NORTHERN UTILTIES, INC. - NEW HAMSHIRE DIVISION
Summer 2010 Cost of Gas Filing

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

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 2010 - October 31, 2010

	Column A	Column B	Column C
1	**ANTICIPATED DIRECT COST OF GAS**		
2	**Purchased Gas:**		
3	Demand Costs:	$ 470,438	
4	Supply Costs:	$ 5,269,861	
5			
6	**Storage & Peaking Gas:**		
7	Demand, Capacity:	$ 576,398	
8	Commodity Costs:	$ 26,395	
9			
10	**Hedging (Gain)/Loss**	$ (6,982)	
11			
12	**Interruptible Included Above**	$ -	
13			
14	**Capacity Release**	$ -	
15			
16	**Adjustment for Actual Costs**	$ -	
15			
16	**Total Anticipated Direct Cost of Gas**		$ 6,336,110
17			
18	**ANTICIPATED INDIRECT COST OF GAS**		
19	**Adjustments:**		
20	Prior Period Under/(Over) Collection	$ (544,057)	
21	Interest	$ (5,817)	
22	Refunds	$ -	
23	Capacity Reserve Charge Revenue	$ -	
24	Interruptible Margins	$ -	
25	Total Adjustments		$ (549,874)
26			
27	**Working Capital:**		
28	Total Anticipated Direct Cost of Gas	$ 6,336,110	
29	Working Capital Percentage	0.190%	
30	Working Capital Allowance	$ 12,039	
31	Plus: Working Capital Reconciliation As of Nov 2009 (Acct 182.21)	$ (8,299)	
32	Plus: Interest on Working Capital Balance (Dec 2009 - Oct 2010)	$ (143)	
33			
34	Total Working Capital Allowance		$ 3,596
35			
36	**Bad Debt:**		
37	Total Anticipated Direct Cost of Gas	$ 6,336,110	
38	Less: Capacity Reserve Charge Revenue	$ -	
39	Plus: Prior Period Under/(Over) Collection	$ (544,057)	
40	Plus: Interest	$ (5,817)	
41	Plus: Total Working Capital	$ 3,596	
42	Subtotal	$ 5,789,832	
43			
44	Bad Debt Percentage	0.450%	
45	Bad Debt Allowance	$ 26,054	
46	Plus: Interest on Bad Debt Balance (Dec 2009 - Oct 2010)	$ 106	
47	Plus: Bad Debt Reconciliation (Acct 182.22)	$ (4,888)	
48	Total Bad Debt Allowance		$ 21,272
49			
50	**Local Production and Storage Capacity**		$ -
51			
52	**Miscellaneous Overhead-25.15% Allocated to Summer Season**		$ 31,261
53			
54	**Total Anticipated Indirect Cost of Gas**		$ (493,745)
55			
56	**Total Cost of Gas**		$ 5,842,365
57			
58			

NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: May 1, 2010 - October 31, 2010

Column A		**Column B**	**Column C**	
Total Anticipated Direct Cost of Gas		$ 6,336,110		
Projected Prorated Sales (05/01/10 - 10/31/10)		8,368,836		
Direct Cost of Gas Rate			$ 0.7571	per therm
Demand Cost of Gas Rate		$ 1,046,835	$ 0.1251	per therm
Commodity Cost of Gas Rate		$ 5,289,274	$ 0.6320	per therm
Total Direct Cost of Gas Rate		$ 6,336,110	$ 0.7571	per therm
Total Anticipated Indirect Cost of Gas		$ (493,745)		
Projected Prorated Sales (05/01/10 - 10/31/10)		8,368,836		
Indirect Cost of Gas			$ (0.0590)	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/10			**$ 0.6981**	**per therm**
RESIDENTIAL COST OF GAS RATE - 05/01/10		**COGwr**	**$ 0.6981**	**per therm**
	Adjusted COGwr		**$ 0.6981**	
	Maximum (COG+25%)		**$ 0.8726**	
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/10		**COGwl**	**$ 0.6571**	**per therm**
	Adjusted COGwl		**$ 0.6571**	
	Maximum (COG+25%)		**$ 0.8214**	
C&I HLF Demand Costs Allocated per SMBA	$ 168,467			
PLUS: Residential Demand Reallocation to C&I HLF	$ 9,394			
C&I HLF Total Adjusted Demand Costs	$ 177,861			
C&I HLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,154,343			
Demand Cost of Gas Rate	**$ 0.0826**			
C&I HLF Commodity Costs Allocated per SMBA	$ 1,366,335			
PLUS: Residential Commodity Reallocation to C&I HLF	$ (1,653)			
C&I HLF Total Adjusted Commodity Costs	$ 1,364,683			
C&I HLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,154,343			
Commodity Cost of Gas Rate	**$ 0.6335**			
Indirect Cost of Gas	**$ (0.0590)**			
Total C&I HLF Cost of Gas Rate	**$ 0.6571**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/10		**COGwh**	**$ 0.7296**	**per therm**
	Adjusted COGwh		**$ 0.7296**	
	Maximum (COG+25%)		**$ 0.9120**	
C&I LLF Demand Costs Allocated per SMBA	$ 419,853			
PLUS: Residential Demand Reallocation to C&I LLF	$ 23,411			
C&I LLF Total Adjusted Demand Costs	$ 443,264			
C&I LLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,811,529			
Demand Cost of Gas Rate	**$ 0.1577**			
C&I LLF Commodity Costs Allocated per SMBA	$ 1,776,067			
PLUS: Residential Commodity Reallocation to C&I LLF	$ (2,148)			
C&I LLF Total Adjusted Commodity Costs	$ 1,773,919			
C&I LLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,811,529			
Commodity Cost of Gas Rate	**$ 0.6309**			
Indirect Cost of Gas	**$ (0.0590)**			
Total C&I LLF Cost of Gas Rate	**$ 0.7296**			

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

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 2010 - October 31, 2010

	Column A	Column D
1	**ANTICIPATED DIRECT COST OF GAS**	
2	**Purchased Gas:**	
3	Demand Costs:	Schedule 1A, LN 71
4	Supply Costs:	Schedule 1B, LN 15
5		
6	**Storage & Peaking Gas:**	
7	Demand, Capacity:	Schedule 1A, LN 73
8	Commodity Costs:	Schedule 1B, LN 16 + Schedule 1B, LN 17
9		
10	**Hedging (Gain)/Loss**	Schedule 1B, LN 15
11		
12	**Interruptible Included Above**	- (Schedule 1B, LN 22)
13		
14	**Capacity Release**	- (Schedule 1A, LN 76)
15		
16	**Adjustment for Actual Costs**	Schedule X3, LN 122 - SUM (LN 3 : LN 14)
15		
16	**Total Anticipated Direct Cost of Gas**	Sum (LN 3 : LN 16)
17		
18	**ANTICIPATED INDIRECT COST OF GAS**	
19	**Adjustments:**	
20	Prior Period Under/(Over) Collection	Schedule 3, LN 101: April
21	Interest	Schedule 3, LN 100: May - Oct
22	Refunds	Company Analysis
23	Capacity Reserve Charge Revenue	Company Analysis
24	Interruptible Margins	- (Schedule 1A, LN 77)
25	Total Adjustments	Sum (LN 20 : LN 24)
26		
27	**Working Capital:**	
28	Total Anticipated Direct Cost of Gas	LN 16
29	Working Capital Percentage	2nd Rev. Pg 21 IV COG Clause 6.1
30	Working Capital Allowance	LN 28 * LN 29
31	Plus: Working Capital Reconciliation As of Nov 2009 (Acct 182.21)	Schedule 3, LN 74: November. 2009 Summer Reconciliatic
32	Plus: Interest on Working Capital Balance (Dec 2009 - Oct 2010)	Schedule 3, LN 73: Total
33		
34	Total Working Capital Allowance	Sum (LN 30 : LN 32)
35		
36	**Bad Debt:**	
37	Total Anticipated Direct Cost of Gas	LN 16
38	Less: Capacity Reserve Charge Revenue	(Forecasted Transportation Therms * $0.0055)
39	Plus: Prior Period Under/(Over) Collection	Schedule 3, LN 101: April
40	Plus: Interest	Schedule 3, LN 100 May - Oct
41	Plus: Total Working Capital	LN 34
42	Subtotal	Sum (LN 37 : LN 41)
43		
44	Bad Debt Percentage	2nd Rev. Pg 21 IV COG Clause 6.1
45	Bad Debt Allowance	LN 44 * LN 42
46	Plus: Interest on Bad Debt Balance (Dec 2009 - Oct 2010)	Schedule 3, LN 90: Total
47	Plus: Bad Debt Reconciliation (Acct 182.22)	Schedule 3, LN 91: October. 2009 Summer Reconciliation
48	Total Bad Debt Allowance	LN 45 + LN 47
49		
50	**Local Production and Storage Capacity**	Schedule 1A, LN 84
51		
52	**Miscellaneous Overhead-25.15% Allocated to Summer Season**	Schedule 1A, LN 83
53		
54	**Total Anticipated Indirect Cost of Gas**	Sum (LN 25 : LN 52)
55		
56	**Total Cost of Gas**	LN 54 + LN 16
57		
58		

NORTHERN UTILITIES, INC.

LN	Column A	Column D
59	CALCULATION OF FIRM SALES COST OF GAS RATE	
60	Period Covered: May 1, 2010 - October 31, 2010	
61		
62	**Column A**	**Column D**
63		
64	Total Anticipated Direct Cost of Gas	LN 16
65	Projected Prorated Sales (05/01/10 - 10/31/10)	Company Analysis
66	**Direct Cost of Gas Rate**	LN 64 / LN 65
67		
68	**Demand Cost of Gas Rate**	Column B : SUM (LN 3 , LN 7 , LN 14)
69	**Commodity Cost of Gas Rate**	Column B : SUM (LN 4 , LN 8 , LN 10 , LN 12)
70	**Total Direct Cost of Gas Rate**	SUM (LN 68 : LN 69)
71		
72	Total Anticipated Indirect Cost of Gas	LN 54
73	Projected Prorated Sales (05/01/10 - 10/31/10)	Company Analysis
74	**Indirect Cost of Gas**	LN 72 / LN 73
75		
76		
77	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/10**	LN 70 + LN 74
78		
79	**RESIDENTIAL COST OF GAS RATE - 05/01/10**	Company Analysis
80		
81		
82		MIN (SUM (LN 79 : LN 81), LN 83)
83		LN 79 * 1.25
84		
85		
86	**COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/10**	Company Analysis
87		
88		
89		MIN (SUM (LN 86 : LN 88), LN 90)
90		LN 86 * 1.25
91		
92	C&I HLF Demand Costs Allocated per SMBA	Schedule 10A, LN 169
93	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 23, LN 16
94	C&I HLF Total Adjusted Demand Costs	Sum (LN 92 : LN 93)
95	C&I HLF Projected Prorated Sales (05/01/10 - 10/31/10)	Company Analysis
96	**Demand Cost of Gas Rate**	LN 94 / LN 95
97		
98	C&I HLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 139
99	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 23, LN 26
100	C&I HLF Total Adjusted Commodity Costs	Sum (LN 98 : LN 99)
101	C&I HLF Projected Prorated Sales (05/01/10 - 10/31/10)	Company Analysis
102	**Commodity Cost of Gas Rate**	LN 100 / LN 101
103		
104	**Indirect Cost of Gas**	LN 74
105		
106	**Total C&I HLF Cost of Gas Rate**	Sum (LN 96, LN 102, LN 104)
107		
108		
109	**COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/10**	Company Analysis
110		
111		
112		MIN (SUM (LN 109 : LN 111), LN 113)
113		LN 109 * 1.25
114		
115	C&I LLF Demand Costs Allocated per SMBA	Schedule 10A, LN 170
116	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 23, LN 17
117	C&I LLF Total Adjusted Demand Costs	Sum (LN 115 : LN 116)
118	C&I LLF Projected Prorated Sales (05/01/10 - 10/31/10)	Company Analysis
119	**Demand Cost of Gas Rate**	LN 117 / LN 118
120		
121	C&I LLF Commodity Costs Allocated per SMBA	Schedule 10A, LN 140
122	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 23, LN 27
123	C&I LLF Total Adjusted Commodity Costs	Sum (LN 121 : LN 122)
124	C&I LLF Projected Prorated Sales (05/01/10 - 10/31/10)	Company Analysis
125	**Commodity Cost of Gas Rate**	LN 123 / LN 124
126		
127	**Indirect Cost of Gas**	LN 74
128		
129	**Total C&I LLF Cost of Gas Rate**	Sum (LN 119, LN 125, LN 127)

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

NH Division Total Annual Demand Cost Allocation

1	**Resource**	Costs
2	Pipeline & Product Demand	$ 2,640,510
3	Storage	$ 9,861,284
4	Peaking	$ 2,453,058
5	Total Gross Demand Cost	$ 14,954,853
6		
7	Capacity Assignment Demand Revenue Estimate	$ 1,657,812
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 14,954,853
9	Capacity Assignment as % of Total Gross Demand Cost	11.09%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 292,712
14	Storage	$ 1,093,167
15	Peaking	$ 271,932
16	Total Capacity Assignment Credit	$ 1,657,812
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,347,798
21	Storage	$ 8,768,117
22	Peaking	$ 2,181,126
23	Total Net Demand Cost (Less Capacity Assignment)	$ 13,297,041
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,441
28	Less 11.09% NH Transp. Capacity Assignment	(1,268)
29	Net Pipeline MDQ	10,172
30		
31	Net Pipeline MDQ	10,172
32	Less: Firm Sales Base Use	3,359
33	Remaining Pipeline MDQ	6,813
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$230.80
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,347,798
40	Less: Base Pipeline Use	$ 775,316
41	Remaining Pipeline Use	$ 1,572,482

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

NH Division Total Annual Demand Cost Allocation

LN		
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	Attachment NUI-FXW-5
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		
13	Pipeline & Product Demand	LN 2 * LN 9
14	Storage	LN 3 * LN 9
15	Peaking	LN 4 * LN 9
16	Total Capacity Assignment Credit	Sum (LN 13 : LN 15)
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		
20	Pipeline & Product Demand	LN 2 - LN 13
21	Storage	LN 3 - LN 14
22	Peaking	LN 4 - LN 15
23	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 16
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DE**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 11.09% NH Transp. Capacity Assignment	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Schedule 10B, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

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

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

45	**All Months**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
46	Remaining Load for All Months	1,739,533	3,689,187	5,196,877	5,587,144	4,059,530	2,524,544	22,796,816
47	Rank	6	4	2	1	3	5	
48	% Max Month	31.13%	66.03%	93.01%	100.00%	72.66%	45.18%	
49	PR	1.34%	5.21%	10.18%	6.99%	2.21%	2.81%	
50	CumPR	4.31%	12.33%	24.72%	31.71%	14.54%	7.12%	94.74%

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52	**Peak Months Only**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
53	Remaining Load for Peak Months Only	1,739,533	3,689,187	5,196,877	5,587,144	4,059,530	2,524,544	
54	Rank	6	4	2	1	3	5	
55	% Max Month	31.13%	66.03%	93.01%	100.00%	72.66%	45.18%	
56	PR	5.19%	5.21%	10.18%	6.99%	2.21%	2.81%	
57	CumPR	5.19%	13.21%	25.60%	32.58%	15.42%	8.00%	100.00%

58
59 **DEMAND COST PR ALLOCATORS**

60		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	50.00%
62	Pipeline - Remaining	4.31%	12.33%	24.72%	31.71%	14.54%	7.12%	94.74%
63	Storage & Peaking	4.31%	12.33%	24.72%	31.71%	14.54%	7.12%	94.74%
64	Capacity Release	5.19%	13.21%	25.60%	32.58%	15.42%	8.00%	100.00%
65	Interr. Margins & Off Sys Sales	5.19%	13.21%	25.60%	32.58%	15.42%	8.00%	100.00%

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67 **DEMAND COSTS ALLOCATED TO MONTHS**

68		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Winter**
69	Pipeline - Base	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 387,658
70	Pipeline - Remaining	$ 67,801	$ 193,935	$ 388,730	$ 498,569	$ 228,679	$ 111,989	$ 1,489,703
71	Total Pipeline	$ 132,411	$ 258,544	$ 453,340	$ 563,179	$ 293,288	$ 176,598	$ 1,877,360
72								
73	Storage & Peaking	$ 472,100	$ 1,350,374	$ 2,706,739	$ 3,471,553	$ 1,592,298	$ 779,781	$ 10,372,845
74								
75	Less Credits to Demand Cost							
76	Cap Rel Margins & Asset Mgt Credit	$ 98,389	$ 250,480	$ 485,361	$ 617,803	$ 292,373	$ 151,670	$ 1,896,076
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79								
80	Total Direct Demand Costs	$ 506,122	$ 1,358,439	$ 2,674,718	$ 3,416,929	$ 1,593,213	$ 804,709	$ 10,354,129

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82	Indirect Demand Costs/(Credits)							
83	Miscellaneous Overhead							
84	Local Production & Storage							
85	Subtotal							

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

NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT
(Based on NH Firm Sales Sendout for Remaining Temperatur

All Months	May	Jun	Jul	Aug	Sep	Oct	Total	Summer
Remaining Load for All Months	1,290,632	653,011	20,697	9,832	84,638	390,752	25,246,378	2,449,562
Rank	7	8	11	12	10	9		
% Max Month	23.10%	11.69%	0.37%	0.18%	1.51%	6.99%		
PR	1.63%	0.59%	0.02%	0.01%	0.11%	0.61%	31.71%	
CumPR	2.97%	1.34%	0.03%	0.01%	0.15%	0.76%	100.00%	5.26%

Peak Months Only	Total	Summer
Remaining Load for Peak Months Only	22,796,816	
Rank		
% Max Month		
PR	32.58%	
CumPR	100.00%	0.00%

DEMAND COST PR ALLOCATORS

	May	Jun	Jul	Aug	Sep	Oct	Total	Summer
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%
Pipeline - Remaining	2.97%	1.34%	0.03%	0.01%	0.15%	0.76%	100.00%	5.26%
Storage & Peaking	2.97%	1.34%	0.03%	0.01%	0.15%	0.76%	100.00%	5.26%
Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%

DEMAND COSTS ALLOCATED TO MONTHS

	May	Jun	Jul	Aug	Sep	Oct	Total	Summer	Winter	Summer
Pipeline - Base	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 775,316	$ 387,658	50.00%	50.00%
Pipeline - Remaining	$ 46,744	$ 21,107	$ 509	$ 231	$ 2,308	$ 11,881	$ 1,572,482	$ 82,780	94.74%	5.26%
Total Pipeline	$ 111,354	$ 85,717	$ 65,118	$ 64,840	$ 66,918	$ 76,491	$ 2,347,798	$ 470,438	79.96%	20.04%
Storage & Peaking	$ 325,480	$ 146,972	$ 3,541	$ 1,606	$ 16,072	$ 82,727	$ 10,949,243	$ 576,398	94.74%	5.26%
Less Credits to Demand Cost										
Cap Rel Margins & Asset Mgt Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,896,076	$ -	100.00%	0.00%
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Direct Demand Costs	$ 436,834	$ 232,689	$ 68,660	$ 66,446	$ 82,990	$ 159,218	$ 11,400,965	$ 1,046,835	90.82%	9.18%

	Total	Summer	Winter	Summer
Indirect Demand Costs/(Credits)				
Miscellaneous Overhead	$ 124,297	$ 31,261	74.85%	25.15%
Local Production & Storage	$ 686,673	$ -	100.00%	0.00%
Subtotal	$ 810,970	$ 31,261	96.15%	3.85%

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

LN		
42	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILIT**	
43	(Based on NH Firm Sales Sendout for Remaining Temperatur	
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	LN 64 * Sum (Schedule 21 LN 88, Schedule 21 LN 89)
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79		
80	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 78)
81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER
	Supply Volumes - Therms							
1	New Hampshire Sales Pipeline	2,316,718	1,653,203	1,044,587	1,022,855	1,076,098	1,413,351	8,526,812
2	New Hampshire Sales Storage	4,366	0	0	0	0	0	4,366
3	New Hampshire Sales Peaking	7,635	7,567	7,631	7,636	7,594	7,203	45,266
4	Total New Hampshire Firm Sales Sendout	2,328,720	1,660,771	1,052,217	1,030,491	1,083,691	1,420,554	8,576,444
5								
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0
7								
8	Total Firm Sendout	2,328,720	1,660,771	1,052,217	1,030,491	1,083,691	1,420,554	8,576,444
9	Total Firm Sales	2,275,544	1,619,594	1,027,021	1,004,288	1,056,046	1,386,344	8,368,836
10	Difference (LAUF & Company Use)	53,176	41,177	25,196	26,204	27,646	34,210	207,608
11	Percent Difference	2.28%	2.48%	2.39%	2.54%	2.55%	2.41%	2.42%
12								
13	**Variable Costs**							
14	New Hampshire Sales Pipeline Commodity	$ 1,409,152	$ 1,010,818	$ 641,230	$ 634,762	$ 671,610	$ 902,289	$ 5,269,861
15	New Hampshire Hedging (Gains) Losses	$ (12,294)	$ -	$ -	$ -	$ -	$ 5,312	$ (6,982)
16	New Hampshire Total Storage	$ 2,760	$ -	$ -	$ -	$ -	$ -	$ 2,760
17	New Hampshire Total Peaking	$ 4,052	$ 3,989	$ 3,997	$ 3,964	$ 3,924	$ 3,709	$ 23,635
18	New Hampshire Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Total New Hampshire Sales Variable Costs	$ 1,403,670	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 911,311	$ 5,289,274
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,415,964	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 905,999	$ 5,296,256
21								$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 1,403,670	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 911,311	$ 5,289,274
24								
25	**Supply Cost/Therm**							
26	New Hampshire Sales Pipeline Commodity Excld Hedges	$ 0.6083	$ 0.6114	$ 0.6139	$ 0.6206	$ 0.6241	$ 0.6384	$ 0.6180
27	New Hampshire Hedging (Gains) Losses	$ (0.0053)	$ -	$ -	$ -	$ -	$ 0.0038	$ (0.0008)
28	New Hampshire Storage Excld Inventory Finance Costs	$ 0.6321	$ -	$ -	$ -	$ -	$ -	$ 0.6321
29	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.5308	$ 0.5271	$ 0.5238	$ 0.5191	$ 0.5167	$ 0.5150	$ 0.5221
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Weighted Average Cost per Dth Sendout	$ 0.6028	$ 0.6110	$ 0.6132	$ 0.6198	$ 0.6234	$ 0.6415	$ 0.6167
32								
33	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34								
35	**Commodity Costs**							
36	Base Commodity, therms	1,038,084	1,007,761	1,031,522	1,020,656	999,050	1,029,801	6,126,874
37	Base Commodity Cost Excld Hedging	$ 631,418	$ 616,175	$ 633,210	$ 633,397	$ 623,523	$ 657,429	$ 3,795,153
38	Base Hedging Commodity Cost	$ (5,509)	$ -	$ -	$ -	$ -	$ 3,871	$ (1,638)
39	Remaining Commodity Excld Hedging	$ 784,546	$ 398,631	$ 12,017	$ 5,329	$ 52,010	$ 248,569	$ 1,501,103
40	Remaining Hedging Commodity	$ (6,785)	$ -	$ -	$ -	$ -	$ 1,442	$ (5,344)
41	Total Commodity Excld Hedging	$ 1,415,964	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 905,999	$ 5,296,256
42	Total Hedging	$ (12,294)	$ -	$ -	$ -	$ -	$ 5,312	$ (6,982)
43	Total Commodity (Incl Hedging)	$ 1,403,670	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 911,311	$ 5,289,274

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Schedule 22, LN 9 * LN 52 * 10
2	New Hampshire Sales Storage	Schedule 22, LN 3 * LN 52 * 10
3	New Hampshire Sales Peaking	Schedule 22, LN 4 * LN 52 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Schedule 22, LN 7 * 10
7		
8	Total Firm Sendout	LN 4
9	Total Firm Sales	Schedule 10B, LN 11
10	Difference (LAUF & Company Use)	LN 8 - LN 9
11	Percent Difference	LN 10 / LN 8
12		
13	**Variable Costs**	
14	New Hampshire Sales Pipeline Commodity	Schedule 22, LN 66 * 10
15	New Hampshire Hedging (Gains) Losses	Schedule 22, LN 67 * 10
16	New Hampshire Total Storage	Schedule 22, LN 68 * 10
17	New Hampshire Total Peaking	Schedule 22, LN 69 * 10
18	New Hampshire Inventory Finance Charge	Schedule 22, LN 72 * 10
19	Total New Hampshire Sales Variable Costs	Sum LN 14 : LN 18
20	Total New Hampshire Sales Variable Costs Excld Hedges	LN 19 - LN 15
21		
22	New Hampshire Interruptible Commodity Costs	Schedule 22, LN 70
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

Estimated Delivered City-Gate Commodity Costs and Volumes May 1, 2010 through October 31, 2010			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
LNG	$43,312	8,280	$5.2309
Empress	$1,137,791	185,801	$6.1237
Chicago	$6,151,941	996,278	$6.1749
Tennessee Production	$1,245,678	201,107	$6.1941
Niagara	$1,115,785	177,875	$6.2728
Tennessee Storage	$5,079	798	$6.3661
Total System	$9,699,585	1,570,139	$6.1775

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

		Winter						Summer						
Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
Volumes	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Residential Heat & Non Heat								1,072,474	673,551	392,617	377,131	382,710	504,480	3,402,963
Sales HLF Classes								361,157	388,387	349,412	363,980	337,334	354,073	2,154,343
Sales LLF Classes								841,913	557,656	284,992	263,176	336,001	527,791	2,811,529
Total								2,275,544	1,619,594	1,027,021	1,004,288	1,056,046	1,386,344	8,368,836
Rates														
Residential Heat & Non Heat CGA								$0.6981	$0.6981	$0.6981	$0.6981	$0.6981	$0.6981	
Sales HLF Classes CGA								$0.6571	$0.6571	$0.6571	$0.6571	$0.6571	$0.6571	
Sales LLF Classes CGA								$0.7296	$0.7296	$0.7296	$0.7296	$0.7296	$0.7296	
Revenues														
Residential Heat & Non Heat								$ (748,694)	$ (470,206)	$ (274,086)	$ (263,275)	$ (267,170)	$ (352,177)	$ (2,375,609)
Sales HLF Classes								$ (237,316)	$ (255,209)	$ (229,599)	$ (239,171)	$ (221,662)	$ (232,661)	$ (1,415,619)
Sales LLF Classes								$ (614,260)	$ (406,866)	$ (207,930)	$ (192,013)	$ (245,146)	$ (385,076)	$ (2,051,292)
Total Sales								$ (1,600,270)	$ (1,132,281)	$ (711,615)	$ (694,460)	$ (733,979)	$ (969,915)	$ (5,842,520)

		Winter						Summer						
Gas Costs and Credits		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	
	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Net Demand Costs (Net of Injection Fees & Cap. Assign.)														
Pipeline								$ 78,406	$ 78,406	$ 78,406	$ 78,406	$ 78,406	$ 78,406	$ 470,438
Storage								$ 76,519	$ 76,519	$ 76,519	$ 76,519	$ 76,519	$ 76,519	$ 459,114
Peaking								$ 19,547	$ 19,547	$ 19,547	$ 19,547	$ 19,547	$ 19,547	$ 117,284
Total Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ 174,473	$ 174,473	$ 174,473	$ 174,473	$ 174,473	$ 174,473	$ 1,046,835
NUI Commodity Costs														
NUI Total Pipeline Volumes								423,272	294,929	190,962	186,863	191,303	273,732	
Pipeline Costs Modeled in Sendout™								$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	
NYMEX Price Used for Forecast								$ 5.65	$ 5.71	$ 5.78	$ 5.85	$ 5.88	$ 5.98	
NYMEX Price Used for Update								$ 5.65	$ 5.71	$ 5.78	$ 5.85	$ 5.88	$ 5.98	
Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
Increase/(Decrease) in Pipeline Costs								$ -	$ -	$ -	$ -	$ -	$ -	
Updated Pipeline Costs								$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	
Interruptible Volumes - NH								0	0	0	0	0	0	
Average Supply Cost ($/MMBtu)								$ 6.08	$ 6.11	$ 6.14	$ 6.21	$ 6.24	$ 6.38	
Interruptible Cost - NH								$ -	$ -	$ -	$ -	$ -	$ -	
Total Updated Pipeline Costs								$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	
New Hampshire Allocated Percentage								54.73%	56.05%	54.70%	54.74%	56.25%	51.63%	
NH Updated Pipeline Costs								$ 1,409,152	$ 1,010,818	$ 641,230	$ 634,762	$ 671,610	$ 902,289	
Hedging (Gain)/Loss Estimate														
NYMEX NG Futures Contracts								25	0	0	0	0	25	
Average Purchase Price								$ 5.56	$ -	$ -	$ -	$ -	$ 6.02	
NYMEX Price Used for Forecast								$ 5.65	$ 5.71	$ 5.78	$ 5.85	$ 5.88	$ 5.98	
NYMEX Price Used for Update								$ 5.65	$ 5.71	$ 5.78	$ 5.85	$ 5.88	$ 5.98	
Increase/(Decrease) NYMEX Price								$ -	$ -	$ -	$ -	$ -	$ -	
NUI Futures Hedging (Gain)/Loss								$ (22,462)	$ -	$ -	$ -	$ -	$ 10,288	$ (12,173)
New Hampshire Allocated Percentage								54.73%	56.05%	54.70%	54.74%	56.25%	51.63%	
NH Futures Hedging (Gain)/Loss								$ (12,294)	$ -	$ -	$ -	$ -	$ 5,312	$ (6,982)
NH Commodity Costs														
Pipeline Excl Hedging								$ 1,409,152	$ 1,010,818	$ 641,230	$ 634,762	$ 671,610	$ 902,289	$ 5,269,861
Hedging (Gain)/Loss Estimate								$ (12,294)	$ -	$ -	$ -	$ -	$ 5,312	$ (6,982)
Storage								$ 2,760	$ -	$ -	$ -	$ -	$ -	$ 2,760
Peaking								$ 4,052	$ 3,989	$ 3,997	$ 3,964	$ 3,924	$ 3,709	$ 23,635
Total Commodity Costs								$ 1,403,670	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 911,311	$ 5,289,274
Inventory Finance Charge														$ -
Asset Management and Capacity Release														
NUI AMA Revenue														$ -
PNGTS Litigation Cost														$ -
NUI Capacity Release														$ -
NUI AMA Rev & Cap. Release Subtotal														$ -
NH AMA Revenue														$ -
NH Capacity Release														$ -
NH Total Asset Management and Capacity Release		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Anticipated Direct Cost of Gas		$ -	$ -	$ -	$ -	$ -	$ -	$ 1,578,143	$ 1,189,279	$ 819,700	$ 813,198	$ 850,006	$ 1,085,783	$ 6,336,110

		Winter						Summer						
	Oct-09	(Forecast) Nov-09	(Forecast) Dec-09	(Forecast) Jan-10	(Forecast) Feb-10	(Forecast) Mar-10	(Forecast) Apr-10	(Forecast) May-10	(Forecast) Jun-10	(Forecast) Jul-10	(Forecast) Aug-10	(Forecast) Sep-10	(Forecast) Oct-10	Total
Working Capital														
Total Anticipated Direct Cost of Gas			$ -	$ -	$ -	$ -	$ -	$ 1,578,143	$ 1,189,279	$ 819,700	$ 813,198	$ 850,006	$ 1,085,783	$ 6,336,110
Working Capital Percentage			0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	
Working Capital Allowance			$ -	$ -	$ -	$ -	$ -	$ 2,998	$ 2,260	$ 1,557	$ 1,545	$ 1,615	$ 2,063	$ 12,039
Beginning Perod Working Capital Balance			$ (8,299)	$ (8,321)	$ (8,344)	$ (8,367)	$ (8,389)	$ (8,412)	$ (5,432)	$ (3,184)	$ (1,633)	$ (91)	$ 1,526	
End of Period Working Capital Allowance			$ (8,299)	$ (8,321)	$ (8,344)	$ (8,367)	$ (8,389)	$ (5,414)	$ (3,173)	$ (1,627)	$ (88)	$ 1,524	$ 3,589	
Interest			$ (22)	$ (23)	$ (23)	$ (23)	$ (23)	$ (19)	$ (12)	$ (7)	$ (2)	$ 2	$ 7	$ (143)
End of period with Interest		$ (8,299)	$ (8,321)	$ (8,344)	$ (8,367)	$ (8,389)	$ (8,412)	$ (5,432)	$ (3,184)	$ (1,633)	$ (91)	$ 1,526	$ 3,596	
Capacity Reserve Charge Credit														
Grandfathered Transport Billed Deliveries														0
Capacity Reserve Charge ($/therm)														
Capacity Reserve Charge Credit		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt														
Total Anticipated Direct Cost of Gas			$ -	$ -	$ -	$ -	$ -	$ 1,578,143	$ 1,189,279	$ 819,700	$ 813,198	$ 850,006	$ 1,085,783	$ 6,336,110
Capacity Reserve Charge Credit			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prior Period Over/Under Collection			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest			$ (1,454)	$ (1,458)	$ (1,462)	$ (1,466)	$ (1,470)	$ (1,496)	$ (1,439)	$ (1,205)	$ (887)	$ (558)	$ (231)	$ (13,125)
Working Capital Allowance (Incld Interest)			$ (22)	$ (23)	$ (23)	$ (23)	$ (23)	$ 2,980	$ 2,248	$ 1,551	$ 1,543	$ 1,617	$ 2,070	$ 11,895
Subtotal			$ (1,476)	$ (1,480)	$ (1,484)	$ (1,488)	$ (1,492)	$ 1,579,626	$ 1,190,088	$ 820,045	$ 813,854	$ 851,065	$ 1,087,622	$ 6,334,880
Bad Debt Percentage			0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	
Bad Debt Allowance			$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ 7,108	$ 5,355	$ 3,690	$ 3,662	$ 3,830	$ 4,894	$ 28,507
Beginning Period Bad Debt Balance			$ (4,888)	$ (4,908)	$ (4,928)	$ (4,948)	$ (4,968)	$ (4,988)	$ 2,116	$ 7,485	$ 11,200	$ 14,898	$ 18,773	
End of Period Bad Debt Balance			$ (4,895)	$ (4,915)	$ (4,935)	$ (4,955)	$ (4,975)	$ 2,120	$ 7,472	$ 11,175	$ 14,862	$ 18,728	$ 23,667	
Interest			$ (13)	$ (13)	$ (13)	$ (13)	$ (13)	$ (4)	$ 13	$ 25	$ 35	$ 46	$ 57	$ 106
End of Period Bad Debt Balance with Interest		$ (4,888)	$ (4,908)	$ (4,928)	$ (4,948)	$ (4,968)	$ (4,988)	$ 2,116	$ 7,485	$ 11,200	$ 14,898	$ 18,773	$ 23,725	
Local Production and Storage Capacity								$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous Overhead								$ 5,210	$ 5,210	$ 5,210	$ 5,210	$ 5,210	$ 5,210	$ 31,261
Gas Cost Other than Bad Debt and Working Capital Over/Under Collection														
Beginning Balance Over/Under Collection			$ (536,749)	$ (538,203)	$ (539,660)	$ (541,122)	$ (542,587)	$ (544,057)	$ (562,470)	$ (501,701)	$ (389,611)	$ (266,550)	$ (145,870)	
Net Costs - Revenues			$ -	$ -	$ -	$ -	$ -	$ (16,917)	$ 62,209	$ 113,295	$ 123,949	$ 121,237	$ 121,078	
Ending Balance before Interest			$ (536,749)	$ (538,203)	$ (539,660)	$ (541,122)	$ (542,587)	$ (560,974)	$ (500,262)	$ (388,406)	$ (265,662)	$ (145,313)	$ (24,792)	
Average Balance			$ (536,749)	$ (538,203)	$ (539,660)	$ (541,122)	$ (542,587)	$ (552,515)	$ (531,366)	$ (445,053)	$ (327,637)	$ (205,931)	$ (85,331)	
Interest Rate			3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Expense			$ (1,454)	$ (1,458)	$ (1,462)	$ (1,466)	$ (1,470)	$ (1,496)	$ (1,439)	$ (1,205)	$ (887)	$ (558)	$ (231)	$ (13,125)
Ending Balance Incl Interest Expense		$ (536,749)	$ (538,203)	$ (539,660)	$ (541,122)	$ (542,587)	$ (544,057)	$ (562,470)	$ (501,701)	$ (389,611)	$ (266,550)	$ (145,870)	$ (25,023)	
Total Indirect Cost of Gas	$ -	$ (549,936)	$ (1,496)	$ (1,500)	$ (1,504)	$ (1,508)	$ (1,512)	$ 13,798	$ 11,387	$ 9,271	$ 9,563	$ 10,145	$ 12,001	$ (491,292)
Total Cost of Gas	$ -	$ (549,936)	$ (1,496)	$ (1,500)	$ (1,504)	$ (1,508)	$ (1,512)	$ 1,591,941	$ 1,200,667	$ 828,971	$ 822,762	$ 860,151	$ 1,097,784	$ 5,844,818

To be Provided in Winter 2010-11 Cost-of-Gas Filing

Northern Utilities, Inc.

