Schedules

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing

Table of Contents

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Summary

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Ln	(a)	Reference (b)		PK 14-15 Nov - Apr (c)
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**			
2	**d/b/a Liberty Utilities**			
3	**Peak 2014 - 2015 Winter Cost of Gas Filing**			
4	**Summary**			
5				PK 14-15
6		Reference		Nov - Apr
7	(a)	(b)		(c)
8				
9	**Anticipated Direct Cost of Gas**			
10	Purchased Gas:			
11	Demand Costs:	Sch. 5A, col (k), ln 43	$	8,590,051
12	Supply Costs	Sch. 6, col (i), ln 44		55,657,311
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (k), ln 58	$	1,006,209
16	Commodity Costs:	Sch. 6, col (i), ln 47		7,630,253
17				
18	Produced Gas:	Sch. 6, col (i), ln 53	$	5,182,397
19				
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	193,505
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 172	$	-
22				
23	**Total Unadjusted Cost of Gas**		$	78,259,727
24				
25	**Adjustments:**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$	14,889,808
28	Interest 10/31/14 - 04//30/15	Sch. 3, col (q) ln 193		324,039
29	Prior Period Adjustments	Sch. 4, ln 26 col (b)		-
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		-
31	Broker Revenues	Sch. 4, ln 26 col (d)		(1,099,927)
32	Fuel Financing	Sch. 4, ln 26 col (e)		-
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		(353,484)
34	Interruptible Sales Margin	Sch. 4, ln 26 col (g)		-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)		(2,674,599)
36	Hedging Costs	Sch. 4, ln 26 col (j)		197,835
37	FPO Premium - Collection			
38	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		50,689
39				
40	**Total Adjustments**		$	11,334,362
41				
42	**Total Anticipated Direct Costs**	lns 23 + 40	$	89,594,088
43				
44	**Anticipated Indirect Cost of Gas**			
45	**Working Capital**			
46	Total Unadjusted Anticipated Cost of Gas	Ln 23	$	78,259,727
47	Lead Lag Days / 365	DG 10-017, 14.27 / 365		0.0391
48	Prime Rate			3.25%
49	Working Capital Percentage	per GTC 16(f), ln 47 * ln 48		0.127%
50	Working Capital	ln 46 * ln 49		99,459
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 100		34,381
52				
53	**Total Working Capital Allowance**	lns 50 + 51	$	133,840
54				
55	**Bad Debt**			
56	Total Unadjusted Anticipated Cost of Gas	ln 23	$	78,259,727
57	Less Refunds	ln 30		-
58	Plus Working Capital	ln 53		133,840
59	Plus Prior Period (Over) Under Recovery	ln 27		14,889,808
60	Subtotal		$	93,283,375
61	Bad Debt Percentage	per GTC 16(f)		1.98%
62				
63	Bad Debt Allowance	ln 60 * ln 61	$	1,847,011
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 181		(511,857)
65				
66	**Total Bad Debt Allowance**	lns 63 + 64	$	1,335,154
67				
68	**Production and Storage Capacity**	per GTC16(f)	$	1,980,428
69				
70	**Miscellaneous Overhead**	per GTC 16(f)	$	13,170
71	Sales Volume	Sch. 10B, ln 23/1000		75,950
72	Divided by Total Sales	Sch. 10B, ln 23/1000		95,853
73	Ratio			79.24%
74				
75	**Miscellaneous Overhead**	lns 70 * 73	$	10,435
76				
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$	3,459,857
78				
79	**Total Cost of Gas**	lns 42 + 77	$	93,053,946
80				
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		76,121,808

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Schedule 1

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Ln			Peak Costs								Peak Period
7	For Month of:		May 14 - Oct 14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10										1,314,181	1.6%
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	2,615,496	12,112,739	16,934,054	16,522,162	14,521,459	12,144,226	4,829,671	79,679,808
13	Lost Gas (Unaccounted for)		-	115,690	206,787	243,515	203,534	169,681	97,630		1,036,838
14	Company Use		-	30,946	55,313	65,138	54,443	45,388	26,115		277,343
15	Unbilled Therms		-	6,276,150	3,780,393	1,781,890	(879,043)	(1,480,165)	(4,640,595)	(4,829,671)	8,959
16											
17	**Total Firm Volumes**	Sch. 6, ln 92	-	9,038,281	16,155,233	19,024,597	15,901,096	13,256,364	7,627,377		81,002,948
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 63	-	694,856	933,968	961,173	840,409	953,431	898,739		5,282,577
22	Niagara Supply	Sch. 6, ln 64	-	689,704	740,443	750,335	655,819	744,292	701,765		4,282,358
23	TGP Supply (Direct)	Sch. 6, ln 65	-	5,030,346	3,214,961	3,257,912	2,848,386	3,231,671	4,110,233		21,693,509
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	2,833,266	4,784,937	3,138,027	-	-		10,756,230
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	1,300,647	1,214,805	668,515	1,193,937	1,728,302	1,504,718		7,610,923
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	-	20,610	454,363	666,620	697,089	67,663	-		1,906,345
28	Propane Truck	Sch. 6, ln 70	-	-	-	635,615	72,785	-	-		708,400
29	PNGTS	Sch. 6, ln 71	-	60,358	83,376	93,792	77,288	73,814	50,929		439,557
30	TGP Supply (Z4)	Sch. 6, ln 72	-	1,774,680	1,906,182	1,931,648	1,689,072	1,916,090	1,841,666		11,059,338
31	Subtotal Pipeline Volumes		-	9,571,201	11,381,364	13,750,547	11,212,814	8,715,262	9,108,050		63,739,236
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 77	-	2,618,224	4,773,869	5,074,064	4,688,282	4,509,577	-		21,664,016
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 80	-	20,610	454,363	717,779	697,089	22,298	20,971		1,933,110
38	Propane	Sch. 6, ln 81	-	-	-	784,441	72,785	76,890	-		934,116
39	Subtotal Produced Gas		-	20,610	454,363	1,502,221	769,875	99,188	20,971		2,867,227
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 86	-	(20,610)	(454,363)	(666,620)	(697,089)	(67,663)	-		(1,906,345)
43	Propane	Sch. 6, ln 87	-	-	-	(635,615)	(72,785)	-	-		(708,400)
44	TGP Storage Refill	Sch. 6, ln 88	-	(3,151,143)	-	-	-	-	(1,501,643)		(4,652,786)
45	Subtotal Refills		-	(3,171,753)	(454,363)	(1,302,235)	(769,875)	(67,663)	(1,501,643)		(7,267,531)
46											
47	Total Firm Sendout Volumes	lns 31 + 34 + 39 + 45	-	9,038,281	16,155,233	19,024,597	15,901,096	13,256,364	7,627,377		81,002,948
48											

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2014 - 2015 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 14 - Oct 14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Nov - Apr
49	**II. Gas Costs**										
50											**REDACTED**
51	**A. Demand Costs**										
52	Supply										
53	Niagara Supply	Sch.5A, ln 12	[redacted]								
54	Subtotal Supply Demand										
55	Less Capacity Credit										
56	Net Pipeline Demand Costs										
57											
58	Pipeline:										
59	Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]								
60	Tenn Gas Pipeline 95346 Z5-Z6	Sch.5A, ln 17									
61	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18									
62	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19									
63	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20									
64	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21									
65	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22									
66	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 23									
67	Portland Natural Gas Trans Service	Sch.5A, ln 24									
68	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 25									
69	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 26									
70	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 27									
71	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 28									
72	National Fuel FST 2358	Sch.5A, ln 29									
73	Subtotal Pipeline Demand		$ 1,348,007	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772		$ 9,578,638
74	Less Capacity Credit		(467,598)	(338,026)	(338,026)	(338,026)	(338,026)	(338,026)	(338,026)		(2,495,756)
75	Net Pipeline Demand Costs		$ 880,409	$ 1,033,746	$ 1,033,746	$ 1,033,746	$ 1,033,746	$ 1,033,746	$ 1,033,746		$ 7,082,883
76											
77	Peaking Supply:										
78	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 34	[redacted]								
79	Granite Ridge Demand	Sch.5A, ln 35									
80	GDF Suez Demand NSB041	Sch.5A, ln 36									
81	Subtotal Peaking Demand		$ -	$ 400,000	$ 400,000	$ 400,000	$ 400,000	$ 400,000	$ -		$ 2,000,000
82	Less Capacity Credit		-	(98,566)	(98,566)	(98,566)	(98,566)	(98,566)	-		(492,832)
83	Net Peaking Supply Demand Costs		$ -	$ 301,434	$ 301,434	$ 301,434	$ 301,434	$ 301,434	$ -		$ 1,507,168
84											
85	Storage:										
86	Dominion - Demand	Sch.5A, ln 46	[redacted]								
87	Dominion - Storage	Sch.5A, ln 47									
88	Honeoye - Demand	Sch.5A, ln 48									
89	National Fuel - Demand	Sch.5A, ln 49									
90	National Fuel - Capacity	Sch.5A, ln 50									
91	Tenn Gas Pipeline - Demand	Sch.5A, ln 51									
92	Tenn Gas Pipeline - Capacity	Sch.5A, ln 52									
93	Subtotal Storage Demand		$ 715,296	$ 119,216	$ 119,216	$ 119,216	$ 119,216	$ 119,216	$ 119,216		$ 1,430,592
94	Less Capacity Credit		(248,123)	(29,377)	(29,377)	(29,377)	(29,377)	(29,377)	(29,377)		(424,383)
95	Net Storage Demand Costs		$ 467,173	$ 89,839	$ 89,839	$ 89,839	$ 89,839	$ 89,839	$ 89,839		$ 1,006,209
96											
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 2,063,303	$ 1,890,988	$ 1,890,988	$ 1,890,988	$ 1,890,988	$ 1,890,988	$ 1,490,988		$ 13,009,231
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(715,721)	(465,969)	(465,969)	(465,969)	(465,969)	(465,969)	(367,403)		(3,412,970)
99	Net Demand Charges		$ 1,347,583	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,123,585		$ 9,596,261
100											
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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Line			Peak Costs May 14 - Oct 14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Peak Period Nov - Apr
6											
7	For Month of:		May 14 - Oct 14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Nov - Apr
102	**B. Commodity Costs**										**REDACTED**
103	Pipeline:										
104	Dawn Supply	Sch. 6, ln 12	[redacted]								
105	Niagara Supply	Sch. 6, ln 13									
106	TGP Supply (Direct)	Sch. 6, ln 14									
107	Dracut Supply 1 - Baseload	Sch. 6, ln 15									
108	Dracut Supply 2 - Swing	Sch. 6, ln 16									
109	City Gate Delivered Supply	Sch. 6, ln 17									
110	LNG Truck	Sch. 6, ln 18									
111	Propane Truck	Sch. 6, ln 19									
112	PNGTS	Sch. 6, ln 20									
113	TGP Supply (Z4)	Sch. 6, ln 21									
114	Subtotal Pipeline Commodity Costs		$ -	$ 4,568,744	$ 13,852,725	$ 17,406,740	$ 14,754,036	$ 6,496,018	$ 3,693,854		$ 60,772,118
115											
116	Storage:										
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ 922,161	$ 1,681,398	$ 1,787,129	$ 1,651,253	$ 1,588,312	$ -		$ 7,630,253
118											
119	Produced Gas Costs:										
120	LNG Vapor	Sch. 6, ln 50	[redacted]								
121	Propane	Sch. 6, ln 51									
122	Subtotal Produced Gas Costs		$ -	$ 32,427	$ 828,959	$ 2,711,385	$ 1,428,103	$ 156,917	$ 24,606		$ 5,182,397
123											
124	Less Storage Refills:										
125	LNG Truck	Sch. 6, ln 37	[redacted]								
126	Propane	Sch. 6, ln 38									
127	TGP Storage Refill	Sch. 6, ln 39									
128	Storage Refill (Trans.)	Sch. 6, ln 40									
129	Subtotal Storage Refill		$ -	$ (1,412,814)	$ (844,024)	$ (2,365,798)	$ (1,427,680)	$ (73,223)	$ (641,307)		$ (6,764,847)
130											
131	Total Supply Commodity Costs		$ -	$ 4,110,518	$ 15,519,057	$ 19,539,457	$ 16,405,713	$ 8,168,024	$ 3,077,153		$ 66,819,922
132											
133	**C. Supply Volumetric Transportation Costs:**										
134	Dawn Supply	Sch. 6, ln 26	[redacted]								
135	Niagara Supply	Sch. 6, ln 27									
136	TGP Supply (Direct)	Sch. 6, ln 28									
137	Dracut Supply 1 - Baseload	Sch. 6, ln 29									
138	Dracut Supply 2 - Swing	Sch. 6, ln 30									
139	Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 252,394	$ 219,046	$ 239,972	$ 206,128	$ 186,341	$ 211,705		$ 1,315,586
140											
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ 40,421	$ 73,700	$ 78,334	$ 72,379	$ 69,620	$ -		$ 334,453
142											
143	Total Supply Volumetric Trans. Costs	lns 139 + 141	$ -	$ 292,815	$ 292,746	$ 318,306	$ 278,506	$ 255,961	$ 211,705		$ 1,650,040
144											
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 4,403,332	$ 15,811,804	$ 19,857,763	$ 16,684,219	$ 8,423,985	$ 3,288,858		$ 68,469,961
146											
147											

