cap	259,337	135,711	$0.0211	12	$34,362
5	Deliverability	Del	4,243	2,220	$1.5400	12	$41,032
6	Firm Transportation-Tenn	Trans	2,653	1,388	$8.3778	12	$139,572
7	Firm Transportation-GSGT	Trans	2,653	1,388	$3.8633	12	$64,362
8	Total						$279,328
9	**W-10 Storage**						
10	W-10	Cap	34,000	17,792	$ 7.0833	12	$1,512,337
11	PNGTS	Trans	33,000	17,269	$ 76.4666	5	$6,602,470
12	Vector - In	Trans	17,172	8,986	$ 7.6042	12	$819,986
13	Vector -Out	Trans	17,086	8,941	$ 4.5625	5	$203,969
14	TCPL	Trans	34,000	17,792	$ 27.4018	12	$5,850,460
15	Firm Transportation-GSGT	Trans	33,000	17,269	$ 3.8633	12	$800,579
16	Total						$15,789,801
17	LNG						
18	ME		10,000	5,233			$316,739
19	Total						$316,739
20	Propane						
21	Capacity						
22	ME		4,000	2,093			
23	Total						$0
24	Maine Summary						
25		Del	4,243	2,220			$41,032
26		Res	0	0			$0
27		Trans	139,564	73,034			$14,481,398
28		Cap	293,337	153,503			$1,546,699
29		Total	437,144	228,757			$16,069,130
30		Gate Station Delivery	35,653	18,657			

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

	Division	UGS Maximum Swings	UGS Sum Positive Swings	Northern UGS Withdrawals	Allocated UGS Withdrawals	Positive UGS Swings as a % of UGS Withdrawals
1	NH	3,532	3,811	4,019,426	1,916,060	0.20%
2	ME	7,580	1,635	4,019,426	2,103,366	0.08%

	Division	LP Max. Swing	LP Sum Positive Swings	LP Tank Capacity	LP Allocated Tank Capacity	LP Swings as a % of Tank Capacity
3	NH	0	0	25,733	12,267	0.00%
4	ME	0	0	25,733	13,466	0.00%

	Division	LNG Max. Swing	LNG Sum Positive Swings	LNG Tank Capacity	LNG Allocated Tank Capacity	LNG Swings as a % of Tank Capacity
5	NH	0	(9,481)	13,750	6,555	144.65%
6	ME	1,418	(26,271)	13,750	7,195	365.11%

	Division	UGS Absolute Value All Swings	UGS Total Absolute Value All Swings	Northern UGS Capacity	Allocated UGS Capacity	Positive UGS Swings as a % of UGS Withdrawals
7	NH	45,999	36,518	293,337	139,834	32.90%
8	ME	94,294	68,023	293,337	153,503	61.43%
9	Total	140,292	104,540		293,337	35.64%

	Division		UGS Max Abs Cum. All Swings		Allocated UGS Capacity	
10	NH		49,355		139,834	
11	ME		34,012		153,503	52.33%
12	Total		83,367		293,337	**28.42%**

Northern Utilities, Inc.
Calculation of Suppliler Balancing Charge

Derivation of Absolute Swings
May 2000 through April 2001
Summary

		Sum Positive Swings		Sum Negative Swings		Sum LP / LNG Swings		ABS all Swings		Total
		Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	52.76%	ABS Swings
1	May	1,060	1,484	8,125	1,162	0	0	9,185		9,185
2	June	0	28	1,213	5,553	0	0	1,213	5,582	6,794
3	July	1,125	0	0	0	0	0	1,125	0	1,125
4	Aug	45	0	99	1,027	0	0	145	1,027	1,172
5	Sept	0	0	301	11,279	0	0	301	11,279	11,580
6	Oct	1,196	123	2,821	26,853	0	0	4,017	26,976	30,993
7	Nov	384	0	3,976	7,620	(2,382)	(2,539)	6,743	10,159	16,901
8	Dec	0	0	7,956	12,177	0	0	7,956	12,177	20,133
9	Jan	0	0	1,873	174	(423)	(13,355)	2,296	13,530	15,826
10	Feb	0	0	2,807	542	(4,431)	(4,339)	7,238	4,880	12,118
11	March	0	0	1,048	0	(2,245)	(6,038)	3,293	6,038	9,331
12	April	0	0	2,487	0	0	0	2,487	0	2,487
13	Total	3,811	1,635	32,707	66,387	(9,481)	(26,271)	45,999	94,294	140,292
14				add back 10% of the scheduled deliveries=				96,625	97,195	193,819
15						Total ABS Swings =		**142,624**	**191,488**	334,112

Schedule 19

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2014-2015
Derivation of Class Assignments and Weightings

Basic assumptions:

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

			Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	227	2,270	228	0.4%		39	189
2	RATE B-Resi Htg	18,499	184,990	18,567	34.8%		1,321	17,246
3	RATE G-40 (R)	10,253	102,530	10,291	19.3%		481	9,810
4	RATE G-50 (Q)	984	9,840	988	1.9%		292	696
5	RATE G-41 (T)	8,726	87,256	8,758	16.4%		495	8,263
6	RATE G-51 (S)	1,249	12,487	1,253	2.3%		378	875
7	RATE G-42 (V)	980	9,795	983	1.8%		65	918
8	RATE G-52a (U)	186	1,855	186	0.3%		57	129
9	Special Contract	1,837	18,370	1,844	3.5%		1,458	386
10	RATE T-40	1,981	19,810	1,988	3.7%		131	1,857
11	RATE T-50	446	4,460	448	0.8%		266	182
12	RATE T-41	5,167	51,670	5,186	9.7%		439	4,747
13	RATE T-51	1,217	12,170	1,221	2.3%		756	465
14	RATE T-42	989	9,890	993	1.9%		87	906
15	RATE T-52	426	4,260	428	0.8%		268	160
16	Total	53,165	531,653	53,360	100.0%		6,533	46,827
17			53,165					-
18	Residential Total		187,260	18,795	**35.2%**		1,360	17,435
19	LLF Total		280,951	28,198	52.8%		1,698	26,500
20	HLF Total		63,442	6,367	11.9%		3,475	2,892
21	Total		531,653	53,360	100.0%		6,533	46,827
22								
23								
24			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
25	Pipeline		(1,163,843)	18,670	(5.19)			29.50%
26	Storage		14,680,718	15,676	78.04			31.86%
27	Peaking		2,706,819	19,014	11.86			38.64%
28	Total		16,223,694	53,360	**25.34**	**60.81**		
29								
30								
31								
32			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
33	Pipeline - Baseload		(407,253)	6,533	(5.19)			
34	Pipeline - Remaining		(756,591)	12,137	(5.19)			
35	Storage		14,680,718	15,676	78.04			
36	Peaking		2,706,819	19,014	11.86			
37	Total		16,223,694	53,360	25.34			
38								
39								
40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.			
41	Pipeline - Base	**35.2%**	(143,443)	2,301	(5.19)			
42	Pipeline - Remaining	**35.2%**	(266,488)	4,275	(5.19)			
43	Storage	**35.2%**	5,170,873	5,522	78.04			
44	Peaking	**35.2%**	953,401	6,697	11.86			
45	Total	**35.2%**	5,714,343	18,795	25.34			

C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		(263,809)	4,232	(5.19)
Pipeline - Remaining		(490,103)	7,862	(5.19)
Storage		9,509,845	10,155	78.04
Peaking		1,753,418	12,317	11.86
Total	**64.8%**	10,509,350	34,566	25.34

LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		(86,593)	1,389	(5.19)
Pipeline - Remaining		(441,873)	7,088	(5.19)
Storage		8,573,997	9,155	78.04
Peaking		1,580,867	11,105	11.86
Total	**59.3%**	9,626,398	28,738	**27.91**

HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		(177,216)	2,843	(5.19)
Pipeline - Remaining		(48,230)	774	(5.19)
Storage		935,847	999	78.04
Peaking		172,551	1,212	11.86
Total	**5.4%**	882,952	5,828	**12.63**

Unit Cost	Residential	LLF C&I	HLF C&I
Pipeline	$ (5.19)	$ (5.19)	$ (5.19)
Storage	$ 78.04	$ 78.04	$ 78.04
Peaking	$ 11.86	$ 11.86	$ 11.86
Total	$ 25.34	$ 27.91	$ 12.63
Checktotal	$ 25.34	$ 27.91	$ 12.63

Load Makeup	Residential	**LLF C&I**	**HLF C&I**		**Storage and Peaking LLF C&I**	**Storage and Peaking HLF C&I**
Pipeline	34.99%	**29.50%**	**62.06%**		**NA**	**NA**
Storage	29.38%	**31.86%**	**17.15%**		**45.19%**	**45.19%**
Peaking	35.63%	**38.64%**	**20.80%**		**54.81%**	**54.81%**
Total	100.00%	**100.00%**	**100.00%**			

Supply Makeup	Residential	LLF C&I	HLF C&I	Total
Pipeline	35.22%	45.41%	19.37%	100.00%
Storage	35.22%	58.40%	6.37%	100.00%
Peaking	35.22%	58.40%	6.37%	100.00%

Schedule 20

Provided in Summer 2015 Cost-of-Gas Filing

Schedule 21

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

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 9,039,940
Storage Demand	$ 30,704,308
Peaking Demand	$ 4,762,011
Subtotal Demand	$ 44,506,260
Capacity Release (Credit)	$ (147,616)
Asset Management (Credit)	$(11,198,056)
Total Net Demand Costs	$ 33,160,587