Pipeline Contract Demand Cost Estimates

November 1, 2009 through October 31, 2010

Pipeline	Contract ID	Rate	Note	Negotiated Rate	Contract Ends	MDQ	Dth / GJ	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Currency	Months Per Year	Annual Demand
Algonquin	93201A1C	AFT-1 (F-2/F-3)		Yes	10/31/2012	286	Dth	Centerville, NJ	Taunton, MA	$ 5.9771	USD	12	$ 20,513
Algonquin	93201A1C	AFT-1 (F-2/F-3)		Yes	10/31/2012	965	Dth	Lambertville, NJ	Taunton, MA	$ 5.9771	USD	12	$ 69,215
Algonquin	93200F	AFT-1 (AFT-2)		No	10/31/2012	4,211	Dth	Mendon, MA	Brockton, MA	$ 6.1138	USD	12	$ 308,943
Granite	09-006-FT-NN	FT-NN		Yes	10/31/2010	100,000	Dth	NA	NA	$ 1.6666	USD	12	$ 1,999,920
Iroquois	R181001	RTS-1		No	10/31/2013	6,569	Dth	Zone 1	Zone 1	$ 6.5971	USD	12	$ 520,036
PNGTS	1997-003	FT		No	3/9/2019	1,100	Dth	Pittsburgh	Westbrook	$ 27.4017	USD	12	$ 361,702
PNGTS	1997-004	FT	1	Yes	3/9/2019	15,100	Dth	Pittsburgh	Westbrook	$ 52.0632	USD	5	$ 3,930,772
PNGTS	1997-004	FT	1	Yes	3/9/2019	4,900	Dth	Pittsburgh	Eliot	$ 52.0632	USD	5	$ 1,275,548
PNGTS	1997-004	FT	1	Yes	3/9/2019	13,000	Dth	Pittsburgh	Newington	$ 52.0632	USD	5	$ 3,384,108
Tennessee	5083	FT-A		No	10/31/2018	4,605	Dth	Zone 0	Zone 6	$ 16.5900	USD	12	$ 916,763
Tennessee	5083	FT-A	2	No	10/31/2018	8,550	Dth	Zone L	Zone 6	$ 15.1500	USD	12	$ 1,554,390
Tennessee	5265	FT-A		No	10/31/2013	2,653	Dth	Zone 4	Zone 6	$ 5.8900	USD	12	$ 187,514
Tennessee	5292	FT-A		No	3/31/2015	1,406	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 83,179
Tennessee	39735	FT-A		No	3/31/2015	929	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 54,960
Tennessee	41099	FT-A		No	10/31/2017	4,267	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 252,436
Tennessee	46314	FT-A		No	3/31/2012	950	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 56,202
Tennessee	31861	NET-284		No	10/31/2012	1,382	Dth	3	3	$ 5.0700	USD	12	$ 84,081
Tennessee	31861	NET-284	3	No	10/31/2012	844	Dth	3	4	$ 10.6100	USD	12	$ 107,458
Texas Eastern	800384	FT-1		Yes	10/31/2017	965	Dth	M3	M3	$ 5.7300	USD	12	$ 66,353
Texas Eastern	800436	CDS		No	10/31/2012	64	Dth	M3	M3	$ 5.2930	USD	12	$ 4,065
Texas Eastern	800464	CDS	4	No	10/31/2012	33	Dth	ELA	M1	$ 2.3750	USD	12	$ 941
Texas Eastern	800464	CDS	4	No	10/31/2012	9	Dth	ETX	M1	$ 2.1890	USD	12	$ 236
Texas Eastern	800464	CDS	4	No	10/31/2012	16	Dth	STX	M1	$ 6.8040	USD	12	$ 1,306
Texas Eastern	800464	CDS	4	No	10/31/2012	18	Dth	WLA	M1	$ 2.8250	USD	12	$ 610
Texas Eastern	800464	CDS	4	No	10/31/2012	59	Dth	M1	M3	$ 11.0360	USD	12	$ 7,813
TransCanada	29594	FT	5	No	10/31/2016	6,264	GJ	Dawn	Iroquois	$ 8.2913	CAD	12	$ 573,068
TransCanada	29833	FT	6	No	10/31/2010	1,196	GJ	Empress	E. Hereford	$ 38.2391	CAD	12	$ 504,628
TransCanada	33322	FT	7	No	3/31/2018	35,872	GJ	Dawn	E. Hereford	$ 13.3229	CAD	12	$ 5,273,355
Vector	CRL-NUI-0725	FT-1		Yes	10/31/2017	17,172	Dth	Alliance	Dawn	$ 7.6042	USD	12	$ 1,566,952
Vector	CRL-NUI-0727	FT-1		Yes	10/31/2017	17,086	Dth	W-10	Dawn	$ 4.5625	USD	5	$ 389,774
Vector	FT-1-NUI-0122	FT-1		Yes	3/31/2016	6,070	Dth	Alliance	St. Clair	$ 8.0908	USD	12	$ 589,334
Vector	FT-1-NUI-C0122	FT-1		Yes	3/31/2016	6,404	GJ	St. Clair	Dawn	$ 0.4623	CAD	12	$ 32,667

Total Annual Demand Costs $ 24,178,843

Exchange Rate (CAD/USD) = 0.9195

Note 1: Rate = 1.9 times the recourse reservation rate
Note 2: The demand rate applied for Zone L to Zone 6 transportation capacity Zone 1 to Zone 6 demand rate.
Note 3: The rate is the Segment 3 demand rate of $5.07 per Dth plus the Segment 4 demand rate of $5.54 per Dth.
Note 4: Rate is expressed in the tariff sheet as as a Delivery Zone of AAB ("Access Area Boundary"). The AAB is the border between the Access Areas (ETX, ELA, WLA, and STX) and the M1 Zone.
Note 5: Rate is the Delivery Pressure Toll for deliveries into Iroquois of $CAD 0.56297 plus the FT Toll for Union Dawn to Iroquois of $CAD 7.72830.
Note 6: Rate is the Delivery Pressure Toll for deliveries into E. Hereford of $CAD 1.41498 plus the FT Toll for Empress to E. Hereford of $CAD 36.82407.
Note 7: Rate is the Delivery Pressure Toll for deliveries into E. Hereford of $CAD 1.41498 plus the FT Toll for Union Dawn to E. Hereford of $CAD 11.90791.

Northern Utilities, Inc.

Pipeline Contract Demand Cost Allocations

November 1, 2009 through October 31, 2010

Pipeline	Contract ID	MDQ	Dth / GJ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Annual Demand	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost
Algonquin	93201A1C	286	Dth	286			100%	0%	0%	$ 20,513	$ 20,513	$ -	$ -
Algonquin	93201A1C	965	Dth	880	85		91%	9%	0%	$ 69,215	$ 63,118	$ 6,097	$ -
Algonquin	93200F	4,211	Dth	4,211			100%	0%	0%	$ 308,943	$ 308,943	$ -	$ -
Granite	09-006-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 1,999,920	$ 477,901	$ 709,472	$ 812,547
Iroquois	R181001	6,569	Dth	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 361,702	$ 361,702	$ -	$ -
PNGTS	1997-004	15,100	Dth		15,100		0%	100%	0%	$ 3,930,772	$ -	$ 3,930,772	$ -
PNGTS	1997-004	4,900	Dth		4,900		0%	100%	0%	$ 1,275,548	$ -	$ 1,275,548	$ -
PNGTS	1997-004	13,000	Dth		13,000		0%	100%	0%	$ 3,384,108	$ -	$ 3,384,108	$ -
Tennessee	5083	4,605	Dth	4,605			100%	0%	0%	$ 916,763	$ 916,763	$ -	$ -
Tennessee	5083	8,550	Dth	8,550			100%	0%	0%	$ 1,554,390	$ 1,554,390	$ -	$ -
Tennessee	5265	2,653	Dth		2,653		0%	100%	0%	$ 187,514	$ -	$ 187,514	$ -
Tennessee	5292	1,406	Dth	1,406	-		100%	0%	0%	$ 83,179	$ 83,179	$ -	$ -
Tennessee	39735	929	Dth	929	-		100%	0%	0%	$ 54,960	$ 54,960	$ -	$ -
Tennessee	41099	4,267	Dth	4,267	-		100%	0%	0%	$ 252,436	$ 252,436	$ -	$ -
Tennessee	46314	950	Dth	950	-		100%	0%	0%	$ 56,202	$ 56,202	$ -	$ -
Tennessee	31861	1,382	Dth	1,382			100%	0%	0%	$ 84,081	$ 84,081	$ -	$ -
Tennessee	31861	844	Dth	844			100%	0%	0%	$ 107,458	$ 107,458	$ -	$ -
Texas Eastern	800384	965	Dth	965	-		100%	0%	0%	$ 66,353	$ 66,353	$ -	$ -
Texas Eastern	800436	64	Dth	64	-		100%	0%	0%	$ 4,065	$ 4,065	$ -	$ -
Texas Eastern	800464	33	Dth	33			100%	0%	0%	$ 941	$ 941	$ -	$ -
Texas Eastern	800464	9	Dth	9			100%	0%	0%	$ 236	$ 236	$ -	$ -
Texas Eastern	800464	16	Dth	16			100%	0%	0%	$ 1,306	$ 1,306	$ -	$ -
Texas Eastern	800464	18	Dth	18			100%	0%	0%	$ 610	$ 610	$ -	$ -
Texas Eastern	800464	59	Dth	59			100%	0%	0%	$ 7,813	$ 7,813	$ -	$ -
TransCanada	29594	6,264	GJ	6,264	-		100%	0%	0%	$ 573,068	$ 573,068	$ -	$ -
TransCanada	29833	1,196	GJ	1,196	-		100%	0%	0%	$ 504,628	$ 504,628	$ -	$ -
TransCanada	33322	35,872	GJ		35,872		0%	100%	0%	$ 5,273,355	$ -	$ 5,273,355	$ -
Vector	CRL-NUI-0725	17,172	Dth		17,172		0%	100%	0%	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086	Dth		17,086		0%	100%	0%	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	Dth	6,070	-		100%	0%	0%	$ 589,334	$ 589,334	$ -	$ -
Vector	FT-1-NUI-C0122	6,404	GJ	6,404	-		100%	0%	0%	$ 32,667	$ 32,667	$ -	$ -
Annual Total Demand Costs										$ 24,178,843	$ 6,642,704	$ 16,723,592	$ 812,547

Northern Utilities, Inc.

Storage Contract Demand Cost Estimates

November 1, 2009 through October 31, 2010

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0185	$ 1.1500	12	$ 57,573	$ 58,553	$ 116,126
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.5370	12	$ 189	$ 1,395	$ 1,585
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	$ 497	$ 687	$ 1,184
W-10	01052	Storage	Yes	3,400,000		34,000			12	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges $ 3,008,895

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.

Peaking Resources Demand Cost Estimates

November 1, 2009 through October 31, 2010

Resource	Contract Quantity	Maximum Daily Quantity	Contract Quantity Demand Rate	MDQ Demand Rate	Months Per Year	Annual CQ Demand Cost	Annual MDQ Demand Cost	Annual Fixed Charges
Peaking Supply 1	755,000	5,000	$ -	$ 41.8506	12	$ -	$ 2,511,036	$ 2,511,036
Peaking Supply 2	1,272,000	53,000	$ 1.3500	$ -	5	$ 1,717,200	$ -	$ 1,717,200

Total Annual Demand Costs $ 4,228,236

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 2009 through October 2010

Asset Management Agreeement Revenue		
Resources	Term	Projected Revenue
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	Nov 2009 - Apr 2010	$ (370,000)
Empress via TCPL, PNGTS	Nov 2009 - Oct 2010	$ (100,000)
Wash 10 via Vector, TCPL, PNGTS	Nov 2009 - Apr 2010	$ (1,000,000)
Tennessee Long-Haul	Nov 2009 - Apr 2010	$ (1,300,000)
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	May 2010 - Oct 2010	$ (250,000)
Wash 10 via Vector, TCPL, PNGTS	May 2010 - Oct 2010	$ (750,000)
Total Asset Management	Nov 2009 - Oct 2010	$ (3,770,000)

Capacity Release Revenue		
Resources	Term	Projected Revenue
Tennessee Long-Haul	May 2010 - Oct 2010	$ (348,566)
Tetco	May 2009 - Oct 2017	$ (66,353)
Tetco	May 2009 - Mar 2010	$ (8,360)
AGT	May 2009 - Oct 2012	$ (98,860)
Tennessee Z4-Z6	Apr 2010 - Oct 2010	$ (16,275)
Tennessee Niagara Z5 - Z6	Apr 2010 - Oct 2010	$ (27,229)
Total Capacity Release	Nov 2009 - Oct 2010	$ (565,644)

Total Asset Management and Capacity Release Revenue	$ (4,335,643)

ALGONQUIN GAS TRANSMISSION, LLC
DISCOUNTED RATE LETTER - SCHEDULE

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

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Proposed Rates Effective 12/01/2008

• RATE SCHEDULE AFT-1

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(F-2/F-3)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(F-4)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(STB/SS-3)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(FTP)	$11.8368	$0.0017	$0.0017	$0.3909	$0.0017	$0.3892
(PSS-T)	$ 9.7854	$0.0017	$0.0017	$0.3234	$0.0017	$0.3217
(AFT-2)	$ 6.1138	$0.0017	$0.0017	$0.2027	$0.0017	$0.2010
(AFT-3)	$10.7554	$0.0017	$0.0017	$0.3553	$0.0017	$0.3536
(AFT-5)	$12.6265	$0.0017	$0.0017	$0.4168	$0.0017	$0.4151
(ITP)	$13.0110	$0.0017	$0.0017	$0.4295	$0.0017	$0.4278
(X-35)	$10.2027	$0.0017	$0.0017	$0.3371	$0.0017	$0.3354
X-39	$13.2089	$0.0017	$0.0017	$0.4360	$0.0017	$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

• RATE SCHEDULE AFT-1S

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(F-2/F-3)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(F-4)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0029	$0.0866
(STB/SS-3)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(Hubline) 1/		$0.0612	$0.0000			

• OTHER FIRM RATE SCHEDULES

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
AFT-E	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0056		$0.0598		
AFT-4	$ 3.5211	$0.0030		$0.1188		
AFT-CL:						
Canal	$ 2.0858	$0.0017	$0.0017	$0.0703	$0.0017	$0.0686
Middletown	$ 3.2764	$0.0017	$0.0017	$0.1094	$0.0017	$0.1077
Cleary	$ 1.4529	$0.0017	$0.0017	$0.0495	$0.0017	$0.0478
Lake Road	$ 0.6476	$0.0017	$0.0017	$0.0230	$0.0017	$0.0213
Brayton Pt.	$ 1.2700	$0.0017	$0.0017	$0.0435	$0.0017	$0.0418
Manchester	$ 2.4500	$0.0017	$0.0017	$0.0822	$0.0017	$0.0805
Bellingham	$ 0.9714	$0.0017	$0.0017	$0.0336	$0.0017	$0.0319
Phelps Dodge	$ 0.0000	$0.0183	$0.0017	$0.0183	$0.0017	$0.0000
Cape Cod	$ 9.0501	$0.0019	$0.0017	$0.2992	$0.0017	$0.2975
Northeast Gateway	$ 4.3449	$0.0019	$0.0017	$0.1445	$0.0017	$0.1428
X-33	$ 3.0873	$0.0412		$0.1427		

• INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun	
	Max	Min	Max	Min
AIT-1	$0.2442	$0.0093	$0.2442	$0.0093
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0435	$0.0017	$0.0435	$0.0017
Manchester	$0.0822	$0.0017	$0.0822	$0.0017
Canal	$0.0703	$0.0017	$0.0703	$0.0017
Cape Cod	$0.2992	$0.0017	$0.2992	$0.0017
Northeast Gateway	$0.1445	$0.0017	$0.1445	$0.0017
PAL	$0.2442	$0.0000	$0.0000	$0.0000

• TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charges of $0.0017 and applicable GRI Commodity Surcharge.

Rate Schedule FT-NN

Firm Transportation Service

______________________$/Dth______________________

Base Total

Tariff ACA Current

Rate Adj. Rate

1/

Reservation Charge:

Maximum $1.6666 $1.6666

Minimum $0.0000 $0.0000

Commodity Charge:

Maximum $0.0000 $0.0017 $0.0017

Minimum $0.0000 $0.0017 $0.0017

Authorized Overrun

Commodity Charge:

Previous Next

Iroquois Gas Transmission System, L.P. Thirty First Revised Sheet No. 4

FERC Gas Tariff Superseding

FIRST REVISED VOLUME NO. 1 Thirtieth Revised Sheet No. 4

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

	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	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

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

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

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

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

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

Issued on: Jan 26, 2009 Effective: Jan 27, 2009

Previous Next

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$27.4017	---------	$27.4017
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$52.0632	---------	$52.0632
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0017	$00.0017
	-- Minimum	$00.0000	$00.0017	$00.0017
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$18.3920	-------	$18.3920
	--Minimum	$00.0000	-------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.2962	$00.0017	$00.2979
	--Minimum	$00.0000	$00.0017	$00.0017

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

PNGTS

ATTACHMENT 1
TO GAS TRANSPORTATION CONTRACT
FOR NEGOTIATED FIRM TRANSPORTATION SERVICE

Statement of Negotiated Firm Transportation Rates
For The Period November 1 Through March 31
(Rates per MMBTU)

1. Following are the reservation rate and usage rate (which are negotiated rates and are subject to change as set forth below):

- The negotiated reservation rate shall equal 1.9 times the Recourse Reservation Rate listed on Sheet No. 6 of the Tariff, as that Recourse Reservation Rate may be revised from time to time.

- The negotiated usage rate shall equal the currently effective Usage Rate under Transporter's Rate Schedule FT, as that Usage Rate may be revised from time to time.

Maximum Reservation Rates 2/

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

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

Notes:

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

2/ Maximum rates are inclusive of base rates and above surcharges.

Issued by: Patrick A. Johnson, Vice President
Issued on: May 30, 2008 Effective on: July 1, 2008

Previous Next Search

TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Thirtieth Revised Sheet No. 26
Superseding
Twenty-Ninth Revised Sheet No. 26

RATES PER DEKATHERM

RATE SCHEDULE NET

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 6/	Rate After Current Adjustments
Demand Rate 1/, 5/					
Segment U	$9.65			$0.00	$9.65
Segment 1	$1.33			$0.00	$1.33
Segment 2	$8.08			$0.00	$8.08
Segment 3	$5.07			$0.00	$5.07
Segment 4	$5.54			$0.00	$5.54
Commodity Rate 2/, 7/					
Segments U, 1, 2, 3 & 4		$0.0017			$0.0017

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.
2/ The applicable surcharges for ACA and TCSM will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.
3/ Reserved for future use.
4/ Reserved for future use.
5/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET.
6/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
7/ The applicable fuel retention percentages are listed on Sheet Nos. 180 and 181.

Issued by: Patrick A. Johnson, Vice President
Issued on: August 29, 2008 Effective on: October 1, 2008

Previous Next Search

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

Currently Effective Rates 2/01/2009

•RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.8040	6.5810	2.7220
WLA-AAB	2.8250	2.6020	1.1300
ELA-AAB	2.3750	2.1520	0.9500
ETX-AAB	2.1890	1.9660	0.8760
STX-STX	5.7340	5.5110	2.2920
STX-WLA	5.8930	5.6700	2.3560
STX-ELA	6.8090	6.5860	2.7220
STX-ETX	6.8090	6.5860	2.7220
WLA-WLA	2.0570	1.8340	0.8220
WLA-ELA	2.8300	2.6070	1.1300
WLA-ETX	2.8300	2.6070	1.1300
ELA-ELA	2.3780	2.1550	0.9500
ETX-ETX	2.1920	1.9690	0.8760
ETX-ELA	2.3780	2.1550	0.9500
M1-M1	4.5310	4.3080	1.8100
M1-M2	8.3970	8.1740	3.3560
M1-M3	11.0360	10.8130	4.4110
M2-M2	6.5210	6.2980	2.6060
M2-M3	9.2960	9.0730	3.7160
M3-M3	5.2930	5.0700	2.1150

7(C) RATE	SCHEDULES
FTS	5.3500
FTS-2	7.9590
FTS-4	7.7160
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0100

SCT DEMAND CHARGES	
Access Area	0.0020
M1-M1	0.0020
M1-M2	0.0030
M1-M3	0.0040

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0021	0.0024	0.0041	0.0041	0.0173	0.0442	0.0623
from WLA		0.0009	0.0027	0.0027	0.0159	0.0428	0.0609
from ELA			0.0021	0.0021	0.0153	0.0422	0.0603
from ETX				0.0021	0.0153	0.0422	0.0603
from M1					0.0132	0.0401	0.0582
from M2						0.0270	0.0452
from M3							0.0184

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0088						
from WLA	0.0096	0.0059					
from ELA	0.0140	0.0103	0.0087				
from ETX	0.0140	0.0103	0.0087	0.0087			
from M1	0.0336	0.0299	0.0283	0.0283	0.0196		
from M2	0.0652	0.0615	0.0599	0.0599	0.0512	0.0359	
from M3	0.0870	0.0833	0.0817	0.0817	0.0730	0.0576	0.0258

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1832	0.1887	0.2205	0.2205	0.3751	0.5291	0.6339
from WLA		0.0611	0.0883	0.0883	0.2429	0.3968	0.5016
from ELA			0.0729	0.0729	0.2275	0.3815	0.4863
from ETX				0.0667	0.2214	0.3753	0.4801
from M1					0.1547	0.3086	0.4134
from M2						0.2339	0.3433
from M3							0.1849

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1899						
from WLA	0.1959	0.0661					
from ELA	0.2304	0.0959	0.0795				
from ETX	0.2304	0.0959	0.0795	0.0733			
from M1	0.3914	0.2569	0.2405	0.2344	0.1611		
from M2	0.5501	0.4155	0.3992	0.3930	0.3197	0.2428	
from M3	0.6586	0.5240	0.5077	0.5015	0.4282	0.3557	0.1923

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1833	0.1888	0.2207	0.2207	0.3756	0.5295	0.6344
from WLA		0.0612	0.0884	0.0884	0.2433	0.3972	0.5021
from ELA			0.0730	0.0730	0.2279	0.3818	0.4867
from ETX				0.0668	0.2217	0.3756	0.4805
from M1					0.1549	0.3088	0.4137
from M2						0.2341	0.3434
from M3							0.1851

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1900						

CURRENTLY EFFECTIVE SERVICE RATES APPLICABLE TO OPEN ACCESS, PART 284, RATE SCHEDULES IN FERC GAS TARIFF, SEVENTH REVISED VOLUME NO. 1

FT-1 INCREMENTAL FACILITY CHARGE

	INCREMENTAL FACILITY CHARGE $/dth Maximum	Minimum
PURSUANT TO SECTION 3.4 OF RATE SCHEDULE FT-1:		
To applicable Customers converting from Rate Schedule FTS in Docket No. CP82-446: RESERVATION CHARGE	0.6600	0.0000
RESERVATION CHARGE ADJUSTMENT	0.0217	0.0000

Customer	dth
Bay State Gas Company	4,235
Boston Gas Company	21,394
Colonial Gas Company	1,951
Connecticut Natural Gas Corporation	6,340
Town of Middleborough, Massachusetts	116
New Jersey Natural Gas Company	1,060
Northern Utilities, Inc.	965
Southern Connecticut Gas Company	4,922
Yankee Gas Services Company	6,066

	Maximum	Minimum
To applicable Customers converting from Rate Schedule FTS-4 in Docket No. CP87-4: RESERVATION CHARGE	3.0110	0.0000
RESERVATION CHARGE ADJUSTMENT	0.0990	0.0000

Customer	dth
Brooklyn Union Gas Company	27,500
Long Island Lighting Company	22,500
New Jersey Natural Gas Company	40,000
NUI Corporation	10,000
Public Service Electric & Gas Company	40,000

	Maximum	Minimum
To applicable Customers converting from Rate Schedule FTS-5 in Docket No. CP87-312: RESERVATION CHARGE	0.0000	0.0000
RESERVATION CHARGE ADJUSTMENT	0.0000	0.0000

Customer	dth
Colonial Gas Company	2,326
Penn Fuel Gas, Inc.	4,000
Yankee Gas Services Company	125

	Maximum	Minimum
To applicable Customers converting from Rate Schedule FTS-7 in Docket No. CP80-170: RESERVATION CHARGE	0.0000	0.0000
RESERVATION CHARGE ADJUSTMENT	0.0000	0.0000

Customer	dth
Connecticut Natural Gas Corporation	4,231
Yankee Gas Services Company	3,015

	Maximum	Minimum
To applicable Customers converting from Rate Schedule FTS-8 in Docket No. CP85-803: RESERVATION CHARGE	0.0000	0.0000
RESERVATION CHARGE ADJUSTMENT	0.0000	0.0000

Customer	dth
Yankee Gas Services Company	39

Transportation Tolls
2009 Final Tolls Effective May 1st

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

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
2	Centra Gas Manitoba - MDA	2.34500	0.00462
3	Union Gas - WDA	16.66667	0.04509
4	Union Gas - NDA	6.45333	0.01622
5	Union Gas - EDA	4.22833	0.00964
6	Kingston PUC	4.06250	0.00908
7	Gaz Metropolitain - EDA	7.51000	0.01911
8	Enbridge - CDA	0.93583	0.00015
9	Enbridge - EDA	2.58833	0.00499
10	Cornwall	5.76167	0.01393
11	Philipsburg	7.58917	0.01914

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
12	ECR Surcharge	0.029

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
13	Emerson - 1 (Viking)	0.06426	0.00000	0.00211
14	Emerson - 2 (Great Lakes)	0.08446	0.00000	0.00278
15	Dawn	0.06286	0.00000	0.00207
16	Niagara Falls	0.10558	0.00000	0.00347
17	Iroquois	0.56297	0.00000	0.01851
18	Chippawa	0.61730	0.00000	0.02029
19	East Hereford	1.41498	0.02139	0.06791

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

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
2009 Final Tolls Effective May 1st
* These tolls will become effective on November 1, 2009

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	STFT Minimum Tolls (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% LF FT Tolls) ($/GJ)
1	Empress	Empress	0.87529	0.00000	0.0288	0.0317
2	Empress	Saskatchewan Zone	4.88397	0.01347	0.1741	0.1915
3	* *Empress*	*Saskatchewan Zone*	4.40283	0.01208	0.1569	0.1726
4	Empress	Manitoba Zone	10.38858	0.02678	0.3683	0.4051
5	Empress	Western Zone	16.70445	0.04506	0.5943	0.6537
6	Empress	Northern Zone	25.63374	0.07038	0.9132	1.0045
7	Empress	Eastern Zone	33.37571	0.09272	1.1900	1.3090
8	Empress	North Bay Junction	27.99976	0.07732	0.9978	1.0976
9	Empress	Southwest Zone	28.08670	0.07751	1.0009	1.1010
10	Empress	Spruce	11.38556	0.02996	0.4043	0.4447
11	Empress	Emerson 1	11.60683	0.03059	0.4122	0.4534
12	Empress	Emerson 2	11.60683	0.03059	0.4122	0.4534
13	Empress	St. Clair	28.03227	0.07741	0.9990	1.0989
14	Empress	Dawn Export	28.28112	0.07812	1.0079	1.1087
15	Empress	Kirkwall	30.25966	0.08376	1.0786	1.1865
16	Empress	Niagara Falls	31.43397	0.08711	1.1205	1.2326
17	Empress	Chippawa	31.45904	0.08718	1.1215	1.2337
18	Empress	Iroquois	32.51411	0.09019	1.1592	1.2751
19	Empress	Cornwall	33.05670	0.09174	1.1785	1.2964
20	Empress	Napierville	34.70134	0.09642	1.2373	1.3610
21	Empress	Philipsburg	34.88444	0.09695	1.2439	1.3683
22	Empress	East Hereford	36.82407	0.10247	1.3132	1.4445
23	* *Empress*	*Welwyn*	7.28893	0.01828	0.2579	0.2837
24	Bayhurst 1	Empress	1.19357	0.00000	0.0392	0.0431
25	Bayhurst 1	Saskatchewan Zone	4.56569	0.01256	0.1627	0.1790
26	* *Bayhurst 1*	*Saskatchewan Zone*	4.08452	0.01117	0.1455	0.1601
27	Bayhurst 1	Manitoba Zone	10.07031	0.02587	0.3570	0.3927
28	Bayhurst 1	Western Zone	16.38618	0.04415	0.5829	0.6412
29	Bayhurst 1	Northern Zone	25.31546	0.06947	0.9018	0.9920
30	Bayhurst 1	Eastern Zone	33.05691	0.09182	1.1786	1.2965
31	Bayhurst 1	North Bay Junction	27.68149	0.07641	0.9865	1.0852
32	Bayhurst 1	Southwest Zone	27.76842	0.07660	0.9895	1.0885
33	Bayhurst 1	Spruce	11.06729	0.02905	0.3930	0.4323
34	Bayhurst 1	Emerson 1	11.28856	0.02968	0.4008	0.4409
35	Bayhurst 1	Emerson 2	11.28856	0.02968	0.4008	0.4409
36	Bayhurst 1	St. Clair	27.71400	0.07651	0.9876	1.0864
37	Bayhurst 1	Dawn Export	27.96285	0.07721	0.9965	1.0962
38	Bayhurst 1	Kirkwall	29.94139	0.08285	1.0673	1.1740
39	Bayhurst 1	Niagara Falls	31.11570	0.08620	1.1092	1.2201
40	Bayhurst 1	Chippawa	31.14076	0.08627	1.1101	1.2211
41	Bayhurst 1	Iroquois	32.19584	0.08928	1.1478	1.2626
42	Bayhurst 1	Cornwall	32.73842	0.09083	1.1671	1.2838
43	Bayhurst 1	Napierville	34.38307	0.09552	1.2259	1.3485
44	Bayhurst 1	Philipsburg	34.56616	0.09604	1.2324	1.3556
45	Bayhurst 1	East Hereford	36.50580	0.10157	1.3018	1.4320
46	* *Bayhurst 1*	*Welwyn*	6.97062	0.01738	0.2466	0.2713
47	Bayhurst 2	Empress	1.19357	0.00000	0.0392	0.0431
48	Bayhurst 2	Saskatchewan Zone	4.56569	0.01256	0.1627	0.1790
49	* *Bayhurst 2*	*Saskatchewan Zone*	4.08452	0.01117	0.1455	0.1601
50	Bayhurst 2	Manitoba Zone	10.07031	0.02587	0.3570	0.3927
51	Bayhurst 2	Western Zone	16.38618	0.04415	0.5829	0.6412
52	Bayhurst 2	Northern Zone	25.31546	0.06947	0.9018	0.9920
53	Bayhurst 2	Eastern Zone	33.05691	0.09182	1.1786	1.2965
54	Bayhurst 2	North Bay Junction	27.68149	0.07641	0.9865	1.0852
55	Bayhurst 2	Southwest Zone	27.76842	0.07660	0.9895	1.0885
56	Bayhurst 2	Spruce	11.06729	0.02905	0.3930	0.4323
57	Bayhurst 2	Emerson 1	11.28856	0.02968	0.4008	0.4409
58	Bayhurst 2	Emerson 2	11.28856	0.02968	0.4008	0.4409
59	Bayhurst 2	St. Clair	27.71400	0.07651	0.9876	1.0864
60	Bayhurst 2	Dawn Export	27.96285	0.07721	0.9965	1.0962
61	Bayhurst 2	Kirkwall	29.94139	0.08285	1.0673	1.1740
62	Bayhurst 2	Niagara Falls	31.11570	0.08620	1.1092	1.2201
63	Bayhurst 2	Chippawa	31.14076	0.08627	1.1101	1.2211
64	Bayhurst 2	Iroquois	32.19584	0.08928	1.1478	1.2626
65	Bayhurst 2	Cornwall	32.73842	0.09083	1.1671	1.2838