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Line	Description	Reference	Peak Costs May 14 - Oct 14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Peak Period Nov - Apr
6											
7	For Month of:										
148	**D. Supply and Demand Costs by Source**										**REDACTED**
149											
150	Purchased Gas Demand Costs										
151	Pipeline Gas Demand Costs	lns 54 + 73	$ 1,348,007	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772		$ 9,578,638
152	Peaking Gas Demand Costs	ln 81	-	400,000	400,000	400,000	400,000	400,000	-		2,000,000
153	Subtotal Purchased Gas Demand Costs		$ 1,348,007	$ 1,771,772	$ 1,771,772	$ 1,771,772	$ 1,771,772	$ 1,771,772	$ 1,371,772		$ 11,578,638
154	Less Capacity Credit	lns 55 + 74 + 82	(467,598)	(436,593)	(436,593)	(436,593)	(436,593)	(436,593)	(338,026)		(2,988,587)
155	Net Purchased Gas Demand Costs		$ 880,409	$ 1,335,179	$ 1,335,179	$ 1,335,179	$ 1,335,179	$ 1,335,179	$ 1,033,746		$ 8,590,051
156											
157	Storage Gas Demand Costs										
158	Storage Demand	ln 93	$ 715,296	$ 119,216	$ 119,216	$ 119,216	$ 119,216	$ 119,216	$ 119,216		$ 1,430,592
159	Less Capacity Credit	ln 94	(248,123)	(29,377)	(29,377)	(29,377)	(29,377)	(29,377)	(29,377)		(424,383)
160	Net Storage Demand Costs		$ 467,173	$ 89,839	$ 89,839	$ 89,839	$ 89,839	$ 89,839	$ 89,839		$ 1,006,209
161											
162	**Total Demand Costs**	lns 155 + 160	$ 1,347,583	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,123,585		$ 9,596,261
163											
164	Purchased Gas Supply										
165	Commodity Costs	ln 114	$ -	$ 4,568,744	$ 13,852,725	$ 17,406,740	$ 14,754,036	$ 6,496,018	$ 3,693,854		$ 60,772,118
166	Less Storage Inj.(TGP Storage)	ln 127	[redacted]								
167	Less Storage Transportation	ln 128									
168	Less LNG Truck	ln 125									
169	Less Propane Truck	ln 126									
170	Plus Transportation Costs	ln 139									
171	Subtotal Purchased Gas Supply		$ -	$ 3,408,324	$ 13,227,747	$ 15,280,914	$ 13,532,484	$ 6,609,137	$ 3,264,252		$ 55,322,857
172											
173	Storage Commodity Costs										
174	Commodity Costs	ln 117	$ -	$ 922,161	$ 1,681,398	$ 1,787,129	$ 1,651,253	$ 1,588,312	$ -		$ 7,630,253
175	Transportation Costs	ln 141	-	40,421	73,700	78,334	72,379	69,620	-		334,453
176	Subtotal Storage Commodity Costs		$ -	$ 962,582	$ 1,755,098	$ 1,865,464	$ 1,723,632	$ 1,657,932	$ -		$ 7,964,706
177											
178	Produced Gas Commodity Costs	ln 122	$ -	$ 32,427	$ 828,959	$ 2,711,385	$ 1,428,103	$ 156,917	$ 24,606		$ 5,182,397
179											
180	**Subtotal Commodity Costs**	lns 171 + 176 + 178	$ -	$ 4,403,332	$ 15,811,804	$ 19,857,763	$ 16,684,219	$ 8,423,985	$ 3,288,858		$ 68,469,961
181											
182	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ 35,336	$ 35,975	$ 32,723	$ 35,293	$ 37,530	$ 16,648		$ 193,505
183											
184	**Total Commodity Costs**	lns 180 + 182	$ -	$ 4,438,668	$ 15,847,779	$ 19,890,486	$ 16,719,512	$ 8,461,515	$ 3,305,506		$ 68,663,466
185											
186	**Total Demand Costs**	ln 99	$ 1,347,583	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,123,585		$ 9,596,261
187	**Total Supply Costs**	ln 184	-	4,438,668	15,847,779	19,890,486	16,719,512	8,461,515	3,305,506		68,663,466
188											
189	**Total Direct Gas Costs**	lns 186 + 187	$ 1,347,583	$ 5,863,686	$ 17,272,798	$ 21,315,505	$ 18,144,531	$ 9,886,534	$ 4,429,091		$ 78,259,727
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191											

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Schedule 2

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**

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3 **Peak 2014 - 2015 Winter Cost of Gas Filing**

4 **Contracts Ranked on a per Unit Cost Basis**

Line	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Peak Period Cost per Unit Dth
7	(a)	(b)	(c)	(d)	(e)	(f)
8						
9	**Demand Costs**					
10	Granite Ridge Demand		Peaking	MDQ	-	[redacted]
11	Niagara Supply		Supply	MDQ	-	
12	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
13	Tenn Gas Pipeline - Cap. Reservations	FS-MA	Storage	ACQ	1,560,391	
14	National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
15	Tenn Gas Pipeline - Demand	FS-MA	Storage	MDQ	21,844	
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	
17	National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
18	National Fuel	FST 2358	Transportation	MDQ	6,098	
19	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
20	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
21	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
22	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
23	Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
24	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
25	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
26	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
27	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
28	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	72694 Z6-Z6	Transportation	MDQ	30,000	
29	ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	
30	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
31	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
32	Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
33	GDF Suez Liquid Demand Charge	NSB041	Peaking	MDQ	4,500	
34						
35	**Supply Costs - Commodity**					
36	TGP Supply (Z4)		Pipeline	Dkt	1,105,934	[redacted]
37	City Gate Delivered Supply		Pipeline	Dkt	-	
38	TGP Supply (Direct)		Pipeline	Dkt	2,169,351	
39	Niagara Supply		Pipeline	Dkt	428,236	
40	Dawn Supply		Pipeline	Dkt	528,258	
41	LNG Truck		Pipeline	Dkt	190,635	
42	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,075,623	
43	PNGTS		Pipeline	Dkt	43,956	
44	LNG Vapor (Storage)		Produced	Dkt	193,311	
45	Propane Truck		Pipeline	Dkt	70,840	
46	Propane		Produced	Dkt	93,412	
47	TGP Storage		Storage	Dkt	2,166,402	
48	Dracut Supply 2 - Swing		Pipeline	Dkt	761,092	
49						
50	**Supply Costs - Volumetric Transportation**					
51	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,075,623	[redacted]
52	Dracut Supply 2 - Swing		Pipeline	Dkt	761,092	
53	Niagara Supply		Pipeline	Dkt	428,236	
54	Dawn Supply		Pipeline	Dkt	528,258	
55	TGP Storage - Withdrawals		Pipeline	Dkt	2,166,402	
56	TGP Supply (Direct)		Pipeline	Dkt	2,169,351	

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Schedule 3

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln	(a)	Days in Month (b)	Prior Period Bal Apr-14 Ending Bal Plus May Billings (c)	May-14 31 (d)	Jun-14 30 (e)	Jul-14 31 (f)	Aug-14 31 (g)	Sep-14 30 (h)	Oct-14 31 (i)	Nov-14 30 (j)	Dec-14 31 (k)	Jan-15 31 (l)	Feb-15 28 (m)	Mar-15 31 (n)	Apr-15 30 (o)	May-15 31 (p)	Peak Period Total (q)
10	**Account 1920-1740 COG (Over)/Under Balance - Interest Calculation**																
12	**Beginning Balance**	Account 1920-1740 1/	**$ 22,728,560**	$ 14,889,808	$ 14,962,729	$ 13,599,778	$ 13,441,115	$ 13,672,506	$ 13,699,704	$ 13,874,813	$ 9,455,020	$ 7,865,716	$ 6,969,945	$ 6,306,600	$ 476,514	$ (3,942,059)	$ 22,728,560
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		224,597	224,597	224,597	224,597	224,597	224,597	5,863,686	17,272,798	21,315,505	18,144,531	9,886,534	4,429,091	-	78,259,727
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	331,811	331,811	331,811	331,811	331,811	331,811		1,990,863
15	Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(2,424,770)	(13,811,015)	(19,591,290)	(19,097,472)	(16,698,830)	(13,848,765)	(5,790,293)	(91,262,435)
16	Projected Unbilled Revenue									(8,235,424)	(13,478,685)	(16,325,940)	(15,983,003)	(14,919,381)	(10,066,720)		(79,009,153)
17	Reverse Prior Month Unbilled										8,235,424	13,478,685	16,325,940	15,983,003	14,919,381	10,066,720	79,009,153
18	Prior Period Adjustment-Unbilled				-					-							-
19	Add Net Adjustments	Schedule 4		(203,624)	(1,625,645)	(420,529)	(30,575)	(233,909)	(87,493)	13,786	(163,508)	(124,987)	(401,682)	(422,571)	(178,748)	-	(3,879,485)
20	Gas Cost Billed	Account 1920-1740 2/	(7,838,752)	-	-	-	-	-	-	-	-	-	-	-	-	-	(7,838,752)
21	Monthly (Over)/Under Recovery		$ 14,889,808	$ 14,910,781	$ 13,561,681	$ 13,403,846	$ 13,635,137	$ 13,663,194	$ 13,836,809	$ 9,423,902	$ 7,841,844	$ 6,949,498	$ 6,290,070	$ 467,165	$ (3,937,437)	$ 334,368	$ (1,522)
22	Average Monthly Balance	(ln 12 + 21)/2		$ 18,819,671	$ 14,262,205	$ 13,501,812	$ 13,538,126	$ 13,667,850	$ 13,768,256	$ 11,649,357	$ 8,648,432	$ 7,407,607	$ 6,630,008	$ 3,386,883	$ (1,730,462)	$ (1,803,846)	
24	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
26	Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 51,947	$ 38,098	$ 37,269	$ 37,369	$ 36,510	$ 38,004	$ 31,118	$ 23,872	$ 20,447	$ 16,530	$ 9,349	$ (4,622)	$ -	$ 335,890
28	**(Over)/Under Balance**	ln 21 + ln 26	$ 14,889,808	$ 14,962,729	$ 13,599,778	$ 13,441,115	$ 13,672,506	$ 13,699,704	$ 13,874,813	$ 9,455,020	$ 7,865,716	$ 6,969,945	$ 6,306,600	$ 476,514	$ (3,942,059)	$ 334,368	334,368
31	**Calculation of COG with Interest**																
33	**Beginning Balance**	ln 12	$ 22,728,560	$ 14,889,808	$ 14,962,729	$ 13,599,778	$ 13,441,115	$ 13,672,506	$ 13,699,704	$ 13,874,813	$ 9,447,048	$ 7,843,431	$ 6,930,760	$ 6,253,241	$ 411,268	$ (4,014,248)	$ 22,728,560
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		224,597	224,597	224,597	224,597	224,597	224,597	5,863,686	17,272,798	21,315,505	18,144,531	9,886,534	4,429,091	-	78,259,727
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	331,811	331,811	331,811	331,811	331,811	331,811	-	1,990,863
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(2,426,590)	(13,821,383)	(19,605,997)	(19,111,808)	(16,711,366)	(13,859,161)	(5,794,639)	(91,330,945)
37	Projected Unbilled Revenue									(8,241,606)	(13,488,803)	(16,338,196)	(15,995,001)	(14,930,581)	(10,074,277)		(79,068,464)
38	Reverse Prior Month Unbilled										8,241,606	13,488,803	16,338,196	15,995,001	14,930,581	10,074,277	79,068,464
39	Add Net Adjustments	ln 19		(203,624)	(1,625,645)	(420,529)	(30,575)	(233,909)	(87,493)	13,786	(163,508)	(124,987)	(401,682)	(422,571)	(178,748)	-	(3,879,485)
40	Gas Cost Billed	ln 20	(7,838,752)		-	-	-	-	-	-	-	-	-	-	-	-	(7,838,752)
41	Add Interest	ln 26		-	-	-	-	-	-	31,118	23,872	20,447	16,530	9,349	(4,622)	-	96,693
42	**(Over)/Under Balance**		$ 14,889,808	$ 14,910,781	$ 13,561,681	$ 13,403,846	$ 13,635,137	$ 13,663,194	$ 13,836,809	$ 9,447,017	$ 7,843,440	$ 6,930,817	$ 6,253,336	$ 411,418	$ (4,014,059)	$ 265,389	$ 26,661
44	Average Monthly Balance			$ 18,819,671	$ 14,262,205	$ 13,501,812	$ 13,538,126	$ 13,667,850	$ 13,768,256	$ 11,660,915	$ 8,645,244	$ 7,387,124	$ 6,592,048	$ 3,332,330	$ (1,801,396)	$ (1,874,430)	
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		51,947	38,098	37,269	37,369	36,510	38,004	31,149	23,863	20,390	16,435	9,198	(4,812)	-	335,421
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ 14,889,808	$ 14,962,729	$ 13,599,778	$ 13,441,115	$ 13,672,506	$ 13,699,704	$ 13,874,813	$ 9,447,048	$ 7,843,431	$ 6,930,760	$ 6,253,241	$ 411,268	$ (4,014,248)	$ 265,389	265,389
51	Forecast Sendout Therms	Sch 1								9,038,281	16,155,233	19,024,597	15,901,096	13,256,364	7,627,377		81,002,948
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								2,022,496	11,519,739	16,341,054	15,929,162	13,928,459	11,551,226	4,829,671	76,121,808
53	Less Forecast Unaccounted For	Sch 1								115,690	206,787	243,515	203,534	169,681	97,630		1,036,838
54	Less Forecast Company Use	Sch 1								30,946	55,313	65,138	54,443	45,388	26,115		277,343
55	Unbilled Volumes									6,869,150	4,373,393	2,374,890	-286,043	-887,165	-4,047,595	-4,829,671	3,566,959
56	Gross Unbilled									6,869,150	11,242,543	13,617,433	13,331,390	12,444,225	8,396,630	3,566,959	
59	COB w/o Interest	Sch. 3, pg. 4, ln 211 col. (c)								$1.1989	$1.1989	$1.1989	$1.1989	$1.1989	$1.1989	$1.1989	
61	COG With Interest	Sch. 3, pg. 4, ln 211 col. (d)								$1.1998	$1.1998	$1.1998	$1.1998	$1.1998	$1.1998	$1.1998	

65 1/ Beginning Balance for Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
66 2/ Gas Cost Billed Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