Proportional Responsibility (PR) Allocators

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

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Pipeline Sendout	1,008,009	1,042,708	992,395	867,776	982,738	784,754	602,881	430,805	387,566	393,070	470,187	697,279	8,660,168
Rank	2	1	3	5	4	6	8	10	12	11	9	7	
% Max Month	96.67%	100.00%	95.17%	83.22%	94.25%	75.26%	57.82%	41.32%	37.17%	37.70%	45.09%	66.87%	
PR	0.75%	3.33%	0.31%	1.59%	2.76%	1.40%	1.59%	0.36%	3.10%	0.05%	0.42%	1.29%	16.94%
CumPR	13.62%	16.94%	12.87%	9.80%	12.56%	8.21%	5.52%	3.51%	3.10%	3.15%	3.93%	6.81%	100.00%
Product and Pipeline Demand Costs	$ 1,230,827	$ 1,531,651	$ 1,163,143	$ 886,064	$ 1,135,233	$ 742,108	$ 498,797	$ 317,059	$ 280,006	$ 284,344	$ 354,996	$ 615,712	$ 9,039,940

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Storage Injection Volume	-	-	-	-	-	29,679	30,668	29,679	30,668	30,668	29,679	30,668	211,710
Design Year Pipeline Sendout	1,008,009	1,042,708	992,395	867,776	982,738	784,754	602,881	430,805	387,566	393,070	470,187	697,279	8,660,168
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	4.8%	6.4%	7.3%	7.2%	5.9%	4.2%	2.4%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 27,043	$ 24,145	$ 20,435	$ 20,532	$ 20,580	$ 21,077	$ 25,940	$ 159,753

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Storage	235,853	766,685	934,239	814,550	512,843	-	-	-	-	-	-	-	3,264,169
Rank	5	3	1	2	4	6	6	6	6	6	6	6	
% Max Month	25.25%	82.07%	100.00%	87.19%	54.89%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	5.05%	9.06%	12.81%	2.56%	7.41%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.89%
CumPR	5.05%	21.52%	36.89%	24.08%	12.46%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ 1,550,287	$ 6,607,038	$ 11,327,248	$ 7,393,587	$ 3,826,148	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,704,308
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 27,043	$ 24,145	$ 20,435	$ 20,532	$ 20,580	$ 21,077	$ 25,940	$ 159,753
TOTAL	$ 1,550,287	$ 6,607,038	$ 11,327,248	$ 7,393,587	$ 3,826,148	$ 27,043	$ 24,145	$ 20,435	$ 20,532	$ 20,580	$ 21,077	$ 25,940	$ 30,864,061

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Peaking Volumes	2,100	24,211	181,784	139,277	12,222	2,100	2,170	2,100	2,170	2,170	2,100	2,170	374,575
Rank	12	3	1	2	4	11	8	10	7	6	9	5	
% Max Month	1.16%	13.32%	100.00%	76.62%	6.72%	1.16%	1.19%	1.16%	1.19%	1.19%	1.16%	1.19%	
PR	0.10%	2.20%	23.38%	31.65%	1.38%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	58.71%
CumPR	0.10%	3.68%	58.71%	35.33%	1.48%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	100.00%
Peaking Demand Costs	$ 4,584	$ 175,333	$ 2,795,984	$ 1,682,456	$ 70,647	$ 4,584	$ 4,814	$ 4,584	$ 4,814	$ 4,814	$ 4,584	$ 4,814	$ 4,762,011

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

LN		
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 5B, PG 6
9	Asset Management (Credit)	Schedule 5B, 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-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual
Pipeline & Product Demand	$ 1,230,827	$ 1,531,651	$ 1,163,143	$ 886,064	$ 1,135,233	$ 742,108	$ 498,797	$ 317,059	$ 280,006	$ 284,344	$ 354,996	$ 615,712	$ 9,039,940
Storage Incld Inj Fees	$ 1,550,287	$ 6,607,038	$ 11,327,248	$ 7,393,587	$ 3,826,148	$ 27,043	$ 24,145	$ 20,435	$ 20,532	$ 20,580	$ 21,077	$ 25,940	$ 30,864,061
Peaking	$ 4,584	$ 175,333	$ 2,795,984	$ 1,682,456	$ 70,647	$ 4,584	$ 4,814	$ 4,584	$ 4,814	$ 4,814	$ 4,584	$ 4,814	$ 4,762,011
Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (27,043)	$ (24,145)	$ (20,435)	$ (20,532)	$ (20,580)	$ (21,077)	$ (25,940)	$ (159,753)
Less: Capacity Release	$ (29,523)	$ (29,523)	$ (29,523)	$ (29,523)	$ (29,523)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (147,616)
Less: Asset Mgmt	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$ (1,866,343)	$(1,866,343)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,198,056)
Total Demand	$ 889,832	$ 6,418,155	$ 13,390,509	$ 8,066,242	$ 3,136,162	$(1,119,650)	$ 503,611	$ 321,643	$ 284,820	$ 289,158	$ 359,580	$ 620,525	$ 33,160,587