FT, STFT and Interruptible Transportation Tolls
2009 Final Tolls Effective May 1st
* These tolls will become effective on November 1, 2009

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	STFT Minimum Tolls (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% LF FT Tolls) ($/GJ)
1	Emerson 2	Napierville	25.40156	0.06991	0.9050	0.9955
2	Emerson 2	Philipsburg	25.58592	0.07044	0.9116	1.0028
3	Emerson 2	East Hereford	27.52555	0.07597	0.9809	1.0790
4	Union Dawn	Empress	28.28112	0.00000	0.9298	1.0228
5	Union Dawn	Transgas SSDA	24.33086	0.00000	0.7999	0.8799
6	* *Union Dawn*	*Transgas SSDA*	24.82353	0.00000	0.8161	0.8977
7	Union Dawn	Centram SSDA	21.86751	0.00000	0.7189	0.7908
8	Union Dawn	Centram MDA	19.03032	0.05218	0.6779	0.7457
9	Union Dawn	Centrat MDA	19.03776	0.05177	0.6777	0.7455
10	Union Dawn	Union WDA	18.74224	0.05102	0.6672	0.7339
11	Union Dawn	Nipigon WDA	16.73298	0.04520	0.5953	0.6548
12	Union Dawn	Union NDA	8.83255	0.02300	0.3134	0.3447
13	Union Dawn	Calstock NDA	13.26448	0.03532	0.4714	0.5185
14	Union Dawn	Tunis NDA	10.53372	0.02753	0.3738	0.4112
15	Union Dawn	GMIT NDA	8.49698	0.02156	0.3010	0.3311
16	Union Dawn	Union SSMDA	7.25587	0.01819	0.2567	0.2824
17	Union Dawn	Union NCDA	5.18095	0.01233	0.1826	0.2009
18	Union Dawn	Union CDA	3.30151	0.00680	0.1153	0.1268
19	Union Dawn	Enbridge CDA	3.98389	0.00880	0.1398	0.1538
20	Union Dawn	Union EDA	6.95563	0.01711	0.2458	0.2704
21	Union Dawn	Enbridge EDA	8.17713	0.02087	0.2897	0.3187
22	Union Dawn	GMIT EDA	9.88931	0.02589	0.3510	0.3861
23	Union Dawn	KPUC EDA	6.44157	0.01587	0.2277	0.2505
24	Union Dawn	North Bay Junction	7.02348	0.01753	0.2484	0.2732
25	Union Dawn	Enbridge SWDA	0.87529	0.00000	0.0288	0.0317
26	Union Dawn	Union SWDA	1.09017	0.00000	0.0358	0.0394
27	Union Dawn	Spruce	19.03776	0.05177	0.6777	0.7455
28	Union Dawn	Emerson 1	17.54958	0.00000	0.5770	0.6347
29	Union Dawn	Emerson 2	17.54958	0.00000	0.5770	0.6347
30	Union Dawn	St. Clair	1.12519	0.00000	0.0370	0.0407
31	Union Dawn	Dawn Export	0.87529	0.00000	0.0288	0.0317
32	Union Dawn	Kirkwall	2.85383	0.00564	0.0994	0.1093
33	Union Dawn	Niagara Falls	4.02646	0.00898	0.1414	0.1555
34	Union Dawn	Chippawa	4.05153	0.00905	0.1423	0.1565
35	Union Dawn	Iroquois	7.72830	0.01953	0.2736	0.3010
36	Union Dawn	Cornwall	8.14221	0.02071	0.2884	0.3172
37	Union Dawn	Napierville	9.78381	0.02539	0.3471	0.3818
38	Union Dawn	Philipsburg	9.96827	0.02592	0.3536	0.3890
39	Union Dawn	East Hereford	11.90791	0.03145	0.4230	0.4653
40	Enbridge CDA	Empress	31.70810	0.08792	1.1304	1.2434
41	Enbridge CDA	Transgas SSDA	27.83218	0.07467	0.9897	1.0887
42	* *Enbridge CDA*	*Transgas SSDA*	28.32485	0.07609	1.0073	1.1080
43	Enbridge CDA	Centram SSDA	24.85939	0.06833	0.8856	0.9742
44	Enbridge CDA	Centram MDA	22.42153	0.06187	0.7990	0.8789
45	Enbridge CDA	Centrat MDA	21.14728	0.05781	0.7531	0.8284
46	Enbridge CDA	Union WDA	16.43683	0.04444	0.5848	0.6433
47	Enbridge CDA	Nipigon WDA	14.65020	0.03987	0.5216	0.5738
48	Enbridge CDA	Union NDA	6.39952	0.01609	0.2265	0.2492
49	Enbridge CDA	Calstock NDA	11.34823	0.03072	0.4038	0.4442
50	Enbridge CDA	Tunis NDA	8.74845	0.02352	0.3111	0.3422
51	Enbridge CDA	GMIT NDA	6.37278	0.01463	0.2241	0.2465
52	Enbridge CDA	Union SSMDA	10.36446	0.02699	0.3677	0.4045
53	Enbridge CDA	Union NCDA	2.74487	0.00541	0.0956	0.1052
54	Enbridge CDA	Union CDA	1.87122	0.00258	0.0641	0.0705
55	Enbridge CDA	Enbridge CDA	0.87529	0.00000	0.0288	0.0317
56	Enbridge CDA	Union EDA	3.93145	0.00878	0.1381	0.1519
57	Enbridge CDA	Enbridge EDA	5.65768	0.01371	0.1997	0.2197
58	Enbridge CDA	GMIT EDA	7.19001	0.01822	0.2546	0.2801
59	Enbridge CDA	KPUC EDA	3.74248	0.00819	0.1312	0.1443
60	Enbridge CDA	North Bay Junction	4.58363	0.01060	0.1613	0.1774
61	Enbridge CDA	Enbridge SWDA	3.98389	0.00880	0.1398	0.1538
62	Enbridge CDA	Union SWDA	4.11969	0.00929	0.1447	0.1592
63	Enbridge CDA	Spruce	21.08017	0.05763	0.7506	0.8257
64	Enbridge CDA	Emerson 1	20.65724	0.05633	0.7354	0.8089
65	Enbridge CDA	Emerson 2	20.65724	0.05633	0.7354	0.8089

CAPACITY RELEASE TRANSACTIONS
CONFIRMATION LETTER

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

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

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

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

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

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

7. Primary Receipt Point(s):

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

8. Primary Delivery Point(s):

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

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

10. Usage Rate: $0.00/Dth

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

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

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

Authorized Signature of Replacement Shipper: DTeD

Name: DON 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: $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 TULCHINSKY

Title: ANALYST

Telephone: ( ) 508-836 7257

Fax: ( ) 508-870-2294

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

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

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

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

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

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

Bank of Canada

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:

10-Year Currency Converter

Using rates for: 12 Aug 2009

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

Currency:	U.S. dollar
Amount:	1.00
Convert:	from $Can / to $Can
Use the:	Nominal rate HELP Cash rate (4%) HELP
Answer:	0.92 CONVERT
Exchange rate:	0.9195

Summary:

On 12 Aug 2009, 1.00 Canadian dollar(s) = 0.92 U.S. dollar(s), at an exchange rate of 0.9195 (using nominal rate.)

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

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

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

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

More comprehensive currency converters include **CanadianForex**, **HiFX**, or **OANDA.com**.

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

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

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA						
Deliverability Rate	$2.02			$0.00	$2.02	
Space Rate	$0.0248			$0.0000	$0.0248	
Injection Rate	$0.0053				$0.0053	1.49%
Withdrawal Rate	$0.0053				$0.0053	
Overrun Rate	$0.2427				$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA						
Deliverability Rate	$1.15			$0.00	$1.15	
Space Rate	$0.0185			$0.0000	$0.0185	
Injection Rate	$0.0102				$0.0102	1.49%
Withdrawal Rate	$0.0102				$0.0102	
Overrun Rate	$0.1380				$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA						
Space Rate	$0.0848			$0.0000	$0.0848	
Injection Rate	$0.0102				$0.0102	1.49%
Withdrawal Rate	$0.0102				$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA						
Space Rate	$0.0993			$0.0000	$0.0993	
Injection Rate	$0.0053				$0.0053	1.49%
Withdrawal Rate	$0.0053				$0.0053	

from WLA	0.1960	0.0662					
from ELA	0.2306	0.0960	0.0796				
from ETX	0.2306	0.0960	0.0796	0.0734			
from M1	0.3919	0.2573	0.2409	0.2347	0.1613		
from M2	0.5505	0.4159	0.3995	0.3933	0.3199	0.2430	
from M3	0.6591	0.5245	0.5081	0.5019	0.4285	0.3558	0.1925

•OTHER TRANSPORTATION SERVICES

	Reservation	Usage-1	Shrinkage In Path	Shrinkage Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3400 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	0.6600		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	7.8849		0.40%	
FT-1/NC	6.5590		0.00%	
FT-1/RIV	10.4380		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	1.2690 2/		0.00%	
FT-1/TME	11.2878		4.03%	4.80%
FT-1/TME2	26.5849		3.20%	4.80%
MLS-1/FH	0.6247		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270		0.01%	

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

•STORAGE SERVICES

	RES.	SPACE	INJ.	WITH.
SS	5.4400	0.1293	0.0280	0.0437
SS-1	5.5370	0.1293	0.0280	0.0436
X-28	4.8410	0.1293	0.0280	0.0394
FSS-1	0.8950	0.1293	0.0280	0.0280
ISS-1		0.0323	0.1837	0.0280

•SHRINKAGE PERCENTAGES (December 1 through March 31)

TRANSPORTATION

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.20%	2.39%	3.41%	3.41%	5.46%	7.35%	8.59%
from WLA	1.64%	1.50%	2.54%	2.54%	4.59%	6.48%	7.72%
from ELA	2.16%	2.16%	2.16%	2.16%	4.21%	6.10%	7.34%
from ETX	2.20%	2.16%	2.16%	2.16%	4.21%	6.10%	7.34%
from M1					2.05%	3.94%	5.18%
from M2						3.03%	4.30%
from M3							2.43%

•SHRINKAGE PERCENTAGES (April 1 through November 30)

TRANSPORTATION

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.25%	2.39%	3.15%	3.16%	5.29%	6.69%	7.63%
from WLA	1.73%	1.73%	2.50%	2.50%	4.64%	6.04%	6.98%
from ELA	2.22%	2.22%	2.22%	2.22%	4.36%	5.76%	6.70%
from ETX	2.25%	2.22%	2.22%	2.22%	4.36%	5.76%	6.70%
from M1					2.14%	3.54%	4.48%
from M2						2.87%	3.81%
from M3							2.42%

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%		

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	3.49%	3.53%
FSS-1,ISS-1	1.27%	1.27%
INJECTIONS	1.27%	1.27%
INVENTORY LEVEL	0.08%	0.08%

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

SHIPPER:

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

INVOICES, STATEMENTS AND NOMINATIONS

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

ALL OTHER MATTERS

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

ARTICLE VIII: FURTHER AGREEMENT

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

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

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2009 through October 2010		
Item	Revenue	Reference
NH Division Pipeline Contract Capacity Assignment	$ (1,373,684)	Page 2
NH Division Storage Contract Capacity Assignment	$ (166,174)	Page 3
NH Division Peaking Contract Capacity Assignment Estimates	$ (246,089)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 152,441	Page 5
NH Division PNGTS Litigation Costs Assigned to Retail Suppliers	$ (24,307)	Page 6
NH Division Capacity Assignment Demand Revenue	$ (1,657,812)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2009 through October 31, 2010

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Peaking Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	Assigned Peaking MDQ	NH Annual Cap Assign Credit
Algonquin	93201A1C	$ 20,513	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Algonquin	93201A1C	$ 63,118	$ 6,097	$ -	N	NA	NA	NA	-	-	-	$ -
Algonquin	93200F	$ 308,943	$ -	$ -	Y	4,211	-	-	(326)	-	-	$ (23,917)
Granite	09-006-FT-NN	$ 477,901	$ 709,472	$ 812,547	Y	23,896	35,475	40,629	(1,849)	(1,961)	(2,034)	$ (116,875)
Iroquois	R181001	$ 520,036	$ -	$ -	Y	6,569	-	-	(508)	-	-	$ (40,216)
PNGTS	1997-003	$ 361,702	$ -	$ -	Y	1,100	-	-	(85)	-	-	$ (27,950)
PNGTS	1997-004	$ -	$ 3,930,772	$ -	Y	-	15,100	-	-	(835)	-	$ (217,364)
PNGTS	1997-004	$ -	$ 1,275,548	$ -	Y	-	4,900	-	-	(271)	-	$ (70,546)
PNGTS	1997-004	$ -	$ 3,384,108	$ -	Y	-	13,000	-	-	(719)	-	$ (187,167)
Tennessee	5083	$ 916,763	$ -	$ -	Y	4,605	-	-	(356)	-	-	$ (70,872)
Tennessee	5083	$ 1,554,390	$ -	$ -	Y	8,550	-	-	(661)	-	-	$ (120,170)
Tennessee	5265	$ -	$ 187,514	$ -	Y	-	2,653	-	-	(147)	-	$ (10,390)
Tennessee	5292	$ 83,179	$ -	$ -	Y	1,406	-	-	(109)	-	-	$ (6,448)
Tennessee	39735	$ 54,960	$ -	$ -	Y	929	-	-	(72)	-	-	$ (4,260)
Tennessee	41099	$ 252,436	$ -	$ -	Y	4,267	-	-	(330)	-	-	$ (19,523)
Tennessee	46314	$ 56,202	$ -	$ -	Y	950	-	-	(73)	-	-	$ (4,319)
Tennessee	31861	$ 84,081	$ -	$ -	Y	1,382	-	-	(107)	-	-	$ (6,510)
Tennessee	31861	$ 107,458	$ -	$ -	Y	844	-	-	(65)	-	-	$ (8,276)
Texas Eastern	800384	$ 66,353	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800436	$ 4,065	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 941	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 236	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 1,306	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 610	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 7,813	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
TransCanada	29594	$ 573,068	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
TransCanada	29833	$ 504,628	$ -	$ -	Y	1,196	-	-	(93)	-	-	$ (39,239)
TransCanada	33322	$ -	$ 5,273,355	$ -	Y	-	35,872	-	-	(1,983)	-	$ (291,510)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	$ -	Y	-	17,172	-	-	(949)	-	$ (86,597)
Vector	CRL-NUI-0727	$ -	$ 389,774	$ -	Y	-	17,086	-	-	(944)	-	$ (21,535)
Vector	FT-1-NUI-0122	$ 589,334	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Vector	FT-1-NUI-C0122	$ 32,667	$ -	$ -	N	NA	NA	NA	-	-	-	$ -

Total NH Capacity Assignment Credits $ (1,373,684)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 1, 2009 through October 31, 2010

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Storage Assigned NH	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 116,126	Y	N	5.53%	(14,336)	(235)	$ (6,419)
W-10	01052	$ 2,890,000	Y	Y	5.53%	(187,946)	(1,879)	$ (159,754)

Total NH Division Storage Capacity Assignment $ (166,174)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
New Hampshire Division Peaking Contract Capacity Assignment Estimates
November 1, 2009 through October 31, 2010

Resource	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Peaking Assigned NH	NH Annual Cap Assign Credit
Peaking Supply 1	$ 2,511,036	Y	Y	5.01%	$ (125,727)
Peaking Supply 2	$ 1,717,200	Y	Y	5.01%	$ (85,980)
Peaking Plants	$ 686,673	Y	Y	5.01%	$ (34,382)

Total NH Division Peaking Capacity Assignment $ (246,089)

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2009 through October 2010

Asset Management Agreeement Revenue						
Resources	Term	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	Nov 2009 - Apr 2010	$ (370,000)	Yes	Pipeline	7.74%	$ 28,626
Empress via TCPL, PNGTS	Nov 2009 - Oct 2010	$ (100,000)	Yes	Pipeline	7.74%	$ 7,737
Wash 10 via Vector, TCPL, PNGTS	Nov 2009 - Apr 2010	$ (1,000,000)	Yes	Storage	5.53%	$ 55,278
Tennessee Long-Haul	Nov 2009 - Apr 2010	$ (1,300,000)	No	Pipeline	7.74%	$ -
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	May 2010 - Oct 2010	$ (250,000)	Yes	Pipeline	7.74%	$ 19,342
Wash 10 via Vector, TCPL, PNGTS	May 2010 - Oct 2010	$ (750,000)	Yes	Storage	5.53%	$ 41,459
Total Asset Management	Nov 2009 - Oct 2010	$ (3,770,000)				$ 152,441

Capacity Release Revenue						
Resources	Term	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Tennessee Long-Haul	May 2010 - Oct 2010	$ (348,566)	No	Pipeline	7.74%	$ -
Tetco	May 2009 - Oct 2017	$ (66,353)	No	Pipeline	7.74%	$ -
Tetco	May 2009 - Mar 2010	$ (8,360)	No	Pipeline	5.53%	$ -
AGT	May 2009 - Oct 2012	$ (98,860)	No	Pipeline	7.74%	$ -
Tennessee Z4-Z6	Apr 2010 - Oct 2010	$ (16,275)	No	Storage	7.74%	$ -
Tennessee Niagara Z5 - Z6	Apr 2010 - Oct 2010	$ (27,229)	No	Pipeline	5.53%	$ -
Total Capacity Release	Nov 2009 - Oct 2010	$ (565,644)				$ -

Total Asset Management and Capacity Release Revenue	$ (4,335,643)	$ 152,441

Northern Utilities, Inc.
New Hampshire Division
PNGTS Litigation Costs - Assigned to Retail Suppliers
November 2009 through October 2010

PNGTS Litigation Costs	$ 434,116

PNGTS Contract	MDQ	Percentage MDQ	Allocated Litigation Costs	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ 14,004	Pipeline	7.74%	$ (1,083)
PNGTS Contract 1997-004	33,000	97%	$ 420,112	Storage	5.53%	$ (23,223)
PNGTS Total	34,100	100%	$ 434,116			$ (24,307)

Northern Utilities, Inc.
Delivered City-Gate Commodity Cost by Supply Source
May 2010 through October 2010

Description	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
Pipeline							
Chicago	$1,078,435	$1,021,257	$ 952,599	$ 958,287	$1,001,008	$1,140,354	$ 6,151,941
Empress	$ 186,596	$ 182,393	$ 190,836	$ 193,004	$ 187,718	$ 197,244	$ 1,137,791
Niagara	$ 463,715	$ 274,096	$ 28,805	$ 8,340	$ 5,227	$ 335,602	$ 1,115,785
Portland Pay-Back	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee Production	$ 845,822	$ 325,538	$ -	$ -	$ -	$ 74,317	$ 1,245,678
TETCO M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TETCO Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage							
Tennessee Storage	$ 5,079	$ -	$ -	$ -	$ -	$ -	$ 5,079
TETCO Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10 Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking							
Peaking Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 7,409	$ 7,123	$ 7,352	$ 7,251	$ 6,991	$ 7,185	$ 43,312
Propane							
Total Commodity Cost	$2,587,056	$1,810,408	$1,179,592	$1,166,882	$1,200,944	$1,754,703	$ 9,699,585

Northern Utilities, Inc.
Delivered City-Gate Volumes by Supply Source
May 2010 through October 2010

Description	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
Pipeline							
Chicago	179,306	168,150	155,077	154,248	160,191	179,306	996,278
Empress	31,303	30,294	31,303	31,303	30,294	31,303	185,801
Niagara	75,330	44,127	4,582	1,312	818	51,705	177,875
Portland Pay-Back	0	0	0	0	0	0	0
Tennessee Production	137,332	52,358	0	0	0	11,417	201,107
TETCO M3	0	0	0	0	0	0	
TETCO Production	0	0	0	0	0	0	
Storage							
Tennessee Storage	798	0	0	0	0	0	798
TETCO Storage	0	0	0	0	0	0	
Washington 10 Storage	0	0	0	0	0	0	0
Peaking							
Peaking Supply 1	0	0	0	0	0	0	0
Peaking Supply 2	0	0	0	0	0	0	0
LNG	1,395	1,350	1,395	1,395	1,350	1,395	8,280
Propane							
Total Delivered	425,465	296,279	192,357	188,258	192,653	275,127	1,570,139

Northern Utilities, Inc. Delivered City-Gate Cost per Dth by Supply Source May 2010 through October 2010							
Description	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
Pipeline							
Chicago	$ 6.0145	$ 6.0735	$ 6.1428	$ 6.2127	$ 6.2488	$ 6.3598	$ 6.1749
Empress	$ 5.9609	$ 6.0209	$ 6.0963	$ 6.1656	$ 6.1966	$ 6.3011	$ 6.1237
Niagara	$ 6.1557	$ 6.2115	$ 6.2869	$ 6.3562	$ 6.3867	$ 6.4907	$ 6.2728
Portland Pay-Back							
Tennessee Production	$ 6.1590	$ 6.2175				$ 6.5094	$ 6.1941
TETCO M3							
TETCO Production							
Storage							
Tennessee Storage	$ 6.3661						$ 6.3661
TETCO Storage							
Washington 10 Storage							
Peaking							
Peaking Supply 1							
Peaking Supply 2							
LNG	$ 5.3115	$ 5.2764	$ 5.2702	$ 5.1976	$ 5.1789	$ 5.1507	$ 5.2309
Propane							
Total Variable Costs	$ 6.0805	$ 6.1105	$ 6.1323	$ 6.1983	$ 6.2337	$ 6.3778	$ 6.1775

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

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Purchased Volumes	Line 9	188,203	176,464	162,641	161,766	168,067	188,203	1,045,343
2	City Gate Delivered Volume	Sum Lines 94, 54 and 74	179,306	168,150	155,077	154,248	160,191	179,306	996,278
3	Total Purchase Cost	Line 14	$ 1,065,416	$ 1,009,197	$ 942,014	$ 947,785	$ 989,748	$ 1,127,334	$ 6,081,493
4	Variable Transportation Costs	Sum Lines 26, 36, 46, 86, 96, 56, 66 and 76	$ 13,020	$ 12,060	$ 10,585	$ 10,502	$ 11,260	$ 13,020	$ 70,447
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 1,078,435	$ 1,021,257	$ 952,599	$ 958,287	$ 1,001,008	$ 1,140,354	$ 6,151,941
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.014	$ 6.073	$ 6.143	$ 6.213	$ 6.249	$ 6.360	$ 6.175
7									
8	Chicago Supply Costs								
9	Purchased Volumes	Sendout Optimization	188,203	176,464	162,641	161,766	168,067	188,203	1,045,343
10	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980	$ 5.808
11	NYMEX Cost	Line 9 times Line 10	$ 1,063,534	$ 1,007,433	$ 940,387	$ 946,167	$ 988,067	$ 1,125,452	$ 6,071,040
12	NYMEX Basis Price	FXW-7A, Line 3 of Page 1	$ 0.010	$ 0.010	$ 0.010	$ 0.010	$ 0.010	$ 0.010	$ 0.010
13	NYMEX Basis Costs	Line 9 times Line 12	$ 1,882	$ 1,765	$ 1,626	$ 1,618	$ 1,681	$ 1,882	$ 10,453
14	Total Purchase Price	Line 10 plus Line 12	$ 5.661	$ 5.719	$ 5.792	$ 5.859	$ 5.889	$ 5.990	$ 5.818
15	Total Purchase Cost	Line 11 plus Line 13	$ 1,065,416	$ 1,009,197	$ 942,014	$ 947,785	$ 989,748	$ 1,127,334	$ 6,081,493
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1&2								
19	Vector Pipeline (Contracts FT-1-NUI-0122 and FT-1-NUI-C0122)								
20	Receipt Point: Alliance								
21	Delivery Point: Dawn (Interconnects with TransCanada)								
22	Received Volume	Line 9	188,203	176,464	162,641	161,766	168,067	188,203	1,045,343
23	Fuel Loss Rate	FXW 7A, Line 17 of Page 2	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
24	Delivered Volume	Line 22 times (1 - Line 23)	186,321	174,699	161,014	160,148	166,387	186,321	1,034,889
25	Variable Transportation Rate	FXW 7A, Line 17 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
26	Variable Transportation Costs	Line 24 times Line 25	$ 354	$ 332	$ 306	$ 304	$ 316	$ 354	$ 1,966
27									
28	Transportation Segment 3								
29	TransCanada Pipeline (Contract 29594)								
30	Receipt Point: Dawn								
31	Delivery Point: Parkway (Interconnects with Iroquois)								
32	Received Volume	Line 24	186,321	174,699	161,014	160,148	166,387	186,321	1,034,889
33	Fuel Loss Rate	FXW 7A, Line 14 of Page 2	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
34	Delivered Volume	Line 32 times (1 - Line 33)	184,048	172,568	159,050	158,194	164,357	184,048	1,022,264
35	Variable Transportation Rate	FXW 7A, Line 14 of Page 2	$ 0.0140	$ 0.0140	$ 0.0140	$ 0.0140	$ 0.0140	$ 0.0140	$ 0.0140
36	Variable Transportation Costs	Line 34 times Line 35	$ 2,577	$ 2,416	$ 2,227	$ 2,215	$ 2,301	$ 2,577	$ 14,312
37									
38	Transportation Segment 4								
39	Iroquois Pipeline (Contract R181001)								
40	Receipt Point: Parkway								
41	Delivery Point: Wright (Interconnection with Tennessee)								
42	Received Volume	Line 34	184,048	172,568	159,050	158,194	164,357	184,048	1,022,264
43	Fuel Loss Rate	FXW 7A, Line 4 of Page 2	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
44	Delivered Volume	Line 42 times (1 - Line 43)	183,311	171,878	158,414	157,561	163,699	183,311	1,018,175
45	Variable Transportation Rate	FXW 7A, Line 4 of Page 2	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0030
46	Variable Transportation Costs	Line 44 times Line 45	$ 550	$ 516	$ 475	$ 473	$ 491	$ 550	$ 3,055
47									
48	Transporation Segment 5A								
49	Tennessee Gas Pipeline (Contract 31861)								
50	Receipt Point: Mendon								
51	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
52	Received Volume	Line 44	39,909	38,622	39,909	39,909	38,622	39,909	236,880
53	Fuel Loss Rate	FXW 7A, Line 12 of Page 2	0.96%	0.96%	0.96%	0.96%	0.96%	0.96%	0.96%
54	City Gate Delivered Volume	Line 52 times (1 - Line 53)	39,526	38,251	39,526	39,526	38,251	39,526	234,606
55	Variable Transportation Rate	FXW 7A, Line 12 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
56	Variable Transportation Costs	Line 54 times Line 55	$ 75	$ 73	$ 75	$ 75	$ 73	$ 75	$ 446
57									
58	Transportation Segment 5B								
59	Tennessee Gas Pipeline (Contract 31861)								
60	Receipt Point: Mendon								
61	Delivery Point: Pleasant St. (Interconnection with Granite)								
62	Received Volume	Line 44	24,447	23,658	24,447	24,447	23,658	24,447	145,104
63	Fuel Loss Rate	FXW 7A, Line 13 of Page 2	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%
64	Delivered Volume	Line 62 times (1 - Line 63)	24,139	23,360	24,139	24,139	23,360	24,139	143,276
65	Variable Transportation Rate	FXW 7A, Line 13 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
66	Variable Transportation Costs	Line 64 times Line 65	$ 46	$ 44	$ 46	$ 46	$ 44	$ 46	$ 272
67									
68	Transportation Segment 6B								
69	Granite State Gas Transmission (Contract 08-003-FT-NN)								
70	Receipt Point: Pleasant St.								
71	Delivery Point: Northern City Gates								
72	Received Volume	Line 64	24,139	23,360	24,139	24,139	23,360	24,139	143,276
73	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
74	City Gate Delivered Volume	Line 72 times (1 - Line 73)	24,018	23,243	24,018	24,018	23,243	24,018	142,560
75	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
76	Variable Transportation Costs	Line 74 times Line 75	$ 46	$ 44	$ 46	$ 46	$ 44	$ 46	$ 271
77									
78	Transportation Segment 5C								
79	Tennessee Gas Pipeline (Contract 41099)								
80	Receipt Point: Wright								
81	Delivery Point: Mendon (Interconnection with Algonquin)								
82	Received Volume	Line 44	118,955	109,598	94,057	93,205	101,419	118,955	636,190
83	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%
84	Delivered Volume	Line 82 times (1 - Line 83)	116,743	107,559	92,308	91,472	99,533	116,743	624,357
85	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
86	Variable Transportation Costs	Line 84 times Line 85	$ 9,153	$ 8,433	$ 7,237	$ 7,171	$ 7,803	$ 9,153	$ 48,950
87									
88	Transportation Segment 6C								
89	Algonquin Gas Transmission (Contract 93200F)								
90	Receipt Point: Mendon								
91	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
92	Received Volume	Line 84	116,743	107,559	92,308	91,472	99,533	116,743	624,357
93	Fuel Loss Rate	FXW 7A, Line 1 of Page 2	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%
94	City Gate Delivered Volume	Line 92 times (1 - Line 93)	115,762	106,656	91,533	90,703	98,697	115,762	619,112
95	Variable Transportation Rate	FXW 7A, Line 1 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
96	Variable Transportation Costs	Line 94 times Line 95	$ 220	$ 203	$ 174	$ 172	$ 188	$ 220	$ 1,176

Source of Supply: Empress, Alberta
Delivered to Northern via TransCanada, PNGTS, and Granite Pipelines

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Purchased Volumes	Line 9	32,367	31,323	32,367	32,367	31,323	32,367	192,113
2	City Gate Delivered Volume	Line 44	31,303	30,294	31,303	31,303	30,294	31,303	185,801
3	Total Purchase Cost	Line 14	$ 182,906	$ 178,822	$ 187,146	$ 189,314	$ 184,147	$ 193,554	$ 1,115,889
4	Variable Transportation Costs	Sum Lines 26, 36 and 46	$ 3,690	$ 3,571	$ 3,690	$ 3,690	$ 3,571	$ 3,690	$ 21,902
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 186,596	$ 182,393	$ 190,836	$ 193,004	$ 187,718	$ 197,244	$ 1,137,791
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.961	$ 6.021	$ 6.096	$ 6.166	$ 6.197	$ 6.301	$ 6.124
7									
8	Empress Supply Costs								
9	Purchased Volumes	Sendout Optimization	32,367	31,323	32,367	32,367	31,323	32,367	192,113
10	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980	$ 5.808
11	NYMEX Cost	Line 9 times Line 10	$ 182,906	$ 178,822	$ 187,146	$ 189,314	$ 184,147	$ 193,554	$ 1,115,889
12	NYMEX Basis Price	FXW-7A, Line 4 of Page 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	NYMEX Basis Costs	Line 9 times Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Total Purchase Price	Line 10 plus Line 12	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980	$ 5.808
15	Total Purchase Cost	Line 11 plus Line 13	$ 182,906	$ 178,822	$ 187,146	$ 189,314	$ 184,147	$ 193,554	$ 1,115,889
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1								
19	TransCanada Pipeline (Contract 29833)								
20	Receipt Point: Empress								
21	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)								
22	Received Volume	Line 9	32,367	31,323	32,367	32,367	31,323	32,367	192,113
23	Fuel Loss Rate	FXW 7A, Line 16 of Page 2	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%
24	Delivered Volume	Line 22 times (1 - Line 23)	31,461	30,446	31,461	31,461	30,446	31,461	186,734
25	Variable Transportation Rate	FXW 7A, Line 16 of Page 2	$ 0.1135	$ 0.1135	$ 0.1135	$ 0.1135	$ 0.1135	$ 0.1135	$ 0.1135
26	Variable Transportation Costs	Line 24 times Line 25	$ 3,571	$ 3,456	$ 3,571	$ 3,571	$ 3,456	$ 3,571	$ 21,194
27									
28	Transportation Segment 2								
29	PNGTS (Contract 1997-003)								
30	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)								
31	Delivery Point: Granite (Westbrook)								
32	Received Volume	Line 24	31,461	30,446	31,461	31,461	30,446	31,461	186,734
33	Fuel Loss Rate	FXW 7A, Line 5 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	Delivered Volume	Line 32 times (1 - Line 33)	31,461	30,446	31,461	31,461	30,446	31,461	186,734
35	Variable Transportation Rate	FXW 7A, Line 5 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
36	Variable Transportation Costs	Line 34 times Line 35	$ 60	$ 58	$ 60	$ 60	$ 58	$ 60	$ 355
37									
38	Transportation Segment 3								
39	Granite State Gas Transmission (Contract 08-003-FT-NN)								
40	Receipt Point: Granite (Westbrook)								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	31,461	30,446	31,461	31,461	30,446	31,461	186,734
43	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	31,303	30,294	31,303	31,303	30,294	31,303	185,801
45	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 59	$ 58	$ 59	$ 59	$ 58	$ 59	$ 353