Ln	(a)	Days in Month (b)	Prior Period Bal Apr-14 Ending Bal + May Collections	May-14 31 (c)	Jun-14 30 (d)	Jul-14 31 (e)	Aug-14 31 (f)	Sep-14 30 (g)	Oct-14 31 (h)	Nov-14 30 (i)	Dec-14 31 (j)	Jan-15 31 (k)	Feb-15 28 (l)	Mar-15 31 (m)	Apr-15 30 (n)	May-15 31 (o)	Peak Period Total (p)
76	**Account 1163-1422 Working Capital (Over)/Under Balance - Interest Calculation**																
78	**Beginning Balance**	Account 1163-1422 1/	**$ 41,967**	$ 34,381	$ 34,772	$ 35,151	$ 35,534	$ 35,918	$ 36,299	$ 36,685	$ 28,219	$ 21,632	$ 15,083	$ 10,017	$ (881)	$ (8,771)	$ 41,967
80	Days Lag			0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391		
81	Prime Rate			3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
82	Forecast Working Capital	ln 34 * 0.091%		285	285	285	285	285	285	7,452	21,952	27,090	23,060	12,565	5,629	-	99,459
84	Projected Revenues w/o Int.	ln 121 * ln 125		-	-	-	-	-	-	(3,640)	(20,736)	(29,414)	(28,672)	(25,071)	(20,792)	(8,693)	(137,019)
85	Projected Unbilled Revenue									(12,364)	(20,237)	(24,511)	(23,997)	(22,400)	(15,114)		(118,622)
86	Reverse Prior Month Unbilled										12,364	20,237	24,511	23,997	22,400	15,114	118,622
88	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Working Capital Billed	Account 1163-1422 2/	(7,586)														(7,586)
92	Monthly (Over)/Under Recovery		$ 34,381	$ 34,666	$ 35,058	$ 35,436	$ 35,819	$ 36,203	$ 36,585	$ 28,133	$ 21,563	$ 15,033	$ 9,985	$ (893)	$ (8,758)	$ (2,351)	$ (3,179)
94	Average Monthly Balance	(ln 78 + ln 92)/2		$ 38,317	$ 34,915	$ 35,294	$ 35,676	$ 36,060	$ 36,442	$ 32,409	$ 24,891	$ 18,332	$ 12,534	$ 4,562	$ (4,819)	$ (5,561)	
96	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
98	Interest Applied	ln 94 * ln 96 / 365 * Days of Month		$ 106	$ 93	$ 97	$ 98	$ 96	$ 101	$ 87	$ 69	$ 51	$ 31	$ 13	$ (13)	$ -	$ 829
100	**(Over)/Under Balance**	ln 92 + ln 98	$ 34,381	$ 34,772	$ 35,151	$ 35,534	$ 35,918	$ 36,299	$ 36,685	$ 28,219	$ 21,632	$ 15,083	$ 10,017	$ (881)	$ (8,771)	$ (2,351)	(2,351)

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**
103 **Calculation of Working Capital with Interest**

104																	
105	**Beginning Balance**	ln 78	$ 41,967	$ 34,381	$ 34,772	$ 35,151	$ 35,534	$ 35,918	$ 36,299	$ 36,685	$ 28,219	$ 21,632	$ 15,084	$ 10,017	$ (880)	$ (8,771)	$ 41,967
106	Forecast Working Capital	ln 82		285	285	285	285	285	285	7,452	21,952	27,090	23,060	12,565	5,629	-	99,459
107	Projected Rev. with interest	ln 121 * ln 127		-	-	-	-	-	-	(3,640)	(20,736)	(29,414)	(28,672)	(25,071)	(20,792)	(8,693)	(137,019)
108	Projected Unbilled Revenue									(12,364)	(20,237)	(24,511)	(23,997)	(22,400)	(15,114)		(118,622)
109	Reverse Prior Month Unbilled										12,364	20,237	24,511	23,997	22,400	15,114	118,622
110	Add Net Adjustments	ln 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital Billed	ln 90	(7,586)	-	-	-	-	-	-								(7,586)
112	Add Interest	ln 98		-	-	-	-	-	-	87	69	51	31	13	(13)	-	237
113	Monthly (Over)/Under Recovery		$ 34,381	$ 34,666	$ 35,058	$ 35,436	$ 35,819	$ 36,203	$ 36,585	$ 28,219	$ 21,632	$ 15,084	$ 10,017	$ (880)	$ (8,771)	$ (2,350)	$ (2,942)
114																	
115	Average Monthly Balance			$ 38,317	$ 34,915	$ 35,294	$ 35,676	$ 36,060	$ 36,442	$ 32,452	$ 24,926	$ 18,358	$ 12,550	$ 4,568	$ (4,825)	$ (5,561)	
116																	
117	Interest Applied	ln 96 * ln 115 / 365 * Days of Month		106	93	97	98	96	101	87	69	51	31	13	(13)	-	$ 829
118																	
119	**(Over)/Under Balance**	-ln 112 +ln 113 + ln 117	$ 34,381	$ 34,772	$ 35,151	$ 35,534	$ 35,918	$ 36,299	$ 36,685	$ 28,219	$ 21,632	$ 15,084	$ 10,017	$ (880)	$ (8,771)	$ (2,350)	$ (2,350)
120																	
121	Forecast Therm Sales	ln 52								2,022,496	11,519,739	16,341,054	15,929,162	13,928,459	11,551,226	4,829,671	76,121,808
122	Unbilled Therm	ln 55								6,869,150	4,373,393	2,374,890	(286,043)	(887,165)	(4,047,595)		
123	Gross Unbilled									6,869,150	11,242,543	13,617,433	13,331,390	12,444,225	8,396,630		
124																	
125	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 228 col. (c)								$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	
126																	
127	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 228 col. (d)								$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018	

128 1/ Beginning Balance for Acct 1163-1422. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.
129 2/ Working Capital Billed Acct 1163-1422. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.

130-133	(a)	Days in Month (b)	Prior Period Bal Apr-14 Ending Bal + May Collections	May-14 31 (c)	Jun-14 30 (d)	Jul-14 31 (e)	Aug-14 31 (f)	Sep-14 30 (g)	Oct-14 31 (h)	Nov-14 30 (i)	Dec-14 31 (j)	Jan-15 31 (k)	Feb-15 28 (l)	Mar-15 31 (m)	Apr-15 30 (n)	May-15 31 (o)	DemandPeriod Total (p)
134																	
135	**Account 1920-1743 Bad Debt (Over)/Under Balance - Interest Calculation**																
136																	
137	Forecast Direct Gas Costs	ln 34		$ 224,597	$ 224,597	$ 224,597	$ 224,597	$ 224,597	$ 224,597	$ 5,863,686	$17,272,798	$21,315,505	$18,144,531	$ 9,886,534	$ 4,429,091	$ -	78,259,727
138	Forecast Working Capital	ln 106		285	285	285	285	285	285	41,833	21,952	27,090	23,060	12,565	5,629		133,840
139	Prior Period Balance	ln 42								2,481,635	2,481,635	2,481,635	2,481,635	2,481,635	2,481,635		14,889,808
140	Total Forecast Direct Gas Costs & Working Capital			224,883	224,883	224,883	224,883	224,883	224,883	8,387,154	19,776,384	23,824,229	20,649,225	12,380,733	6,916,354	-	78,393,567
141																	
142	**Beginning Balance**	Account 1920-1743 1/	**$ (392,847)**	$ (511,857)	$ (508,647)	$ (505,547)	$ (502,484)	$ (499,412)	$ (496,287)	$ (493,198)	$ (484,040)	$ (371,777)	$ (228,413)	$ (93,714)	$ (77,034)	$ (71,602)	$ (392,847)
143																	
144	Forecast Bad Debt	ln 140 * 0.0198		4,453	4,453	4,453	4,453	4,453	4,453	166,066	391,572	471,720	408,855	245,139	136,944		1,847,011
145																	
146	Projected Revenues w/o int	ln 183 * ln 187		-	-	-	-	-	-	(35,394)	(201,595)	(285,968)	(278,760)	(243,748)	(202,146)	(84,519)	(1,332,132)
147	Projected Unbilled Revenue									(120,210)	(196,745)	(238,305)	(233,299)	(217,774)	(146,941)		(1,153,274)
148	Reverse Prior Month Unbilled										120,210	196,745	238,305	233,299	217,774	146,941	1,153,274
149																	
150	Bad Debt Billed	Account 1920-1743 2/	(119,010)		-	-	-	-	-		-	-	-	-	-	-	(119,010)
151																	
152	Add Net Adjustments		-	-	-	-	-	-	-		-	-	-	-	-	-	-
153																	
154	Monthly (Over)/Under Recovery		$ (511,857)	$ (507,404)	$ (504,194)	$ (501,094)	$ (498,031)	$ (494,959)	$ (491,834)	$ (482,736)	$ (370,597)	$ (227,586)	$ (93,313)	$ (76,798)	$ (71,403)	$ (9,180)	$ 3,022
155																	
156	Average Monthly Balance	(ln 142 + ln 154)/2		$ (450,126)	$ (506,420)	$ (503,321)	$ (500,257)	$ (497,185)	$ (494,061)	$ (487,967)	$ (427,319)	$ (299,681)	$ (160,863)	$ (85,256)	$ (74,219)	$ (40,391)	
157																	
158	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
159																	
160	Interest Applied	ln 156 * ln 158 / 365 * Days of Month		$ (1,242)	$ (1,353)	$ (1,389)	$ (1,381)	$ (1,328)	$ (1,364)	$ (1,303)	$ (1,180)	$ (827)	$ (401)	$ (235)	$ (198)		$ (12,202)
161																	
162	**(Over)/Under Balance**	ln 154 + ln 160	$ (511,857)	$ (508,647)	$ (505,547)	$ (502,484)	$ (499,412)	$ (496,287)	$ (493,198)	$ (484,040)	$ (371,777)	$ (228,413)	$ (93,714)	$ (77,034)	$ (71,602)	$ (9,180)	(9,180)
163																	
164																	
165	**Calculation of Bad Debt with Interest**																
166																	
167	**Beginning Balance**	ln 142	$ (392,847)	$ (511,857)	$ (508,647)	$ (505,547)	$ (502,484)	$ (499,412)	$ (496,287)	$ (493,198)	$ (484,932)	$ (374,264)	$ (232,773)	$ (99,638)	$ (84,261)	$ (79,580)	$ (392,847)
168	Forecast Bad Debt	ln 144		4,453	4,453	4,453	4,453	4,453	4,453	166,066	391,572	471,720	408,855	245,139	136,944	-	1,847,011
169	Projected Revenues with int.	ln 183 * ln 189		-	-	-	-	-	-	(35,596)	(202,747)	(287,603)	(280,353)	(245,141)	(203,302)	(85,002)	(1,339,744)
170	Projected Unbilled Revenue									(120,897)	(197,869)	(239,667)	(234,632)	(219,018)	(147,781)		(1,159,864)
171	Reverse Prior Month Unbilled										120,897	197,869	239,667	234,632	219,018	147,781	1,159,864
172	Bad Debt Billed	ln 150	(119,010)		-	-	-	-	-	-	-	-	-	-	-	-	(119,010)
173	Add Interest	ln 160		-	-	-	-	-	-	(1,303)	(1,180)	(827)	(401)	(235)	(198)	-	(4,145)
174	Add Net Adjustments	ln 152	-							-	-	-	-	-	-	-	0
175	Monthly (Over)/Under Recovery		$ (511,857)	$ (507,404)	$ (504,194)	$ (501,094)	$ (498,031)	$ (494,959)	$ (491,834)	$ (484,929)	$ (374,258)	$ (232,773)	$ (99,638)	$ (84,261)	$ (79,580)	$ (16,801)	$ (8,735)
176																	
177	Average Monthly Balance			$ (450,126)	$ (506,420)	$ (503,321)	$ (500,257)	$ (497,185)	$ (494,061)	$ (489,064)	$ (429,595)	$ (303,518)	$ (166,205)	$ (91,950)	$ (81,921)	$ (48,191)	
178																	
179	Interest Applied	ln 158 * ln 177 / 365 * Days of Month		(1,242)	(1,353)	(1,389)	(1,381)	(1,328)	(1,364)	(1,306)	(1,186)	(827)	(401)	(235)	(198)	-	$ (12,211)
180																	
181	**(Over)/Under Balance**	-ln 173 +ln 175 + ln 179	$ (511,857)	$ (508,647)	$ (505,547)	$ (502,484)	$ (499,412)	$ (496,287)	$ (493,198)	$ (484,932)	$ (374,264)	$ (232,773)	$ (99,638)	$ (84,261)	$ (79,580)	$ (16,801)	$ (16,801)
182																	
183	Forecast Term Sales	ln 52								2,022,496	11,519,739	16,341,054	15,929,162	13,928,459	11,551,226	4,829,671	76,121,808
184	Unbilled Therm	ln 55								6,869,150	4,373,393	2,374,890	(286,043)	(887,165)	(4,047,595)		
185	Gross Unbilled									6,869,150	11,242,543	13,617,433	13,331,390	12,444,225	8,396,630		
186																	
187	COG Rate Without Interest	Sch. 3, pg. 4, ln 245 col. (c)								$0.0175	$0.0175	$0.0175	$0.0175	$0.0175	$0.0175	$0.0175	
188																	
189	COG With Interest	Sch. 3, pg. 4, ln 245 col. (d)								$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	

190 1/ Beginning Balance for Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.
191 2/ Bad Debt Billed Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.
192

193	**Total Interest**	lns 46 + 117 + 179	$ -	$ 50,811	$ 36,838	$ 35,977	$ 36,087	$ 35,278	$ 36,741	$ 29,929	$ 22,746	$ 19,614	$ 16,065	$ 8,975	$ (5,023)	$ -	$ 324,039
194																	

			COG Rate Without Interest	COG Rate With Interest
195	**Calculation of COG**			
196	(a)	(b)	(c)	(d)
197	(Over)Under Recovery Balance	ln 12, col. (g)	$ 22,728,560	$ 22,728,560
198				
199	Unadjusted Forecast of Gas Costs	ln 13, col. (g)	78,259,727	78,259,727
200				