Capacity Cost Allocator based on Design Year Firm Sendout

	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual
Therms													
Maine	667,393	960,802	1,093,905	948,177	788,725	410,547	328,696	243,924	222,698	225,304	262,650	370,667	6,523,488
New Hampshire	578,569	872,802	1,014,514	873,426	719,078	376,307	276,355	188,981	167,038	169,936	209,637	328,782	5,775,425
Total	1,245,962	1,833,604	2,108,419	1,821,603	1,507,803	786,854	605,051	432,905	389,736	395,240	472,287	699,449	12,298,913

Percentage of Total	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual
Maine	53.56%	52.40%	51.88%	52.05%	52.31%	52.18%	54.33%	56.35%	57.14%	57.00%	55.61%	52.99%	52.33%
New Hampshire	46.44%	47.60%	48.12%	47.95%	47.69%	47.82%	45.67%	43.65%	42.86%	43.00%	44.39%	47.01%	47.67%
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%

Allocation of Demand Costs by Division

Maine	$476,634	$3,363,091	$6,947,359	$4,198,624	$1,640,512	($584,186)	$273,588	$181,233	$162,748	$164,832	$199,971	$328,842	$17,353,249
New Hampshire	$413,198	$3,055,065	$6,443,150	$3,867,619	$1,495,650	($535,464)	$230,023	$140,411	$122,072	$124,325	$159,609	$291,683	$15,807,339
Total	$ 889,832	$ 6,418,155	$ 13,390,509	$ 8,066,242	$ 3,136,162	$ (1,119,650)	$ 503,611	$ 321,643	$ 284,820	$ 289,158	$ 359,580	$ 620,525	$ 33,160,587

Detailed Allocation of Demand Costs by Division

Maine	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	
Pipeline & Product Demand	$ 659,286	$ 802,579	$ 603,470	$ 461,212	$ 593,835	$ 387,201	$ 270,973	$ 178,650	$ 159,998	$ 162,088	$ 197,422	$ 326,291	$ 4,803,006	53.13%
Storage Incld Injection Fees	$ 830,403	$ 3,462,064	$ 5,876,884	$ 3,848,495	$ 2,001,441	$ 14,110	$ 13,117	$ 11,514	$ 11,732	$ 11,731	$ 11,722	$ 13,747	$ 16,106,960	52.19%
Peaking	$ 2,456	$ 91,874	$ 1,450,632	$ 875,749	$ 36,955	$ 2,392	$ 2,615	$ 2,583	$ 2,750	$ 2,744	$ 2,549	$ 2,551	$ 2,475,850	51.99%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (14,110)	$ (13,117)	$ (11,514)	$ (11,732)	$ (11,731)	$ (11,722)	$ (13,747)	$ (87,673)	54.88%
Capacity Release (Credit)	$ (15,814)	$ (15,470)	$ (15,317)	$ (15,367)	$ (15,443)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (77,412)	52.44%
Asset Management (Credit)	$ (999,697)	$ (977,957)	$ (968,309)	$ (971,465)	$ (976,275)	$ (973,778)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,867,481)	52.40%
Total Allocated Demand	$ 476,634	$ 3,363,091	$ 6,947,359	$ 4,198,624	$ 1,640,512	$ (584,186)	$ 273,588	$ 181,233	$ 162,748	$ 164,832	$ 199,971	$ 328,842	$ 17,353,249	52.33%

New Hampshire	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Annual	
Pipeline & Product Demand	$ 571,541	$ 729,071	$ 559,673	$ 424,852	$ 541,398	$ 354,908	$ 227,824	$ 138,409	$ 120,009	$ 122,256	$ 157,574	$ 289,421	$ 4,236,935	46.87%
Storage Incld Injection Fees	$ 719,884	$ 3,144,973	$ 5,450,364	$ 3,545,093	$ 1,824,707	$ 12,933	$ 11,028	$ 8,921	$ 8,800	$ 8,848	$ 9,356	$ 12,193	$ 14,757,101	47.81%
Peaking	$ 2,129	$ 83,459	$ 1,345,352	$ 806,708	$ 33,692	$ 2,192	$ 2,199	$ 2,001	$ 2,063	$ 2,070	$ 2,035	$ 2,263	$ 2,286,161	48.01%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (12,933)	$ (11,028)	$ (8,921)	$ (8,800)	$ (8,848)	$ (9,356)	$ (12,193)	$ (72,080)	
Capacity Release	$ (13,709)	$ (14,053)	$ (14,206)	$ (14,156)	$ (14,080)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (70,204)	47.56%
Asset Management	$ (866,646)	$ (888,386)	$ (898,033)	$ (894,878)	$ (890,067)	$ (892,564)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,330,574)	47.60%
Total Allocated Demand	$ 413,198	$ 3,055,065	$ 6,443,150	$ 3,867,619	$ 1,495,650	$ (535,464)	$ 230,023	$ 140,411	$ 122,072	$ 124,325	$ 159,609	$ 291,683	$ 15,807,339	47.67%