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

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Purchased Volumes	Line 9	76,810	44,964	4,669	1,337	834	52,685	181,298
2	City Gate Delivered Volume	Sum Lines 24, 54 and 44	75,330	44,127	4,582	1,312	818	51,705	177,875
3	Total Purchase Cost	Line 14	$ 457,786	$ 270,636	$ 28,446	$ 8,237	$ 5,163	$ 331,549	$ 1,101,817
4	Variable Transportation Costs	Sum Lines 26, 56, 36 and 46	$ 5,929	$ 3,460	$ 359	$ 103	$ 64	$ 4,054	$ 13,969
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	$ 463,715	$ 274,096	$ 28,805	$ 8,340	$ 5,227	$ 335,602	$ 1,115,785
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.156	$ 6.211	$ 6.287	$ 6.356	$ 6.387	$ 6.491	$ 6.273
7									
8	Niagara Supply Costs								
9	Purchased Volumes	Sendout Optimization	76,810	44,964	4,669	1,337	834	52,685	181,298
10	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980	$ 5.767
11	NYMEX Cost	Line 9 times Line 10	$ 434,052	$ 256,698	$ 26,994	$ 7,820	$ 4,902	$ 315,058	$ 1,045,524
12	NYMEX Basis Price	FXW-7A, Line 5 of Page 1	$ 0.309	$ 0.310	$ 0.311	$ 0.312	$ 0.312	$ 0.313	$ 0.310
13	NYMEX Basis Costs	Line 9 times Line 12	$ 23,734	$ 13,939	$ 1,452	$ 417	$ 260	$ 16,490	$ 56,293
14	Total Purchase Price	Line 10 plus Line 12	$ 5.960	$ 6.019	$ 6.093	$ 6.161	$ 6.191	$ 6.293	$ 6.077
15	Total Purchase Cost	Line 11 plus Line 13	$ 457,786	$ 270,636	$ 28,446	$ 8,237	$ 5,163	$ 331,549	$ 1,101,817
16									
17	Transportation Fuel Losses and Variable Charges								
18	Transportation Segment 1A								
19	Tennessee Gas Pipeline (Contract 5292)								
20	Receipt Point: Niagara								
21	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
22	Received Volume	Line 9	39,653	26,483	2,267	414	805	31,303	100,924
23	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	38,915	25,990	2,225	406	790	30,721	99,047
25	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
26	Variable Transportation Costs	Line 24 times Line 25	$ 3,051	$ 2,038	$ 174	$ 32	$ 62	$ 2,409	$ 7,765
27									
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 39735)								
30	Receipt Point: Niagara								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 9	10,324	-	-	-	-	-	10,324
33	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	1.86%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	1.86%
34	Delivered Volume	Line 32 times (1 - Line 33)	10,132	-	-	-	-	-	10,132
35	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.0784
36	Variable Transportation Costs	Line 34 times Line 35	$ 794	$ -	$ -	$ -	$ -	$ -	$ 794
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 08-003-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	10,132	-	-	-	-	-	10,132
43	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	10,081	-	-	-	-	-	10,081
45	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 19	$ -	$ -	$ -	$ -	$ -	$ 19
47									
48	Transportation Segment 1C								
49	Tennessee Gas Pipeline (Contract 46314)								
50	Receipt Point: Niagara								
51	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)								
52	Received Volume	Line 9	26,833	18,481	2,401	923	29	21,382	70,050
53	Fuel Loss Rate	FXW 7A, Line 11 of Page 2	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%
54	City Gate Delivered Volume	Line 52 times (1 - Line 53)	26,334	18,137	2,357	906	29	20,984	68,747
55	Variable Transportation Rate	FXW 7A, Line 11 of Page 2	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784	$ 0.0784
56	Variable Transportation Costs	Line 54 times Line 55	$ 2,065	$ 1,422	$ 185	$ 71	$ 2	$ 1,645	$ 5,390

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

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	City Gate Volumes - Z0	Line 2 of Page 5	8,827	-	-	-	-	-	8,827
2	City Gate Volumes - Z1	Line 2 of Page 6	128,506	52,358	-	-	-	11,417	192,281
3	Total City Gate Volumes	Line 1 plus Line 2	137,332	52,358	-	-	-	11,417	201,107
4	City Gate Delivered Costs - Z0	Line 6 of Page 5	$ 54,860	$ -	$ -	$ -	$ -	$ -	$ 54,860
5	City Gate Delivered Costs - Z1	Line 6 of Page 6	$ 790,963	$ 325,538	$ -	$ -	$ -	$ 74,317	$ 1,190,818
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ 845,822	$ 325,538	$ -	$ -	$ -	$ 74,317	$ 1,245,678
7	Average Delivered Price	Line 6 divided by Line 3	$ 6.582	$ 6.218	#DIV/0!	#DIV/0!	#DIV/0!	$ 6.509	$ 6.478

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

Line	City Gate Delivered Costs	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Purchased Volumes	Line 32	9,582	-	-	-	-	-	9,582
2	City Gate Delivered Volume	Line 44	8,827	-	-	-	-	-	8,827
3	Total Purchase Price	Line 24	$ 5.573	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.573
4	Total Purchase Cost	Line 2 times Line 3	$ 53,400	$ -	$ -	$ -	$ -	$ -	$ 53,400
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 1,460	$ -	$ -	$ -	$ -	$ -	$ 1,460
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 54,860	$ -	$ -	$ -	$ -	$ -	$ 54,860
7	Average Delivered Price	Line 6 divided by Line 2	$ 6.215	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 6.215
8									
9	**Tennessee Northern Storage Injection Meter Deliveries**								
10	Purchased Volumes	Line 52	9,143	-	-	-	-	-	9,143
11	Storage Delivered Volume	Line 54	8,613	-	-	-	-	-	8,613
12	Total Purchase Price	Line 24	$ 5.573	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.573
13	Total Purchase Cost	Line 10 times Line 12	$ 50,954	$ -	$ -	$ -	$ -	$ -	$ 50,954
14	Variable Transportation Costs	Line 56	$ 979	$ -	$ -	$ -	$ -	$ -	$ 979
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ 51,933	$ -	$ -	$ -	$ -	$ -	$ 51,933
16	Average Delivered Price	Line 15 divided by Line 11	$ 6.030	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 6.030
17									
18	Tennessee Zone 0 Supply Costs								
19	Purchased Volumes	Sendout Optimization	18,725	-	-	-	-	-	18,725
20	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 5.651	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.651
21	NYMEX Cost	Line 25 times Line 26	$ 105,814	$ -	$ -	$ -	$ -	$ -	$ 105,814
22	NYMEX Basis Price	FXW-7A, Line 6 of Page 1	$ (0.078)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ (0.078)
23	NYMEX Basis Costs	Line 25 times Line 28	$ (1,461)	$ -	$ -	$ -	$ -	$ -	$ (1,461)
24	Total Purchase Price	Line 26 plus Line 28	$ 5.573	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 5.573
25	Total Purchase Cost	Line 27 plus Line 29	$ 104,353	$ -	$ -	$ -	$ -	$ -	$ 104,353
26									
27	Transportation Fuel Losses and Variable Charges								
28	Transportation Segment 1A								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone 0								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	9,582	-	-	-	-	-	9,582
33	Fuel Loss Rate	FXW 7A, Line 7 of Page 2	7.42%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	7.42%
34	Delivered Volume	Line 32 times (1 - Line 33)	8,871	-	-	-	-	-	8,871
35	Variable Transportation Rate	FXW 7A, Line 7 of Page 2	$ 0.1627	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1627
36	Variable Transportation Costs	Line 34 times Line 35	$ 1,443	$ -	$ -	$ -	$ -	$ -	$ 1,443
37									
38	Transportation Segment 2A								
39	Granite State Gas Transmission (Contract 08-003-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	8,871	-	-	-	-	-	8,871
43	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	8,827	-	-	-	-	-	8,827
45	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	9,143	-	-	-	-	-	9,143
53	Fuel Loss Rate	FXW 7A, Line 6 of Page 2	5.80%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	5.80%
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	8,613	-	-	-	-	-	8,613
55	Variable Transportation Rate	FXW 7A, Line 6 of Page 2	$ 0.1137	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1137
56	Variable Transportation Costs	Line 54 times Line 55	$ 979	$ -	$ -	$ -	$ -	$ -	$ 979

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

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Purchased Volumes	Line 32	138,381	56,382	-	-	-	12,294	207,058
2	City Gate Delivered Volume	Line 44	128,506	52,358	-	-	-	11,417	192,281
3	Total Purchase Price	Line 24	$ 5.572	$ 5.630	$ 5.703	$ 5.770	$ 5.800	$ 5.901	$ 5.643
4	Total Purchase Cost	Line 2 times Line 3	$ 771,062	$ 317,430	$ -	$ -	$ -	$ 72,549	$ 1,161,040
5	Variable Transportation Costs	Sum Lines 36 and 46	$ 19,901	$ 8,108	$ -	$ -	$ -	$ 1,768	$ 29,778
6	Total City Gate Delivered Costs	Sum Lines 4 and 5	$ 790,963	$ 325,538	$ -	$ -	$ -	$ 74,317	$ 1,190,818
7	Average Delivered Price	Line 6 divided by Line 2	$ 6.155	$ 6.218	#DIV/0!	#DIV/0!	#DIV/0!	$ 6.509	$ 6.193
8									
9	**Tennessee Northern Storage Injection Meter Deliveries**								
10	Purchased Volumes	Line 52	43,492	52,394	54,140	54,140	5,515	-	209,682
11	Storage Delivered Volume	Line 54	41,292	49,743	51,401	51,401	5,236	-	199,072
12	Total Purchase Price	Line 24	$ 5.572	$ 5.630	$ 5.703	$ 5.770	$ 5.800	$ 5.901	$ 5.677
13	Total Purchase Cost	Line 10 times Line 12	$ 242,339	$ 294,978	$ 308,762	$ 312,390	$ 31,988	$ -	$ 1,190,456
14	Variable Transportation Costs	Line 56	$ 4,265	$ 5,138	$ 5,310	$ 5,310	$ 541	$ -	$ 20,564
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ 246,604	$ 300,116	$ 314,072	$ 317,700	$ 32,528	$ -	$ 1,211,020
16	Average Delivered Price	Line 15 divided by Line 11	$ 5.972	$ 6.033	$ 6.110	$ 6.181	$ 6.212	#DIV/0!	$ 6.083
17									
18	<u>Tennessee Zone 0 Supply Costs</u>								
19	Purchased Volumes	Sendout Optimization	181,874	108,776	54,140	54,140	5,515	12,294	416,740
20	Monthly NYMEX Price	FXW-7A, Line 1 of Page 1	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980	$ 5.722
21	NYMEX Cost	Line 25 times Line 26	$ 1,027,768	$ 621,001	$ 313,039	$ 316,667	$ 32,423	$ 73,520	$ 2,384,419
22	NYMEX Basis Price	FXW-7A, Line 7 of Page 1	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)	$ (0.079)
23	NYMEX Basis Costs	Line 25 times Line 28	$ (14,368)	$ (8,593)	$ (4,277)	$ (4,277)	$ (436)	$ (971)	$ (32,922)
24	Total Purchase Price	Line 26 plus Line 28	$ 5.572	$ 5.630	$ 5.703	$ 5.770	$ 5.800	$ 5.901	$ 5.643
25	Total Purchase Cost	Line 27 plus Line 29	$ 1,013,400	$ 612,407	$ 308,762	$ 312,390	$ 31,988	$ 72,549	$ 2,351,496
26									
27	<u>Transportation Fuel Losses and Variable Charges</u>								
28	Transportation Segment 1B								
29	Tennessee Gas Pipeline (Contract 5083)								
30	Receipt Point: Tennessee Zone 0								
31	Delivery Point: Pleasant St. (Interconnection with Granite)								
32	Received Volume	Line 19	138,381	56,382	-	-	-	12,294	207,058
33	Fuel Loss Rate	FXW 7A, Line 9 of Page 2	6.67%	6.67%	#DIV/0!	#DIV/0!	#DIV/0!	6.67%	6.67%
34	Delivered Volume	Line 32 times (1 - Line 33)	129,151	52,621	-	-	-	11,474	193,247
35	Variable Transportation Rate	FXW 7A, Line 9 of Page 2	$ 0.1522	$ 0.1522	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.1522	$ 0.1522
36	Variable Transportation Costs	Line 34 times Line 35	$ 19,657	$ 8,009	$ -	$ -	$ -	$ 1,746	$ 29,412
37									
38	Transportation Segment 2B								
39	Granite State Gas Transmission (Contract 08-003-FT-NN)								
40	Receipt Point: Pleasant St.								
41	Delivery Point: Northern City Gates								
42	Received Volume	Line 34	129,151	52,621	-	-	-	11,474	193,247
43	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
44	City Gate Delivered Volume	Line 42 times (1 - Line 43)	128,506	52,358	-	-	-	11,417	192,281
45	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
46	Variable Transportation Costs	Line 44 times Line 45	$ 244	$ 99	$ -	$ -	$ -	$ 22	$ 365
47									
48	Transportation Segment 3								
49	Tennessee Gas Pipeline (Contract 5083)								
50	Receipt Point: Tennessee Zone 0								
51	Delivery Point: Tennessee Market Area Storage								
52	Received Volume	Line 25 minus Line 38	43,492	52,394	54,140	54,140	5,515	-	209,682
53	Fuel Loss Rate	FXW 7A, Line 7 of Page 2	5.06%	5.06%	5.06%	5.06%	5.06%	#DIV/0!	5.06%
54	Storage Delivered Volume	Line 52 times (1 - Line 53)	41,292	49,743	51,401	51,401	5,236	-	199,072
55	Variable Transportation Rate	FXW 7A, Line 7 of Page 2	$ 0.1033	$ 0.1033	$ 0.1033	$ 0.1033	$ 0.1033	#DIV/0!	$ 0.1033
56	Variable Transportation Costs	Line 54 times Line 55	$ 4,265	$ 5,138	$ 5,310	$ 5,310	$ 541	$ -	$ 20,564

Northern Utilities, Inc.
New Hampshire Division
Schedule 6B

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

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Gross Withdrawn Volume	Line 9	817	-	-	-	-	-	817
2	City Gate Delivered Volume	Line 35	798	-	-	-	-	-	798
3	Total Withdrawal Costs	Line 16	$ 5,009	$ -	$ -	$ -	$ -	$ -	$ 5,009
4	Variable Transportation Costs	Sum Lines 27 and 37	$ 70	$ -	$ -	$ -	$ -	$ -	$ 70
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 5,079	$ -	$ -	$ -	$ -	$ -	$ 5,079
6	Average Delivered Price	Line 5 divided by Line 2	$ 6.366	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 6.366
7									
8	Tennessee FS-MA Withdrawn Inventory (Segment 1)								
9	Gross Withdrawn Volume	Sendout Optimization	817	-	-	-	-	-	817
10	Withdrawal Rate		$ 0.0102	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.010
11	Withdrawal Charges	Line 9 times Line 10	8	-	-	-	-	-	$ 8
12	Inventory Rate	FXW-8, Page 1	$ 6.1170	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 6.117
13	Withdrawn Inventory Value	Line 9 times Line 12	5,000	-	-	-	-	-	$ 5,000
14	Withdrawal Fuel Losses		-	-	-	-	-	-	$ 1.000
15	Net Withdrawn Volume	Line 9 minus Line 14	817	-	-	-	-	-	$ 817
16	Total Withdrawal Costs	Line 11 plus Line 13	5,009	-	-	-	-	-	5,009
17									
18	Transportation Fuel Losses and Variable Charges								
19	Transportation Segment 2								
20	Tennessee Gas Pipeline (Contract 5265)								
21	Receipt Point: Tennessee FS-MA Withdrawal Meter								
22	Delivery Point: Pleasant St. (Interconnection with Granite)								
23	Received Volume	Line 15	817	-	-	-	-	-	817
24	Fuel Loss Rate	FXW 7A, Line 10 of Page 2	1.92%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	1.92%
25	Delivered Volume	Line 23 times (1 - Line 24)	802	-	-	-	-	-	802
26	Variable Transportation Rate	FXW 7A, Line 10 of Page 2	$ 0.0853	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 0.0853
27	Variable Transportation Costs	Line 25 times Line 26	$ 68	$ -	$ -	$ -	$ -	$ -	68
28									
29	Transportation Segment 3								
30	Granite State Gas Transmission (Contract 08-003-FT-NN)								
31	Receipt Point: Pleasant St.								
32	Delivery Point: Northern City Gates								
33	Received Volume	Line 25	802	-	-	-	-	-	802
34	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	798	-	-	-	-	-	798
36	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019
37	Variable Transportation Costs	Line 35 times Line 36	$ 2	$ -	$ -	$ -	$ -	$ -	2

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

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Purchased Volumes	Line 10	-	-	-	-	-	-	-
2	City Gate Delivered Volume	Line 33	-	-	-	-	-	-	-
3	Total Purchase Price	Line 24	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717
4	Total Purchase Cost	Line 1 times Line 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Variable Transportation Costs	Line 35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Total City Gate Delivered Costs	Line 4 plus Line 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Average Delivered Price	Line 6 divided by Line 2	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
8									
9	**LNG Storage Deliveries**								
10	Purchased Volumes	Line 41	1,395	1,350	1,395	2,330	1,530	1,105	9,105
11	Storage Delivered Volume	Line 43	1,395	1,350	1,395	2,330	1,530	1,105	9,105
12	Total Purchase Price	Line 24	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717
13	Total Purchase Cost	Line 10 times Line 12	$ 5,185	$ 5,018	$ 5,185	$ 8,661	$ 5,687	$ 4,106	$ 33,844
14	Variable Transportation Costs	Line 45	$ 1,744	$ 1,688	$ 1,744	$ 2,912	$ 1,913	$ 1,381	$ 11,381
15	Total Storage Delivered Costs	Line 13 plus Line 14	$ 6,929	$ 6,706	$ 6,929	$ 11,574	$ 7,600	$ 5,487	$ 45,225
16	Average Delivered Price	Line 15 divided by Line 11	$ 4.967	$ 4.967	$ 4.967	$ 4.967	$ 4.967	$ 4.967	$ 4.967
17									
18	Peaking Supply 1 Costs (Segment 1)								
19	Purchased Volumes	Sendout Optimization	1,395	1,350	1,395	2,330	1,530	1,105	9,105
20	Peaking Supply 1 Prices	Contract Rate	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717
21	Peaking Supply 1 Costs	Line 19 times Line 20	$ 5,185	$ 5,018	$ 5,185	$ 8,661	$ 5,687	$ 4,106	$ 33,844
22	NYMEX Basis Price	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	NYMEX Basis Costs	Line 19 times Line 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Total Purchase Price	Line 20 plus Line 22	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717	$ 3.717
25	Total Purchase Cost	Line 23 times (1 - Line 24)	$ 5,185	$ 5,018	$ 5,185	$ 8,661	$ 5,687	$ 4,106	$ 33,844
26									
27	Transportation Segment 2								
28	Granite State Gas Transmission (Contract 08-003-FT-NN)								
29	Receipt Point: Pleasant St.								
30	Delivery Point: Northern City Gates								
31	Received Volume	Sendout Optimization	-	-	-	-	-	-	-
32	Fuel Loss Rate	FXW 7A, Line 3 of Page 2	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	#DIV/0!
33	City Gate Delivered Volume	Line 31 times (1 - Line 32)	-	-	-	-	-	-	-
34	Variable Transportation Rate	FXW 7A, Line 3 of Page 2	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	#DIV/0!
35	Variable Transportation Costs	Line 33 times Line 34	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36									
37	Transportation Segment 3								
38	Trucking Contract (TransGas)								
39	Receipt Point: Distrigas Terminal								
40	Delivery Point: Northern LNG Facility (Lewiston, ME)								
41	Received Volume	Line 19 minus Line 31	1,395	1,350	1,395	2,330	1,530	1,105	9,105
42	Fuel Loss Rate	Company Forecast	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Storage Delivered Volume	Line 41 times (1 - Line 42)	1,395	1,350	1,395	2,330	1,530	1,105	9,105
44	Variable Transportation Rate	Company Forecast	$ 1.2500	$ 1.2500	$ 1.2500	$ 1.2500	$ 1.2500	$ 1.2500	$ 1.2500
45	Variable Transportation Costs	Line 43 times Line 44	$ 1,744	$ 1,688	$ 1,744	$ 2,912	$ 1,913	$ 1,381	$ 11,381

Source of Supply: Northern LNG Inventory
On-System Storage

Line	**City Gate Delivered Costs**	Reference	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
1	Gross Withdrawn Volume	Line 9	1,395	1,350	1,395	1,395	1,350	1,395	8,280
2	City Gate Delivered Volume	Line 15	1,395	1,350	1,395	1,395	1,350	1,395	8,280
3	Total Withdrawal Costs	Line 16	$ 7,409	$ 7,123	$ 7,352	$ 7,251	$ 6,991	$ 7,185	$ 43,312
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 7,409	$ 7,123	$ 7,352	$ 7,251	$ 6,991	$ 7,185	$ 43,312
6	Average Delivered Price	Line 5 divided by Line 2	$ 5.311	$ 5.276	$ 5.270	$ 5.198	$ 5.179	$ 5.151	$ 5.231
7									
8	Northern LNG Withdrawn Inventory								
9	Gross Withdrawn Volume	Sendout Optimization	1,395	1,350	1,395	1,395	1,350	1,395	8,280
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	-	-	-	-	-	-	$ -
12	Inventory Rate	FXW-8, Page 1	$ 5.3115	$ 5.2764	$ 5.2702	$ 5.1976	$ 5.1789	$ 5.1507	$ 5.231
13	Withdrawn Inventory Value	Line 9 times Line 12	7,409	7,123	7,352	7,251	6,991	7,185	$ 43,312
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	$ 1.000
15	Net Withdrawn Volume	Line 9 minus Line 14	1,395	1,350	1,395	1,395	1,350	1,395	$ 8,280
16	Total Withdrawal Costs	Line 11 plus Line 13	7,409	7,123	7,352	7,251	6,991	7,185	43,312

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Clearport Settlement for January 25, 2010

Line	Item	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
1	NYMEX NG	$5.651	$5.709	$5.782	$5.849	$5.879	$5.980
2	Adders to NYMEX by Supply Source						
3	Chicago	$0.010	$0.010	$0.010	$0.010	$0.010	$0.010
4	Empress	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
5	Niagara	$0.309	$0.310	$0.311	$0.312	$0.312	$0.313
6	TGP Z0	($0.078)	($0.078)	($0.078)	($0.078)	($0.078)	($0.078)
7	TGP Z1	($0.079)	($0.079)	($0.079)	($0.079)	($0.079)	($0.079)

Northern Utilities, Inc.
Pipeline Variable Rates

Line	Pipeline	Rate	Receipt	Delivery	Variable Commodity Rate	May-10 Fuel Rate	Jun-10 Fuel Rate	Jul-10 Fuel Rate	Aug-10 Fuel Rate	Sep-10 Fuel Rate	Oct-10 Fuel Rate	Reference
1	Algonquin	AFT-1 (AFT-2)	N/A	N/A	$ 0.0019	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	Pages 3 and 4
2	Algonquin	AFT-1 (F-2/F-3)	N/A	N/A	$ 0.0131	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	Pages 3 and 4
3	Granite	FT-NN	N/A	N/A	$ 0.0019	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	Pages 5 and 6
4	Iroquois	RTS-1	Zone 1	Zone 1	$ 0.0030	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	Page 7
5	PNGTS	FT	N/A	N/A	$ 0.0019	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	Page 8
6	Tennessee	FT-A	Zone 0	Zone 4	$ 0.1137	5.80%	5.80%	5.80%	5.80%	5.80%	5.80%	Pages 10-12
7	Tennessee	FT-A	Zone 0	Zone 6	$ 0.1627	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	Pages 10-12
8	Tennessee	FT-A	Zone L	Zone 4	$ 0.1033	5.06%	5.06%	5.06%	5.06%	5.06%	5.06%	Pages 10-12
9	Tennessee	FT-A	Zone L	Zone 6	$ 0.1522	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	Pages 10-12
10	Tennessee	FT-A	Zone 4	Zone 6	$ 0.0853	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	Pages 10-12
11	Tennessee	FT-A	Zone 5	Zone 6	$ 0.0784	1.86%	1.86%	1.86%	1.86%	1.86%	1.86%	Pages 10-12
12	Tennessee	NET-284	Segment 3	Segment 3	$ 0.0019	0.96%	0.96%	0.96%	0.96%	0.96%	0.96%	Pages 14 and 16
13	Tennessee	NET-284	Segment 3	Segment 4	$ 0.0019	1.26%	1.26%	1.26%	1.26%	1.26%	1.26%	Pages 14 and 16
14	TransCanada	FT	Dawn	Iroquois	$ 0.0140	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	Pages 17 and 22
15	TransCanada	FT	Dawn	E. Hereford	$ 0.0605	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	Pages 17 and 22
16	TransCanada	FT	Empress	E. Hereford	$ 0.1135	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	Pages 17 and 22
17	Vector	FT	Alliance	W-10 Storage	$ 0.0019	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	Pages 23 and 24
18	Vector	FT	W-10 Storage	Dawn	$ 0.0019	0.34%	0.34%	0.34%	0.34%	0.34%	0.34%	Pages 23 and 24
19	Vector	FT	Alliance	Dawn	$ 0.0019	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	Pages 23 and 24

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2009

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

•RATE SCHEDULE AFT-1S

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

•OTHER FIRM RATE SCHEDULES

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

•INTERRUPTIBLE SERVICE

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

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

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

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP

System Services

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

Incremental Ramapo Services

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

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

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

Rate Schedule FT-1

Firm Transportation Service

$/Dth

Base Total

Tariff ACA Current

Rate Adj. Rate

1/

Reservation Charge:

Maximum $1.6666 $1.6666

Minimum $0.0000 $0.0000

Commodity Charge:

Maximum $0.0000 $0.0019 $0.0019

Minimum $0.0000 $0.0019 $0.0019

Authorized Overrun

Commodity Charge:

Maximum $0.0548 $0.0019 $0.0567

Minimum $0.0000 $0.0019 $0.0019

Fuel and Losses

Percentage 0.5%

Volumetric

Reservation Charge

Maximum $0.0548 $0.0548

Minimum $0.0000 $0.0000

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

Issued by:
Issue date: 10/01/09 Effective date: 10/01/09

Iroquois Gas Transmission System, L.P. Thirty First Revised Sheet No. 4

FERC Gas Tariff Superseding

FIRST REVISED VOLUME NO. 1 Thirtieth Revised Sheet No. 4

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

	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	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

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

____

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

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

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

(Footnotes continued on Sheet 4.01)

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

Issued on: Jan 26, 2009 Effective: Jan 27, 2009

Statement of Transportation Rates

(Rates per DTH)

Rate Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ Rate

FT Recourse Reservation Rate

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

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

Seasonal Recourse Reservation Rate

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

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

Recourse Usage Rate

-- Maximum $00.0000 $00.0019 $00.0019

-- Minimum $00.0000 $00.0019 $00.0019

FT-FLEX Recourse Reservation Rate

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

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

Recourse Usage Rate

--Maximum $00.2962 $00.0019 $00.2981

--Minimum $00.0000 $00.0019 $00.0019

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

Minimum down to -1.00%

Maximum up to +1.00%

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

Issued by:

Issue date: 10/01/09 Effective date: 10/01/09

TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Twenty-First Revised Sheet No. 23A
Superseding
Twentieth Revised Sheet No. 23A

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum
Commodity Rates 2/

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

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6

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

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0019

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Issued by: Patrick A. Johnson, Vice President
Issued on: August 31, 2009 Effective on: October 1, 2009

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

NOVEMBER - MARCH

Delivery Zone

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

APRIL - OCTOBER

Delivery Zone

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

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G,

Issued by: Patrick A. Johnson, Vice President
Issued on: February 29, 2008 Effective on: April 1, 2008

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TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Forty-Third Revised Sheet No. 26B
Superseding
Forty-Second Revised Sheet No. 26B

RATES PER DEKATHERM

RATE SCHEDULE NET 284

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

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.

2/ The applicable surcharges for ACA and TCSM will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.

3/ The Incremental Pressure Charge associated with service to MassPower shall be $0.0334 plus an additional Incremental Fuel Charge of 5.83%.

4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.

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

6/ The applicable fuel retention percentages are listed on Sheet No. 220A.

7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

Issued by: Patrick A. Johnson, Vice President
Issued on: August 31, 2009 Effective on: October 1, 2009

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TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

[illegible]. 26B.01
Superseding
Eighth Revised Sheet No. 26B.01

RATES PER DEKATHERM

AUTHORIZED OVERRUN RATES
FOR RATE SCHEDULE NET 284

Maximum Commodity Rate 1/	
Segment U	$0.3173
Segment 1	$0.0437
Segment 2	$0.2656
Segment 3	$0.1667
Segment 4	$0.1821

Notes:
1/ The Authorized Overrun Commodity Rates are additive for each segment of the contract and the total Commodity Rate will be increased by $.0019 for ACA.

Issued by: Patrick A. Johnson, Vice President
Issued on: August 31, 2009 Effective on: October 1, 2009

TransCanada Variable Transportation Rates

Line	Item	Units	Value	Reference
1	Union Dawn to Iroquois			
2	Commodity Rate	$CAD / GJ	$ 0.01413	Page 20
3	Delivery Pressure Commodity Rate	$CAD / GJ	$ -	Page 18
4	Variable Transportation Rate	$CAD / GJ	$ 0.01413	Line 2 plus Line 3
5	$CAD to $US	Ratio	0.9429	Page 21
6	Variable Transportation Rate	$US / GJ	$ 0.0133	Line 4 times Line 5
7	GJ per Dth	Ratio	1.0551	
8	Variable Transportation Rate	$US / Dth	$ 0.0140	Line 6 times Line 7
9				
10	Empress to East Hereford			
11	Commodity Rate	$CAD / GJ	$ 0.07609	Page 19
12	Delivery Pressure Commodity Rate	$CAD / GJ	$ 0.03798	Page 18
13	Variable Transportation Rate	$CAD / GJ	$ 0.11407	Line 11 plus Line 12
14	$CAD to $US	Ratio	0.9429	Page 21
15	Variable Transportation Rate	$US / GJ	$ 0.1076	Line 13 times Line 14
16	GJ per Dth	Ratio	1.0551	
17	Variable Transportation Rate	$US / Dth	$ 0.1135	Line 15 times Line 16
18				
19	Union Dawn to East Hereford			
20	Commodity Rate	$CAD / GJ	$ 0.02275	Page 20
21	Delivery Pressure Commodity Rate	$CAD / GJ	$ 0.03798	Page 18
22	Variable Transportation Rate	$CAD / GJ	$ 0.06073	Line 11 plus Line 12
23	$CAD to $US	Ratio	0.9429	Page 21
24	Variable Transportation Rate	$US / GJ	$ 0.0573	Line 13 times Line 14
25	GJ per Dth	Ratio	1.0551	
26	Variable Transportation Rate	$US / Dth	$ 0.0605	Line 15 times Line 16

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

Storage Transportation Service

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

Enhanced Capacity Release

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

Delivery Pressure

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

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

TransCanada
In business to deliver

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

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% FT Tolls) ($/GJ)
1	Empress	Empress	1.08608	0.00000	0.0357	0.0393
2	Empress	Saskatchewan Zone	8.03190	0.01027	0.2744	0.3018
3	Empress	Manitoba Zone	14.32875	0.01897	0.4901	0.5391
4	Empress	Western Zone	23.79107	0.03296	0.8152	0.8967
5	Empress	Northern Zone	36.72520	0.05154	1.2589	1.3848
6	Empress	Eastern Zone	47.77094	0.06753	1.6381	1.8019
7	Empress	North Bay Junction	39.69751	0.05601	1.3611	1.4972
8	Empress	Southwest Zone	39.79320	0.05606	1.3644	1.5008
9	Empress	Spruce	16.02499	0.02167	0.5485	0.6034
10	Empress	Emerson 1	16.33950	0.02213	0.5593	0.6152
11	Empress	Emerson 2	16.33950	0.02213	0.5593	0.6152
12	Empress	St. Clair	39.68603	0.05599	1.3607	1.4968
13	Empress	Dawn Export	40.03974	0.05650	1.3729	1.5102
14	Empress	Kirkwall	45.62395	0.06460	1.5646	1.7211
15	Empress	Niagara Falls	47.29307	0.06703	1.6218	1.7840
16	Empress	Chippawa	47.32869	0.06708	1.6231	1.7854
17	Empress	Iroquois	46.11404	0.06532	1.5814	1.7395
18	Empress	Cornwall	48.18427	0.06832	1.6524	1.8176
19	Empress	Napierville	50.52176	0.07171	1.7327	1.9060
20	Empress	Philipsburg	50.78201	0.07209	1.7416	1.9158
21	Empress	East Hereford	53.53893	0.07609	1.8363	2.0199
22	Empress	Welwyn	10.20215	0.01322	0.3486	0.3835
23	Bayhurst 1	Empress	1.53846	0.00000	0.0506	0.0557
24	Bayhurst 1	Saskatchewan Zone	7.57952	0.00961	0.2588	0.2847
25	Bayhurst 1	Manitoba Zone	13.87636	0.01832	0.4745	0.5220
26	Bayhurst 1	Western Zone	23.33869	0.03230	0.7996	0.8796
27	Bayhurst 1	Northern Zone	36.27282	0.05088	1.2434	1.3677
28	Bayhurst 1	Eastern Zone	47.31856	0.06687	1.6226	1.7849
29	Bayhurst 1	North Bay Junction	39.24498	0.05535	1.3456	1.4802
30	Bayhurst 1	Southwest Zone	39.34082	0.05540	1.3488	1.4837
31	Bayhurst 1	Spruce	15.57261	0.02101	0.5330	0.5863
32	Bayhurst 1	Emerson 1	15.88712	0.02147	0.5438	0.5982
33	Bayhurst 1	Emerson 2	15.88712	0.02147	0.5438	0.5982
34	Bayhurst 1	St. Clair	39.23365	0.05534	1.3452	1.4797
35	Bayhurst 1	Dawn Export	39.58736	0.05585	1.3574	1.4931
36	Bayhurst 1	Kirkwall	45.17157	0.06395	1.5491	1.7040
37	Bayhurst 1	Niagara Falls	46.84069	0.06637	1.6064	1.7670
38	Bayhurst 1	Chippawa	46.87631	0.06642	1.6075	1.7683
39	Bayhurst 1	Iroquois	45.66166	0.06466	1.5659	1.7225
40	Bayhurst 1	Cornwall	47.73189	0.06766	1.6370	1.8007
41	Bayhurst 1	Napierville	50.06937	0.07105	1.7172	1.8889
42	Bayhurst 1	Philipsburg	50.32962	0.07143	1.7261	1.8987
43	Bayhurst 1	East Hereford	53.08655	0.07543	1.8207	2.0028
44	Bayhurst 1	Welwyn	9.74977	0.01257	0.3331	0.3664
45	Bayhurst 2	Empress	1.53846	0.00000	0.0506	0.0557
46	Bayhurst 2	Saskatchewan Zone	7.57952	0.00961	0.2588	0.2847
47	Bayhurst 2	Manitoba Zone	13.87636	0.01832	0.4745	0.5220
48	Bayhurst 2	Western Zone	23.33869	0.03230	0.7996	0.8796
49	Bayhurst 2	Northern Zone	36.27282	0.05088	1.2434	1.3677
50	Bayhurst 2	Eastern Zone	47.31856	0.06687	1.6226	1.7849
51	Bayhurst 2	North Bay Junction	39.24498	0.05535	1.3456	1.4802
52	Bayhurst 2	Southwest Zone	39.34082	0.05540	1.3488	1.4837
53	Bayhurst 2	Spruce	15.57261	0.02101	0.5330	0.5863
54	Bayhurst 2	Emerson 1	15.88712	0.02147	0.5438	0.5982
55	Bayhurst 2	Emerson 2	15.88712	0.02147	0.5438	0.5982
56	Bayhurst 2	St. Clair	39.23365	0.05534	1.3452	1.4797
57	Bayhurst 2	Dawn Export	39.58736	0.05585	1.3574	1.4931
58	Bayhurst 2	Kirkwall	45.17157	0.06395	1.5491	1.7040
59	Bayhurst 2	Niagara Falls	46.84069	0.06637	1.6064	1.7670
60	Bayhurst 2	Chippawa	46.87631	0.06642	1.6075	1.7683
61	Bayhurst 2	Iroquois	45.66166	0.06466	1.5659	1.7225
62	Bayhurst 2	Cornwall	47.73189	0.06766	1.6370	1.8007
63	Bayhurst 2	Napierville	50.06937	0.07105	1.7172	1.8889
64	Bayhurst 2	Philipsburg	50.32962	0.07143	1.7261	1.8987
65	Bayhurst 2	East Hereford	53.08655	0.07543	1.8207	2.0028
66	Bayhurst 2	Welwyn	9.74977	0.01257	0.3331	0.3664
67	Calstock NDA	Empress	30.69725	0.00000	1.0092	1.1101
68	Calstock NDA	Transgas SSDA	24.27670	0.00000	0.7981	0.8779
69	Calstock NDA	Centram SSDA	21.58118	0.00000	0.7095	0.7805

TransCanada
In business to deliver

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

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

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:

10-Year Currency Converter

Using rates for: 26 Jan 2010

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

Currency:	U.S. dollar
Amount:	1.00
Convert:	from $Can / to $Can
Use the:	Nominal rate HELP Cash rate (4%) HELP
Answer:	0.94 CONVERT
Exchange rate:	0.9429

Summary:

On 26 Jan 2010, 1.00 Canadian dollar(s) = 0.94 U.S. dollar(s), at an exchange rate of 0.9429 (using nominal rate.)