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**			
2	**d/b/a Liberty Utilities**			
3	**Peak 2014 - 2015 Winter Cost of Gas Filing**			
4	**COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**			
201	Production & Storage and Misc Overhead	ln 14, col. (g)	1,990,863	1,990,863
202				
203	Adjustments	ln 19, col. (g)	(11,718,237)	(11,718,237)
204				
205	Interest Nov -Apr	ln 46, col. (g)	-	$ 69,852
206				
207	Total Gas To Be Recovered		$ 91,260,913	$ 91,330,765
208				
209	Forecast Gas Sales (Nov - Apr)	ln 52, col. (g)	76,121,808	76,121,808
210				
211	Preliminary COG Rate	ln. 207 / ln. 209	$1.1989	$1.1998
212				
213				
214	**Calculation of Working Capital Rate**		Working Capital Rate without interest	Working Capital Rate with Interest
215	(a)	(b)	(c)	(d)
216	(Over)Under Recovery Balance	ln 78, col. (g)	$ 41,967	$ 41,967
217				
218	Unadjusted Working Capital Forecast	ln 82, col. (g)	99,459	99,459
219				
220	Adjustments without interest	ln 88, col. (g)	(7,586)	(7,586)
221				
222	Interest Nov -Apr	ln 117, col. (g)	-	$ 38
223				
224	Total Gas To Be Recovered		$ 133,840	$ 133,878
225				
226	Forecast Gas Sales (Nov - Apr)	ln 52, col. (g)	76,121,808	76,121,808
227				
228	Preliminary Working Capital COG Rate		$0.0018	$0.0018
229				
230				
231	**Calculation of Bad Debt Rate**		Bad Debt Rate without Interest	Bad Debt Rate with interest
232	(a)	(b)	(c)	
233	(Over)Under Recovery Balance	ln 142, col. (g)	$ (392,847)	$ (392,847)
234				
235	Unadjusted Bad Debt Forecast	ln 144, col. (g)	1,847,011	1,847,011
236				
237	Adjustments without interest	ln 152, col. (g)	(119,010)	(119,010)
238				
239	Interest Nov -Apr	ln 179, col. (g)	-	$ 3,974
240				
241	Total Gas To Be Recovered		$ 1,335,154	$ 1,339,128
242				
243	Forecast Gas Sales (Nov - Apr)	ln 52, col. (g)	76,121,808	76,121,808
244				
245	Preliminary Bad Debt COG Rate		$0.0175	$0.0176

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Schedule 4

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Liberty Utilities (EnergyNorth Natural Gas) Corp. **REDACTED**

Peak 2014 - 2015 Winter Cost of Gas Filing
Adjustments to Gas Costs

Adjustments		Prior Period Adjustments	Refunds from Suppliers	Broker Revenue	Inventory Finance Charges	Transportation CGA Revenues (Schedule 17)	Interruptible Sales Margin	Off System Sales Margin	Capacity Release	Net Option Premiums	Fixed Price Option Administrative Costs	Total Adjustments
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
May-14		$ -	$ -	$0.00	$ -	$ -	[redacted]			$ -	$ -	$ (203,624)
Jun-14		-	-	(23,720)	-	-	[redacted]			-	-	(1,625,645)
Jul-14	1/	-	-	(36,056)	-	-	[redacted]			-	-	(420,529)
Aug-14	1/	-	-	(604)	-	-	[redacted]			-	-	(30,575)
Sep-14	1/	-	-	(667)	-	-	[redacted]			-	-	(233,909)
Oct-14	1/	-	-	(30,234)	-	-	[redacted]			-	-	(87,493)
Nov-14	1/	-	-	(26,420)	-	(38,825)	[redacted]			43,550	50,689	13,786
Dec-14	1/	-	-	(96,625)	-	(52,457)	[redacted]			40,790	-	(163,508)
Jan-15	1/	-	-	(60,516)	-	(64,915)	[redacted]			30,860	-	(124,987)
Feb-15	1/	-	-	(331,915)	-	(70,460)	[redacted]			31,110	-	(401,682)
Mar-15	1/	-	-	(365,464)	-	(67,084)	[redacted]			25,185	-	(422,571)
Apr-15	1/	-	-	(127,704)	-	(59,742)	[redacted]			26,340	-	(178,748)
Subtotal May 14 - Oct 14		$ -	$ -	$ (91,282)	$ -	$ -	$ -	$ (337,061)	$ (2,173,432)	$ -	$ -	$ (2,601,775)
Subtotal Nov 14 - Apr 15		$ -	$ -	$ (1,008,645)	$ -	$ (353,484)	$ -	$ -	$ (164,106)	$ 197,835	$ 50,689	$ (1,277,711)
Total Peak Period		$ -	$ -	$ (1,099,927)	$ -	$ (353,484)	$ -	$ (337,061)	$ (2,337,538)	$ 197,835	$ 50,689	$ (3,879,485)

1/ Estimates are based on prior years actual, except transportation revenue is calculated on Schedule 17.

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Schedule 5

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1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										**REDACTED**
2	**d/b/a Liberty Utilities**										
3	**Peak 2014 - 2015 Winter Cost of Gas Filing**										
4	**Demand Costs**										
5											
6											Peak
7				Peak Costs							May -Apr
8		Peak	Reference	May 14 -Oct 14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
10											
11	**Supply**										
12	Niagara Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	[redacted]							
13	Subtotal Supply Demand & Reservation Charges										
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 24 x days								
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 26 x days								
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 28 x days								
25	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 21 * Sch 5C ln 44 x days								
26	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 22 * Sch 5C ln 30 x days								
27	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 23 * Sch 5C ln 32 x days								
28	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 24 * Sch 5C ln 34 x days								
29	National Fuel FST 2358	peak	Sch 5B, ln 25 * Sch 5C ln 36 x days								
30											
31	Subtotal Pipeline Demand Charges			$ 1,348,007	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 1,371,772	$ 9,578,638
32											
33	**Peaking Supply**										
34	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 28 * Sch 5C ln 26 x days	[redacted]							
35	Granite Ridge Demand	peak	Sch 5B, ln 29 * Sch 5C ln 47 x days								
36	GDF Suez Demand NSB041	peak	Per Contract								
37	Subtotal Peaking Demand Charges			$ -	$ 400,000	$ 400,000	$ 400,000	$ 400,000	$ 400,000	$ -	$ 2,000,000
38											
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 1,348,007	$ 1,771,772	$ 1,771,772	$ 1,771,772	$ 1,771,772	$ 1,771,772	$ 1,371,772	$ 11,578,638
40											
41	Less Transportation Capacity Credit			$ (467,598)	$ (436,593)	$ (436,593)	$ (436,593)	$ (436,593)	$ (436,593)	$ (338,026)	$ (2,988,587)
42											
43	**Total Supply, Pipeline & Peaking Demand**			$ 880,409	$ 1,335,179	$ 1,335,179	$ 1,335,179	$ 1,335,179	$ 1,335,179	$ 1,033,746	$ 8,590,051
44											
45											
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 51 x days	$ 10,333	$ 1,722	$ 1,722	$ 1,722	$ 1,722	$ 1,722	$ 1,722	$ 20,665
47	Dominion - Storage	peak	Sch 5B, ln 34 * Sch 5C ln 52 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
48	Honeoye - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 55 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
49	National Fuel - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 57 x days	90,833	15,139	15,139	15,139	15,139	15,139	15,139	181,667
50	National Fuel - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 58 x days	153,345	25,557	25,557	25,557	25,557	25,557	25,557	306,690
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 61 x days	201,839	33,640	33,640	33,640	33,640	33,640	33,640	403,677
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 62 x days	197,546	32,924	32,924	32,924	32,924	32,924	32,924	395,091
53											
54	**Subtotal Storage Demand Costs**			$ 715,296	$ 119,216	$ 119,216	$ 119,216	$ 119,216	$ 119,216	$ 119,216	$ 1,430,592
55											
56	Less Transportation Capacity Credit			$ (248,123)	$ (29,377)	$ (29,377)	$ (29,377)	$ (29,377)	$ (29,377)	$ (29,377)	$ (424,383)
57											
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 467,173	$ 89,839	$ 89,839	$ 89,839	$ 89,839	$ 89,839	$ 89,839	$ 1,006,209
59											
60	**Total Demand Charges**		ln 39 + ln 54	$ 2,063,303	$ 1,890,988	$ 1,890,988	$ 1,890,988	$ 1,890,988	$ 1,890,988	$ 1,490,988	$ 13,009,231
61											
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (715,721)	$ (465,969)	$ (465,969)	$ (465,969)	$ (465,969)	$ (465,969)	$ (367,403)	$ (3,412,970)
63											
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 1,347,583	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,425,019	$ 1,123,585	$ 9,596,261
65											
66							**THIS PAGE HAS BEEN REDACTED**				

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Demand Volumes

	Peak	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply								
Niagara Supply			0	0	0	0	0	0
Pipeline								
Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
Tenn Gas Pipeline		95346 Z5-Z6	4,000	4,000	4,000	4,000	4,000	4,000
Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
Tenn Gas Pipeline (Concord Lateral)		72694 Z6-Z6	30,000	30,000	30,000	30,000	30,000	30,000
Portland Natural Gas Trans Service		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
ANE (TransCanada via Union to Iroquois)		Union Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
National Fuel	peak	FST 2358	6,098	6,098	6,098	6,098	6,098	6,098
Peaking								
Tenn Gas Pipeline (Concord Lateral)	peak		0	0	0	0	0	0
Granite Ridge Demand	peak		0	0	0	0	0	0
GDF Suez Liquid Demand Charge	peak	NSB041	4,500	4,500	4,500	4,500	4,500	0
Storage								
Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
Honeoye - Capacity	peak	SS-NY	245,280	245,280	245,280	245,280	245,280	245,280
National Fuel - Demand	peak	FSS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
National Fuel - Capacity Reservation	peak	FSS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
Tenn Gas Pipeline - Demand	peak	FS-MA	21,844	21,844	21,844	21,844	21,844	21,844
Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Liberty Utilities (EnergyNorth Natural Gas) Corp. **REDACTED**
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Demand Rates

				Nov-14	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Nov - Apr**
Tariff Rates				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagara Supply		[redacted]		[redacted]						
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$6.5971	First Revised Sheet No. 4	$0.2199	$0.2128	$0.2128	$0.2356	$0.2128	$0.2199	$0.2190
Tenn Gas Pipeline	95346 Z5-Z6	$7.3560	Sixth Rev Sheet No.14	$0.2452	$0.2373	$0.2373	$0.2627	$0.2373	$0.2452	$0.2442
Tenn Gas Pipeline	2302 Z5-Z6	$7.3560	Sixth Rev Sheet No.14	$0.2452	$0.2373	$0.2373	$0.2627	$0.2373	$0.2452	$0.2442
Tenn Gas Pipeline	8587 Z0-Z6	$23.9133	Sixth Rev Sheet No.14	$0.7971	$0.7714	$0.7714	$0.8540	$0.7714	$0.7971	$0.7937
Tenn Gas Pipeline	8587 Z1-Z6	$21.2245	Sixth Rev Sheet No.14	$0.7075	$0.6847	$0.6847	$0.7580	$0.6847	$0.7075	$0.7045
Tenn Gas Pipeline	8587 Z4-Z6	$8.3778	Sixth Rev Sheet No.14	$0.2793	$0.2703	$0.2703	$0.2992	$0.2703	$0.2793	$0.2781
TGP Dracut	42076 FTA Z6-Z6	$4.8698	Sixth Rev Sheet No.14	$0.1623	$0.1571	$0.1571	$0.1739	$0.1571	$0.1623	$0.1616
TGP Concord Lateral	72694 Z6-Z6	$12.1700	Per contract	$0.4057	$0.3926	$0.3926	$0.4346	$0.3926	$0.4057	$0.4040
Portland Natural Gas	FT-1999-001	$40.2456	Part 4.1 v.3.0.0	$1.3415	$1.2982	$1.2982	$1.4373	$1.2982	$1.3415	$1.3359
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.3778	Sixth Rev Sheet No.14	$0.2793	$0.2703	$0.2703	$0.2992	$0.2703	$0.2793	$0.2781
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.3778	Sixth Rev Sheet No.14	$0.2793	$0.2703	$0.2703	$0.2992	$0.2703	$0.2793	$0.2781
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.3560	Sixth Rev Sheet No.14	$0.2452	$0.2373	$0.2373	$0.2627	$0.2373	$0.2452	$0.2442
National Fuel	FST 2358	$3.7805	4.020 Version 7.0.0 Pg 1	$0.1260	$0.1220	$0.1220	$0.1350	$0.1220	$0.1260	$0.1255
ANE Union Gas		$2.3820								
TransCanada Pipelines Limited		$9.24034	Union Parkway to Iroquois							
Delivery Pressure Demand Charge		0.4366	Union Parkway to Iroquois							
Sub Total Demand Charges		12.0590								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		0.9184	updated 8_18_14							
Demand Rate/US$		$13.8539		$0.4618	$0.4469	$0.4469	$0.4948	$0.4469	$0.4618	$0.4598
Peaking										
Granite Ridge Demand		[redacted]		[redacted]						
GDF Suez Demand NSB041										
Storage										
Dominion - Demand	GSS 300076	$1.8438	Rec No 10.30 Ver 7.0.0	$0.0615	$0.0595	$0.0595	$0.0659	$0.0595	$0.0615	$0.0611
Dominion - Capacity	GSS 300076	$0.0145	Rec No 10.30 Ver 7.0.0	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.8583		$0.0619	$0.0599	$0.0599	$0.0664	$0.0599	$0.0619	$0.0616
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0.2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129
National Fuel - Demand	FSS-1 2357	$2.4826	4.020 Version 7.0.0 Pg 1	$0.0828	$0.0801	$0.0801	$0.0887	$0.0801	$0.0828	$0.0823
National Fuel - Capacity	FSS-1 2357	$0.0381	4.020 Version 7.0.0 Pg 1	$0.0013	$0.0012	$0.0012	$0.0014	$0.0012	$0.0013	$0.0013
		$2.5207		$0.0840	$0.0813	$0.0813	$0.0900	$0.0813	$0.0840	$0.0836
Tenn Gas Pipeline	FS-MA	$1.5400	Ninth Rev Sheet No.61	$0.0513	$0.0497	$0.0497	$0.0550	$0.0497	$0.0513	$0.0511
Tenn Gas Pipeline - Space	FS-MA	$0.0211	Ninth Rev Sheet No.61	$0.0007	$0.0007	$0.0007	$0.0008	$0.0007	$0.0007	$0.0007
		$1.5611		$0.0520	$0.0504	$0.0504	$0.0558	$0.0504	$0.0520	$0.0518

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subject to an allowable variation of not more than one percent above or below the aggregate of said scheduled daily deliveries of said month.