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

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	916,039	947,637	961,402	837,790	928,066	628,089	6,741,888	5,219,022
3	Total Storage	(8,470)	319,612	550,163	461,944	132,883	0	1,456,132	1,456,132
4	Total Peaking	7,252	2,781	106,258	45,342	32,030	2,100	208,643	195,763
5	Total Off-system Sales	(50,708)				(55,259)		(105,967)	(105,967)
6	Subtotal	864,113	1,270,030	1,617,823	1,345,076	1,037,720	630,189	8,300,696	6,764,950
7	Less Interruptible - Maine	0	0	0	0	0	0	0	0
8	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
9	Total Firm Supply	864,113	1,270,030	1,617,823	1,345,076	1,037,720	630,189	8,300,696	6,764,950
10	Total Firm Pipeline Sendout	916,039	947,637	961,402	837,790	928,066	628,089	6,741,888	5,219,022
11	**Variable Costs**								
12	Pipeline Costs Modeled in Sendout™	$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 47,897,852	$ 42,756,455
13	NYMEX Price Used for Forecast	$3.938	$4.018	$4.092	$4.078	$4.009	$3.790		
14	NYMEX Price Used for Update	$3.938	$4.018	$4.092	$4.078	$4.009	$3.790		
15	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
16	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -		$ -
17	Total Updated Pipeline Costs	$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 47,897,852	$ 42,756,455
18									
19	Total Pipeline	$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 47,897,852	$ 42,756,455
20	Total Storage	$ (47,696)	$ 1,400,728	$ 2,446,275	$ 2,049,521	$ 562,078	$ -	$ 6,410,905	$ 6,410,905
21	Total Peaking	$ 59,171	$ 28,114	$ 2,242,392	$ 961,270	$ 607,106	$ 29,848	$ 4,094,086	$ 3,927,900
22	Total Off-sytem Sales	$ (299,837)				$ (545,071)		$ (545,071)	$ (545,071)
23									
24	Subtotal	$ 7,487,560	$ 9,670,054	$13,252,475	$10,549,469	$ 8,729,211	$ 2,561,584	$ 57,557,936	$ 52,250,353
25									
26	Hedging Expense & (Gain)/Loss Estimate								
27	NYMEX Options Contracts								
28	Number of contracts	8	12	13	12	9	-	54	54
29	Option Contract Price	$ 0.0105	$ 0.0115	$ 0.0110	$ 0.1050	$ 0.1040			
30	Hedging Expense	$ 8,400	$ 13,800	$ 14,300	$ 12,600	$ 9,360		$ 58,460	$ 58,460
31	NYMEX Option Strike Price	$ 5.800	$ 6.100	$ 5.900	$ 5.750	$ 5.850	$ -		
32	NYMEX Price Used for Forecast	$ 3.938	$ 4.018	$ 4.092	$ 4.078	$ 4.009			
33	Strike Price Hit	No	No	No	No	No			
34	Option Hedging Gain (Credit)	$ -	$ -	$ -	$ -	$ -		$ -	$ -
35	Total Option Cost	$ 8,400	$ 13,800	$ 14,300	$ 12,600	$ 9,360	$ -	$ 58,460	$ 58,460
36									
37	Interruptible Cost Estimate								
38	Variable Pipeline Costs Excld Hedges	$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 47,897,852	$ 42,756,455
39	Average Supply Cost ($/MMBtu)	$ 8.489	$ 8.697	$ 8.908	$ 8.998	$ 8.733	$ 4.031		
40	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42									
43	Firm Sales Pipeline Commodity Excld Hedge	$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 47,897,852	$ 42,756,455
44	Total Storage	$ (47,696)	$ 1,400,728	$ 2,446,275	$ 2,049,521	$ 562,078	$ -	$ 6,410,905	$ 6,410,905
45	Total Peaking	$ 59,171	$ 28,114	$ 2,242,392	$ 961,270	$ 607,106	$ 29,848	$ 4,094,086	$ 3,927,900
46	Off-system Sales	$ (299,837)	$ -	$ -	$ -	$ (545,071)	$ -	$ (844,908)	$ (844,908)
47	Firm Sales Variable Costs Excld Hedge	$ 7,487,560	$ 9,670,054	$13,252,475	$10,549,469	$ 8,729,211	$ 2,561,584	$ 57,557,936	$ 52,250,353
48	Plus Net Hedging Expense / (Gain)	$ 8,400	$ 13,800	$ 14,300	$ 12,600	$ 9,360	$ -	$ 58,460	$ 58,460
49	Total Firm Sales Variable Costs	$ 7,495,960	$ 9,683,854	$13,266,775	$10,562,069	$ 8,738,571	$ 2,561,584	$ 57,616,396	$ 52,308,813