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

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

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

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

More comprehensive currency converters include **CanadianForex** and **OANDA.com**.

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

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

Historic TransCanada Fuel Loss Rates

	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Last Apr - Oct
Union Dawn - Iroquois	1.43%	1.49%	1.03%	1.59%	1.40%	0.69%	0.94%	1.22%
Union Dawn - East Hereford	1.14%	1.23%	0.59%	1.39%	1.17%	0.00%	0.50%	0.86%
Empress - East Hereford	3.53%	3.75%	2.12%	4.30%	3.87%	0.00%	2.01%	2.80%

Previous Next

Vector Pipeline L.P.
FERC Gas Tariff — Tenth Revised Sheet No. 20
Original Volume No. 1 — Superseding
Ninth Revised Sheet No. 20

STATEMENT OF RATES AND CHARGES

All rates are stated in U.S. $

Rate Schedule FT-1 1/

Recourse Rates:

	Zone 1 2/		Zone 2 2/	
	Maximum	Minimum	Maximum	Minimum
Reservation Charge ($ per Dth per month)	$1.4539	0.0000	$9.3197	0.0000
Usage Charge ($ per Dth)	0.0000	0.0000	0.0000	0.0000
ACA Charge	0.0019	0.0019	0.0019	0.0019
Usage and ACA Charge	0.0019	0.0019	0.0019	0.0019

Negotiated Rates:

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

Rate Schedule FT-L 1/

Recourse Rates:

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

Historic Vector Fuel Loss Rates

Receipt	Delivery	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Last Apr Oct
W-10 Storage	Dawn	0.35%	0.31%	0.31%	0.44%	0.32%	0.32%	0.30%	0.34%
Alliance	W-10 Storage	1.05%	0.93%	0.93%	1.33%	0.97%	0.95%	0.91%	1.01%
Alliance	Dawn	1.05%	0.93%	0.93%	1.33%	0.97%	0.95%	0.91%	1.01%

Northern Utilities, Inc.
Hedging Gains and Losses
May 2010 through October 2010
As of 1/25/2010

Description	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Season
NYMEX NG Futures Contracts	25					25	50
Average Purchase Price	$ 5.561					$ 6.021	$ 5.791
Current NYMEX Price	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980	$ 5.816
Hedging (Gains) or Losses	$(22,462)	$ -	$ -	$ -	$ -	$ 10,288	$ (12,173)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Summer 2010 vs. Summer 2009

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2009 - 2010																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.0980	$119.68						$119.68								
	CGA 2	$1.0980		$164.70					$164.70								
	CGA 3	$1.0218			$191.08				$191.08								
	CGA 4	$1.0758				$202.25			$202.25								
	CGA 5	$1.0758					$178.58		$178.58								
	CGA 6	$1.0758						$142.01	$142.01								
	LDAC	$0.0297	$3.24	$4.46	$5.55	$5.58	$4.93	$3.92	$27.68								
Summer 2010																	
Customer Charge	units @	$ 9.50								$ 9.50	$9.50	$9.50	$9.50	$ 9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.6981								$62.83						$62.83	
	CGA 2	$0.6981									$38.40					$38.40	
	CGA 3	$0.6981										$20.94				$20.94	
	CGA 4	$0.6981											$20.94			$20.94	
	CGA 5	$0.6981												$29.32		$29.32	
	CGA 6	$0.6981													$49.57	$49.57	
	LDAC	$ 0.0297								$2.67	$1.63	$0.89	$0.89	$1.25	$2.11	$9.44	
	TOTAL		$170.57	$229.07	$267.60	$279.11	$248.21	$200.45	$1,395.01	$107.47	$71.53	$43.64	$43.64	$57.30	$87.96	$411.54	$1,806.55

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2008 - 2009																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.2636	$137.73						$137.73								
	CGA 2	$1.2636		$189.54					$189.54								
	CGA 3	$1.2636			$236.29				$236.29								
	CGA 4	$1.2636				$237.56			$237.56								
	CGA 5	$1.0540					$174.96		$174.96								
	CGA 6	$1.0540						$139.13	$139.13								
	LDAC	$ 0.0255	$2.78	$3.83	$4.77	$4.79	$4.23	$3.37	$23.77								
Summer 2009																	
Customer Charge	units @	$ 9.50								$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.7385								$66.47						$66.47	
	CGA 2	$0.7385									$40.62					$40.62	
	CGA 3	$0.7385										$22.16				$22.16	
	CGA 4	$0.7385											$22.16			$22.16	
	CGA 5	$0.7385												$31.02		$31.02	
	CGA 6	$0.9231													$65.54	$65.54	
	LDAC	$ 0.0255								$2.30	$1.40	$0.77	$0.77	$1.07	$1.81	$8.11	
	TOTAL		$188.16	$253.28	$312.03	$313.62	$243.89	$197.02	$1,508.01	$110.73	$73.53	$44.73	$44.73	$58.82	$103.64	$436.16	$1,944.17
	Change		($17.59)	($24.21)	($44.43)	($34.52)	$4.32	$3.43	($113.00)	($3.26)	($1.99)	($1.09)	($1.09)	($1.52)	($15.68)	**($24.62)**	($137.62)
	% Chg		-9.35%	-9.56%	-14.24%	-11.01%	1.77%	1.74%	-7.49%	-2.94%	-2.71%	-2.43%	-2.43%	-2.58%	-15.13%	**-5.64%**	-7.08%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2010 vs. Actual Summer 2009

Residential Heating

	Summer 2009	Summer 2010
Customer Charge	$9.50	$9.50
First 50 Therms	$0.4102	$0.4102
Over 50 therms	$0.2990	$0.2990
LDAC	$0.0255	$0.0297
CGA	$0.7797	$0.6981

	Usage (Therms)	Summer 2009 Bill Amount	Summer 2010 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$15.58	$15.19	($0.39)	-2.5%	$0.00	0.0%	($0.41)	-2.6%	$0.02	0.1%
	10	$21.65	$20.88	($0.77)	-3.6%	$0.00	0.0%	($0.82)	-3.8%	$0.04	0.2%
	20	$33.81	$32.26	($1.55)	-4.6%	$0.00	0.0%	($1.63)	-4.8%	$0.08	0.2%
	25	$39.89	$37.95	($1.94)	-4.9%	$0.00	0.0%	($2.04)	-5.1%	$0.11	0.3%
	30	$45.96	$43.64	($2.32)	-5.1%	$0.00	0.0%	($2.45)	-5.3%	$0.13	0.3%
	45	$64.19	$60.71	($3.48)	-5.4%	$0.00	0.0%	($3.67)	-5.7%	$0.19	0.3%
Average Monthly	50	$70.27	$66.40	($3.87)	-5.5%	$0.00	0.0%	($4.08)	-5.8%	$0.21	0.3%
	75	$112.83	$107.02	($5.81)	-5.1%	$0.00	0.0%	($6.12)	-5.4%	$0.32	0.3%
	125	$168.04	$158.36	($9.68)	-5.8%	$0.00	0.0%	($10.20)	-6.1%	$0.53	0.3%
	150	$195.64	$184.03	($11.61)	-5.9%	$0.00	0.0%	($12.24)	-6.3%	$0.63	0.3%
	200	$250.85	$235.37	($15.48)	-6.2%	$0.00	0.0%	($16.32)	-6.5%	$0.84	0.3%

NORTHERN UTILITIES, INC.
CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: May 1, 2010 - October 31, 2010

1	Total Anticipated Direct Cost of Gas			$ 6,336,110		
2	Projected Prorated Sales (05/01/10 - 10/31/10)			8,368,836		
3	**Direct Cost of Gas Rate**				**$ 0.7571**	**per therm**
4						
5	**Demand Cost of Gas Rate**			**$ 1,046,835**	**$ 0.1251**	**per therm**
6	**Commodity Cost of Gas Rate**			5,289,274	**$ 0.6320**	**per therm**
7	**Total Direct Cost of Gas Rate**			**$ 6,336,110**	**$ 0.7571**	**per therm**
8						
9	Total Anticipated Indirect Cost of Gas			$ (493,745)		
10	Projected Prorated Sales (05/01/10 - 10/31/10)			8,368,836		
11	Indirect Cost of Gas				$ (0.0590)	per therm
12						
13						
14	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/2010			$ 5,842,365	$ 0.6981	per therm
15						
16	**RESIDENTIAL COST OF GAS RATE - 05/01/10**		**COGwr**		**$ 0.6981**	**per therm**
17			**Maximum (COG+25%)**		**$ 0.8726**	
18						
19	**COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/10**		**COGwl**		**$ 0.6571**	**per therm**
20			**Maximum (COG+25%)**		**$ 0.8213**	
21	C&I HLF Demand Costs Allocated per SMBA	$ 168,467				
22	PLUS: Residential Demand Reallocation to C&I HLF	$ 9,394				
23	C&I HLF Total Adjusted Demand Costs	$ 177,861				
24	C&I HLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,154,343				
25	**Demand Cost of Gas Rate**	**$ 0.0826**				
26						
27	C&I HLF Commodity Costs Allocated per SMBA	$ 1,366,335				
28	PLUS: Residential Commodity Reallocation to C&I HLF	$ (1,653)				
29	C&I HLF Total Adjusted Commodity Costs	$ 1,364,683				
30	C&I HLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,154,343				
31	**Commodity Cost of Gas Rate**	**$ 0.6335**				
32						
33	**Indirect Cost of Gas**	$ (0.0590)				
34						
35	**Total C&I HLF Cost of Gas Rate**	**$ 0.6571**				
36						
37	**COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/10**		**COGwh**		**$ 0.7296**	**per therm**
38			**Maximum (COG+25%)**		**$ 0.9120**	
39	C&I LLF Demand Costs Allocated per SMBA	$ 419,853				
40	PLUS: Residential Demand Reallocation to C&I LLF	$ 23,411				
41	C&I LLF Total Adjusted Demand Costs	$ 443,264				
42	C&I LLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,811,529				
43	**Demand Cost of Gas Rate**	**$ 0.1577**				
44						
45	C&I LLF Commodity Costs Allocated per SMBA	$ 1,776,067				
46	PLUS: Residential Commodity Reallocation to C&I LLF	$ (2,148)				
47	C&I LLF Total Adjusted Commodity Costs	$ 1,773,919				
48	C&I LLF Projected Prorated Sales (05/01/10 - 10/31/10)	2,811,529				
49	**Commodity Cost of Gas Rate**	**$ 0.6309**				
50						
51	**Indirect Cost of Gas**	$ (0.0590)				
52						
53	**Total C&I LLF Cost of Gas Rate**	**$ 0.7296**				

NORTHERN UTILITIES, INC.
CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: May 1, 2009 - October 31, 2009

Total Anticipated Direct Cost of Gas		$ 6,188,204		
Projected Prorated Sales (05/01/09 - 10/31/09)		9,197,893		
Direct Cost of Gas Rate			**$ 0.6728**	**per therm**
Demand Cost of Gas Rate		**$ 1,436,711**	**$ 0.1562**	**per therm**
Commodity Cost of Gas Rate		4,751,379	**$ 0.5166**	**per therm**
Total Direct Cost of Gas Rate		**$ 6,188,090**	**$ 0.6728**	**per therm**
Total Anticipated Indirect Cost of Gas		$ 604,516		
Projected Prorated Sales (05/01/09 - 10/31/09)		9,197,893		
Indirect Cost of Gas			$ 0.0657	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/2009		$ 6,792,606	$ 0.7385	per therm
RESIDENTIAL COST OF GAS RATE - 05/01/09		**COGwr**	**$ 0.7385**	**per therm**
		Maximum (COG+25%)	**$ 0.9231**	
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/09		**COGwl**	**$ 0.6785**	**per therm**
		Maximum (COG+25%)	**$ 0.8481**	
C&I HLF Demand Costs Allocated per SMBA	$ 485,280			
PLUS: Residential Demand Reallocation to C&I HLF	$ -			
C&I HLF Total Adjusted Demand Costs	$ 485,280			
C&I HLF Projected Prorated Sales (05/01/09 - 10/31/09)	3,688,779			
Demand Cost of Gas Rate	**$ 0.1316**			
C&I HLF Commodity Costs Allocated per SMBA	$ 1,775,192			
PLUS: Residential Commodity Reallocation to C&I HLF	$ -			
C&I HLF Total Adjusted Commodity Costs	$ 1,775,192			
C&I HLF Projected Prorated Sales (05/01/09 - 10/31/09)	3,688,779			
Commodity Cost of Gas Rate	**$ 0.4812**			
Indirect Cost of Gas	$ 0.0657			
Total C&I HLF Cost of Gas Rate	**$ 0.6785**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/09		**COGwh**	**$ 0.8355**	**per therm**
		Maximum (COG+25%)	**$ 1.0443**	
C&I LLF Demand Costs Allocated per SMBA	$ 447,333			
PLUS: Residential Demand Reallocation to C&I LLF	$ -			
C&I LLF Total Adjusted Demand Costs	$ 447,333			
C&I LLF Projected Prorated Sales (05/01/09 - 10/31/09)	2,281,126			
Demand Cost of Gas Rate	**$ 0.1961**			
C&I LLF Commodity Costs Allocated per SMBA	$ 1,308,609			
PLUS: Residential Commodity Reallocation to C&I LLF	$ -			
C&I LLF Total Adjusted Commodity Costs	$ 1,308,609			
C&I LLF Projected Prorated Sales (05/01/09 - 10/31/09)	2,281,126			
Commodity Cost of Gas Rate	**$ 0.5737**			
Indirect Cost of Gas	0.0657			
Total C&I LLF Cost of Gas Rate	**$ 0.8355**			

NORTHERN UTILITIES, INC.
CALCULATION OF FIRM SALES COST OF GAS RATE
VARIANCE BETWEEN OFF PEAK 2010 and OFF PEAK 2009

107	Total Anticipated Direct Cost of Gas		$	147,906		
108	Projected Prorated Sales			(829,057)		
109	Direct Cost of Gas Rate				$ 0.0843	per therm
110						
111	**Demand Cost of Gas Rate**		**$**	**(389,875)**	**$ (0.0311)**	**per therm**
112	**Commodity Cost of Gas Rate**			537,895	**$ 0.1154**	**per therm**
113	**Total Direct Cost of Gas Rate**		**$**	**148,020**	**$ 0.0843**	**per therm**
114						
115	Total Anticipated Indirect Cost of Gas		$	(1,098,261)		
116	Projected Prorated Sales			(829,057)		
117	Indirect Cost of Gas				$ (0.1247)	per therm
118						
119						
120	TOTAL PERIOD AVERAGE COST OF GAS		$	(950,241)	$ (0.0404)	per therm
121						
122	**RESIDENTIAL COST OF GAS RATE**		**COGwr**		**$ (0.0404)**	**per therm**
123			**Maximum (COG+25%)**		**$ (0.0505)**	
124						
125	**COM/IND LOW WINTER USE COST OF GAS RATE**		**COGwl**		**$ (0.0214)**	**per therm**
126			**Maximum (COG+25%)**		**$ (0.0268)**	
127	C&I HLF Demand Costs Allocated per SMBA					
128	PLUS: Residential Demand Reallocation to C&I HLF					
129	C&I HLF Total Adjusted Demand Costs					
130	C&I HLF Projected Prorated Sales					
131	**Demand Cost of Gas Rate**	**$ (0.0490)**				
132						
133	C&I HLF Commodity Costs Allocated per SMBA					
134	PLUS: Residential Commodity Reallocation to C&I HLF					
135	C&I HLF Total Adjusted Commodity Costs					
136	C&I HLF Projected Prorated Sales					
137	**Commodity Cost of Gas Rate**	**$ 0.1523**				
138						
139	Indirect Cost of Gas	$ (0.1247)				
140						
141	Total C&I HLF Cost of Gas Rate	$ (0.0214)				
142						
143	**COM/IND HIGH WINTER USE COST OF GAS RATE**		**COGwh**		**$ (0.1059)**	**per therm**
144			**Maximum (COG+25%)**		**$ (0.1323)**	
145	C&I LLF Demand Costs Allocated per SMBA					
146	PLUS: Residential Demand Reallocation to C&I LLF					
147	C&I LLF Total Adjusted Demand Costs					
148	C&I LLF Projected Prorated Sales					
149	**Demand Cost of Gas Rate**	**$ (0.0384)**				
150						
151	C&I LLF Commodity Costs Allocated per SMBA					
152	PLUS: Residential Commodity Reallocation to C&I LLF					
153	C&I LLF Total Adjusted Commodity Costs					
154	C&I LLF Projected Prorated Sales					
155	**Commodity Cost of Gas Rate**	**$ 0.0572**				
156						
157	**Indirect Cost of Gas**	-0.1247				
158						
159	**Total C&I LLF Cost of Gas Rate**	**$ (0.1059)**				

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

Base Capacity Costs

1	**BASE SENDOUT BY CLASS**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**	
2	**Total Therms**								
3	Res Heat	377,414	365,240	377,414	369,438	365,240	377,414	2,232,160	Schedule 10B, LN 52
4	Res General	17,196	16,641	16,860	17,196	15,698	17,196	100,786	Schedule 10B, LN 53
5	G50 Low Annual-Low Winter	136,985	132,566	129,297	136,985	129,468	125,433	790,735	Schedule 10B, LN 54
6	G40 Low Annual-High Winter	128,493	124,348	128,493	125,268	124,348	128,493	759,443	Schedule 10B, LN 55
7	G51 Med Annual-Low Winter	202,971	199,463	206,111	205,072	194,968	206,111	1,214,696	Schedule 10B, LN 56
8	G41 Med Annual-High Winter	140,904	136,359	140,904	132,447	136,359	140,904	827,877	Schedule 10B, LN 57
9	G52 High Annual-Low Winter	22,505	21,903	21,537	22,634	21,729	22,634	132,942	Schedule 10B, LN 58
10	G42 High Annual-High Winter	11,616	11,241	10,905	11,616	11,241	11,616	68,236	Schedule 10B, LN 59
11	Total Firm Sales	1,038,084	1,007,761	1,031,522	1,020,656	999,050	1,029,801	6,126,874	Sum LN 3 : LN 10
12									
13	**% of Total**								
14	Res Heat	36.36%	36.24%	36.59%	36.20%	36.56%	36.65%		LN 3 / LN 11
15	Res General	1.66%	1.65%	1.63%	1.68%	1.57%	1.67%		LN 4 / LN 11
16	G50 Low Annual-Low Winter	13.20%	13.15%	12.53%	13.42%	12.96%	12.18%		LN 5 / LN 11
17	G40 Low Annual-High Winter	12.38%	12.34%	12.46%	12.27%	12.45%	12.48%		LN 6 / LN 11
18	G51 Med Annual-Low Winter	19.55%	19.79%	19.98%	20.09%	19.52%	20.01%		LN 7 / LN 11
19	G41 Med Annual-High Winter	13.57%	13.53%	13.66%	12.98%	13.65%	13.68%		LN 8 / LN 11
20	G52 High Annual-Low Winter	2.17%	2.17%	2.09%	2.22%	2.18%	2.20%		LN 9 / LN 11
21	G42 High Annual-High Winter	1.12%	1.12%	1.06%	1.14%	1.13%	1.13%		LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		LN 11 / LN 11
23									
24	**PIPELINE BASE DEMAND COSTS**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 387,658	Schedule 1A, LN 69
26	Res Heat	$ 23,490	$ 23,416	$ 23,639	$ 23,386	$ 23,620	$ 23,679	$ 141,231	LN 25 * LN 14
27	Res General	$ 1,070	$ 1,067	$ 1,056	$ 1,089	$ 1,015	$ 1,079	$ 6,376	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 8,526	$ 8,499	$ 8,099	$ 8,671	$ 8,373	$ 7,870	$ 50,037	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 7,997	$ 7,972	$ 8,048	$ 7,930	$ 8,042	$ 8,062	$ 48,051	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 12,633	$ 12,788	$ 12,910	$ 12,981	$ 12,609	$ 12,931	$ 76,852	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 8,770	$ 8,742	$ 8,826	$ 8,384	$ 8,818	$ 8,840	$ 52,381	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 1,401	$ 1,404	$ 1,349	$ 1,433	$ 1,405	$ 1,420	$ 8,412	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 723	$ 721	$ 683	$ 735	$ 727	$ 729	$ 4,318	LN 25 * LN 21
34									
35	Residential	$ 24,560	$ 24,483	$ 24,695	$ 24,475	$ 24,636	$ 24,758	$ 147,607	LN 26 + LN 27
36	SALES HLF CLASSES	$ 22,559	$ 22,691	$ 22,357	$ 23,086	$ 22,387	$ 22,221	$ 135,302	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 17,490	$ 17,435	$ 17,557	$ 17,049	$ 17,587	$ 17,631	$ 104,749	LN 29 + LN 31 + LN 33
38									

Remaining Capacity Costs

Ln		Column A	Column B	Column C	Column D	
39		Design Day Demand (MMBtu)	Avg Daily Base Use Load (MMBtu)	Remaining Design Day Demand (MMBtu)	% of Total Remaining Design Day Demand	
40	Res Heat	16,217	0	16,217	46%	Company Analysis
41	Res General	139	0	139	0.4%	Company Analysis
42	G50 Low Annual-Low Winter	532	0	532	1.5%	Company Analysis
43	G40 Low Annual-High Winter	8,437	0	8,437	24%	Company Analysis
44	G51 Med Annual-Low Winter	1,091	0	1,091	3.1%	Company Analysis
45	G41 Med Annual-High Winter	7,803	0	7,803	22%	Company Analysis
46	G52 High Annual-Low Winter	66	0	66	0.2%	Company Analysis
47	G42 High Annual-High Winter	415	0	415	1.2%	Company Analysis
48	TOTAL	34,700	0	34,700	99%	Sum LN 40 : LN 47

49

50 **REMAINING PIPELINE DEMAND**

Ln		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER	
51		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 46,744	$ 21,107	$ 509	$ 231	$ 2,308	$ 11,881	$ 82,780	Schedule 1A, LN 70
53									
54	Res Heat	$ 21,851	$ 9,867	$ 238	$ 108	$ 1,079	$ 5,554	$ 38,697	LN 40 Col D * LN 52
55	Res General	$ 196	$ 89	$ 2	$ 1	$ 10	$ 50	$ 347	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 688	$ 310	$ 7	$ 3	$ 34	$ 175	$ 1,218	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 11,338	$ 5,120	$ 123	$ 56	$ 560	$ 2,882	$ 20,078	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 1,564	$ 706	$ 17	$ 8	$ 77	$ 397	$ 2,769	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 10,448	$ 4,718	$ 114	$ 52	$ 516	$ 2,655	$ 18,502	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 100	$ 45	$ 1	$ 0	$ 5	$ 26	$ 178	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 560	$ 253	$ 6	$ 3	$ 28	$ 142	$ 991	LN 47 Col D * LN 52
62	TOTAL	$ 46,744	$ 21,107	$ 509	$ 231	$ 2,308	$ 11,881	$ 82,780	Sum LN 54 : LN 61
63									
64	Residential	$ 22,047	$ 9,956	$ 240	$ 109	$ 1,089	$ 5,604	$ 39,044	LN 54 + LN 55
65	SALES HLF CLASSES	$ 2,352	$ 1,062	$ 26	$ 12	$ 116	$ 598	$ 4,165	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 22,345	$ 10,090	$ 243	$ 110	$ 1,103	$ 5,679	$ 39,571	LN 57 + LN 59 + LN 61

67

68 **PEAKING AND STORAGE DEMAND**

Ln		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER	
69		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 325,480	$ 146,972	$ 3,541	$ 1,606	$ 16,072	$ 82,727	$ 576,398	Schedule 1A, LN 73
71									
72	Res Heat	$ 152,151	$ 68,704	$ 1,655	$ 751	$ 7,513	$ 38,672	$ 269,447	LN 40 Col D * LN 70
73	Res General	$ 1,365	$ 616	$ 15	$ 7	$ 67	$ 347	$ 2,417	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 4,788	$ 2,162	$ 52	$ 24	$ 236	$ 1,217	$ 8,478	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 78,944	$ 35,648	$ 859	$ 389	$ 3,898	$ 20,065	$ 139,804	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 10,889	$ 4,917	$ 118	$ 54	$ 538	$ 2,768	$ 19,284	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 72,747	$ 32,849	$ 792	$ 359	$ 3,592	$ 18,490	$ 128,829	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 699	$ 316	$ 8	$ 3	$ 35	$ 178	$ 1,238	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 3,897	$ 1,759	$ 42	$ 19	$ 192	$ 990	$ 6,900	LN 47 Col D * LN 70
80	TOTAL	$ 325,480	$ 146,972	$ 3,541	$ 1,606	$ 16,072	$ 82,727	$ 576,398	Sum LN 72 : LN 79
81									
82	Residential	$ 153,516	$ 69,321	$ 1,670	$ 757	$ 7,581	$ 39,019	$ 271,864	LN 72 + LN 73
83	SALES HLF CLASSES	$ 16,376	$ 7,395	$ 178	$ 81	$ 809	$ 4,162	$ 29,000	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 155,588	$ 70,256	$ 1,693	$ 768	$ 7,683	$ 39,546	$ 275,533	LN 75 + LN 77 + LN 79

85

LN	CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS								
87		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 76
89									
90	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 88
91	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 88
98	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 90 : LN 97
99									
100	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 90 + LN 91
101	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 93 + LN 95 + LN 97

103

LN	INTERRUPTIBLE MARGINS BY CLASS								
105		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER	
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 77
107									
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117									
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115

121

122 **REMAINING RE-ENTRY FEE CREDIT**

LN		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER	
123		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**	
124	NH DIVISION - RE-ENTRY FEE CREDITS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Schedule 1A, LN 78
125									
126	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 124
127	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 124
128	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 124
129	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 124
130	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 124
131	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 124
132	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 124
133	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 124
134	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 126 : LN 133
135									
136	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 126 + LN 127
137	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 128 + LN 130 + LN 132
138	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 129 + LN 131 + LN 133

139

140 **TOTAL NON-BASE CAPACITY COSTS**

LN		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER	
141		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**	
142	Res Heat	$ 174,003	$ 78,571	$ 1,893	$ 858	$ 8,592	$ 44,226	$ 308,144	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 1,561	$ 705	$ 17	$ 8	$ 77	$ 397	$ 2,764	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 5,475	$ 2,472	$ 60	$ 27	$ 270	$ 1,392	$ 9,696	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 90,282	$ 40,767	$ 982	$ 445	$ 4,458	$ 22,947	$ 159,882	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 12,453	$ 5,623	$ 135	$ 61	$ 615	$ 3,165	$ 22,054	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 83,195	$ 37,567	$ 905	$ 410	$ 4,108	$ 21,146	$ 147,331	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 799	$ 361	$ 9	$ 4	$ 39	$ 203	$ 1,416	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 4,456	$ 2,012	$ 48	$ 22	$ 220	$ 1,133	$ 7,891	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 372,224	$ 168,079	$ 4,050	$ 1,836	$ 18,380	$ 94,608	$ 659,178	Sum LN 142 : LN 149
151									
152	Residential	$ 175,563	$ 79,276	$ 1,910	$ 866	$ 8,669	$ 44,623	$ 310,908	LN 142 + LN 143
153	SALES HLF CLASSES	$ 18,728	$ 8,457	$ 204	$ 92	$ 925	$ 4,760	$ 33,165	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 177,933	$ 80,346	$ 1,936	$ 878	$ 8,786	$ 45,225	$ 315,104	LN 145 + LN 147 + LN 149

155

156 **TOTAL CAPACITY COSTS**

LN		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	SUMMER	
157		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**	
158	Res Heat	$ 197,493	$ 101,988	$ 25,533	$ 24,245	$ 32,213	$ 67,905	$ 449,375	LN 142 + LN 26
159	Res General	$ 2,631	$ 1,772	$ 1,073	$ 1,096	$ 1,092	$ 1,476	$ 9,140	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 14,001	$ 10,971	$ 8,158	$ 8,698	$ 8,643	$ 9,261	$ 59,734	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 98,279	$ 48,739	$ 9,030	$ 8,375	$ 12,500	$ 31,009	$ 207,933	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 25,086	$ 18,411	$ 13,045	$ 13,043	$ 13,224	$ 16,097	$ 98,906	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 91,965	$ 46,309	$ 9,731	$ 8,795	$ 12,927	$ 29,986	$ 199,712	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 2,200	$ 1,765	$ 1,358	$ 1,437	$ 1,445	$ 1,623	$ 9,828	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 5,179	$ 2,733	$ 732	$ 757	$ 947	$ 1,861	$ 12,209	LN 149 + LN 33
166	TOTAL	$ 436,834	$ 232,689	$ 68,660	$ 66,446	$ 82,990	$ 159,218	$ 1,046,835	Sum LN 158 : LN 165
167									
168	Residential	$ 200,124	$ 103,759	$ 26,606	$ 25,341	$ 33,305	$ 69,381	$ 458,515	LN 158 + LN 159
169	SALES HLF CLASSES	$ 41,287	$ 31,148	$ 22,561	$ 23,178	$ 23,312	$ 26,981	$ 168,467	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 195,423	$ 97,781	$ 19,493	$ 17,927	$ 26,373	$ 62,856	$ 419,853	LN 161 + LN 163 + LN 165
171									
172	% ALLOCATION BETWEEN SALES HLF AND LLF								
173	SALES HLF CLASSES							29%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES							71%	LN 170 / (LN 169 + LN 170)