The amount of gas in storage for Buyer's account at any time (exclusive of Buyer's share of cushion gas) shall be Buyer's Gas Storage Balance at that time and shall not exceed Buyer's Maximum Quantity Stored (MQS).

Seller shall be ready at all times to deliver to Buyer, and Buyer shall have the right at all times to receive from Seller, natural gas up to the MDWQ Seller is obligated to deliver to Buyer on that day.

Buyer's MQS, Buyer's MDWQ and Buyer's ADWQ shall be specified in the Gas Storage Agreement providing for service under this Rate Schedule.

3. RATE

Buyer shall pay Seller for each month of the year during the term of the Gas Storage Agreement a Demand Charge which shall be six dollars and forty one point eight seven cents per MMBTU ($6.4187/MMBTU)** multiplied by the ADWQ as provided for in the Gas Storage Agreement.

4. MINIMUM BILL

The Minimum Bill for each month shall consist of the Demand Charge for the ADWQ as defined in Article 3.

5. COMPRESSOR FUEL ALLOWANCE

Buyer will make available without charge to Seller such additional quantities of gas as needed by Seller for

** The Demand Charge Rate set forth in individual service agreements shall be deemed to have been converted to a thermal billing basis utilizing a factor of 1022/MMBTU per 1 MCF as adjusted pursuant to Section III of the General Terms & Conditions, provided however, the total Maximum Quantity Stored in the field shall not exceed 4.8 BCF and provided that each Buyer shall receive its allowable share of same.

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

(Footnotes continued on Sheet 4.01)

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity	1/

MEASUREMENT VARIANCE/FUEL USE FACTOR:

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

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

RATES FOR TRANSPORTATION SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Base Rate (3)	TSCA (4)	TSCA Surch. (5)	Current Rate [2/] (6)
FT/FT-S						
	Reservation	(Max)	$3.7805	-	-	$ 3.7805
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA[3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA[3/]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA[3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA[3/]
	Maximum Volumetric Rate		0.1378	-	-	$0.1378 plus ACA[3/]
EFT	Reservation	(Max)	3.9653	0.0000	(0.0001)	$3.9652
		(Min)	0.0000	0.0000	(0.0001)	$(0.0001)
	Commodity	(Max)	0.0148	0.0000	0.0000	$0.0148 plus ACA[3/]
		(Min)	0.0148	0.0000	0.0000	$0.0148 plus ACA[3/]
	Overrun	(Max)	0.1452	-	-	$0.1452 plus ACA[3/]
		(Min)	0.0148	-	-	$0.0148 plus ACA[3/]
	Maximum Volumetric Rate		0.1452	0.0000	(0.0000)	$0.1452 plus ACA[3/]
FST	Reservation	(Max)	3.7805	-	-	$ 3.7805
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA[3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA[3/]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA[3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA[3/]
	Maximum Volumetric Rate		0.1378	-	-	$0.1378 plus ACA[3/]
IT	Commodity	(Max)	$0.1378	-	-	$ 0.1378 plus ACA[3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA[3/]
	Overrun	(Max)	0.1378	-		$0.1378 plus ACA[3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA[3/]

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.

2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.42% and the Transportation LAUF Retention for all applicable rate schedules is 0.12%. Transporter may from time to time identify point pair transactions where the Transportation Fuel and Company Use Retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF Retention.

3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component [1] (2)			Rate [2] (3)	
ESS	Demand	(Max)		$2.5959	
		(Min)		0.0000	
	Capacity	(Max)		0.0404	
		(Min)		0.0000	
	Injection/	(Max)		0.0411	plus ACA[3]
	Withdrawal	(Min)		0.0000	
	Max. Volumetric Dem. Rate [4]			0.0853	plus ACA[3]
	Max. Volumetric Cap. Rate [5]			0.0013	
	Storage Balance Transfer	(Max)	6	3.8600	
		(Min)	6	0.0000	
ISS	Injection	(Max)		0.9923	plus ACA[3]
		(Min)		0.0000	
	Storage Balance Transfer	(Max)	6	3.8600	
		(Min)	6/	0.0000	
FSS	Demand	(Max)		2.4826	
		(Min)		0.0000	
	Capacity	(Max)		0.0381	
		(Min)		0.0000	
	Injection/	(Max)		0.0391	plus ACA[3] .0012 - pay on both Inj & W/D
	Withdrawal	(Min)		0.0000	
	Max. Volumetric Dem. Rate 4/			0.0816	plus ACA[3]
	Max. Volumetric Cap. Rate 5/			0.0013	
	Storage Balance Transfer	(Max)	6	3.8600	
		(Min)	6	0.0000	

.0391
.0012
.0403

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.
2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 1.19%.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
5/ Assessed per dekatherm per day on storage balance.
6/ Rate per nomination.

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 2/
FT	Short Term Recourse Reservation Rate		
	-- Maximum	See Table 1 Below	
	-- Minimum	$00.0000	---------
	Recourse Usage Rate		
	-- Maximum	$00.0000	3/
	-- Minimum	$00.0000	3/
IT	Recourse Usage Rate		
	-- Maximum	See Table 1 Below	
	-- Minimum	$00.0000	3/
PAL	Usage Rate		
	-- Maximum	See Table 1 Below	
	-- Minimum	$00.0000	3/

-- Table 1 --
The following maximum rates apply (by month, as applicable) to all service provided pursuant to: (a) Short Term FT service under Rate Schedule FT (i.e., firm service that has a term of less than one year); (b) IT Service under Rate Schedule IT; and (c) Park and Loan Service under Rate Schedule PAL.

Month	Rate Multiplier	Maximum Base Unit Rate 1/ ($/Dth/day)	ACA Unit Charge 2/
January	150%	$1.9847	3/
February	150%	$1.9847	3/
March	60%	$0.7939	3/
April	60%	$0.7939	3/
May	60%	$0.7939	3/
June	100%	$1.3231	3/
July	100%	$1.3231	3/
August	100%	$1.3231	3/
September	60%	$0.7939	3/
October	60%	$0.7939	3/
November	150%	$1.9847	3/
December	150%	$1.9847	3/

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum
Commodity Rates 1/, 2/

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

Maximum
Commodity Rates 1/, 2/, 3/

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

Notes:

1/ Includes a per Dth charge for (ACA) Annual Charge Adjustment of $0.0018
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

TRANSPORTATION RATES

(A) Applicability

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

Applicable Points

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

Dawn as a delivery point: Dawn (Facilities).

(B) Services

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

(C) Rates

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

	Monthly Demand Charge (applied to daily contract demand) Rate/GJ	Commodity and Fuel Charges Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1)				
Dawn to Parkway	$2.420	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$2.042			
Kirkwall to Parkway	$0.378			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$3.008	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$5.807	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$5.807			
Parkway (TCPL) to Parkway (Cons) (2)		0.154%		

Authorized Overrun (3)

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

Transportation Overrun	If Union supplies fuel Commodity Charge Rate/GJ	Commodity and Fuel Charges Fuel Ratio %	AND	Commodity Charge Rate/GJ
Dawn to Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.080
Dawn to Kirkwall				$0.067
Kirkwall to Parkway				$0.012
Parkway to Dawn				$0.080
Parkway (TCPL) Overrun (4)	n/a	0.652%		n/a
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.099

TRANSCANADA FUEL RATIOS

November 2013

Pressure Point	Pressure (%)
Chippawa	0.00
Emerson 1	0.00
Emerson 2	0.00
Iroquois	0.00
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	0.0000	0.38	0.00

December 2013

Pressure Point	Pressure (%)
Chippawa	0.00
Emerson 1	0.00
Emerson 2	0.00
Iroquois	0.00
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	0.0000	1.18	0.00

January 2014

Pressure Point	Pressure (%)
Chippawa	0.00
Emerson 1	0.00
Emerson 2	0.00
Iroquois	0.00
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	0.0000	0.88	0.00

February 2014

Pressure Point	Pressure (%)
Chippawa	0.00
Emerson 1	0.00
Emerson 2	0.00
Iroquois	0.00
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	0.0000	1.69	0.00

March 2014

Pressure Point	Pressure (%)
Chippawa	0.00
Emerson 1	0.00
Emerson 2	0.00
Iroquois	0.00
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	0.0000	1.35	0.00

April 2014

Pressure Point	Pressure (%)
Chippawa	0.00
Emerson 1	0.00
Emerson 2	0.00
Iroquois	0.00
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	0.0000	0.84	0.00

Daily Currency Converter

All Bank of Canada exchange rates are indicative rates only, obtained from averages of transaction prices and price quotes from financial institutions. Please read our full **terms and conditions** for details.

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

Currency Converter

Amount: 1.00

From: Canadian Dollar

To: U.S. dollar

☐ cash rate

Convert

Answer: 0.92

Exchange Rate: 0.9184

Summary: On 18 August 2014, 1.00 Canadian Dollar(s) = 0.92 U.S. dollar(s), at an exchange rate of 0.9184 (using nominal rate).

http://www.bankofcanada.ca/rates/exchange/daily-converter

Schedule 6

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1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2014 - 2015 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 63 * ln 102	[redacted]						
13	Niagara Supply	ln 64 * ln 107							
14	TGP Supply (Direct)	ln 65 * ln 123							
15	Dracut Supply 1 - Baseload	ln 66 * ln 112							
16	Dracut Supply 2 - Swing	ln 67 * ln 117							
17	City Gate Delivered Supply	ln 68 * ln 129							
18	LNG Truck	ln 69 * ln 131							
19	Propane Truck	ln 70 * ln 133							
20	PNGTS	ln 71 * ln 138							
21	TGP Supply (Z4)	ln 72 * ln 143							
22									
23	Subtotal Pipeline Gas Costs		$ 4,568,744	$ 13,852,725	$ 17,406,740	$ 14,754,036	$ 6,496,018	$ 3,693,854	$ 60,772,118
24									
25	**Volumetric Transportation Costs**								
26	Dawn Supply	ln 63 * ln 176	[redacted]						
27	Niagara Supply	ln 64 * ln 187							
28	TGP Supply (Direct)	ln 65 * ln 214							
29	Dracut Supply 1 - Baseload	ln 66 * ln 235							
30	Dracut Supply 2 - Swing	ln 67 * ln 235							
31	City Gate Delivered Supply	ln 68 * ln 235							
32	TGP Storage - Withdrawals	ln 77 * ln 165							
33									
34	**Total Volumetric Transportation Costs**		$ 292,815	$ 292,746	$ 318,306	$ 278,506	$ 255,961	$ 211,705	$ 1,650,040
35									
36	**Less - Gas Refill:**								
37	LNG Truck	ln 86 * ln 150	[redacted]						
38	Propane	ln 87 * ln 151							
39	TGP Storage Refill	ln 88 * ln 121							
40	Storage Refill (Trans.)	ln 88 * ln 214							
41									
42	Subtotal Refills		$ (1,412,814)	$ (844,024)	$ (2,365,798)	$ (1,427,680)	$ (73,223)	$ (641,307)	$ (6,764,847)
43									
44	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 34 + ln 42	$ 3,448,744	$ 13,301,447	$ 15,359,249	$ 13,604,862	$ 6,678,757	$ 3,264,252	$ 55,657,311
45									
46	**Storage Gas:**								
47	TGP Storage - Withdrawals	ln 77 * ln 157	$ 922,161	$ 1,681,398	$ 1,787,129	$ 1,651,253	$ 1,588,312	$ -	$ 7,630,253
48									
49	**Produced Gas:**								
50	LNG Vapor	ln 80 * ln 145	[redacted]						
51	Propane	ln 81 * ln 147							
52									
53	**Total Produced Gas**	ln 50 + ln 51	$ 32,427	$ 828,959	$ 2,711,385	$ 1,428,103	$ 156,917	$ 24,606	$ 5,182,397
54									
55									
56	**Total Commodity Gas & Trans. Costs**	ln 44 + ln 47 + ln 53	$ 4,403,332	$ 15,811,804	$ 19,857,763	$ 16,684,219	$ 8,423,985	$ 3,288,858	$ 68,469,961
57									$ 81,002,948
58						**THIS PAGE HAS BEEN REDACTED**			

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

5									Peak
6	For Month of:	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
59									
60	**Volumes (Therms)**								
61									
62	**Pipeline Gas:**	See Schedule 11A							
63	Dawn Supply		694,856	933,968	961,173	840,409	953,431	898,739	5,282,577
64	Niagara Supply		689,704	740,443	750,335	655,819	744,292	701,765	4,282,358
65	TGP Supply (Direct)		5,030,346	3,214,961	3,257,912	2,848,386	3,231,671	4,110,233	21,693,509
66	Dracut Supply 1 - Baseload		-	2,833,266	4,784,937	3,138,027	-	-	10,756,230
67	Dracut Supply 2 - Swing		1,300,647	1,214,805	668,515	1,193,937	1,728,302	1,504,718	7,610,923
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		20,610	454,363	666,620	697,089	67,663	-	1,906,345
70	Propane Truck		-	-	635,615	72,785	-	-	708,400
71	PNGTS		60,358	83,376	93,792	77,288	73,814	50,929	439,557
72	TGP Supply (Z4)		1,774,680	1,906,182	1,931,648	1,689,072	1,916,090	1,841,666	11,059,338
73									
74	Subtotal Pipeline Volumes		9,571,201	11,381,364	13,750,547	11,212,814	8,715,262	9,108,050	63,739,236
75									
76	**Storage Gas:**								
77	TGP Storage		2,618,224	4,773,869	5,074,064	4,688,282	4,509,577	-	21,664,016
78									
79	**Produced Gas:**								
80	LNG Vapor		20,610	454,363	717,779	697,089	22,298	20,971	1,933,110
81	Propane		-	-	784,441	72,785	76,890	-	934,116
82									
83	Subtotal Produced Gas		20,610	454,363	1,502,221	769,875	99,188	20,971	2,867,227
84									
85	**Less - Gas Refill:**								
86	LNG Truck		(20,610)	(454,363)	(666,620)	(697,089)	(67,663)	-	(1,906,345)
87	Propane		-	-	(635,615)	(72,785)	-	-	(708,400)
88	TGP Storage Refill		(3,151,143)	-	-	-	-	(1,501,643)	(4,652,786)
89									
90	Subtotal Refills		(3,171,753)	(454,363)	(1,302,235)	(769,875)	(67,663)	(1,501,643)	(7,267,531)
91									
92	**Total Sendout Volumes**		9,038,281	16,155,233	19,024,597	15,901,096	13,256,364	7,627,377	81,002,948
93									
94									
95									