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	Total Off-system Sales	Schedule 6A, page 2
6	Subtotal	SUM LN 2: LN 4
7	Less Interruptible - Maine	Company Analysis
8	Less Interruptible - New Hampshire	Company Analysis
9	Total Firm Supply	LN 6 - LN 7 - LN 8
10	Total Firm Pipeline Sendout	LN 2 - LN 7 - LN 8
11	Variable Costs	
12	Pipeline Costs Modeled in Sendout™	0
13	NYMEX Price Used for Forecast	Attachment to Schedule 5A, PG 1, LN 21
14	NYMEX Price Used for Update	Attachment to Schedule 5A, PG 1, LN 21
15	Increase/(Decrease) NYMEX Price	LN 14 - LN 13
16	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 15
17	Total Updated Pipeline Costs	LN 16 + LN 12
18		
19	Total Pipeline	LN 17
20	Total Storage	Schedule 6A, page 1
21	Total Peaking	Schedule 6A, page 1
22	Total Off-sytem Sales	Schedule 6A, page 1
23		
24	Subtotal	Sum LN 18 : LN 20
25		
26	Hedging Expense & (Gain)/Loss Estimate	
27	NYMEX Options Contracts	
28	Number of contracts	Schedule 7
29	Option Contract Price	Schedule 7
30	Hedging Expense	Schedule 7
31	NYMEX Option Strike Price	Schedule 7
32	NYMEX Price Used for Forecast	Line 13
33	Strike Price Hit	IF LN 32 > 31, Yes, else No
34	Option Hedging Gain (Credit)	IF LN 33 = Yes, (LN 32 - LN 31) * LN 28*10,000 - else 0
35	Total Option Cost	LN 30 + LN 34
36		
37	Interruptible Cost Estimate	
38	Variable Pipeline Costs Excld Hedges	LN 17
39	Average Supply Cost ($/MMBtu)	LN 38 / LN 2
40	Interruptible Cost - Maine	LN 39 * LN 7
41	Interruptible Cost - New Hampshire	LN 39 * LN 8
42		
43	Firm Sales Pipeline Commodity Excld Hedge	LN 38 - LN 40 - LN 41
44	Total Storage	LN 20
45	Total Peaking	LN 21
46	Off-system Sales	LN 22
47	Firm Sales Variable Costs Excld Hedge	Sum LN 43 : LN 46
48	Plus Net Hedging Expense / (Gain)	LN 35
49	Total Firm Sales Variable Costs	LN 47 + LN 48

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter
Maine	449,766	660,145	847,877	701,416	547,331	337,757	4,337,727	3,544,292
New Hampshire	413,892	609,726	769,744	643,491	496,069	292,358	3,967,362	3,225,279
Total	863,658	1,269,871	1,617,621	1,344,907	1,043,400	630,115	8,305,089	6,769,571
Percentage of Total								
Maine	52.08%	51.99%	52.42%	52.15%	52.46%	53.60%	52.23%	52.36%
New Hampshire	47.92%	48.01%	47.58%	47.85%	47.54%	46.40%	47.77%	47.64%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Commodity Allocation by Jurisdiction