Northern Utilities - NEW HAMPSHIRE DIVISION
2009 - 2010 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Normal Winter	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL	Summer
1	Res Heat	1,048,455	652,382	376,161	360,045	367,413	486,902	15,839,881	3,291,358
2	Res General	24,019	21,169	16,456	17,086	15,298	17,578	305,838	111,606
3	**Total Residential**	**1,072,474**	**673,551**	**392,617**	**377,131**	**382,710**	**504,480**	**16,145,719**	**3,402,963**
4	G50 Low Annual-Low Winter	140,830	147,328	126,201	140,995	126,165	122,412	1,733,000	803,931
5	G40 Low Annual-High Winter	407,778	235,886	128,564	122,083	129,351	191,971	7,996,739	1,215,633
6	G51 Med Annual-Low Winter	198,336	217,272	202,190	199,858	189,994	202,879	2,917,613	1,210,529
7	G41 Med Annual-High Winter	406,829	307,407	145,785	129,079	162,102	269,248	7,029,986	1,420,450
8	G52 High Annual-Low Winter	21,991	23,787	21,021	23,127	21,175	28,782	341,302	139,883
9	G42 High Annual-High Winter	27,306	14,363	10,644	12,014	44,548	66,572	678,265	175,447
10	**Total C&I**	**1,203,070**	**946,043**	**634,404**	**627,156**	**673,336**	**881,864**	**20,696,904**	**4,965,873**
11	**Total Sales**	**2,275,544**	**1,619,594**	**1,027,021**	**1,004,288**	**1,056,046**	**1,386,344**	**36,842,623**	**8,368,836**
12									
13	Residential Heat & Non Heat	1,072,474	673,551	392,617	377,131	382,710	504,480	16,145,719	3,402,963
14	SALES HLF CLASSES	361,157	388,387	349,412	363,980	337,334	354,073	4,991,914	2,154,343
15	SALES LLF CLASSES	841,913	557,656	284,992	263,176	336,001	527,791	15,704,990	2,811,529
16	**Total Firm Sales**	**2,275,544**	**1,619,594**	**1,027,021**	**1,004,288**	**1,056,046**	**1,386,344**	**36,842,623**	**8,368,836**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)								
20	Normal Winter	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**TOTAL**	**Summer**
21	Res Heat	1,072,954	668,969	385,390	369,438	377,030	498,916	16,092,568	3,372,697
22	Res General	24,580	21,707	16,860	17,532	15,698	18,012	311,285	114,389
23	G50 Low Annual-Low Winter	144,120	151,074	129,297	144,674	129,468	125,433	1,765,906	824,065
24	G40 Low Annual-High Winter	417,307	241,883	131,718	125,268	132,737	196,708	8,119,242	1,245,621
25	G51 Med Annual-Low Winter	202,971	222,796	207,151	205,072	194,968	207,885	2,971,427	1,240,842
26	G41 Med Annual-High Winter	416,335	315,222	149,361	132,447	166,345	275,892	7,142,046	1,455,603
27	G52 High Annual-Low Winter	22,505	24,392	21,537	23,730	21,729	29,492	347,582	143,385
28	G42 High Annual-High Winter	27,944	14,729	10,905	12,327	45,714	68,215	689,649	179,833
29	**Subtotal**								
30	Residential	1,097,534	690,676	402,250	386,970	392,728	516,928	16,403,853	3,487,086
31	SALES HLF CLASSES	369,596	398,262	357,985	373,476	346,164	362,810	5,084,916	2,208,292
32	SALES LLF CLASSES	861,586	571,834	291,984	270,042	344,796	540,815	15,950,937	2,881,057
33	**Total Firm Sales**	2,328,715	1,660,772	1,052,219	1,030,488	1,083,689	1,420,553	37,439,705	8,576,436

Northern Utilities - NEW HAMPSHIRE DIVISION
2009 - 2010 Period

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

Sendout by Class - Allocation between Base & Remaining Sendout

35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	12,175
37	Res General	555
38	G50 Low Annual-Low Winter	4,419
39	G40 Low Annual-High Winter	4,145
40	G51 Med Annual-Low Winter	6,649
41	G41 Med Annual-High Winter	4,545
42	G52 High Annual-Low Winter	730
43	G42 High Annual-High Winter	375
44	**Subtotal**	
45	Residential	12,729
46	SALES HLF CLASSES	11,798
47	SALES LLF CLASSES	9,065
48	**Total Firm Sales**	**33,592**

49	**BASE SENDOUT BY CLASS - Therms**								
50	Days per Month	31	30	31	31	30	31		
51		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**TOTAL**	**SUMMER**
52	Res Heat	377,414	365,240	377,414	369,438	365,240	377,414	4,435,772	2,232,160
53	Res General	17,196	16,641	16,860	17,196	15,698	17,196	201,187	100,786
54	G50 Low Annual-Low Winter	136,985	132,566	129,297	136,985	129,468	125,433	1,576,846	790,735
55	G40 Low Annual-High Winter	128,493	124,348	128,493	125,268	124,348	128,493	1,509,675	759,443
56	G51 Med Annual-Low Winter	202,971	199,463	206,111	205,072	194,968	206,111	2,418,121	1,214,696
57	G41 Med Annual-High Winter	140,904	136,359	140,904	132,447	136,359	140,904	1,650,576	827,877
58	G52 High Annual-Low Winter	22,505	21,903	21,537	22,634	21,729	22,634	265,093	132,942
59	G42 High Annual-High Winter	11,616	11,241	10,905	11,616	11,241	11,616	136,059	68,236
60	**Subtotal**								
61	Residential	394,610	381,881	394,274	386,634	380,938	394,610	4,636,959	2,332,946
62	SALES HLF CLASSES	362,461	353,933	356,945	364,691	346,164	354,178	4,260,059	2,138,372
63	SALES LLF CLASSES	281,013	271,948	280,302	269,331	271,948	281,013	3,296,310	1,655,556
64	**Total Firm Sales**	1,038,084	1,007,761	1,031,522	1,020,656	999,050	1,029,801	12,193,328	6,126,874
65									

66	**REMAINING SENDOUT BY CLASS - Therms**								
67		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**TOTAL**	**SUMMER**
68	Res Heat	695,540	303,729	7,976	-	11,790	121,502	11,656,796	1,140,537
69	Res General	7,384	5,066	-	336	-	816	110,098	13,603
70	G50 Low Annual-Low Winter	7,135	18,507	-	7,688	-	-	189,061	33,331
71	G40 Low Annual-High Winter	288,814	117,535	3,225	-	8,389	68,215	6,609,566	486,178
72	G51 Med Annual-Low Winter	-	23,333	1,039	-	-	1,774	553,306	26,146
73	G41 Med Annual-High Winter	275,431	178,864	8,457	-	29,986	134,988	5,491,471	627,726
74	G52 High Annual-Low Winter	-	2,489	-	1,097	-	6,858	82,490	10,444
75	G42 High Annual-High Winter	16,328	3,487	-	711	34,473	56,599	553,590	111,597
76	**Subtotal**								
77	Residential	702,924	308,796	7,976	336	11,790	122,318	11,766,894	1,154,140
78	SALES HLF CLASSES	7,135	44,329	1,039	8,785	-	8,632	824,857	69,920
79	SALES LLF CLASSES	580,573	299,886	11,682	711	72,848	259,802	12,654,627	1,225,501
80	**Total Firm Sales**	1,290,632	653,011	20,697	9,832	84,638	390,752	25,246,378	2,449,562

Sendout by Class - Allocation between Base & Remaining Sendout

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

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

	Total Division Billed Deliveries (Dth)										
	2010	Compared to 2009					Compared to 2008				
	Forecast	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	432,762	437,655	-4,893	-1.1%	2,820	-7,713	537,641	-104,879	-19.5%	9,253	-114,132
Jun	342,189	317,236	24,952	7.9%	6,037	18,915	388,205	-46,017	-11.9%	10,288	-56,304
Jul	284,559	281,438	3,121	1.1%	1,839	1,282	381,822	-97,263	-25.5%	10,835	-108,098
Aug	270,037	266,995	3,042	1.1%	1,748	1,294	270,911	-874	-0.3%	7,701	-8,575
Sep	310,686	307,587	3,099	1.0%	2,016	1,083	290,395	20,291	7.0%	7,983	12,308
Oct	352,562	349,364	3,199	0.9%	2,292	907	357,596	-5,034	-1.4%	9,823	-14,857
Off-Peak	1,992,795	1,960,274	32,521	1.7%	16,852	15,669	2,226,571	-233,775	-10.5%	57,682	-291,458

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

	Total Division Meter Counts						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	28,050	27,870	180	0.6%	27,575	475	1.7%
Jun	28,282	27,754	528	1.9%	27,552	730	2.7%
Jul	28,272	28,089	184	0.7%	27,492	780	2.8%
Aug	28,223	28,040	184	0.7%	27,443	780	2.8%
Sep	28,189	28,006	184	0.7%	27,435	754	2.7%
Oct	28,170	27,987	184	0.7%	27,417	753	2.7%
Off-Peak	28,198	27,957	240	0.9%	27,486	712	2.6%

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

	Total Division Use Per Meter						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	15.43	15.70	-0.27	-1.8%	19.50	-4.07	-20.9%
Jun	12.10	11.43	0.67	5.9%	14.09	-1.99	-14.1%
Jul	10.06	10.02	0.05	0.5%	13.89	-3.82	-27.5%
Aug	9.57	9.52	0.05	0.5%	9.87	-0.30	-3.1%
Sep	11.02	10.98	0.04	0.3%	10.58	0.44	4.1%
Oct	12.52	12.48	0.03	0.3%	13.04	-0.53	-4.0%
Off-Peak	70.67	70.12	0.56	0.8%	81.01	-10.28	-12.7%

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

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

	Residential Non-Heat Billed Deliveries (Dth)										
	2010	Compared to 2009					Compared to 2008				
	Forecast	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	2,456	2,562	-106	-4.1%	-92	-14	2,343	113	4.8%	-137	250
Jun	2,046	2,457	-412	-16.8%	-85	-327	2,185	-139	-6.4%	-152	13
Jul	1,748	1,811	-63	-3.5%	-66	2	1,874	-126	-6.7%	-131	5
Aug	1,646	1,706	-59	-3.5%	-62	3	1,736	-90	-5.2%	-122	32
Sep	1,688	1,751	-63	-3.6%	-65	2	1,814	-126	-6.9%	-129	3
Oct	1,728	1,793	-65	-3.6%	-67	2	1,858	-130	-7.0%	-134	4
Off-Peak	11,312	12,080	-769	-6.4%	-437	-331	11,811	-499	-4.2%	-810	311

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

	Residential Non-Heat Meter Counts						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1,614	1,674	-60	-3.6%	1,714	-100	-5.8%
Jun	1,610	1,667	-57	-3.4%	1,730	-120	-7.0%
Jul	1,600	1,660	-60	-3.6%	1,720	-120	-7.0%
Aug	1,596	1,656	-60	-3.6%	1,716	-120	-7.0%
Sep	1,574	1,634	-60	-3.7%	1,694	-120	-7.1%
Oct	1,550	1,610	-60	-3.7%	1,670	-120	-7.2%
Off-Peak	1,590	1,650	-60	-3.6%	1,707	-117	-6.9%

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

	Residential Non-Heat Use Per Meter						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	1.52	1.53	-0.01	-0.6%	1.37	0.15	11.3%
Jun	1.27	1.47	-0.20	-13.8%	1.26	0.01	0.6%
Jul	1.09	1.09	0.00	0.1%	1.09	0.00	0.3%
Aug	1.03	1.03	0.00	0.2%	1.01	0.02	2.0%
Sep	1.07	1.07	0.00	0.1%	1.07	0.00	0.2%
Oct	1.12	1.11	0.00	0.1%	1.11	0.00	0.2%
Off-Peak	7.11	7.32	-0.21	-2.8%	6.92	0.19	2.7%

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

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

	Residential Heat Billed Deliveries (Dth)										
	2010	Compared to 2009					Compared to 2008				
	Forecast	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	107,209	106,345	865	0.8%	1,018	-154	102,985	4,224	4.1%	2,687	1,537
Jun	63,043	37,302	25,741	69.0%	853	24,888	59,578	3,465	5.8%	2,132	1,332
Jul	39,947	39,588	359	0.9%	376	-17	37,086	2,862	7.7%	1,329	1,533
Aug	34,690	34,380	310	0.9%	327	-17	31,431	3,259	10.4%	1,128	2,131
Sep	40,548	40,187	361	0.9%	382	-21	37,534	3,014	8.0%	1,344	1,669
Oct	47,867	47,440	427	0.9%	451	-23	44,954	2,913	6.5%	1,610	1,304
Off-Peak	333,305	305,241	28,063	9.2%	3,579	24,485	313,568	19,737	6.3%	10,726	9,011

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

	Residential Heat Meter Counts						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	20,140	19,949	191	1.0%	19,628	512	2.6%
Jun	20,318	19,864	454	2.3%	19,616	702	3.6%
Jul	20,298	20,107	191	1.0%	19,596	702	3.6%
Aug	20,257	20,066	191	1.0%	19,555	702	3.6%
Sep	20,303	20,112	191	0.9%	19,601	702	3.6%
Oct	20,307	20,116	191	0.9%	19,605	702	3.6%
Off-Peak	20,271	20,036	235	1.2%	19,600	670	3.4%

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data. Page 2 - 4; Sum of Column 2 of Meter Counts table.
Note 3 Actual Data. Page 2 - 4; Sum of Column 5 of Meter Counts table.

	Residential Heat Use Per Meter						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	5.32	5.33	-0.01	-0.1%	5.25	0.08	1.5%
Jun	3.10	1.88	1.22	65.2%	3.04	0.07	2.2%
Jul	1.97	1.97	0.00	0.0%	1.89	0.08	4.0%
Aug	1.71	1.71	0.00	0.0%	1.61	0.11	6.5%
Sep	2.00	2.00	0.00	-0.1%	1.91	0.08	4.3%
Oct	2.36	2.36	0.00	0.0%	2.29	0.06	2.8%
Off-Peak	16.44	15.23	1.21	7.9%	16.00	0.47	2.9%

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

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

	Total Division C&I Billed Deliveries (Dth)										
	2010	Compared to 2009					Compared to 2008				
	Forecast	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
May	323,097	328,748	-5,651	-1.7%	2,565	-8,216	432,312	-109,215	-25.3%	4,352	-113,567
Jun	277,100	277,477	-377	-0.1%	5,863	-6,239	326,443	-49,342	-15.1%	7,810	-57,153
Jul	242,864	240,039	2,825	1.2%	2,003	823	342,862	-99,998	-29.2%	11,019	-111,017
Aug	233,701	230,909	2,791	1.2%	1,928	864	237,744	-4,043	-1.7%	7,645	-11,689
Sep	268,450	265,649	2,801	1.1%	2,238	563	251,047	17,403	6.9%	7,052	10,351
Oct	302,967	300,131	2,836	0.9%	2,528	308	310,785	-7,817	-2.5%	8,677	-16,494
Off-Peak	1,648,179	1,642,952	5,226	0.3%	17,079	-11,853	1,901,192	-253,013	-13.3%	48,833	-301,847

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

	Total Division C&I Meter Counts						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	6,296	6,247	49	0.8%	6,233	63	1.0%
Jun	6,354	6,223	131	2.1%	6,206	148	2.4%
Jul	6,374	6,322	53	0.8%	6,176	198	3.2%
Aug	6,370	6,318	53	0.8%	6,172	198	3.2%
Sep	6,312	6,260	53	0.8%	6,140	172	2.8%
Oct	6,313	6,261	53	0.8%	6,142	171	2.8%
Off-Peak	6,337	6,272	65	1.0%	6,178	159	2.6%

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data. Page 2 - 4; Sum of Column 2 of Meter Counts table.
Note 3 Actual Data. Page 2 - 4; Sum of Column 5 of Meter Counts table.

	Total Division C&I Use Per Meter						
	2010	Compared to 2009			Compared to 2008		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
May	51.32	52.62	-1.31	-2.5%	69.36	-18.04	-26.0%
Jun	43.61	44.59	-0.98	-2.2%	52.60	-8.99	-17.1%
Jul	38.10	37.97	0.13	0.3%	55.52	-17.42	-31.4%
Aug	36.68	36.55	0.14	0.4%	38.52	-1.83	-4.8%
Sep	42.53	42.44	0.09	0.2%	40.89	1.64	4.0%
Oct	47.99	47.94	0.05	0.1%	50.60	-2.61	-5.2%
Off-Peak	260.09	261.96	-1.87	-0.7%	307.73	-47.26	-15.4%

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

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

Sales Service Deliveries (Dth)
Total Forecast Deliveries times Sales Service Percentage

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-10	2,456	107,209	41,697	14,400	41,600	20,281	2,792	2,249	0	232,685
Jun-10	2,046	63,043	22,795	14,237	29,706	20,996	1,388	2,299	0	156,509
Jul-10	1,748	39,947	13,653	13,402	15,482	21,472	1,130	2,232	0	109,067
Aug-10	1,646	34,690	11,763	13,585	12,437	19,256	1,158	2,228	0	96,763
Sep-10	1,688	40,548	14,275	13,924	17,890	20,968	4,916	2,337	0	116,545
Oct-10	1,728	47,867	18,873	12,034	26,470	19,945	6,545	2,830	0	136,291
Off-Peak	11,312	333,305	123,056	81,583	143,584	122,918	17,929	14,174	0	847,861

Total Forecast Deliveries (Dth)
Company Forecast

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-10	2,456	107,209	48,502	16,317	60,457	29,238	18,182	54,536	95,865	432,762
Jun-10	2,046	63,043	26,515	16,132	43,172	30,269	9,038	55,749	96,226	342,189
Jul-10	1,748	39,947	15,881	15,186	22,500	30,955	7,361	54,142	96,840	284,559
Aug-10	1,646	34,690	13,682	15,393	18,074	27,761	7,537	54,042	97,211	270,037
Sep-10	1,688	40,548	16,605	15,777	25,999	30,228	32,014	56,676	91,152	310,686
Oct-10	1,728	47,867	21,953	13,636	38,468	28,753	42,617	68,623	88,916	352,562
Off-Peak	11,312	333,305	143,139	92,440	208,670	177,203	116,750	343,768	566,209	1,992,795

Sales Service Percentage
Company Forecast

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
May-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	54%
Jun-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	46%
Jul-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	38%
Aug-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	36%
Sep-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	38%
Oct-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	39%

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

	Total Deliveries (Dth)	Estimated Company Use Factor	Estimated Company Use (Dth)	Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Estimated Receipts to Deliveries Ratio	Estimated Division City-Gate Receipts (Dth)
May-10	432,762	0.02%	101	232,685	232,786	1.00	232,872
Jun-10	342,189	0.11%	383	156,509	156,892	1.06	166,077
Jul-10	284,559	0.06%	172	109,067	109,239	0.96	105,222
Aug-10	270,037	0.11%	300	96,763	97,063	1.06	103,049
Sep-10	310,686	0.12%	371	116,545	116,916	0.93	108,369
Oct-10	352,562	0.07%	234	136,291	136,525	1.04	142,055
Off-Peak	1,992,795	0.2%	1,561	847,861	849,421	1.010	857,644

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

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**
2	**Total Therms**							
3	Res Heat	377,414	365,240	377,414	369,438	365,240	377,414	2,232,160
4	Res General	17,196	16,641	16,860	17,196	15,698	17,196	100,786
5	G50 Low Annual-Low Winter	136,985	132,566	129,297	136,985	129,468	125,433	790,735
6	G40 Low Annual-High Winter	128,493	124,348	128,493	125,268	124,348	128,493	759,443
7	G51 Med Annual-Low Winter	202,971	199,463	206,111	205,072	194,968	206,111	1,214,696
8	G41 Med Annual-High Winter	140,904	136,359	140,904	132,447	136,359	140,904	827,877
9	G52 High Annual-Low Winter	22,505	21,903	21,537	22,634	21,729	22,634	132,942
10	G42 High Annual-High Winter	11,616	11,241	10,905	11,616	11,241	11,616	68,236
11	Total Firm Sales	1,038,084	1,007,761	1,031,522	1,020,656	999,050	1,029,801	6,126,874
12	**% of Total**							
13	Res Heat	36.36%	36.24%	36.59%	36.20%	36.56%	36.65%	
14	Res General	1.66%	1.65%	1.63%	1.68%	1.57%	1.67%	
15	G50 Low Annual-Low Winter	13.20%	13.15%	12.53%	13.42%	12.96%	12.18%	
16	G40 Low Annual-High Winter	12.38%	12.34%	12.46%	12.27%	12.45%	12.48%	
17	G51 Med Annual-Low Winter	19.55%	19.79%	19.98%	20.09%	19.52%	20.01%	
18	G41 Med Annual-High Winter	13.57%	13.53%	13.66%	12.98%	13.65%	13.68%	
19	G52 High Annual-Low Winter	2.17%	2.17%	2.09%	2.22%	2.18%	2.20%	
20	G42 High Annual-High Winter	1.12%	1.12%	1.06%	1.14%	1.13%	1.13%	
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

22	**BASE COMMODITY COSTS Excld Hedging**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**
23	TOTAL BASE COMMODITY Excld Hedging	$ 631,418	$ 616,175	$ 633,210	$ 633,397	$ 623,523	$ 657,429	$ 3,795,153
24	Res Heat	$ 229,563	$ 223,318	$ 231,680	$ 229,265	$ 227,952	$ 240,943	$ 1,382,722
25	Res General	$ 10,459	$ 10,175	$ 10,350	$ 10,671	$ 9,797	$ 10,978	$ 62,430
26	G50 Low Annual-Low Winter	$ 83,322	$ 81,055	$ 79,370	$ 85,010	$ 80,803	$ 80,077	$ 489,637
27	G40 Low Annual-High Winter	$ 78,156	$ 76,030	$ 78,877	$ 77,739	$ 77,608	$ 82,030	$ 470,440
28	G51 Med Annual-Low Winter	$ 123,458	$ 121,957	$ 126,524	$ 127,263	$ 121,682	$ 131,582	$ 752,467
29	G41 Med Annual-High Winter	$ 85,705	$ 83,374	$ 86,495	$ 82,194	$ 85,104	$ 89,954	$ 512,826
30	G52 High Annual-Low Winter	$ 13,688	$ 13,392	$ 13,221	$ 14,046	$ 13,562	$ 14,449	$ 82,359
31	G42 High Annual-High Winter	$ 7,066	$ 6,873	$ 6,694	$ 7,209	$ 7,016	$ 7,416	$ 42,273
32								
33	Residential	$ 240,023	$ 233,493	$ 242,029	$ 239,937	$ 237,749	$ 251,921	$ 1,445,152
34	SALES HLF CLASSES	$ 220,468	$ 216,405	$ 219,115	$ 226,319	$ 216,047	$ 226,109	$ 1,324,462
35	SALES LLF CLASSES	$ 170,927	$ 166,277	$ 172,066	$ 167,141	$ 169,727	$ 179,400	$ 1,025,539

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**							
37	TOTAL BASE HEDGING COMMODITY	$ (5,509)	$ -	$ -	$ -	$ -	$ 3,871	$ (1,638)
38	Res Heat	$ (2,003)	$ -	$ -	$ -	$ -	$ 1,419	$ (584)
39	Res General	$ (91)	$ -	$ -	$ -	$ -	$ 65	$ (27)
40	G50 Low Annual-Low Winter	$ (727)	$ -	$ -	$ -	$ -	$ 471	$ (255)
41	G40 Low Annual-High Winter	$ (682)	$ -	$ -	$ -	$ -	$ 483	$ (199)
42	G51 Med Annual-Low Winter	$ (1,077)	$ -	$ -	$ -	$ -	$ 775	$ (302)
43	G41 Med Annual-High Winter	$ (748)	$ -	$ -	$ -	$ -	$ 530	$ (218)
44	G52 High Annual-Low Winter	$ (119)	$ -	$ -	$ -	$ -	$ 85	$ (34)
45	G42 High Annual-High Winter	$ (62)	$ -	$ -	$ -	$ -	$ 44	$ (18)
46								
47	Residential	$ (2,094)	$ -	$ -	$ -	$ -	$ 1,483	$ (611)
48	SALES HLF CLASSES	$ (1,923)	$ -	$ -	$ -	$ -	$ 1,331	$ (592)
49	SALES LLF CLASSES	$ (1,491)	$ -	$ -	$ -	$ -	$ 1,056	$ (435)

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

Base Commodity Costs

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

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

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**
51	**Total Therms**							
52	Res Heat	695,540	303,729	7,976	-	11,790	121,502	1,140,537
53	Res General	7,384	5,066	-	336	-	816	13,603
54	G50 Low Annual-Low Winter	7,135	18,507	-	7,688	-	-	33,331
55	G40 Low Annual-High Winter	288,814	117,535	3,225	-	8,389	68,215	486,178
56	G51 Med Annual-Low Winter	-	23,333	1,039	-	-	1,774	26,146
57	G41 Med Annual-High Winter	275,431	178,864	8,457	-	29,986	134,988	627,726
58	G52 High Annual-Low Winter	-	2,489	-	1,097	-	6,858	10,444
59	G42 High Annual-High Winter	16,328	3,487	-	711	34,473	56,599	111,597
60	Total Firm Sales	1,290,632	653,011	20,697	9,832	84,638	390,752	2,449,562
61	**% of Total**							
62	Res Heat	53.89%	46.51%	26.13%	26.13%	13.93%	31.09%	
63	Res General	0.57%	0.78%	1.10%	1.10%	0.00%	0.21%	
64	G50 Low Annual-Low Winter	0.55%	2.83%	25.18%	25.18%	0.00%	0.00%	
65	G40 Low Annual-High Winter	22.38%	18.00%	10.56%	10.56%	9.91%	17.46%	
66	G51 Med Annual-Low Winter	0.00%	3.57%	3.40%	3.40%	0.00%	0.45%	
67	G41 Med Annual-High Winter	21.34%	27.39%	27.70%	27.70%	35.43%	34.55%	
68	G52 High Annual-Low Winter	0.00%	0.38%	3.59%	3.59%	0.00%	1.76%	
69	G42 High Annual-High Winter	1.27%	0.53%	2.33%	2.33%	40.73%	14.48%	
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**
72	REMAINING COMMODITY Excld Hedging	$ 784,546	$ 398,631	$ 12,017	$ 5,329	$ 52,010	$ 248,569	$ 1,501,103
73	Res Heat	$ 422,803	$ 185,412	$ 3,139	$ 1,392	$ 7,245	$ 77,291	$ 697,283
74	Res General	$ 4,489	$ 3,093	$ 132	$ 59	$ -	$ 519	$ 8,292
75	G50 Low Annual-Low Winter	$ 4,337	$ 11,298	$ 3,026	$ 1,342	$ -	$ -	$ 20,003
76	G40 Low Annual-High Winter	$ 175,563	$ 71,750	$ 1,269	$ 563	$ 5,155	$ 43,394	$ 297,694
77	G51 Med Annual-Low Winter	$ -	$ 14,244	$ 409	$ 181	$ -	$ 1,128	$ 15,962
78	G41 Med Annual-High Winter	$ 167,428	$ 109,188	$ 3,329	$ 1,476	$ 18,426	$ 85,870	$ 385,717
79	G52 High Annual-Low Winter	$ -	$ 1,519	$ 432	$ 191	$ -	$ 4,363	$ 6,505
80	G42 High Annual-High Winter	$ 9,925	$ 2,129	$ 280	$ 124	$ 21,184	$ 36,004	$ 69,646
81								
82	Residential	$ 427,292	$ 188,505	$ 3,272	$ 1,451	$ 7,245	$ 77,810	$ 705,575
83	SALES HLF CLASSES	$ 4,337	$ 27,061	$ 3,867	$ 1,715	$ -	$ 5,491	$ 42,471
84	SALES LLF CLASSES	$ 352,917	$ 183,066	$ 4,878	$ 2,163	$ 44,765	$ 165,268	$ 753,057

85	**REMAINING COMMODITY HEDGING COSTS**							
86	TOTAL REMAINING COMMODITY HEDGING	$ (6,785)	$ -	$ -	$ -	$ -	$ 1,442	$ (5,344)
87	Res Heat	$ (3,657)	$ -	$ -	$ -	$ -	$ 448	$ (3,208)
88	Res General	$ (39)	$ -	$ -	$ -	$ -	$ 3	$ (36)
89	G50 Low Annual-Low Winter	$ (38)	$ -	$ -	$ -	$ -	$ -	$ (38)
90	G40 Low Annual-High Winter	$ (1,518)	$ -	$ -	$ -	$ -	$ 252	$ (1,267)
91	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ 7	$ 7
92	G41 Med Annual-High Winter	$ (1,448)	$ -	$ -	$ -	$ -	$ 498	$ (950)
93	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ 25	$ 25
94	G42 High Annual-High Winter	$ (86)	$ -	$ -	$ -	$ -	$ 209	$ 123
95								$ -
96	Residential	$ (3,695)	$ -	$ -	$ -	$ -	$ 451	$ (3,244)
97	SALES HLF CLASSES	$ (38)	$ -	$ -	$ -	$ -	$ 32	$ (6)
98	SALES LLF CLASSES	$ (3,052)	$ -	$ -	$ -	$ -	$ 958	$ (2,094)

Remaining Commodity Costs

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

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

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

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**							
100	TOTAL COMMODITY Excld Hedging	$ 1,415,964	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 905,999	$ 5,296,256
101	Res Heat	$ 652,367	$ 408,730	$ 234,819	$ 230,658	$ 235,197	$ 318,234	$ 2,080,005
102	Res General	$ 14,948	$ 13,267	$ 10,482	$ 10,730	$ 9,797	$ 11,497	$ 70,722
103	G50 Low Annual-Low Winter	$ 87,659	$ 92,353	$ 82,397	$ 86,352	$ 80,803	$ 80,077	$ 509,640
104	G40 Low Annual-High Winter	$ 253,720	$ 147,780	$ 80,146	$ 78,301	$ 82,763	$ 125,424	$ 768,134
105	G51 Med Annual-Low Winter	$ 123,458	$ 136,201	$ 126,933	$ 127,445	$ 121,682	$ 132,711	$ 768,429
106	G41 Med Annual-High Winter	$ 253,134	$ 192,561	$ 89,824	$ 83,670	$ 103,530	$ 175,824	$ 898,543
107	G52 High Annual-Low Winter	$ 13,688	$ 14,912	$ 13,652	$ 14,237	$ 13,562	$ 18,812	$ 88,864
108	G42 High Annual-High Winter	$ 16,991	$ 9,002	$ 6,974	$ 7,333	$ 28,199	$ 43,420	$ 111,919
109								
110	Residential	$ 667,315	$ 421,998	$ 245,301	$ 241,388	$ 244,994	$ 329,731	$ 2,150,727
111	SALES HLF CLASSES	$ 224,805	$ 243,466	$ 222,982	$ 228,034	$ 216,047	$ 231,600	$ 1,366,933
112	SALES LLF CLASSES	$ 523,844	$ 349,343	$ 176,945	$ 169,304	$ 214,492	$ 344,668	$ 1,778,596
113	**TOTAL HEDGING COMMODITY COSTS**							
114	TOTAL HEDGING COMMODITY	$ (12,294)	$ -	$ -	$ -	$ -	$ 5,312	$ (6,982)
115	Res Heat	$ (5,659)	$ -	$ -	$ -	$ -	$ 1,867	$ (3,793)
116	Res General	$ (130)	$ -	$ -	$ -	$ -	$ 68	$ (62)
117	G50 Low Annual-Low Winter	$ (764)	$ -	$ -	$ -	$ -	$ 471	$ (293)
118	G40 Low Annual-High Winter	$ (2,200)	$ -	$ -	$ -	$ -	$ 735	$ (1,466)
119	G51 Med Annual-Low Winter	$ (1,077)	$ -	$ -	$ -	$ -	$ 781	$ (296)
120	G41 Med Annual-High Winter	$ (2,196)	$ -	$ -	$ -	$ -	$ 1,028	$ (1,168)
121	G52 High Annual-Low Winter	$ (119)	$ -	$ -	$ -	$ -	$ 110	$ (9)
122	G42 High Annual-High Winter	$ (147)	$ -	$ -	$ -	$ -	$ 252	$ 105
123								
124	Residential	$ (5,790)	$ -	$ -	$ -	$ -	$ 1,934	$ (3,855)
125	SALES HLF CLASSES	$ (1,961)	$ -	$ -	$ -	$ -	$ 1,363	$ (598)
126	SALES LLF CLASSES	$ (4,543)	$ -	$ -	$ -	$ -	$ 2,015	$ (2,529)
127	**TOTAL COMMODITY**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**SUMMER**
128	Res Heat	$ 646,707	$ 408,730	$ 234,819	$ 230,658	$ 235,197	$ 320,101	$ 2,076,212
129	Res General	$ 14,818	$ 13,267	$ 10,482	$ 10,730	$ 9,797	$ 11,565	$ 70,659
130	G50 Low Annual-Low Winter	$ 86,895	$ 92,353	$ 82,397	$ 86,352	$ 80,803	$ 80,548	$ 509,347
131	G40 Low Annual-High Winter	$ 251,519	$ 147,780	$ 80,146	$ 78,301	$ 82,763	$ 126,159	$ 766,668
132	G51 Med Annual-Low Winter	$ 122,380	$ 136,201	$ 126,933	$ 127,445	$ 121,682	$ 133,492	$ 768,133
133	G41 Med Annual-High Winter	$ 250,938	$ 192,561	$ 89,824	$ 83,670	$ 103,530	$ 176,851	$ 897,375
134	G52 High Annual-Low Winter	$ 13,569	$ 14,912	$ 13,652	$ 14,237	$ 13,562	$ 18,923	$ 88,855
135	G42 High Annual-High Winter	$ 16,843	$ 9,002	$ 6,974	$ 7,333	$ 28,199	$ 43,672	$ 112,024
136	Total Firm Sales	$ 1,403,670	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 911,311	$ 5,289,274
137								
138	Residential	$ 661,525	$ 421,998	$ 245,301	$ 241,388	$ 244,994	$ 331,665	$ 2,146,872
139	SALES HLF CLASSES	$ 222,844	$ 243,466	$ 222,982	$ 228,034	$ 216,047	$ 232,963	$ 1,366,335
140	SALES LLF CLASSES	$ 519,301	$ 349,343	$ 176,945	$ 169,304	$ 214,492	$ 346,683	$ 1,776,067
141								
142	% ALLOCATION BETWEEN SALES HLF AND LLF							
143	SALES HLF CLASSES							43.48%
144	SALES LLF CLASSES							56.52%