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty Utilities**								
3	**Peak 2014 - 2015 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
96	**Gas Costs and Volumetric Transportation Rates**								**REDACTED**
97									
98	**Pipeline Gas:**								
99	**Dawn Supply**								Average Rate
100	NYMEX Price	Sch 7, ln 10/10	[redacted]						
101	Basis Differential								
102	**Net Commodity Costs**								
103									
104	**Niagara Supply**								
105	NYMEX Price	Sch 7, ln 10/10	[redacted]						
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Dracut Supply 1 - Baseload**								
110	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 2 - Swing**								
115	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119									
120	**TGP Supply (Direct)**								
121	NYMEX Price	Sch 7, ln 10/10	[redacted]						
122	Basis Differential								
123	**Net Commodity Costs**								
124									
125									
126	**City Gate Delivered Supply**								
127	NYMEX Price	Sch 7, ln 10/10	[redacted]						
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131	**LNG Truck**	Sch 7, ln 10/10	**$0.6521**	**$1.8576**	**$1.9275**	**$1.8705**	**$1.0822**	**$0.4756**	**$1.3109**
132									
133	**Propane Truck**	Propane WACOG	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**
134									
135	**PNGTS**								
136	NYMEX Price	Sch 7, ln 10/10	[redacted]						
137	Basis Differential								
138	**Net Commodity Cost**								
139									
140	**TGP Supply (Z4)**								
141	NYMEX Price	Sch 7, ln 10/10	[redacted]						
142	Basis Differential								
143	**Net Commodity Cost**								
144									
145	**LNG Vapor (Storage)**	Sch 16, ln 95 /10	**$1.5734**	**$1.8244**	**$1.9190**	**$1.8711**	**$1.1733**	**$1.1733**	**$1.5891**
146									
147	**Propane**	Sch 16, ln 66 /10	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**
148									
149	**Storage Refill:**								
150	**LNG Truck**	ln 131	**$0.6521**	**$1.8576**	**$1.9275**	**$1.8705**	**$1.0822**	**$0.4756**	**$1.5891**
151	**Propane**	ln 133	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**
152									
153					**THIS PAGE HAS BEEN REDACTED**				

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln									
5									Peak
6	For Month of:	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
154									**REDACTED**
155									
156	**TGP Storage**								Average Rate
157	**Commodity Costs - Storage withdrawal**	Sch 16, ln 34 /10	$0.3522	$0.3522	$0.3522	$0.3522	$0.3522	$0.3270	$0.3480
158									
159	TGP - Max Commodity - Z 4-6	Ninth Rev Sheet No.15	$0.01073	$0.01073	$0.01073	$0.01073	$0.01073	$0.01073	$0.01073
160	TGP - Max Comm. ACA Rate - Z 4-6	Ninth Rev Sheet No.15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
161	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.01087	$0.01087	$0.01087	$0.01087	$0.01087	$0.01087	$0.01087
162	TGP - Fuel Charge % - Z 4-6	Eighth Rev Sheet No. 32	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
163	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00370	$0.00370	$0.00370	$0.00370	$0.00370	$0.00343	$0.00365
164	TGP - Withdrawal Charge	Ninth Rev Sheet No.61	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087
165	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.01544	$0.01544	$0.01544	$0.01544	$0.01544	$0.01517	$0.01539
166									
167	**Total TGP - Comm. & Vol. Trans. Rate**	ln 157 + ln 165	**$0.36765**	**$0.36765**	**$0.36765**	**$0.36765**	**$0.36765**	**$0.34216**	**$0.36340**
168									
169									
156	**Per Unit Volumetric Transportation Rates**								
157	**Dawn Supply Volumetric Transportation Charge**								
158	**Commodity Costs**	ln 102	**$0.4439**	**$0.4519**	**$0.4522**	**$0.4509**	**$0.4478**	**$0.4315**	**$0.4464**
159									
160	TransCanada - Commodity Rate/GJ	Union Parkway to Iroquois	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
161	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
162	Conversion Rate to US$	updated 8_18_14	0.9184	0.9184	0.9184	0.9184	0.9184	0.9184	0.9184
163	Commodity Rate/US$	ln 160 x ln 161 x ln 162	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
164	TransCanada Fuel %	Union Parkway to Iroquois	0.38%	1.18%	0.88%	1.69%	1.35%	0.84%	1.05%
165	TransCanada Fuel * Percentage	ln 158 x ln 164	$0.00169	$0.00533	$0.00398	$0.00762	$0.00604	$0.00362	$0.00471
166	Subtotal TransCanada		**$0.00169**	**$0.00533**	**$0.00398**	**$0.00762**	**$0.00604**	**$0.00362**	**$0.00471**
167	IGTS - Z1 RTS Commodity	First Revised Sheet No. 4	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
168	IGTS - Z1 RTS ACA Rate Commodity	Third Revised Sheet 4A	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
169	IGTS - Z1 RTS Deferred Asset Surcharge	Third Revised Sheet 4A	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
170	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**
171	TGP NET-NE - Comm. Segments 3 & 4	Ninth Rev Sheet No.15	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018
172	IGTS -Fuel Use Factor - Percentage	Third Revised Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
173	IGTS -Fuel Use Factor - Fuel * Percentage	ln 158 x ln 172	**$0.00444**	**$0.00452**	**$0.00452**	**$0.00451**	**$0.00448**	**$0.00431**	**$0.00446**
174	TGP FTA Fuel Charge % Z 5-6	Eighth Rev Sheet No. 32	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%	1.06%
175	TGP FTA Fuel * Percentage	ln 158 x ln 174	**$0.00471**	**$0.00479**	**$0.00479**	**$0.00478**	**$0.00475**	**$0.00457**	**$0.00473**
176	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01145**	**$0.01526**	**$0.01391**	**$0.01753**	**$0.01589**	**$0.01313**	**$0.01453**
177									
178									
179	**Niagara Supply Volumetric Transportation Charge**								
180	**Commodity Costs**	Ln 107	[redacted]						
181									
182	TGP FTA - FTA Z 5-6 Comm. Rate	Ninth Rev Sheet No.15	$0.00811	$0.00811	$0.00811	$0.00811	$0.00811	$0.00811	$0.00811
183	TGP FTA - FTA Z 5-6 - ACA Rate	Ninth Rev Sheet No.15	$0.00014	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
184	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00825**	**$0.0083**	**$0.0083**	**$0.0083**	**$0.0083**	**$0.0083**	**$0.0083**
185	TGP FTA Fuel Charge % Z 5-6	Eighth Rev Sheet No. 32	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
186	TGP FTA Fuel * Percentage	ln 180 x ln 185	[redacted]						
187	**Total Volumetric Transportation Rate - Niagara Supply**								
188									
189									
190					**THIS PAGE HAS BEEN REDACTED**				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln	For Month of:	Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
191									**REDACTED**
192									
193	**TGP Direct Volumetric Transportation Charge**								Average Rate
194	**Commodity Costs**	Ln 121	[redacted]						
195									
196	TGP - Max Comm. Base Rate - Z 0-6	Ninth Rev Sheet No.15	$0.03124	$0.03124	$0.03124	$0.03124	$0.03124	$0.03124	$0.03124
197	TGP - Max Commodity ACA Rate - Z 0-6	Ninth Rev Sheet No.15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
198	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03138	$0.03138	$0.03138	$0.03138	$0.03138	$0.03138	$0.03138
199	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
200	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.01023**	**$0.01023**	**$0.01023**	**$0.01023**	**$0.01023**	**$0.01023**	**$0.01023**
201	TGP - Max Comm. Base Rate - Z 1-6	Ninth Rev Sheet No.15	$0.02723	$0.02723	$0.02723	$0.02723	$0.02723	$0.02723	$0.02723
202	TGP - Max Commodity ACA Rate - Z 1-6	Ninth Rev Sheet No.15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
203	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02737	$0.02737	$0.02737	$0.02737	$0.02737	$0.02737	$0.02737
204	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
205	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01845**	**$0.01845**	**$0.01845**	**$0.01845**	**$0.01845**	**$0.01845**	**$0.01845**
206	TGP - Fuel Charge % - Z 0 -6	Eighth Rev Sheet No. 32	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%
207	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
208	Prorated TGP Fuel Charge % - Z 0-6		1.46%	1.46%	1.46%	1.46%	1.46%	1.46%	1.46%
209	TGP - Fuel Charge % - Z 1 -6	Eighth Rev Sheet No. 32	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
210	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
211	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%
212	TGP - Fuel Charge % - Z 0-6	ln 194 x ln 208	**$0.00584**	**$0.00598**	**$0.00609**	**$0.00607**	**$0.00596**	**$0.00560**	**$0.00592**
213	TGP - Fuel Charge % - Z 1-6	ln 194 x ln 211	**$0.01062**	**$0.01087**	**$0.01107**	**$0.01104**	**$0.01084**	**$0.01019**	**$0.01077**
214	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.04514**	**$0.04553**	**$0.04584**	**$0.04579**	**$0.04547**	**$0.04446**	**$0.04537**
215									
216	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
217	**Commodity Costs**	Ln 121	[redacted]						
218									
219	TGP - Max Comm. Base Rate - Z 6-6	Ninth Rev Sheet No.15	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334
220	TGP - Max Commodity ACA Rate - Z 6-6	Ninth Rev Sheet No.15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
221	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**
222	TGP - Fuel Charge % - Z 6-6	Eighth Rev Sheet No. 32	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
223	TGP - Fuel Charge	ln 217 x ln 222	**$0.00184**	**$0.00188**	**$0.00191**	**$0.00191**	**$0.00187**	**$0.00176**	**$0.00186**
224	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00532**	**$0.00536**	**$0.00539**	**$0.00539**	**$0.00535**	**$0.00524**	**$0.00534**
225									
226									
227	**TGP Dracut**								
228	**Commodity Costs - NYMEX Price**	Ln 112	[redacted]						
229									
230	TGP - Trans Charge - Comm. - Z 6-6	Ninth Rev Sheet No.15	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334
231	TGP - Trans Charge - ACA Rate - Z6-6	Ninth Rev Sheet No.15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
232	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**	**$0.00348**
233	TGP - Fuel Charge % - Z 6-6	Eighth Rev Sheet No. 32	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
234	TGP - Fuel Charge	ln 228 x ln 233	[redacted]						
235	**Total Volumetric Transportation Rate - TGP Dracut**								
236									
237			**THIS PAGE HAS BEEN REDACTED**						

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Schedule 7

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Ln		Reference								
5										Peak
6	For Month of:	Reference		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**									
9	Opening Prices (15 day average)			3.9895	4.0837	4.1591	4.1467	4.0703	3.8261	$ 4.0459
10	NYMEX	ln 201	**Filed COG**	3.9895	4.0837	4.1591	4.1467	4.0703	3.8261	$ 4.0459
11										
12										
13										
14										
15										
16										
17										
18										
19										
20	**II. Development of Hedging Costs and Savings**									
21										
22	**TGP (Direct) Volumes**									Total
23	Hedged Volumes (Dth)	ln 83		83,500	85,950	78,850	86,600	93,700	61,500	490,100
24	Market Priced Volumes (Dth)			688,055	807,794	963,437	781,058	572,070	660,046	4,472,460
25	Total Volumes (Dth)	Sch 6, lns 63 - 68 / 10		771,555	893,744	1,042,287	867,658	665,770	721,546	4,962,560
26										
27										Weighted Average
28	Hedge Price	ln 170		$ 4.4126	$ 4.5023	$ 4.5741	$ 4.5542	$ 4.4708	$ 4.0968	$ 4.4508
29	NYMEX Price	ln 10		$ 3.9895	$ 4.0837	$ 4.1591	$ 4.1467	$ 4.0703	$ 3.8261	$ 4.0560
30										
31	Hedged Volumes at Hedged Price	ln 23 * ln 28		$ 368,456	$ 386,972	$ 360,666	$ 394,394	$ 418,914	$ 251,951	$ 2,181,353
32	Less Hedged Volumes at NYMEX	ln 24 * ln 29		333,120	350,997	327,942	359,101	381,384	235,303	1,987,848
33										
34	Hedge Contract (Savings)/Loss	ln 31 - ln 32		$ 35,336	$ 35,975	$ 32,723	$ 35,293	$ 37,530	$ 16,648	$ 193,505
35										
36	Total Financial Hedge	ln 23		835,000	859,500	788,500	866,000	937,000	615,000	4,901,000
37	Total Underground Storage	Sch 6, Ln 77		2,618,224	4,773,869	5,074,064	4,688,282	4,509,577	-	21,664,016
38	Sub Total			3,453,224	5,633,369	5,862,564	5,554,282	5,446,577	615,000	26,565,016
39	Total Throughput	Sch 6, ln 92		9,038,281	16,155,233	19,024,597	15,901,096	13,256,364	7,627,377	81,002,948
40	Hedge Percentage	ln 38 / ln 39		38%	35%	31%	35%	41%	8%	33%