	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Annual	Winter
Maine								
Firm Sales Pipeline Commodity Excld Hedge	$ 4,049,458	$ 4,284,212	$ 4,488,725	$ 3,931,683	$ 4,251,649	$ 1,357,073	$ 25,022,830	$ 22,362,801
Net Hedging Expense / (Gain)	$ 4,374	$ 7,174	$ 7,495	$ 6,571	$ 4,910	$ -	$ 30,525	$ 30,525
Storage	$ (24,839)	$ 728,171	$ 1,282,217	$ 1,068,896	$ 294,846	$ -	$ 3,349,292	$ 3,349,292
Peaking	$ 30,815	$ 14,615	$ 1,175,351	$ 501,336	$ 318,466	$ 15,999	$ 2,141,905	$ 2,056,582
Off-system Sales	$ (156,146)	$ -	$ -	$ -	$ (285,925)	$ -	$ (442,071)	$ (442,071)
Total Maine Commodity Costs	$ 3,903,663	$ 5,034,173	$ 6,953,789	$ 5,508,486	$ 4,583,946	$ 1,373,073	$ 30,102,482	$ 27,357,129
Maine Inventory Finance Costs	$ 804	$ 1,268	$ 1,689	$ 1,381	$ 1,015	$ 553	$ 6,709	$ 6,709
Total Maine Variable Costs	$ 3,904,466	$ 5,035,441	$ 6,955,477	$ 5,509,867	$ 4,584,961	$ 1,373,625	$ 30,109,191	$ 27,363,838
New Hampshire								
Firm Sales Pipeline Commodity Excld Hedge	$ 3,726,464	$ 3,957,000	$ 4,075,082	$ 3,606,995	$ 3,853,450	$ 1,174,663	$ 22,875,022	$ 20,393,655
Net Hedging Expense / (Gain)	$ 4,026	$ 6,626	$ 6,805	$ 6,029	$ 4,450	$ -	$ 27,935	$ 27,935
Storage	$ (22,857)	$ 672,556	$ 1,164,058	$ 980,624	$ 267,232	$ -	$ 3,061,613	$ 3,061,613
Peaking	$ 28,357	$ 13,499	$ 1,067,041	$ 459,934	$ 288,640	$ 13,849	$ 1,952,181	$ 1,871,318
Off-system Sales	$ (143,691)	$ -	$ -	$ -	$ (259,146)	$ -	$ (402,837)	$ (402,837)
Total New Hampshire Commodity Costs	$ 3,592,298	$ 4,649,681	$ 6,312,986	$ 5,053,582	$ 4,154,625	$ 1,188,512	$ 27,513,915	$ 24,951,684
New Hampshire Inventory Finance Costs	$ 752	$ 1,201	$ 1,574	$ 1,301	$ 937	$ 469	$ 6,234	$ 6,234
Total New Hampshire Variable Costs	$ 3,593,050	$ 4,650,882	$ 6,314,560	$ 5,054,883	$ 4,155,562	$ 1,188,981	$ 27,520,149	$ 24,957,919
Northern Utilities								
Firm Sales Pipeline Commodity Excld Hedge	$ 7,775,922	$ 8,241,212	$ 8,563,808	$ 7,538,678	$ 8,105,099	$ 2,531,737	$ 47,897,852	$ 42,756,455
Net Hedging Expense / (Gain)	$ 8,400	$ 13,800	$ 14,300	$ 12,600	$ 9,360	$ -	$ 58,460	$ 58,460
Storage	$ (47,696)	$ 1,400,728	$ 2,446,275	$ 2,049,521	$ 562,078	$ -	$ 6,410,905	$ 6,410,905
Peaking	$ 59,171	$ 28,114	$ 2,242,392	$ 961,270	$ 607,106	$ 29,848	$ 4,094,086	$ 3,927,900
Off-system Sales	$ (299,837)	$ -	$ -	$ -	$ (545,071)	$ -	$ (844,908)	$ (844,908)
Total Northern Commodity Costs	$ 7,495,960	$ 9,683,854	$ 13,266,775	$ 10,562,069	$ 8,738,571	$ 2,561,584	$ 57,616,396	$ 52,308,813
Northern Inventory Finance Costs	$ 1,556	$ 2,469	$ 3,263	$ 2,682	$ 1,952	$ 1,022	$ 12,943	$ 12,943
Total Northern Variable Costs	$ 7,497,516	$ 9,686,323	$ 13,270,037	$ 10,564,750	$ 8,740,523	$ 2,562,606	$ 57,629,339	$ 52,321,756

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

50	**Commodity Allocation Factors**	
51	Firm Sales Sendout for Normal Winter, MMBtu	
52		
53	Maine	Company Analysis
54	New Hampshire	Schedule 10B, LN 33 / 10
55	Total	LN 53 + LN 54
56		
57	**Percentage of Total**	
58	Maine	LN 53 / LN 55
59	New Hampshire	LN 54 / LN 55
60	Total	LN 58 + LN 59
61		
62	**Commodity Allocation by Jurisdiction**	
63	**Maine**	
64	Firm Sales Pipeline Commodity Excld Hedge	LN 43 * LN 58
65	Net Hedging Expense / (Gain)	LN 35 * LN 58
66	Storage	LN 44 * LN 58
67	Peaking	LN 45 * LN 58
68	Off-system Sales	LN 46 * LN 58
69	Total Maine Commodity Costs	Sum LN 64 : LN 68
70	Maine Inventory Finance Costs	LN 111
71	Total Maine Variable Costs	LN 69 + LN 70
72	**New Hampshire**	
73	Firm Sales Pipeline Commodity Excld Hedge	LN 43 * LN 59
74	Net Hedging Expense / (Gain)	LN 35 * LN 59
75	Storage	LN 44 * LN 59
76	Peaking	LN 45 * LN 59
77	Off-system Sales	LN 46 * LN 59
78	Total New Hampshire Commodity Costs	Sum LN 73 : LN 77
79	New Hampshire Inventory Finance Costs	LN 116
80	Total New Hampshire Variable Costs	LN 78 + LN 79
81	**Northern Utilities**	
82	Firm Sales Pipeline Commodity Excld Hedge	LN 64 + LN 73
83	Net Hedging Expense / (Gain)	LN 65 + LN 74
84	Storage	LN 66 + LN 75
85	Peaking	LN 67 + LN 76
86	Off-system Sales	LN 68 + LN 77
87	Total Northern Commodity Costs	LN 69 + LN 78
88	Northern Inventory Finance Costs	LN 70 + LN 79
89	Total Northern Variable Costs	LN 87 + LN 88
90		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