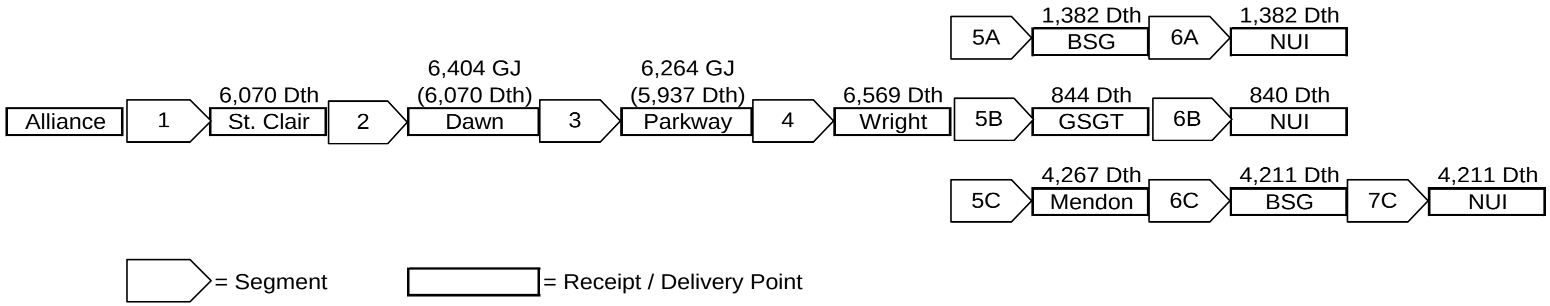
Total Commodity Costs

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)

To be Provided in Winter 2010-11 Cost-of-Gas Filing

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

Capacity Path Diagram

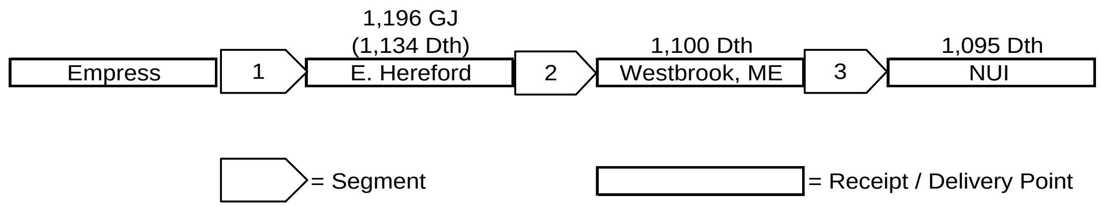


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	TransCanada
3	Transportation	TransCanada	29594	FT	10/31/2016	6,264	GJ	Year-Round	Dawn	Parkway	Iroquois
4	Transportation	Iroquois	R181001	RTS-1	10/31/2013	6,569	Dth	Year-Round	Parkway	Wright	Tennessee
5A	Transportation	Tennessee	31861	NET-284	10/31/2012	1,382	Dth	Year-Round	Wright	Bay State City Gate	
6A	Exchange	Bay State Gas	NA	NA	Evergreen	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
5B	Transportation	Tennessee	31861	NET-284	10/31/2012	844	Dth	Year-Round	Wright	Pleasant St.	Granite
6B	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	840	Dth	Year-Round	Pleasant St.	Northern City Gates	
5C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
6C	Transportation	Algonquin	93200F	AFT-1	10/31/2012	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
7C	Exchange	Bay State Gas	NA	NA	Evergreen	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,433	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Empress, Alberta

Capacity Path Diagram

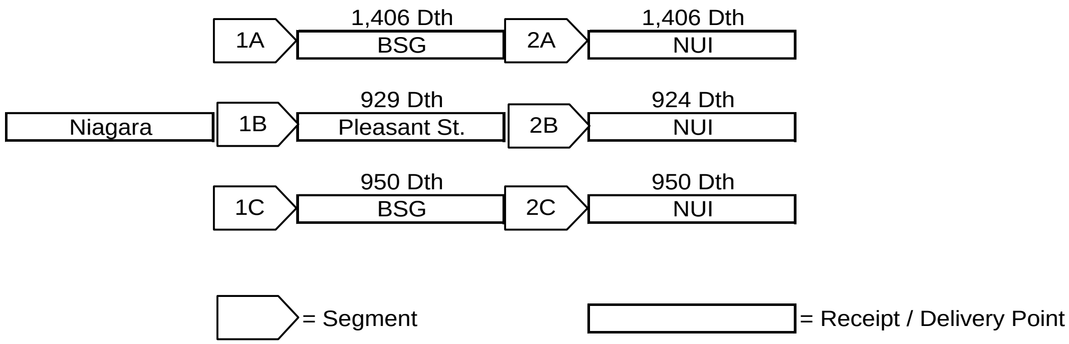


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	TransCanada	29833	FT	10/31/2010	1,196	GJ	Year-Round	Empress, Alberta	East Hereford	PNGTS
2	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
3	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	1,095	Dth	Year-Round	Westbrook, ME	Northern City Gates	
Total Path Deliverable						1,095	Dth				

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

Capacity Path Diagram

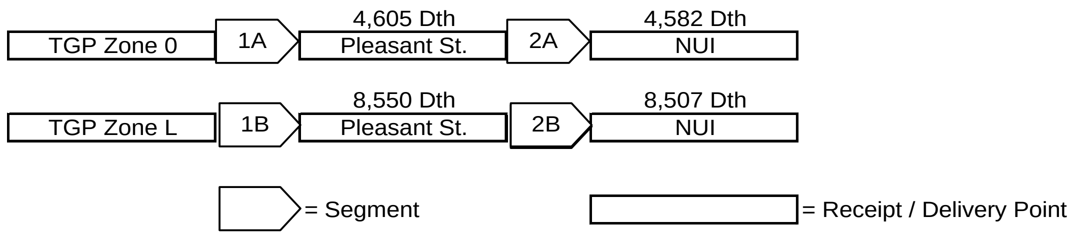


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2015	1,406	Dth	Year-Round	Niagara	Bay State City Gate	
2A	Exchange	Bay State Gas	NA	NA	Evergreen	1,406	Dth	Year-Round	Bay State City Gate	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2015	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	924	Dth	Year-Round	Pleasant St.	Northern City Gates	
1C	Transportation	Tennessee	46314	FT-A	3/31/2012	950	Dth	Year-Round	Niagara	Bay State City Gate	
2C	Exchange	Bay State Gas	NA	NA	Evergreen	950	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						3,280	Dth				

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

Capacity Path Diagram



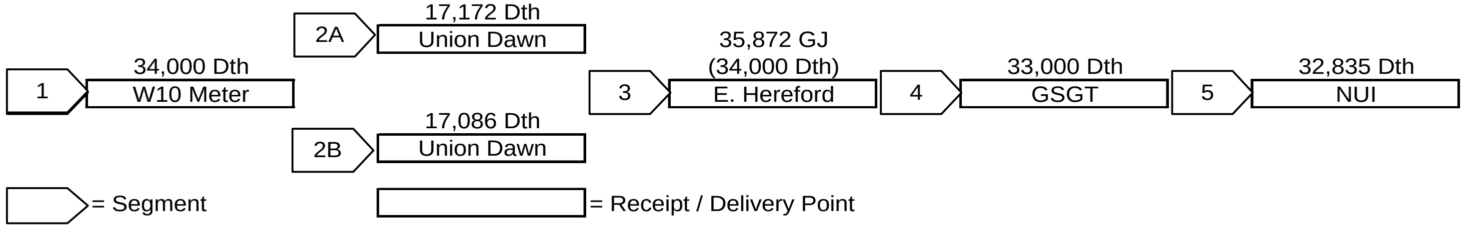
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	4,582	Dth	Year-Round	Pleasant St.	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	8,507	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						13,089	Dth				

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

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

Capacity Path Diagram



Capacity Path Detail

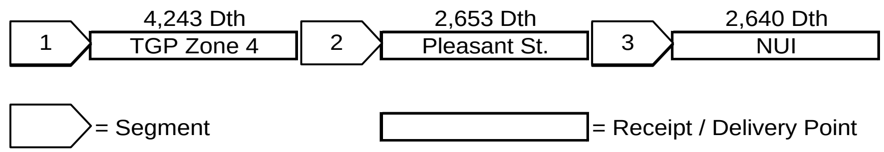
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-0725	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-0727	FT	10/31/2017	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	09-006-FT-NN	FT-NN	10/31/2010	32,835	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,835	Dth				

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

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

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

Capacity Path Diagram



Capacity Path Detail

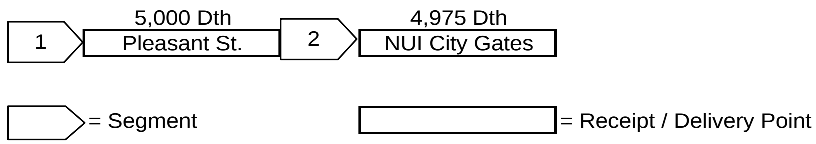
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	10/31/2013	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	10/31/2013	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	2,640	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,640	Dth				

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

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

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

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	10/31/2011	5,000	Dth	Year-Round	NA	Pleasant St.	Granite
2	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	4,975	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						4,975	Dth				

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

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

Capacity Path Diagram

1 → Newington or Westbrook (53,000 Dth) → 2 → NUI City Gates (52,735 Dth)

= Segment

= Receipt / Delivery Point

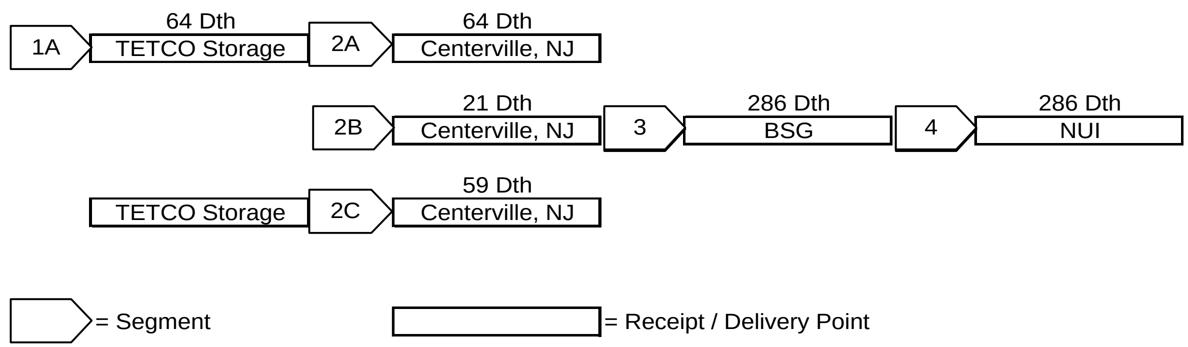
Capacity Path Detail

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	3/31/2011	53,000	Dth	Winter Only (Nov-Mar)	NA	Newington, NH or Westbrook, ME	Granite
2	Transportation	Granite	09-006-FT-NN	FT-NN	10/31/2010	52,735	Dth	Year-Round	Newington, NH or Westbrook, ME	Northern City Gates	
Total Path Deliverable						52,735	Dth				

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

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

Capacity Path Diagram



Capacity Path Detail

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

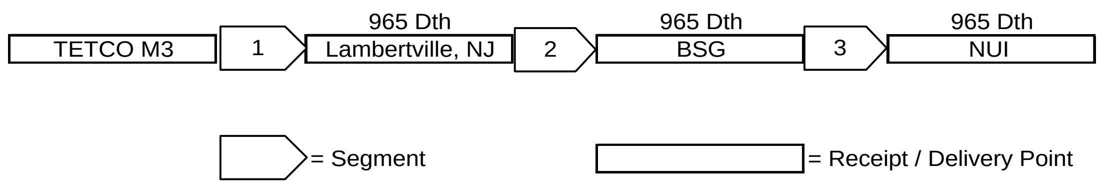
Note 1: Texas Eastern Contract No. 400513 has a maximum storage quantity of 3,840 Dth.

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

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

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

Capacity Path Diagram



Capacity Path Detail

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

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

To be Provided in Winter 2010-11 Cost-of-Gas Filing

Northern Utilities, Inc.
Storage Analysis

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawal Charges	Withdrawn Value plus Charges
May-10	-	49,161	817	48,343	$ -		$ 6.08	$ 299,046	$ 4,973	$ 294,074	3.25%	$ 398	$ 294,074	$ -	$ 4,973
Jun-10	48,343	49,002	-	97,345	$ 294,074	$ 6.08	$ 6.13	$ 300,623	$ -	$ 594,697	3.25%	$ 1,204	$ 594,697	$ -	$ -
Jul-10	97,345	50,635	-	147,980	$ 594,697	$ 6.11	$ 6.21	$ 314,596	$ -	$ 909,293	3.25%	$ 2,037	$ 909,293	$ -	$ -
Aug-10	147,980	50,635	-	198,615	$ 909,293	$ 6.14	$ 6.28	$ 318,224	$ -	$ 1,227,517	3.25%	$ 2,894	$ 1,227,517	$ -	$ -
Sep-10	198,615	5,158	-	203,773	$ 1,227,517	$ 6.18	$ 6.32	$ 32,582	$ -	$ 1,260,099	3.25%	$ 3,369	$ 1,260,099	$ -	$ -
Oct-10	203,773	-	-	203,773	$ 1,260,099	$ 6.18		$ -	$ -	$ 1,260,099	3.25%	$ 3,413	$ 1,260,099	$ -	$ -

Washington 10 Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawal Charges	Withdrawn Value plus Charges
May-10	929,750	313,732	-	1,243,482	$ 3,774,877	$ 4.06	$ 5.78	$1,811,953	$ -	$ 5,586,830	3.25%	$12,677	$ 5,586,830	$ -	$ -
Jun-10	1,243,482	313,732	-	1,557,213	$ 5,586,830	$ 4.49	$ 5.83	$1,830,511	$ -	$ 7,417,341	3.25%	$17,610	$ 7,417,341	$ -	$ -
Jul-10	1,557,213	313,732	-	1,870,945	$ 7,417,341	$ 4.76	$ 5.91	$1,853,869	$ -	$ 9,271,210	3.25%	$22,599	$ 9,271,210	$ -	$ -
Aug-10	1,870,945	313,732	-	2,184,677	$ 9,271,210	$ 4.96	$ 5.98	$1,875,307	$ -	$ 11,146,517	3.25%	$27,649	$ 11,146,517	$ -	$ -
Sep-10	2,184,677	313,732	-	2,498,409	$11,146,517	$ 5.10	$ 6.01	$1,884,906	$ -	$ 13,031,423	3.25%	$32,741	$ 13,031,423	$ -	$ -
Oct-10	2,498,409	313,732	-	2,812,140	$13,031,423	$ 5.22	$ 6.11	$1,917,350	$ -	$ 14,948,774	3.25%	$37,890	$ 14,948,774	$ -	$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawal Charges	Withdrawn Value plus Charges
May-10	11,250	1,395	1,395	11,250	$ 60,188	$ 5.35	$ 4.97	$ 6,929	$ 7,404	$ 59,713	3.25%	$ 162	$ 59,713		$ 7,404
Jun-10	11,250	1,350	1,350	11,250	$ 59,713	$ 5.31	$ 4.97	$ 6,706	$ 7,116	$ 59,302	3.25%	$ 161	$ 59,302		$ 7,116
Jul-10	11,250	1,395	1,395	11,250	$ 59,302	$ 5.27	$ 4.97	$ 6,929	$ 7,307	$ 58,925	3.25%	$ 160	$ 58,925		$ 7,307
Aug-10	11,250	2,330	1,395	12,185	$ 58,925	$ 5.24	$ 4.97	$ 11,574	$ 7,242	$ 63,257	3.25%	$ 165	$ 63,257		$ 7,242
Sep-10	12,185	1,530	1,350	12,365	$ 63,257	$ 5.19	$ 4.97	$ 7,600	$ 6,975	$ 63,882	3.25%	$ 172	$ 63,882		$ 6,975
Oct-10	12,365	1,105	1,395	12,075	$ 63,882	$ 5.17	$ 4.97	$ 5,487	$ 7,184	$ 62,185	3.25%	$ 171	$ 62,185		$ 7,184

Unitil
Unitil Service Corp.

January 29, 2010

Ms. Debra Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit St. Suite 10
Concord, New Hampshire 03301-2429

Re: Northern Utilities, Inc. – New Hampshire Division, Docket DG 09-052, 2009 Summer Period Cost of Gas (COG) Adjustment Reconciliation

Dear Ms. Howland:

Enclosed are an original and eight copies of Northern Utilities, Inc. -- New Hampshire Division's ("Northern" or "the Company") 2009 Summer Period Cost of Gas Adjustment Reconciliation (Form III). The objective of this reconciliation is to present the details of Northern's summer period 2009 over-collection.

Form III, Schedules 1 through 5, of the attached reconciliation contain the accounting of six months of recoveries and costs assigned to the summer period. The schedules illustrate the Company's over-collection of $536,749 as follows:

Schedule 1 provides the summary of the summer period ending balance;

Schedule 2 shows the deferred gas cost activity, allowable costs and revenues for the period November 2008 through November 2009, including interest;

Schedule 3, shows the summary of summer period gas cost collections for the period November 2008 through November 2009;

Schedule 4 (2 pages) presents the monthly detail of purchase gas costs allocated to the summer period; and

Schedule 5 contains the purchased and made volumes, the sendout metered at Northern's NH gate stations, and volumes by Residential and Commercial & Industrial customer classifications for the period, November 2008 through October 2009.

Attachment A presents the reconciliation of the working capital allowance and recoveries. The over-collection of $8,299 will be reflected on Revised Page 39 of Northern's Tariff No. 10 as an addition to the costs used to calculate the COG rate.

Attachment B shows the reconciliation of the bad debt allowance and collections. The over-collection of $4,888 will also be reflected on Revised Page 39 of Northern's Tariff No. 10 as an addition to the costs used in calculating the COG rate.

Attachment C details the summer period sales variance analysis.

Frederick J. Stewart
Manager Regulatory Services

6 Liberty Lane West
Hampton, NH 03842

Phone: 603-773-6534
Fax: 603-773-6734

stewart@unitil.com

If you have any questions regarding this reconciliation or if you require any further information, please let me know.

Very truly yours,

Frederick J. Stewart

Enclosure

cc: Matthew Fossum, Staff Counsel
Meredith Hatfield, Consumer Advocate
Susan Geiger, Esq.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 1: SUMMARY OF SUMMER PERIOD BALANCE
May 2009 - October 2009

	AMOUNT	
Summer Period Beg. Balance	$489,758	SCHEDULE 2
Less: Reported Collections	($6,392,626)	SCHEDULE 2
Less: Billing Adjustment	$0	SCHEDULE 2
Add: Cost of Firm Gas Allowable	$5,355,992	SCHEDULE 4
Add: Interest	$10,128	SCHEDULE 2
Summer Period Ending Balance	($536,749)	

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER PERIOD ACCOUNTS
November 2008 - November 2009
Acct 191.10

	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Total
SUMMER PERIOD														
Summer Period Account Beginning Balance (1)	$ 525,907	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 496,574	$ 728,829	$ 306,554	$ 266,708	$ 106,002	$ (255,320)	$ 91,535	$ 489,758
Plus: Cost of Firm Gas (Schedule 4)	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ 1,400,967	$ 501,695	$ 594,295	$ 592,389	$ 413,590	$ 1,940,581	$ (87,526)	$ 5,355,992
Less: Reported Collections (Schedule 3)(2)	$ (39,866)	$ -	$ -	$ -	$ -	$ -	$ (1,170,369)	$ (925,371)	$ (634,916)	$ (753,599)	$ (774,711)	$ (1,593,505)	$ (540,155)	$ (6,392,626)
Less: Billing Adjustment														
Summer Period Account Ending Balance	$ 488,068	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 727,172	$ 305,154	$ 265,933	$ 105,498	$ (255,118)	$ 91,756	$ (536,147)	$ (546,877)
Month's Average Balance	$ 506,987	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 611,873	$ 516,991	$ 286,243	$ 186,103	$ (74,558)	$ (81,782)	$ (222,306)	
Interest Rate (Prime Rate)	4.00%	3.61%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ 1,690	$ 1,473	$ 1,330	$ 1,334	$ 1,338	$ 1,341	$ 1,657	$ 1,400	$ 775	$ 504	$ (202)	$ (221)	$ (602)	$ 10,128
Summer Period Account Ending Balance w/int(3)	$ 489,758	$ 491,231	$ 492,561	$ 493,895	$ 495,233	$ 496,574	$ 728,829	$ 306,554	$ 266,708	$ 106,002	$ (255,320)	$ 91,535		$ (536,749)

(1) Summer period balance as of October 31, 2008, $2,032,076, is adjusted by ($1,506,169) to account for the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(2) Reported collections for November 2008 are the reversal of October 2008 accrued revenues in order to reflect the transition to accrual accounting as required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(3) Summer period actual ending balance with interest per DG 08-041 Audit Report is $494,007. This is adjusted by ($1,735) for a correction to November 2008 revenues, and ($2,514) to adjust interest due to the transition to accrual accounting.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS(1)
November 2008 - November 2009

FORM III
Schedule 3

	November	December	January	February	March	April	May	June	July	August	September	October	November	Total
Accrued Revenue	$ (1,506,169)	$ -	$ -	$ -	$ -	$ -	$ 613,494	$ (283,725)	$ (27,943)	$ 107,080	$ 117,255	$ 458,140	$ (984,300)	$ -
Billed Revenue	$ 1,546,035	$ -	$ -	$ -	$ -	$ -	$ 556,876	$ 1,209,096	$ 662,859	$ 646,519	$ 657,456	$ 1,135,365	$ 1,524,456	$ 6,392,626
Calendarized Revenue	**$ 39,866**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,170,369**	**$ 925,371**	**$ 634,916**	**$ 753,599**	**$ 774,711**	**$ 1,593,505**	**$ 540,155**	**$ 6,392,626**

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

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS ALLOCATED TO SUMMER PERIOD
May 2009 - October 2009

Commodity Costs:	November (Actual)	December (Actual)	January (Actual)	February (Actual)	March (Actual)	April (Actual)	May (Actual)	June (Actual)	July (Actual)	August (Actual)	September (Actual)	October (Actual)	November (Actual)	Total Summer
Anadarka Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,195	$ 49,874	$ 24,397	$ 25,637	$ 79,156	$ 83,446	**$ 292,705**
Distrigas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,097	**$ 5,097**
DTE Energy Trading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,540	$ -	$ -	$ -	$ -	**$ 13,540**
Emera Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,726	$ 65,494	$ 77,222	$ 63,100	$ 50,930	$ 117,672	**$ 442,143**
Hess	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,683	$ -	$ -	$ -	$ -	**$ 17,683**
JP Morgan	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,064	$ 167,353	$ 237,707	$ 241,820	$ -	$ 393,504	**$ 1,274,449**
South Jersey Resources	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,049	$ 156,014	**$ 220,063**
Tennessee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,320	$ 2,051	$ 890	$ -	$ 5,236	$ 3,156	**$ 12,654**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 333,305	$ 315,995	$ 340,218	$ 330,556	$ 199,370	$ 758,889	**$ 2,278,333**
Commodity Cost Estimates	$ -	$ -	$ -	$ -	$ -	$ -	$ 415,087	$ 314,544	$ 331,235	$ 329,454	$ 210,109	$ 835,648	$ -	**$ 2,436,077**
Commodity Cost Reversals	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (415,087)	$ (314,544)	$ (331,235)	$ (329,454)	$ (210,109)	$ (835,648)	**$ (2,436,077)**
Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ 415,087	$ 232,762	$ 332,686	$ 338,437	$ 211,211	$ 824,909	$ (76,759)	**$ 2,278,333**
Withdrawal Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,180	$ 1,416	$ (1,334)	$ 1,346	$ (719)	$ 177	$ -	**$ 2,066**
Interruptible Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ (390)	$ -	$ (7,661)	$ (4,412)	$ (11,317)	$ (11,884)	$ -	**$ (35,665)**
Non Traditional Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,031)	$ -	$ -	$ -	$ (15,847)	$ -	$ -	**$ (21,878)**
Net OBA Adj	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,338	$ 1,077	$ 646	$ 304	$ 470	$ 31,547	$ -	**$ 77,382**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,372)	$ (9,065)	$ -	$ -	$ (18,887)	$ (3,602)	$ (10,767)	**$ (49,693)**
LNG Boiloff	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,110	$ -	$ 10,619	$ 7,534	$ 7,111	$ 4,863	$ -	**$ 35,237**
Transportation Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,084)	$ 25,398	$ 9,519	$ -	$ (8,625)	$ (130,224)	$ -	**$ (119,017)**
Hedging Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 785,953	$ 6,412	$ 5,627	$ 5,393	$ 6,412	$ 978,505	$ -	**$ 1,788,302**
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ (67,162)	$ -	$ -	$ -	$ -	$ -	$ -	**$ (67,162)**
Prior Period Adjustment	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Subtotal	$ 2,027	$ -	$ -	$ -	$ -	$ -	$ 739,542	$ 25,237	$ 17,415	$ 10,164	$ (41,401)	$ 869,382	$ (10,767)	$ 1,609,573
Total Commodity Costs	**$ 2,027**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,154,629**	**$ 257,998**	**$ 350,102**	**$ 348,601**	**$ 169,810**	**$ 1,694,291**	**$ (87,526)**	**$ 3,887,906**

Demand Costs	November (Actual)	December (Actual)	January (Actual)	February (Actual)	March (Actual)	April (Actual)	May (Actual)	June (Actual)	July (Actual)	August (Actual)	September (Actual)	October (Actual)	November (Actual)	Total Summer
Forecasted Summer Demand Costs (DG 09-052	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,471	$ 239,471	$ 239,471	$ 239,471	$ 239,471	$ 239,471	$ -	$ 1,436,825
Miscellaneous Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,867	$ 4,226	$ 4,723	$ 4,317	$ 4,309	$ 6,818	$ -	$ 31,261
Total Demand Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 246,338**	**$ 243,697**	**$ 244,194**	**$ 243,788**	**$ 243,780**	**$ 246,289**	**$ -**	**$ 1,468,086**
Total Gas Costs	**$ 2,027**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,400,967**	**$ 501,695**	**$ 594,295**	**$ 592,389**	**$ 413,590**	**$ 1,940,581**	**$ (87,526)**	**$ 5,355,992**

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2009 SUMMER PERIOD RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
November 2008 - October 2009

New Hampshire	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total
Throughput IN													
BTU Factor	1.043	1.046	1.033	1.031	1.037	1.035	1.058	1.043	1.046	1.029	1.050	1.042	
GST Meter Throughput (MCF)	644,728	858,124	1,034,316	809,663	772,880	513,047	318,202	259,715	275,694	259,076	278,578	460,252	6,484,275
Salem Meter (MCF)	36,383	55,135	71,820	50,982	42,498	23,072	13,740	10,711	11,098	10,145	11,353	21,545	358,482
GST Meter Throughput (DTH)	672,451	897,598	1,068,448	834,763	801,477	531,004	336,658	270,883	288,376	266,589	292,507	479,583	6,740,335
Salem Meter (DTH)	37,947	57,671	74,190	52,562	44,070	23,880	14,537	11,172	11,609	10,439	11,921	22,450	372,448
LNG/Propane													0
Total Throughput	710,399	955,269	1,142,638	887,325	845,547	554,883	351,195	282,054	299,984	277,028	304,428	502,032	7,112,783
Throughput OUT													
Residential Gas													
Charged	107,101	198,238	314,584	294,937	246,711	176,594	91,409	45,514	54,713	33,949	34,637	53,953	1,652,338
Uncharged Current	107,200	101,913	157,316	125,763	108,917	57,682	40,334	10,780	19,977	21,823	32,708	47,772	832,185
Uncharged Prior	-81,473	-107,200	-101,913	-157,316	-125,763	-108,917	-57,682	-40,334	-10,780	-19,977	-21,823	-32,708	-865,886
Total Residential Gas	**132,828**	**192,950**	**369,987**	**263,384**	**229,865**	**125,359**	**74,060**	**15,960**	**63,910**	**35,795**	**45,522**	**69,016**	1,618,637
Interruptible	**2,929**	**1,558**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	4,487
Commercial/Industrial Gas													
Charged	145,792	274,760	410,979	356,022	292,486	206,342	95,223	92,202	53,650	54,112	54,903	82,024	2,118,495
Uncharged Current	142,000	137,776	205,117	151,061	128,281	65,679	41,496	33,674	21,433	33,488	37,652	56,218	1,053,876
Uncharged Prior	-79,307	-142,000	-137,776	-205,117	-151,061	-128,281	-65,679	-41,496	-33,674	-21,433	-33,488	-37,652	-1,076,965
Total C/I Gas	**208,485**	**270,536**	**478,321**	**301,966**	**269,706**	**143,740**	**71,040**	**84,379**	**41,409**	**66,168**	**59,067**	**100,589**	2,095,406
Transportation													
Charged	304,029	354,798	327,455	357,460	355,546	305,728	205,707	194,417	194,706	180,110	199,077	252,958	3,231,989
Uncharged Current	14,000	42,348	58,061	41,697	39,026	21,875	16,613	42,700	40,205	12,581	70,882	101,472	501,460
Uncharged Prior	-21,399	-14,000	-42,348	-58,061	-41,697	-39,026	-21,875	-16,613	-42,700	-40,205	-12,581	-70,882	-421,388
Total Transportation	**296,630**	**383,146**	**343,168**	**341,096**	**352,875**	**288,577**	**200,445**	**220,504**	**192,210**	**152,485**	**257,379**	**283,547**	**3,312,062**
Company Use	**100**	**203**	**343**	**219**	**328**	**190**	**88**	**47**	**5**	**1**	**7**	**21**	**1,551**
Total Throughput OUT	**640,972**	**848,394**	**1,191,818**	**906,665**	**852,774**	**557,866**	**345,633**	**320,891**	**297,533**	**254,449**	**361,975**	**453,174**	**7,032,143**
Total Throughput IN	**710,399**	**955,269**	**1,142,638**	**887,325**	**845,547**	**554,883**	**351,195**	**282,054**	**299,984**	**277,028**	**304,428**	**502,032**	**7,112,783**
Difference IN/OUT	69,427	106,875	-49,180	-19,340	-7,227	-2,983	5,562	-38,836	2,451	22,579	-57,547	48,859	80,640
%													1.13%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED OFF-PEAK WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
Period Ending 10/31/2009

OFF-PEAK PERIOD - Acct 182.21

		BEGINNING BALANCE(1)	WORKING CAP ALLOWANCE(2)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS(3)	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
		A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2008	$	5,156	1	0.0694%	216	217	5,373	5,264	4.00%	18	5,390
December 2008	$	5,390	0	0.0626%	0	0	5,390	5,390	3.61%	16	5,407
January 2009	$	5,407	0	0.0564%	0	0	5,407	5,407	3.25%	15	5,421
February	$	5,421	0	0.0564%	0	0	5,421	5,421	3.25%	15	5,436
March	$	5,436	0	0.0564%	0	0	5,436	5,436	3.25%	15	5,451
April	$	5,451	0	0.0564%	0	0	5,451	5,451	3.25%	15	5,466
May	$	5,466	790	0.0564%	(3,263)	(2,474)	2,992	4,229	3.25%	11	3,003
June	$	3,003	283	0.0564%	(2,590)	(2,307)	696	1,850	3.25%	5	701
July	$	701	335	0.0564%	(1,825)	(1,490)	(789)	(44)	3.25%	(0)	(789)
August	$	(789)	334	0.0564%	(2,142)	(1,808)	(2,597)	(1,693)	3.25%	(5)	(2,601)
September	$	(2,601)	233	0.0564%	(2,189)	(1,956)	(4,557)	(3,579)	3.25%	(10)	(4,567)
October	$	(4,567)	1,094	0.0564%	(3,552)	(2,458)	(7,025)	(5,796)	3.25%	(16)	(7,041)
November	$	(7,041)	(49)	0.0564%	(1,189)	(1,238)	(8,279)	(7,660)	3.25%	(21)	(8,299)

(1) Balance for November 2008, $7,918, approved in DG 09-052, is adjusted by ($2,762) for the transition to accrual accounting required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.
(2) Working Capital Allowance Calculated by taking Eligible Gas Costs from Sch 4 and multiplying by (6.33/365)*Interest Rate.
(3) Working Capital Collections for November 2008, ($2,547), is adjusted by $2,762 for the transition to accrual accounting required by Commission Order No. 25,038, dated October 30, 2009 in DG 07-033.

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
Period Ending 10/31/2009

OFF-PEAK PERIOD - Acct 182.22

	BEGINNING BALANCE(1)	BAD DEBT ALLOWANCE(2)	% ALLOWED BAD DEBT	BAD DEBT COLLECTIONS(3)	BAD DEBT DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	J = F + I
November 2008	12,464	9	0.45%	499	508	12,972	12,718	4.00%	42	13,014
December 2008	13,014	0	0.45%	0	0	13,014	13,014	3.61%	39	13,054
January 2009	13,054	0	0.45%	0	0	13,054	13,054	3.25%	35	13,089
February	13,089	0	0.45%	0	0	13,089	13,089	3.25%	35	13,124
March	13,124	0	0.45%	0	0	13,124	13,124	3.25%	36	13,160
April	13,160	0	0.45%	0	0	13,160	13,160	3.25%	36	13,196
May	13,196	6,308	0.45%	(8,236)	(1,928)	11,267	12,231	3.25%	33	11,300
June	11,300	2,259	0.45%	(6,537)	(4,278)	7,022	9,161	3.25%	25	7,047
July	7,047	2,676	0.45%	(4,607)	(1,931)	5,116	6,082	3.25%	16	5,132
August	5,132	2,667	0.45%	(5,405)	(2,737)	2,395	3,764	3.25%	10	2,405
September	2,405	1,862	0.45%	(5,524)	(3,662)	(1,257)	574	3.25%	2	(1,256)
October	(1,256)	8,738	0.45%	(8,965)	(228)	(1,483)	(1,369)	3.25%	(4)	(1,487)
November	(1,487)	(394)	0.45%	(2,998)	(3,392)	(4,879)	(3,183)	3.25%	(9)	(4,888)

(1) Balance for November 2008, $18,852, approved in DG 09-052, is adjusted by ($6,388) for the transition to accrual accounting required by Order No. 25,038.
(2) Bad Debt Allowance calculated by multiplying Bad Debt % by Gas Cost on Schedule 4 and Working Capital Allowance on Attachment A.
(3) Bad Debt Collections for November 2008, ($5,889), is adjusted by $6,388 for the transition to accrual accounting required by Order No. 25,038.