Line						Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Peak Strip Average
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**											
2	**d/b/a Liberty Utilities**											
3	**Peak 2014 - 2015 Winter Cost of Gas Filing**											
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**											
5												Peak
6	For Month of:				Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41												**REDACTED**
42	Hedged Volumes (Dth)											
43	Hedge #	1	Trade Date	11-Oct-13	Swaps	[redacted]						
44	Hedge #	2	Trade Date	18-Oct-13	Swaps							
45	Hedge #	3	Trade Date	27-Dec-13	Swaps							
46	Hedge #	4	Trade Date	7-Jan-14	Swaps							
47	Hedge #	5	Trade Date	31-Jan-14	Swaps							
48	Hedge #	6	Trade Date	7-Feb-14	Swaps							
49	Hedge #	7	Trade Date	28-Feb-14	Swaps							
50	Hedge #	8	Trade Date	3-Mar-14	Swaps							
51	Hedge #	9	Trade Date	18-Mar-14	Swaps							
52	Hedge #	10	Trade Date	1-Apr-14	Swaps							
53	Hedge #	11	Trade Date	16-Apr-14	Swaps							
54	Hedge #	12	Trade Date	2-May-14	Swaps							
55	Hedge #	13	Trade Date	16-May-14	Swaps							
56	Hedge #	14	Trade Date	18-Jun-14	Swaps							
57	Hedge #	15	Trade Date	6-Jun-14	Swaps							
58	Hedge #	16	Trade Date	18-Jul-14	Swaps							
59	Hedge #	17	Trade Date	3-Jul-14	Swaps							
60	Hedge #	18	Trade Date		Swaps							
61	Hedge #	19	Trade Date		Swaps							
62	Hedge #	20	Trade Date		Swaps							
63	Hedge #	21	Trade Date		Swaps							
64	Hedge #	22	Trade Date		Swaps							
65	Hedge #	23	Trade Date		Swaps							
66	Hedge #	24										
67	Hedge #	25										
68	Hedge #	26										
69	Hedge #	27										
70	Hedge #	28										
71	Hedge #	29										
72	Hedge #	30										
73												
74												
75												
76												
77												
78												
79												
80	Subtotal Hedge Volumes					83,500	85,950	78,850	86,600	93,700	61,500	490,100
81	Remaining					-	-	-	-	-	-	-
82	Total Volumes					83,500	85,950	78,850	86,600	93,700	61,500	490,100
83												
84								**THIS PAGE HAS BEEN REDACTED**				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line						Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Peak Strip Average
5												
6	For Month of:				Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
85	Strike Price											**REDACTED** Weighted Average
86	Hedge #	1	Trade Date	11-Oct-13	Swaps	[redacted]						
87	Hedge #	2	Trade Date	18-Oct-13	Swaps							
88	Hedge #	3	Trade Date	27-Dec-13	Swaps							
89	Hedge #	4	Trade Date	7-Jan-14	Swaps							
90	Hedge #	5	Trade Date	31-Jan-14	Swaps							
91	Hedge #	6	Trade Date	7-Feb-14	Swaps							
92	Hedge #	7	Trade Date	28-Feb-14	Swaps							
93	Hedge #	8	Trade Date	3-Mar-14	Swaps							
94	Hedge #	9	Trade Date	18-Mar-14	Swaps							
95	Hedge #	10	Trade Date	1-Apr-14	Swaps							
96	Hedge #	11	Trade Date	16-Apr-14	Swaps							
97	Hedge #	12	Trade Date	2-May-14	Swaps							
98	Hedge #	13	Trade Date	16-May-14	Swaps							
99	Hedge #	14	Trade Date	18-Jun-14	Swaps							
100	Hedge #	15	Trade Date	6-Jun-14	Swaps							
101	Hedge #	16	Trade Date	18-Jul-14	Swaps							
102	Hedge #	17	Trade Date	3-Jul-14	Swaps							
103	Hedge #	18	Trade Date		Swaps							
104	Hedge #	19	Trade Date		Swaps							
105	Hedge #	20	Trade Date		Swaps							
106	Hedge #	21	Trade Date		Swaps							
107	Hedge #	22	Trade Date		Swaps							
108	Hedge #	23	Trade Date		Swaps							
109	Hedge #	24										
110	Hedge #	25										
111	Hedge #	26										
112	Hedge #	27										
113	Hedge #	28										
114	Hedge #	29										
115	Hedge #	30										
116												
117												
118												
119												
120												
121												
122												
123	Subtotal Weighted Average Hedge Prices					$4.4126	$4.5023	$4.5741	$4.5542	$4.4708	$4.0968	4.4508
124	NYMEX					$3.9895	$4.0837	$4.1591	$4.1467	$4.0703	$3.8261	#DIV/0!
125												
126								**THIS PAGE HAS BEEN REDACTED**				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line											Peak
5											
6	For Month of:			Reference	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Strip Average
7		(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
127	Hedge Dollars										**REDACTED**
128	Hedge # 1	Trade Date	11-Oct-13	Swaps	[redacted]						
129	Hedge # 2	Trade Date	18-Oct-13	Swaps							
130	Hedge # 3	Trade Date	27-Dec-13	Swaps							
131	Hedge # 4	Trade Date	7-Jan-14	Swaps							
132	Hedge # 5	Trade Date	31-Jan-14	Swaps							
133	Hedge # 6	Trade Date	7-Feb-14	Swaps							
134	Hedge # 7	Trade Date	28-Feb-14	Swaps							
135	Hedge # 8	Trade Date	3-Mar-14	Swaps							
136	Hedge # 9	Trade Date	18-Mar-14	Swaps							
137	Hedge # 10	Trade Date	1-Apr-14	Swaps							
138	Hedge # 11	Trade Date	16-Apr-14	Swaps							
139	Hedge # 12	Trade Date	2-May-14	Swaps							
140	Hedge # 13	Trade Date	16-May-14	Swaps							
141	Hedge # 14	Trade Date	18-Jun-14	Swaps							
142	Hedge # 15	Trade Date	6-Jun-14	Swaps							
143	Hedge # 16	Trade Date	18-Jul-14	Swaps							
144	Hedge # 17	Trade Date	3-Jul-14	Swaps							
145	Hedge # 18	Trade Date	0-Jan-00	Swaps							
146	Hedge # 19	Trade Date	0-Jan-00	Swaps							
147	Hedge # 20	Trade Date	0-Jan-00	Swaps							
148	Hedge # 21	Trade Date	0-Jan-00	Swaps							
149	Hedge # 22	Trade Date	0-Jan-00	Swaps							
150	Hedge # 23	Trade Date	0-Jan-00	Swaps							
151	Hedge # 24										
152	Hedge # 25										
153	Hedge # 26										
154	Hedge # 27										
155	Hedge # 28										
156	Hedge # 29										
157	Hedge # 30										
158											
159											
160											
161											
162											
163											
164											
165	Subtotal Hedge Dollars				$368,456	$386,972	$360,666	$394,394	$418,914	$251,951	$2,181,353
166	Remaining				-	-	-	-	-	-	-
167											
168		Target Hedged Dollars			$368,456	$386,972	$360,666	$394,394	$418,914	$251,951	$2,181,353
169											
170		Weighted Average Hedged Cost per Unit			$4.4126	$4.5023	$4.5741	$4.5542	$4.4708	$4.0968	$4.4508
171											
172							**THIS PAGE HAS BEEN REDACTED**				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line										Peak
5										
6	For Month of:	Reference		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
173	NYMEX Settlement - 15 Day Average									
174		Days	Date							
175		1	7-Aug	3.9620	4.0490	4.1250	4.1140	4.0450	3.8210	
176		2	8-Aug	4.0450	4.1290	4.2050	4.1900	4.1140	3.8620	
177		3	11-Aug	4.0510	4.1340	4.2050	4.1890	4.1110	3.8580	
178		4	12-Aug	4.0670	4.1530	4.2220	4.2050	4.1270	3.8690	
179		5	13-Aug	3.9350	4.0310	4.1060	4.0940	4.0210	3.7950	
180										
181										
182		6	14-Aug	3.9990	4.0900	4.1600	4.1460	4.0670	3.8230	
183		7	15-Aug	3.8790	3.9770	4.0540	4.0450	3.9730	3.7520	
184		8	18-Aug	3.9010	3.9990	4.0770	4.0690	3.9930	3.7660	
185		9	19-Aug	3.9770	4.0710	4.1450	4.1350	4.0550	3.8130	
186		10	20-Aug	3.9330	4.0300	4.1080	4.1000	4.0220	3.7820	
187										
188										
189		11	21-Aug	4.0010	4.1020	4.1780	4.1660	4.0880	3.8330	
190		12	22-Aug	3.9560	4.0620	4.1410	4.1310	4.0560	3.8160	
191		13	25-Aug	4.0490	4.1500	4.2260	4.2100	4.1290	3.8660	
192		14	26-Aug	4.0180	4.1190	4.1980	4.1850	4.1080	3.8560	
193		15	27-Aug	4.0690	4.1600	4.2360	4.2210	4.1450	3.8790	
194			28-Aug							
195			29-Aug							
196			30-Aug							
197			31-Aug							
198			1-Sep							
199			2-Sep							
200										
201			15 Day Average	3.9895	4.0837	4.1591	4.1467	4.0703	3.8261	

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Schedule 8

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Liberty Utilities (EnergyNorth Natural Gas) Corp.

1 **d/b/a Liberty Utilities**
2 **Peak 2014 - 2015 Winter Cost of Gas Filing**
3 **Annual Bill Comparisons, Nov 13 - Apr 14 vs Nov 14 - Apr 15 - Residential Heating Rate R-3**

6 **November 1, 2014 - April 30, 2015** / **May 1, 2014 - October 31, 2014**
7 **Residential Heating (R3)**

Line			Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Winter Nov-Apr	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Summer May-Oct	Total Nov-Oct
10	**average Usage (Therms)**		51	96	130	144	131	98	649	52	27	17	15	16	23	151	800
11		7/1/2014															
12	**Winter:**																
13	Cust. Chg	$17.51	$17.51	$17.51	$17.51	$17.51	$17.51	$17.51	$105.06								
14	Headblock	$0.2769	$14.00	$26.49	$27.69	$27.69	$27.69	$27.17	$150.74								
15	Tailblock	$0.2288	$0.00	$0.00	$6.79	$10.13	$7.00	$0.00	$23.91								
16	HB Threshold	100															
17																	
18	**Summer:**																
19	Cust. Chg	$17.51								$17.40	$17.40	$17.51	$17.51	$17.51	$17.51	$104.84	$209.90
20	Headblock	$0.2769								$5.50	$5.50	$4.82	$4.22	$4.55	$5.54	$30.13	$180.87
21	Tailblock	$0.2288								$7.23	$1.62	$0.00	$0.00	$0.00	$0.66	$9.51	$33.43
22	HB Threshold	20															
23																	
24	Total Base Rate Amount		$31.51	$44.00	$51.99	$55.33	$52.20	$44.68	$279.71	$30.14	$24.52	$22.33	$21.73	$22.06	$23.71	$144.48	$424.19
25																	
26	CGA Rate - (Seasonal)		$1.2225	$1.2225	$1.2225	$1.2225	$1.2225	$1.2225	$1.2225	$0.5436	$0.5436	$0.5436	$0.5436	$0.3936	$0.3936	$0.5045	$1.0871
27	CGA amount		$61.82	$116.95	$158.52	$176.37	$159.63	$119.97	$793.26	$28.16	$14.74	$9.46	$8.29	$6.46	$9.01	$76.12	$869.38
28																	
29	LDAC		$0.0769	$0.0769	$0.0769	$0.0769	$0.0769	$0.0769	0.0769	$0.0290	$0.0290	$0.0290	$0.0290	$0.0290	$0.0290	$0.0290	$0.0679
30	LDAC amount		$3.89	$7.36	$9.97	$11.09	$10.04	$7.55	$49.90	$1.50	$0.79	$0.50	$0.44	$0.48	$0.66	$4.38	$54.27
31																	
32	**Total Bill**		**$97.22**	**$168.30**	**$220.48**	**$242.80**	**$221.87**	**$172.20**	**$1,122.87**	**$59.80**	**$40.05**	**$32.29**	**$30.46**	**$28.99**	**$33.38**	**$224.98**	**$1,347.85**

34 **November 1, 2013 - April 30, 2014** / **May 1, 2013 - October 31, 2013**
35 **Residential Heating (R3)**

Line					Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Winter Nov-Apr	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Summer May-Oct	Total Nov-Oct
38	**average Usage (Therms)**				51	96	130	144	131	98	649	52	27	17	15	16	23	151	800
39																			
40	**Winter:**	7/1/2012	7/1/2013	7/1/2014															
41	Cust. Chg	$17.31	$17.40	$17.51	$17.40	$17.40	$17.40	$17.40	$17.40	$17.40	$104.40								
42	Headblock	$0.2739	$0.2752	$0.2769	13.92	26.33	27.52	27.52	27.52	27.01	$149.81								
43	Tailblock	$0.2263	$0.2274	$0.2288	$0.00	$0.00	$6.75	$10.07	$6.95	$0.00	$23.77								
44	HB Thresh	100	100	100															
45																			
46	**Summer:**																		
47	Cust. Chg	$17.31	$17.40	$17.51								$17.31	$17.31	$17.40	$17.40	$17.40	$17.40	$104.22	$208.62
48	Headblock	$0.2739	$0.2752	$0.2769								$5.48	$5.48	$4.79	$4.20	$4.52	$5.50	$29.96	$179.77
49	Tailblock	$0.2263	$0.2274	$0.2288								$7.20	$1.61	$0.00	$0.00	$0.00	$0.66	$9.47	$33.23
50	HB Thresh	20	20	20															
51																			
52	Total Base Rate Amount				$31.32	$43.73	$51.67	$54.99	$51.87	$44.41	$277.98	$29.98	$24.40	$22.19	$21.60	$21.92	$23.56	$143.65	$421.63
53																			
54	CGA Rate - (Seasonal)				$0.8895	$0.8895	$1.0196	$1.1119	$1.2919	$1.2919	$1.1068	$0.6732	$0.7091	$0.7091	$0.6640	$0.6640	$0.6640	$0.6805	$1.0264
55	CGA amount				$44.98	$85.09	$132.21	$160.42	$168.70	$126.78	$718.17	$34.87	$19.23	$12.34	$10.12	$10.90	$15.20	$102.67	$820.84
56																			
57	LDAC				$0.0258	$0.0258	$0.0258	$0.0258	$0.0258	$0.0258	0.0258	$0.0258	$0.0258	$0.0258	$0.0258	$0.0258	$0.0258	$0.0258	$0.0258
58	LDAC amount				$1.30	$2.47	$3.35	$3.72	$3.37	$2.53	$16.74	$1.34	$0.70	$0.45	$0.39	$0.42	$0.59	$3.89	$20.63
59																			
60	**Total Bill**				**$77.60**	**$131.29**	**$187.22**	**$219.12**	**$223.94**	**$173.72**	**$1,012.89**	**$66.20**	**$44.33**	**$34.98**	**$32.11**	**$33.24**	**$39.35**	**$250.21**	**$1,263.10**