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

Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
Inventory Finance Charge	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Annual**	
Storage	$ 1,644	$ 1,465	$ 1,042	$ 578	$ 226	$ 176	$ 9,667	
Peaking	$ 175	$ 198	$ 281	$ 355	$ 350	$ 309	$ 3,277	
Total	$ 1,819	$ 1,663	$ 1,323	$ 932	$ 577	$ 485	$ 12,943	
Inventory Finance Charge Allocation by Jurisdiction								
Maine	$ 947	$ 865	$ 693	$ 486	$ 303	$ 260	$ 6,709	
New Hampshire	$ 872	$ 799	$ 630	$ 446	$ 274	$ 225	$ 6,234	
Total	$ 1,819	$ 1,663	$ 1,323	$ 932	$ 577	$ 485	$ 12,943	
Inventory Finance Charge Allocation by Month								
Maine								
Firm Sales Normal Remaining Sendout	358,658	566,001	753,733	616,382	453,187	246,649	2,994,610	2,994,610
Monthly % Sendout of Total Winter	11.98%	18.90%	25.17%	20.58%	15.13%	8.24%	100.00%	100.00%
ME Allocated Inventory Finance Charge	$ 804	$ 1,268	$ 1,689	$ 1,381	$ 1,015	$ 553	$ 6,709	$ 6,709
New Hampshire								
Firm Sales Normal Remaining Sendout	323,049	515,855	675,873	558,705	402,198	201,515	2,677,194	2,677,194
Monthly % Sendout of Total Winter	12.07%	19.27%	25.25%	20.87%	15.02%	7.53%	100.00%	100.00%
NH Allocated Inventory Finance Charge	$ 752	$ 1,201	$ 1,574	$ 1,301	$ 937	$ 469	$ 6,234	$ 6,234

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

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

97	**Inventory Finance Charge**	
98	Storage	"Schedule 14 - Carrying Costs"
99	Peaking	"Schedule 14 - Carrying Costs"
100	Total	Sum LN 98 : LN 199
101		
102	**Inventory Finance Charge Allocation by Jurisdiction**	
103	Maine	LN 100 * LN 58
104	New Hampshire	LN 100 * LN 59
105	Total	Sum LN 103 : LN 104
106		
107	**Inventory Finance Charge Allocation by Month**	
108	**Maine**	
109	Firm Sales Remaining Sendout	Company Analysis
110	Monthly % Sendout of Total Winter	LN 109 / LN 109 Col N
111	ME Allocated Inventory Finance Charge	LN 103 Col N * LN 110
112		
113	**New Hampshire**	
114	Firm Sales Remaining Sendout	NH Schedule 10B, LN 80 / 10
115	Monthly % Sendout of Total Winter	LN 114 / LN 114 Col N
116	NH Allocated Inventory Finance Charge	LN 104 Col N* LN 115

Schedule 23

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

		Winter	Summer	Annual	
1	Demand	$ 12,605,326	$ 937,315	$ 13,542,640	Schedule 1A, LN 80
2	Commodity	$ 25,360,756	$ 2,562,230	$ 27,922,986	Schedule 1B, LN 43
3	Total	$ 37,966,081	$ 3,499,545	$ 41,465,626	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	32,046,338	7,371,305	39,417,643	Schedule 10B, LN 11
6	Forecasted Residential Sales (Therms)	14,756,521	3,308,911	18,065,432	Schedule 10B, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Annual**	
8	Average Demand Rate	$0.3933	$0.1272		LN 1 / LN 5
9	Average Commodity Rate	$0.7914	$0.3476		LN 2 / LN 5
10	Average Rate	$1.1847	$0.4748		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Annual**	
13	Demand Costs Allocated To Residential per SMBA	$ 5,743,713	$ 424,926	$ 6,168,638	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 5,804,431	$ 420,893	$ 6,225,324	LN 8 * LN 6
15	**Demand Reallocation:**	$ (60,718)	$ 4,032	$ (56,686)	LN 13 - LN 14
16	**HLF Allocation**	$ (5,512)	$ 770	$ (4,742)	LN 15 / LN 20
17	**LLF Allocation**	$ (55,206)	$ 3,262	$ (51,944)	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	9.08%	19.11%		Schedule 10A, LN 173
21	LLF	90.92%	80.89%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 11,678,344	$ 1,150,498	$ 12,828,842	Schedule 10C, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 11,677,981	$ 1,150,177	$ 12,828,158	LN 9 * LN 6
25	**Commodity Reallocation:**	$ 363	$ 321	$ 683	LN 23 - LN 24
26	**HLF Allocation**	$ 47	$ 121	$ 168	LN 25 * LN 30
27	**LLF Allocation**	$ 316	$ 200	$ 516	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	13.03%	37.61%		Schedule 10C, LN 143
31	LLF	86.97%	62.39%		Schedule 10C, LN 144

Schedule 24

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

NU Short-Term Debt Limit Calculation (11/1/14 - 4/30/2015)			
Fuel Financing Purposes			
NU ME winter gas costs		40,922	
NU NH winter gas costs		35,439	
	Total	76,361	
30% of total winter gas costs		22,908	(a)
Non-Fuel Financing Purposes			
Estimated net utility plant @ 12/31/14 before plant acquisition adjustment		314,832	
15% of Net Utility Plant		47,225	(b)
Short-Term Debt Limit			
Short Term Debt Limit		**70,133**	(a) + (b)