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

	May	June	July	August	September	October	TOTAL
Forecast Calendar Month Sales	202,050	124,344	138,957	127,031	126,789	200,618	919,789
Actual Sales	186,632	137,716	108,363	88,061	89,540	135,976	746,288
Difference	(15,418)	13,372	(30,594)	(38,970)	(37,249)	(64,642)	(173,501)
Add:							
Volume Variance due to Weather							
Normal Cal. Month Actual Sales	145,100	100,339	105,319	101,963	104,589	169,605	726,916
Actual Sales	186,632	137,716	108,363	88,061	89,540	135,976	746,288
Weather Variance	(41,532)	(37,376)	(3,044)	13,901	15,050	33,629	(19,372)
Total Variance Excluding Weather (excl weather effect)	(56,950)	(24,005)	(33,638)	(25,068)	(22,200)	(31,013)	(192,873)
Variance-difference due to meter count							(41,044)
-difference in load pattern							(69,837)
SALES							(110,881)

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

	NORMAL MMBtu			METERS		
	2009 Forecast	2009 Actual	Difference	2009 Forecast	2009 Actual	Difference
Res Heat	311,361	317,880	6,519	118,747	119,842	1,095
Res General	11,438	12,438	1,000	9,883	10,038	155
Total Res	322,799	330,318	7,519	128,630	129,880	1,250
G-40	115,571	101,803	(13,768)	25,158	24,999	(159)
G-50	75,918	80,471	4,553	5,904	5,869	(35)
G-41	63,899	156,701	92,802	2,280	2,235	(45)
G-51	179,984	107,068	(72,916)	1,038	976	(62)
G-42	48,642	12,180	(36,462)	72	82	10
G-52	112,975	20,366	(92,609)	36	24	(12)
Total C & I	596,989	478,589	(118,400)	34,488	34,185	(303)
Total Company	919,789	808,907	(110,881)	163,118	164,065	947

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2009 Forecast	2009 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	2.62	2.65	0.03	2,871	3,648	6,519	2.09%
Res General	1.16	1.24	0.08	179	821	1,000	8.74%
Total Res	3.78	3.89	0.11	3,051	4,468	7,519	2.33%
G-40	4.59	4.07	(0.52)	(730)	(13,038)	(13,768)	-11.91%
G-50	12.86	13.71	0.85	(450)	5,003	4,553	6.00%
G-41	28.03	70.11	42.09	(1,261)	94,063	92,802	145.23%
G-51	173.39	109.70	(63.69)	(10,750)	(62,166)	(72,916)	-40.51%
G-42	675.58	148.54	(527.05)	6,756	(43,218)	(36,462)	-74.96%
G-52	3,138.19	848.58	(2,289.61)	(37,658)	(54,951)	(92,609)	-81.97%
Total C & I	17.31	14.00	(3.31)	(44,095)	(74,305)	(118,400)	-19.83%
Total Company	5.64	4.93	(0.71)	(41,044)	(69,837)	(110,881)	-12.06%

Provided in Winter 2009-10 Cost-of-Gas Filing

Provided in Winter 2009-10 Cost-of-Gas Filing

Provided in Winter 2009-10 Cost-of-Gas Filing

Provided in Winter 2009-10 Cost-of-Gas Filing

		Off-Peak Season		Peak Season								
		May-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak Season	Off-Peak Season	Total Contracts
	*Ceilings**	*8.646*	*9.193*	*9.540*	*9.940*	*10.248*	*10.208*	*9.946*	*8.600*			
Scheduled Purchases	04/28/10	2	1	1	2	2	1	2	0	8	3	11
	05/26/10	2	1	1	1	1	2	2	1	8	3	11
	06/28/10	1	1	0	2	1	2	2	1	8	2	10
	07/28/10	2	1	1	1	2	2	1	1	8	3	11
	08/27/10	1	1	1	1	2	2	1	1	8	2	10
	09/28/10	1	1	0	1	2	2	2	1	8	2	10
	10/27/10	2	1	1	1	1	2	1	2	8	3	11
	11/24/10	2	1	1	1	2	2	1	1	8	3	11
	12/28/10	1	1	1	1	2	2	1	1	8	2	10
	01/27/11	1	1	0	2	2	1	2	1	8	2	10
	02/24/11	1	1	1	1	2	2	1	1	8	2	10
	03/29/11	2	1	1	2	2	2	1	0	8	3	11
Make-Up Purchases (white area) Scheduled Sales (gray area)	04/27/11	-18								0	-18	-18
	05/26/11									0	0	0
	06/28/11									0	0	0
	07/27/11									0	0	0
	08/29/11									0	0	0
	09/28/11		-12							0	-12	-12
	10/27/11			-9						-9	0	-9
	11/28/11				-16					-16	0	-16
	12/28/11					-21				-21	0	-21
	01/27/12						-22			-22	0	-22
	02/27/12							-17		-17	0	-17
	03/28/12								-11	-11	0	-11
	Scheduled	18	12	9	16	21	22	17	11	96	30	126
	check	0	0	0	0	0	0	0	0	0	0	0

*Note: Price Ceilings reflect 2010-11 levels and will be updated for 2011-12 with the Cost of Gas update in mid-April.

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts	City-Gate Volumes	Percent of Sendout	Futures Contracts	City-Gate Volumes	Percent of Sendout	Futures Contracts
	SUMMER PERIOD	SUMMER 2011			SUMMER 2012			SUMMER 2013		
1	Sendout Requirement (May, Oct)	742,547			746,468			750,390		
2	Financial Hedge Volume	300,000	40%	30	300,000	40%	30	300,000	40%	30
	WINTER PERIOD	WINTER 2011-12			WINTER 2012-13			WINTER 2013-14		
3	Sendout Requirement	5,565,421			5,560,346			5,592,573		
4	Washington 10 Storage	2,724,393	49%		2,724,393	49%		2,724,393	49%	
5	Tennessee Storage	207,019	4%		207,019	4%		207,019	4%	
6	Fixed Price Physical Contracts	0	0%		0	0%		0	0%	
7	Financial Hedge Volume	960,000	17%	96	960,000	17%	96	980,000	18%	98
8	Total Hedged Volume	3,891,412	70%		3,891,412	70%		3,911,412	70%	
	HEDGE PLAN YEAR	PLAN YEAR 2011-12			PLAN YEAR 2012-13			PLAN YEAR 2013-14		
9	Financial Hedge Volume	1,260,000	20%	126	1,260,000	20%	126	1,280,000	20%	128

Line	Description	City-Gate Volumes	Percent of Sendout	Futures Contracts
	SUMMER PERIOD	SUMMER 2010		
1	Sendout Requirement (May, Oct)	700,592		
2	Financial Hedge Volume	280,000	40%	28
3	Currently Held Financial Contracts	520,000	74%	52
4	Current Status - SUMMER 2010	Financial Hedges Exceed Proposed Plan		
	WINTER PERIOD	WINTER 2010-11		
4	Sendout Requirement	5,493,162		
5	Washington 10 Storage	2,724,393	50%	
6	Tennessee Storage	207,019	4%	
7	Fixed Price Physical Contracts	616,871	11%	
8	Currently Held Financial Contracts - ME & NH	380,000	7%	38
9	Currently Held Financial Contracts - NH Only	260,000	5%	26
10	Total Hedged Volume	4,188,283	76%	
11	Current Status - WINTER 2010-11	Financial Hedges Exceed Proposed Plan		

Northern Utilities

Simplified Market Based Allocator (MBA) Calculations

ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 6,642,704
Storage Demand	$ 19,732,486
Peaking Demand	$ 5,040,783
Subtotal Demand	$ 31,415,974
Litigation Expense - PNGTS	$ 434,095
Capacity Release (Credit)	$ (565,644)
Asset Management (Credit)	$ (3,770,000)
Total Net Demand Costs	$ 27,514,425

Proportional Responsibility (PR) Allocators

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

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Pipeline Sendout	737,320	730,905	719,723	649,699	709,268	677,285	673,624	564,493	363,991	378,816	347,638	549,202	7,101,963
Rank	1	2	3	7	4	5	6	8	11	10	12	9	
% Max Month	100.00%	99.13%	97.61%	88.12%	96.20%	91.86%	91.36%	76.56%	49.37%	51.38%	47.15%	74.49%	
PR	0.87%	0.76%	0.47%	1.65%	1.08%	0.10%	0.54%	0.26%	0.20%	0.20%	3.93%	2.57%	12.64%
CumPR	12.64%	11.76%	11.01%	8.81%	10.53%	9.45%	9.35%	7.16%	4.13%	4.33%	3.93%	6.90%	100.00%
Product and Pipeline Demand Costs	$ 839,316	$ 781,514	$ 731,144	$ 585,190	$ 699,747	$ 627,711	$ 621,116	$ 475,527	$ 274,390	$ 287,746	$ 260,996	$ 458,307	$ 6,642,704

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	5,234	472,551	464,677	503,099	503,099	486,870	503,099	2,938,629
Design Year Pipeline Sendout	737,320	730,905	719,723	649,699	709,268	677,285	673,624	564,493	363,991	378,816	347,638	549,202	7,101,963
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	41.2%	45.2%	58.0%	57.0%	58.3%	47.8%	29.3%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 4,814	$ 256,077	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 1,170,333

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	-	591,730	955,218	778,530	309,026	201,863	31,220	-	-	-	-	-	2,867,586
Rank	7	3	1	2	4	5	6	7	7	7	7	7	
% Max Month	0.00%	61.95%	100.00%	81.50%	32.35%	21.13%	3.27%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	9.87%	18.50%	9.78%	2.80%	3.57%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	45.06%
CumPR	0.00%	16.79%	45.06%	26.57%	6.92%	4.12%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ -	$3,312,594	$8,891,960	$5,242,009	$1,365,932	$ 812,503	$ 107,488	$ -	$ -	$ -	$ -	$ -	$ 19,732,486
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 4,814	$ 256,077	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 1,170,333
TOTAL	$ -	$3,312,594	$8,891,960	$5,242,009	$1,365,932	$ 817,317	$ 363,565	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 20,902,819

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	161,537	160,854	234,895	352,284	510,379	127,700	115,441	36,231	1,395	1,395	1,350	1,395	1,704,855
Rank	4	5	3	2	1	6	7	8	11	10	12	9	
% Max Month	31.65%	31.52%	46.02%	69.02%	100.00%	25.02%	22.62%	7.10%	0.27%	0.27%	0.26%	0.27%	
PR	0.03%	1.30%	4.79%	11.50%	30.98%	0.40%	2.22%	0.85%	0.00%	0.00%	0.02%	0.00%	52.09%
CumPR	4.83%	4.79%	9.62%	21.12%	52.09%	3.49%	3.09%	0.88%	0.02%	0.02%	0.02%	0.02%	100.00%
Peaking Demand Costs	$ 243,274	$ 241,587	$ 484,785	$1,064,481	$2,625,914	$ 176,099	$ 155,919	$ 44,159	$ 1,152	$ 1,152	$ 1,111	$ 1,152	$ 5,040,783

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

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

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

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
50	Pipeline & Product Demand	$ 839,316	$ 781,514	$ 731,144	$ 585,190	$ 699,747	$ 627,711	$ 621,116	$ 475,527	$ 274,390	$ 287,746	$ 260,996	$ 458,307	$ 6,642,704
51	Storage	$ -	$3,312,594	$8,891,960	$5,242,009	$1,365,932	$ 817,317	$ 363,565	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 20,902,819
52	Peaking	$ 243,274	$ 241,587	$ 484,785	$1,064,481	$2,625,914	$ 176,099	$ 155,919	$ 44,159	$ 1,152	$ 1,152	$ 1,111	$ 1,152	$ 5,040,783
53	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (4,814)	$(256,077)	$(214,704)	$(159,205)	$(164,148)	$(152,271)	$(219,114)	$ (1,170,333)
54	Less: Capacity Release	$ (113,129)	$ (113,129)	$ (113,129)	$ (113,129)	$ (113,129)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (565,644)
55	Less: Asset Mgmt	$ (555,984)	$ (555,984)	$ (555,984)	$ (555,984)	$ (555,984)	$ (555,984)	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,335,905)
56	Total Demand	$ 413,477	$3,666,582	$9,438,776	$6,222,567	$4,022,480	$1,060,329	$ 884,523	$ 519,686	$ 275,541	$ 288,898	$ 262,108	$ 459,459	$ 27,514,425

57

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

59		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
60	**Therms**													
61	Maine	436,834	781,046	1,058,729	870,820	793,156	511,874	397,079	311,210	215,411	219,924	199,155	294,565	6,089,803
62	New Hampshire	462,023	702,442	851,107	909,692	735,516	494,974	423,206	289,514	149,975	160,287	149,833	256,032	5,584,601
63	Total	898,857	1,483,488	1,909,836	1,780,512	1,528,672	1,006,848	820,285	600,724	365,386	380,211	348,988	550,597	11,674,404

64	**Percentage of Total**	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
65	Maine	48.60%	52.65%	55.44%	48.91%	51.89%	50.84%	48.41%	51.81%	58.95%	57.84%	57.07%	53.50%	52.54%
66	New Hampshire	51.40%	47.35%	44.56%	51.09%	48.11%	49.16%	51.59%	48.19%	41.05%	42.16%	42.93%	46.50%	47.46%
67	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

68

69 **Allocation of Demand Costs by Division**

70	Maine	$200,945	$1,930,430	$5,232,442	$3,043,358	$2,087,076	$539,063	$428,175	$269,228	$162,444	$167,106	$149,575	$245,807	$14,455,648
71	New Hampshire	$212,532	$1,736,153	$4,206,334	$3,179,209	$1,935,404	$521,266	$456,348	$250,459	$113,098	$121,792	$112,532	$213,652	$13,058,777
72	Total	$ 413,477	$ 3,666,582	$ 9,438,776	$ 6,222,567	$ 4,022,480	$ 1,060,329	$ 884,523	$ 519,686	$ 275,541	$ 288,898	$ 262,108	$ 459,459	$ 27,514,425

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

74	**Maine**	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL	
75	Pipeline & Product Demand	$ 407,898	$ 411,461	$ 405,314	$ 286,207	$ 363,066	$ 319,123	$ 300,666	$ 246,351	$ 161,765	$ 166,440	$ 148,941	$ 245,191	$ 3,462,423	52.12%
76	Storage		$ 1,744,058	$ 4,929,311	$ 2,563,783	$ 708,718	$ 415,518	$ 175,992	$ 111,229	$ 93,858	$ 94,948	$ 86,896	$ 117,224	$ 11,041,535	52.76%
77	Peaking	$ 118,228	$ 127,194	$ 268,743	$ 520,621	$ 1,362,463	$ 89,528	$ 75,476	$ 22,877	$ 679	$ 666	$ 634	$ 616	$ 2,587,725	51.34%
78	Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,447)	$ (123,960)	$ (111,229)	$ (93,858)	$ (94,948)	$ (86,896)	$ (117,224)	$ (630,562)	
79	Capacity Release (Credit)	$ (54,979)	$ (59,562)	$ (62,714)	$ (55,329)	$ (58,697)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (291,281)	51.50%
80	Asset Management (Credit)	$ (270,202)	$ (292,722)	$ (308,213)	$ (271,923)	$ (288,474)	$ (282,658)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,714,192)	51.39%
81	**Total Allocated Demand**	$ 200,945	$ 1,930,430	$ 5,232,442	$ 3,043,358	$ 2,087,076	$ 539,063	$ 428,175	$ 269,228	$ 162,444	$ 167,106	$ 149,575	$ 245,807	$ 14,455,648	52.54%

82

83	**New Hampshire**	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL	
84	Pipeline & Product Demand	$ 431,418	$ 370,052	$ 325,830	$ 298,983	$ 336,681	$ 308,587	$ 320,449	$ 229,176	$ 112,625	$ 121,306	$ 112,055	$ 213,117	$ 3,180,281	47.88%
85	Storage	$ -	$ 1,568,537	$ 3,962,649	$ 2,678,226	$ 657,214	$ 401,799	$ 187,572	$ 103,475	$ 65,347	$ 69,201	$ 65,375	$ 101,890	$ 9,861,284	47.24%
86	Peaking	$ 125,046	$ 114,393	$ 216,041	$ 543,860	$ 1,263,451	$ 86,572	$ 80,442	$ 21,282	$ 473	$ 485	$ 477	$ 535	$ 2,453,058	48.66%
87	Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,367)	$ (132,116)	$ (103,475)	$ (65,347)	$ (69,201)	$ (65,375)	$ (101,890)	$ (539,770)	
88	Capacity Release	$ (58,150)	$ (53,567)	$ (50,415)	$ (57,799)	$ (54,432)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (274,363)	48.50%
89	Asset Management (Credit)	$ (285,782)	$ (263,262)	$ (247,771)	$ (284,061)	$ (267,510)	$ (273,326)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,621,713)	48.61%
90	**Total Allocated Demand**	$ 212,532	$ 1,736,153	$ 4,206,334	$ 3,179,209	$ 1,935,404	$ 521,266	$ 456,348	$ 250,459	$ 113,098	$ 121,792	$ 112,532	$ 213,652	$ 13,058,777	47.46%

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

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL	SUMMER
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	423,272	294,929	190,962	186,863	191,303	273,732	4,392,745	1,561,061
3	Total Storage	798	0	0	0	0	0	2,349,738	798
4	Total Peaking	1,395	1,350	1,395	1,395	1,350	1,395	280,484	8,280
5	Subtotal	425,465	296,279	192,357	188,258	192,653	275,127	7,022,967	1,570,139
6	Less Interruptible - Maine	0	0	0	0	0	0	0	0
7	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
8	Total Firm Supply	425,465	296,279	192,357	188,258	192,653	275,127	7,022,967	1,570,139
9	Total Firm Pipeline Sendout	423,272	294,929	190,962	186,863	191,303	273,732	4,392,745	1,561,061
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	$ 25,970,213	$ 9,651,193
12	NYMEX Price Used for Forecast	$5.651	$5.709	$5.782	$5.849	$5.879	$5.980		
13	NYMEX Price Used for Update	$5.651	$5.709	$5.782	$5.849	$5.879	$5.980		
14	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
15	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -		
16	Total Updated Pipeline Costs	$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	$ 26,540,503	$ 9,651,193
17									
18	Total Pipeline	$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	$ 26,540,503	$ 9,651,193
19	Total Storage	$ 5,043	$ -	$ -	$ -	$ -	$ -	$ 9,893,717	$ 5,043
20	Total Peaking	$ 7,404	$ 7,116	$ 7,307	$ 7,242	$ 6,975	$ 7,184	$ 1,373,860	$ 43,228
21	Subtotal	$ 2,587,015	$ 1,810,400	$ 1,179,547	$ 1,166,873	$ 1,200,928	$ 1,754,701	$ 37,808,079	$ 9,699,464
22									
23	Hedging (Gain)/Loss Estimate								
24	NYMEX NG Futures Contracts	25	-	-	-	-	25	199	50
25	Average Purchase Price	$ 5.561	$ -	$ -	$ -	$ -	$ 6.021		
26	NYMEX Price Used for Forecast	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980		
27	NYMEX Price Used for Update	$ 5.651	$ 5.709	$ 5.782	$ 5.849	$ 5.879	$ 5.980		
28	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
29	Futures Hedging (Gain)/Loss	$ (22,462)	$ -	$ -	$ -	$ -	$ 10,288	$ 3,675,287	$ (12,173)
30									
31	Interruptible Cost Estimate								
32	Variable Pipeline Costs Excld Hedges	$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	$ 26,540,503	$ 9,651,193
33	Average Supply Cost ($/MMBtu)	$ 6.083	$ 6.114	$ 6.139	$ 6.206	$ 6.241	$ 6.384		
34	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36									
37	Firm Sales Pipeline Commodity Excld Hedge	$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	$ 26,540,503	$ 9,651,193
38	Total Storage	$ 5,043	$ -	$ -	$ -	$ -	$ -	$ 9,893,717	$ 5,043
39	Total Peaking	$ 7,404	$ 7,116	$ 7,307	$ 7,242	$ 6,975	$ 7,184	$ 1,373,860	$ 43,228
40	Firm Sales Variable Costs Excld Hedge	$ 2,587,015	$ 1,810,400	$ 1,179,547	$ 1,166,873	$ 1,200,928	$ 1,754,701	$ 37,808,079	$ 9,699,464
41	Plus Hedging (Gain)/Loss	$ (22,462)	$ -	$ -	$ -	$ -	$ 10,288	$ 3,675,287	$ (12,173)
42	Total Firm Sales Variable Costs	$ 2,564,553	$ 1,810,400	$ 1,179,547	$ 1,166,873	$ 1,200,928	$ 1,764,989	$ 41,483,366	$ 9,687,291

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Schedule 6A
3	Total Storage	Schedule 6A
4	Total Peaking	Schedule 6A
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Schedule 6A
7	Less Interruptible - New Hampshire	Schedule 6A
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Schedule 6A
12	NYMEX Price Used for Forecast	Schedule 6A
13	NYMEX Price Used for Update	
14	Increase/(Decrease) NYMEX Price	LN 13 - LN 12
15	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 14
16	Total Updated Pipeline Costs	LN 15 + LN 11
17		
18	Total Pipeline	LN 16
19	Total Storage	Schedule 6A
20	Total Peaking	Schedule 6A
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	NYMEX NG Futures Contracts	Schedule 6A
25	Average Purchase Price	Schedule 6A
26	NYMEX Price Used for Forecast	Schedule 6A
27	NYMEX Price Used for Update	Company Analysis
28	Increase/(Decrease) NYMEX Price	LN 27 - LN 26
29	Futures Hedging (Gain)/Loss	(LN 25 - LN 26 - LN 28) * LN 24*10,000
30		
31	Interruptible Cost Estimate	
32	Variable Pipeline Costs Excld Hedges	LN 16
33	Average Supply Cost ($/MMBtu)	LN 32 / LN 2
34	Interruptible Cost - Maine	LN 33 * LN 6
35	Interruptible Cost - New Hampshire	LN 33 * LN 7
36		
37	Firm Sales Pipeline Commodity Excld Hedge	LN 32 - LN 34 - LN 35
38	Total Storage	LN 19
39	Total Peaking	LN 20
40	Firm Sales Variable Costs Excld Hedge	Sum LN 37 : LN 39
41	Plus Hedging (Gain)/Loss	LN 29
42	Total Firm Sales Variable Costs	LN 40 + LN 41

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Line		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL	SUMMER
43	**Commodity Allocation Factors**								
44	Firm Sales Sendout for Normal Winter, MMBtu								
45		**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**TOTAL**	**SUMMER**
46	Maine	192,593	130,202	87,135	85,209	84,284	133,072	3,265,494	712,494
47	New Hampshire	232,872	166,077	105,222	103,049	108,369	142,055	3,743,971	857,644
48	Total	425,464	296,279	192,357	188,257	192,652	275,127	7,009,465	1,570,137
49									
50	**Percentage of Total**								
51	Maine	45.27%	43.95%	45.30%	45.26%	43.75%	48.37%	46.59%	45.38%
52	New Hampshire	54.73%	56.05%	54.70%	54.74%	56.25%	51.63%	53.41%	54.62%
53	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
54									
55	**Commodity Allocation by Jurisdiction**								
56	**Maine**								
57	Firm Sales Pipeline Commodity Excld Hedge	$ 1,165,416	$ 792,466	$ 531,010	$ 524,869	$ 522,343	$ 845,228	$ 12,286,749	$ 4,381,332
58	Hedging (Gains) Losses	$ (10,168)	$ -	$ -	$ -	$ -	$ 4,976	$ 1,722,159	$ (5,191)
59	Storage	$ 2,283	$ -	$ -	$ -	$ -	$ -	$ 4,663,153	$ 2,283
60	Peaking	$ 3,352	$ 3,127	$ 3,310	$ 3,278	$ 3,051	$ 3,475	$ 640,397	$ 19,593
61	Maine Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Total Maine Commodity Costs	$ 1,160,883	$ 795,593	$ 534,320	$ 528,147	$ 525,395	$ 853,679	$ 19,312,459	$ 4,398,016
63	Maine Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 121,916	$ -
64	Total Maine Variable Costs	$ 1,160,883	$ 795,593	$ 534,320	$ 528,147	$ 525,395	$ 853,679	$ 19,434,375	$ 4,398,016
65	**New Hampshire**								
66	Firm Sales Pipeline Commodity Excld Hedge	$ 1,409,152	$ 1,010,818	$ 641,230	$ 634,762	$ 671,610	$ 902,289	$ 14,253,754	$ 5,269,861
67	Hedging (Gains) Losses	$ (12,294)	$ -	$ -	$ -	$ -	$ 5,312	$ 1,953,127	$ (6,982)
68	Storage	$ 2,760	$ -	$ -	$ -	$ -	$ -	$ 5,230,563	$ 2,760
69	Peaking	$ 4,052	$ 3,989	$ 3,997	$ 3,964	$ 3,924	$ 3,709	$ 733,463	$ 23,635
70	New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	Total New Hampshire Commodity Costs	$ 1,403,670	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 911,311	$ 22,170,907	$ 5,289,274
72	New Hampshire Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 142,704	$ -
73	Total New Hampshire Variable Costs	$ 1,403,670	$ 1,014,807	$ 645,227	$ 638,726	$ 675,533	$ 911,311	$ 22,313,612	$ 5,289,274
74	**Northern Utilities**								
75	Firm Sales Pipeline Commodity Excld Hedge	$ 2,574,568	$ 1,803,284	$ 1,172,240	$ 1,159,631	$ 1,193,953	$ 1,747,517	$ 26,540,503	$ 9,651,193
76	Hedging (Gains) Losses	$ (22,462)	$ -	$ -	$ -	$ -	$ 10,288	$ 3,675,287	$ (12,173)
77	Storage	$ 5,043	$ -	$ -	$ -	$ -	$ -	$ 9,893,717	$ 5,043
78	Peaking	$ 7,404	$ 7,116	$ 7,307	$ 7,242	$ 6,975	$ 7,184	$ 1,373,860	$ 43,228
79	Northern Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80	Total Northern Commodity Costs	$ 2,564,553	$ 1,810,400	$ 1,179,547	$ 1,166,873	$ 1,200,928	$ 1,764,989	$ 41,483,366	$ 9,687,291
81	Northern Inventory Finance Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 264,620	$ -
82	Total Northern Variable Costs	$ 2,564,553	$ 1,810,400	$ 1,179,547	$ 1,166,873	$ 1,200,928	$ 1,764,989	$ 41,747,986	$ 9,687,291
83									

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

LN	Description	Reference
43	**Commodity Allocation Factors**	
44	Firm Sales Sendout for Normal Winter, MMBtu	
45		
46	Maine	ME Attachment NUI-JDS-4, LN 33 / 10
47	New Hampshire	NH Schedule 10B, LN 33 / 10
48	Total	LN 46 + LN 47
49		
50	**Percentage of Total**	
51	Maine	LN 46 / LN 48
52	New Hampshire	LN 47 / LN 48
53	Total	LN 51 + LN 52
54		
55	**Commodity Allocation by Jurisdiction**	
56	**Maine**	
57	Firm Sales Pipeline Commodity Excld Hedge	LN 37 * LN 51
58	Hedging (Gains) Losses	LN 29 * LN 51
59	Storage	LN 38 * LN 51
60	Peaking	LN 39 * LN 51
61	Maine Interruptible	LN 34
62	Total Maine Commodity Costs	Sum LN 57 : LN 61
63	Maine Inventory Finance Costs	LN 104
64	Total Maine Variable Costs	LN 62 + LN 63
65	**New Hampshire**	
66	Firm Sales Pipeline Commodity Excld Hedge	LN 37 * LN 52
67	Hedging (Gains) Losses	LN 29 * LN 52
68	Storage	LN 38 * LN 52
69	Peaking	LN 39 * LN 52
70	New Hampshire Interruptible	LN 35
71	Total New Hampshire Commodity Costs	Sum LN 66 : LN 70
72	New Hampshire Inventory Finance Costs	LN 109
73	Total New Hampshire Variable Costs	LN 71 + LN 72
74	**Northern Utilities**	
75	Firm Sales Pipeline Commodity Excld Hedge	LN 57 + LN 66
76	Hedging (Gains) Losses	LN 58 + LN 67
77	Storage	LN 59 + LN 68
78	Peaking	LN 60 + LN 69
79	Northern Interruptible	LN 61 + LN 70
80	Total Northern Commodity Costs	LN 62 + LN 71
81	Northern Inventory Finance Costs	LN 63 + LN 72
82	Total Northern Variable Costs	LN 80 + LN 81
83		

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 H	Col I	Col J	Col K	Col L	Col M	Col N	Col P
Inventory Finance Charge	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**TOTAL**	**SUMMER**
Storage	$ 13,076	$ 18,813	$ 24,636	$ 30,543	$ 36,110	$ 41,303	$ 262,258	$ 164,479
Peaking	$ 162	$ 161	$ 160	$ 165	$ 172	$ 171	$ 2,363	$ 992
Total	$ 13,238	$ 18,975	$ 24,796	$ 30,708	$ 36,282	$ 41,473	$ 264,620	$ 165,471
Inventory Finance Charge Allocation by Jurisdiction								
Maine	$ 5,992	$ 8,338	$ 11,232	$ 13,899	$ 15,873	$ 20,060	$ 121,916	$ 75,395
New Hampshire	$ 7,246	$ 10,636	$ 13,564	$ 16,809	$ 20,409	$ 21,414	$ 142,704	$ 90,077
Total	$ 13,238	$ 18,975	$ 24,796	$ 30,708	$ 36,282	$ 41,473	$ 264,620	$ 165,471
Inventory Finance Charge Allocation by Month								
Maine								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,049,867	0
Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
ME Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 121,916	$ -
New Hampshire								
Firm Sales Normal Remaining Sendout	0	0	0	0	0	0	2,279,682	0
Monthly % Sendout of Total Winter	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
NH Allocated Inventory Finance Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ 142,704	$ -

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

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

87		
88		
89		
90	**Inventory Finance Charge**	
91	Storage	Company Analysis, Schedule 14 - 'Carrying Costs'
92	Peaking	Company Analysis, Schedule 14 - 'Carrying Costs'
93	Total	Sum LN 91 : LN 92
94		
95	**Inventory Finance Charge Allocation by Jurisdiction**	
96	Maine	LN 93 * LN 51
97	New Hampshire	LN 93 * LN 52
98	Total	Sum LN 96 : LN 97
99		
100	**Inventory Finance Charge Allocation by Month**	
101	**Maine**	
102	Firm Sales Remaining Sendout	ME Attachment NUI-JDS-4, LN 80 / 10
103	Monthly % Sendout of Total Winter	LN 102 / LN 102 Col N
104	ME Allocated Inventory Finance Charge	LN 96 Col N * LN 103
105		
106	**New Hampshire**	
107	Firm Sales Remaining Sendout	NH Schedule 10B, LN 80 / 10
108	Monthly % Sendout of Total Winter	LN 107 / LN 107 Col N
109	NH Allocated Inventory Finance Charge	LN 97 Col N* LN 108

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

		Winter	Summer	Total	
1	Demand	$ 10,354,129	$ 1,046,835	$ 11,400,965	Schedule 1A, LN 80
2	Commodity	$ 17,024,337	$ 5,289,274	$ 22,313,612	Schedule 1B, LN 0
3	Total	$ 27,378,467	$ 6,336,110	$ 33,714,577	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,473,787	8,368,836	36,842,623	Schedule 10B, LN 11 * 10
6	Forecasted Residential Sales (Therms)	12,742,755	3,402,963	16,145,719	Schedule 10B, LN 3 * 10
7	Average Residential Rate:	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$0.3636	$0.1251		LN 1 / LN 5
9	Average Commodity Rate	$0.5979	$0.6320		LN 2 / LN 5
10	Average Rate	$0.9615	$0.7571		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 4,848,029	$ 458,515	$ 5,306,544	Schedule 10A, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 4,633,741	$ 425,711	$ 5,059,451	LN 8 * LN 6
15	**Demand Reallocation:**	$ 214,288	$ 32,804	$ 247,092	LN 13 - LN 14
16	**HLF Allocation**	$ 24,792	$ 9,394	$ 34,185	LN 15 / LN 20
17	**LLF Allocation**	$ 189,497	$ 23,411	$ 212,907	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	11.57%	28.64%		Schedule 10A, LN 173
21	LLF	88.43%	71.36%		Schedule 10A, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 7,547,013	$ 2,146,872	$ 9,693,884	Schedule 10A, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 7,618,831	$ 2,150,673	$ 9,769,504	LN 18 * LN 16
25	**Commodity Reallocation:**	$ (71,818)	$ (3,801)	$ (75,620)	LN 23 - LN 24
26	**HLF Allocation**	$ (14,992)	$ (1,653)	$ (16,645)	LN 25 / LN 30
27	**LLF Allocation**	$ (56,826)	$ (2,148)	$ (58,975)	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	20.88%	43.48%		Schedule 10A, LN 143
31	LLF	79.12%	56.52%		Schedule 10A, LN 144