62 **DIFFERENCE:**

Line		Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
63	**Total Bill**	**$19.62**	**$37.02**	**$33.26**	**$23.67**	**($2.07)**	**($1.52)**	**$109.98**	**($6.40)**	**($4.28)**	**($2.68)**	**($1.65)**	**($4.25)**	**($5.97)**	**($25.23)**	**$84.75**
64	% Change	**25.28%**	**28.20%**	**17.76%**	**10.80%**	**-0.92%**	**-0.87%**	**10.86%**	**-9.66%**	**-9.65%**	**-7.68%**	**-5.14%**	**-12.78%**	**-15.17%**	**-10.08%**	**6.71%**
65																
66	**Base Rate**	$0.20	$0.27	$0.32	$0.34	$0.32	$0.28	$1.73	$0.15	$0.12	$0.14	$0.14	$0.14	$0.15	$0.84	$2.57
67	% Change	0.63%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.50%	0.51%	0.63%	0.63%	0.63%	0.63%	0.58%	0.61%
68																
69	**CGA & LDAC**	$19.42	$36.74	$32.94	$23.33	($2.39)	($1.80)	$108.24	($6.55)	($4.40)	($2.82)	($1.79)	($4.39)	($6.12)	($26.06)	$82.18
70	% Change	43.18%	43.18%	24.91%	14.54%	-1.42%	-1.42%	15.07%	-18.78%	-22.89%	-22.89%	-17.65%	-40.24%	-40.24%	-25.39%	10.01%
	check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 13 - Apr 14 vs Nov 14 - Apr 15 - Commercial Rate G-41

November 1, 2014 - April 30, 2015
Commercial Rate (G-41)

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Winter Nov-Apr
average Usage (Therms)		111	252	381	433	394	295	1,865
Winter:	7/1/2014							
Cust. Chg	$41.19	$41.19	$41.19	$41.19	$41.19	$41.19	$41.19	$247.14
Headblock	$0.3287	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$197.22
Tailblock	$0.2138	$2.27	$32.45	$60.09	$71.26	$62.88	$41.60	$270.55
HB Threshold	100							
Summer:								
Cust. Chg	$41.19							
Headblock	$0.3287							
Tailblock	$0.2138							
HB Threshold	20							
Total Base Rate Amount		$76.33	$106.51	$134.15	$145.32	$136.94	$115.66	$714.91
CGA Rate - (Seasonal)		$1.2248	$1.2248	$1.2248	$1.2248	$1.2248	$1.2248	$1.2248
CGA amount		$135.51	$308.37	$466.70	$530.72	$482.72	$360.78	$2,284.78
LDAC		$0.0628	$0.0628	$0.0628	$0.0628	$0.0628	$0.0628	0.0628
LDAC amount		$6.95	$15.81	$23.93	$27.21	$24.75	$18.50	$117.15
Total Bill		**$218.79**	**$430.69**	**$624.77**	**$703.25**	**$644.42**	**$494.93**	**$3,116.84**

May 1, 2014 - October 31, 2014

	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Summer May-Oct	Total Nov-Oct
average Usage (Therms)	148	42	25	22	24	40	302	2,167
Cust. Chg (Summer)	$40.94	$40.94	$41.19	$41.19	$41.19	$41.19	$246.64	$493.78
Headblock (Summer)	$6.53	$6.53	$6.57	$6.57	$6.57	$6.57	$39.36	$236.58
Tailblock (Summer)	$27.30	$4.67	$1.00	$0.51	$0.83	$4.34	$38.65	$309.20
Total Base Rate Amount	$74.78	$52.15	$48.76	$48.27	$48.59	$52.10	$324.65	$1,039.56
CGA Rate - (Seasonal)	$0.5456	$0.5456	$0.5456	$0.5456	$0.3956	$0.3956	$0.5137	$1.1258
CGA amount	$81.02	$22.91	$13.46	$12.21	$9.44	$15.94	$154.98	$2,439.76
LDAC	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0590
LDAC amount	$5.30	$1.50	$0.88	$0.80	$0.85	$1.44	$10.77	$127.92
Total Bill	**$161.10**	**$76.56**	**$63.10**	**$61.28**	**$58.89**	**$69.48**	**$490.40**	**$3,607.24**

November 1, 2013 - April 30, 2014
Commercial Rate (G-41)

	7/1/2012	7/1/2013	7/1/2014	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Winter Nov-Apr
average Usage (Therms)				111	252	381	433	394	295	1,865
Winter:										
Cust. Chg	40.74	$40.94	$41.19	$40.94	$40.94	$40.94	$40.94	$40.94	$40.94	$245.64
Headblock	0.3251	$0.3267	$0.3287	32.67	32.67	32.67	32.67	32.67	32.67	$196.02
Tailblock	0.2114	$0.2125	$0.2138	$2.26	$32.25	$59.72	$70.83	$62.50	$41.34	$268.90
HB Thresho	100	100	100							
Summer:										
Cust. Chg	40.74	$40.94	$41.19							
Headblock	0.3251	$0.3267	$0.3287							
Tailblock	0.2114	$0.2125	$0.2138							
HB Thresho	20	20	20							
Total Base Rate Amount				$75.87	$105.86	$133.33	$144.44	$136.11	$114.95	$710.56
CGA Rate - (Seasonal)				$0.8908	$0.8908	$1.0209	$1.1135	$1.2935	$1.2935	$1.1178
CGA amount				$98.55	$224.28	$389.00	$482.49	$509.80	$381.01	$2,085.13
LDAC				$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	0.0357
LDAC amount				$3.95	$8.99	$13.60	$15.47	$14.07	$10.52	$66.60
Total Bill				**$178.37**	**$339.13**	**$535.94**	**$642.40**	**$659.98**	**$506.48**	**$2,862.29**

May 1, 2013 - October 31, 2013

	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Summer May-Oct	Total Nov-Oct
average Usage (Therms)	148	42	25	22	24	40	302	2,167
Cust. Chg (Summer)	$40.74	$40.74	$40.94	$40.94	$40.94	$40.94	$245.24	$490.88
Headblock (Summer)	$6.50	$6.50	$6.53	$6.53	$6.53	$6.53	$39.14	$235.16
Tailblock (Summer)	$27.16	$4.65	$0.99	$0.51	$0.82	$4.31	$38.44	$307.35
Total Base Rate Amount	$74.41	$51.89	$48.46	$47.98	$48.30	$51.79	$322.82	$1,033.39
CGA Rate - (Seasonal)	$0.6759	$0.7118	$0.7118	$0.6667	$0.6667	$0.6667	$0.6812	$1.0570
CGA amount	$100.37	$29.89	$17.56	$14.92	$15.91	$26.87	$205.51	$2,290.64
LDAC	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0333
LDAC amount	$2.78	$0.79	$0.46	$0.42	$0.45	$0.75	$5.64	$72.24
Total Bill	**$177.55**	**$82.57**	**$66.48**	**$63.32**	**$64.66**	**$79.41**	**$533.97**	**$3,396.27**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
Total Bill	**$40.41**	**$91.56**	**$88.84**	**$60.85**	**($15.56)**	**($11.55)**	**$254.55**
% Change	**22.66%**	**27.00%**	**16.58%**	**9.47%**	**-2.36%**	**-2.28%**	**8.89%**
Base Rate	$0.46	$0.65	$0.82	$0.88	$0.83	$0.70	$4.35
% Change	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
CGA & LDAC	$39.95	$90.91	$88.02	$59.97	($16.40)	($12.25)	$250.21
% Change	40.54%	40.54%	22.63%	12.43%	-3.22%	-3.22%	12.00%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	

	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($16.45)**	**($6.01)**	**($3.38)**	**($2.04)**	**($5.77)**	**($9.92)**	**($43.57)**	**$210.98**
% Change	**-9.27%**	**-7.28%**	**-5.09%**	**-3.22%**	**-8.92%**	**-12.50%**	**-8.16%**	**6.21%**
Base Rate	$0.37	$0.26	$0.30	$0.29	$0.30	$0.32	$1.83	$6.18
% Change	0.50%	0.49%	0.61%	0.61%	0.61%	0.61%	0.57%	0.60%
CGA & LDAC	($16.82)	($6.27)	($3.68)	($2.33)	($6.06)	($10.24)	($45.40)	$204.80
% Change	-16.76%	-20.96%	-20.96%	-15.61%	-38.11%	-38.11%	-22.09%	8.94%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 13 - Apr 14 vs Nov 14 - Apr 15 - Commercial Rate G-42

November 1, 2014 - April 30, 2015 / **May 1, 2014 - October 31, 2014**
C&I High Winter Use Medium G-42

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Winter Nov-Apr	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Summer May-Oct	Total Nov-Oct
average Usage (Therms)		932	1,812	2,580	2,704	2,503	1,930	12,460	1,221	569	301	262	323	431	3,106	15,567
	7/1/2014															
Winter:																
Cust. Chg	$123.58	$123.58	$123.58	$123.58	$123.58	$123.58	$123.58	$741.48								
Headblock	$0.3072	$286.33	$307.20	$307.20	$307.20	$307.20	$307.20	$1,822.33								
Tailblock	$0.2030	$0.00	$164.79	$320.77	$345.86	$305.02	$188.82	$1,325.26								
HB Threshold	1,000															
Summer:																
Cust. Chg	$123.58								$122.81	$122.81	$123.58	$123.58	$123.58	$123.58	$739.94	$1,481.42
Headblock	$0.3072								$122.12	$122.12	$92.50	$80.48	$99.19	$122.88	$639.29	$2,461.62
Tailblock	$0.2030								$165.56	$34.01	$0.00	$0.00	$0.00	$6.29	$205.87	$1,531.13
HB Threshold	400															
Total Base Rate Amount		$409.91	$595.57	$751.55	$776.64	$735.80	$619.60	$3,889.07	$410.49	$278.94	$216.08	$204.06	$222.77	$252.75	$1,585.09	$5,474.17
CGA Rate - (Seasonal)		$1.2248	$1.2248	$1.2248	$1.2248	$1.2248	$1.2248	$1.2248	$0.5456	$0.5456	$0.5456	$0.5456	$0.3956	$0.3956	$0.5092	$1.0820
CGA amount		$1,141.60	$2,219.07	$3,160.18	$3,311.57	$3,065.12	$2,364.02	$15,261.56	$666.09	$310.25	$164.28	$142.93	$127.73	$170.50	$1,581.78	$16,843.34
LDAC		$0.0628	$0.0628	$0.0628	$0.0628	$0.0628	$0.0628	0.0628	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0574
LDAC amount		$58.53	$113.78	$162.03	$169.80	$157.16	$121.21	$782.52	$43.58	$20.30	$10.75	$9.35	$11.53	$15.39	$110.90	$893.42
Total Bill		**$1,610.04**	**$2,928.43**	**$4,073.77**	**$4,258.01**	**$3,958.08**	**$3,104.83**	**$19,933.15**	**$1,120.16**	**$609.49**	**$391.11**	**$356.34**	**$362.03**	**$438.63**	**$3,277.77**	**$23,210.92**

November 1, 2013 - April 30, 2014 / **May 1, 2013 - October 31, 2013**
C&I High Winter Use Medium G-42

				Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Winter Nov-Apr	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Summer May-Oct	Total Nov-Oct
average Usage (Therms)				932	1,812	2,580	2,704	2,503	1,930	12,460	1,221	569	301	262	323	431	3,106	15,567
	7/1/2012	7/1/2013	7/1/2014															
Winter:																		
Cust. Chg	122.22	$122.81	$123.58	$122.81	$122.81	$122.81	$122.81	$122.81	$122.81	$736.86								
Headblock	0.3038	$0.3053	$0.3072	284.56	305.30	305.30	305.30	305.30	305.30	$1,811.06								
Tailblock	0.2007	$0.2017	$0.2030	$0.00	$163.74	$318.72	$343.65	$303.06	$187.61	$1,316.78								
HB Thresh	1000	1,000	1,000															
Summer:																		
Cust. Chg	122.22	$122.81	$123.58								$122.22	$122.22	$122.81	$122.81	$122.81	$122.81	$735.68	$1,472.54
Headblock	0.3038	$0.3053	$0.3072								$121.52	$122.12	$91.93	$79.98	$98.58	$122.12	$636.24	$2,447.30
Tailblock	0.2007	$0.2017	$0.2030								$164.74	$34.01	$0.00	$0.00	$0.00	$6.25	$205.00	$1,521.78
HB Thresh	400	400	400															
Total Base Rate Amount				$407.37	$591.85	$746.83	$771.76	$731.17	$615.72	$3,864.70	$408.48	$278.35	$214.74	$202.79	$221.39	$251.18	$1,576.93	$5,441.62
CGA Rate - (Seasonal)				$0.8908	$0.8908	$1.0209	$1.1135	$1.2935	$1.2935	$1.1093	$0.6759	$0.7118	$0.7118	$0.6667	$0.6667	$0.6667	$0.6829	$1.0242
CGA amount				$830.29	$1,613.94	$2,634.09	$3,010.64	$3,237.05	$2,496.62	$13,822.62	$825.16	$404.75	$214.32	$174.66	$215.27	$287.34	$2,121.50	$15,944.12
LDAC				$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	0.0357	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0323
LDAC amount				$33.27	$64.68	$92.11	$96.52	$89.34	$68.91	$444.84	$22.83	$10.63	$5.63	$4.90	$6.04	$8.06	$58.09	$502.93
Total Bill				**$1,270.93**	**$2,270.46**	**$3,473.03**	**$3,878.92**	**$4,057.56**	**$3,181.25**	**$18,132.15**	**$1,256.47**	**$693.74**	**$434.69**	**$382.34**	**$442.70**	**$546.58**	**$3,756.52**	**$21,888.67**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$339.11**	**$657.96**	**$600.74**	**$379.09**	**($99.48)**	**($76.41)**	**$1,801.00**	**($136.31)**	**($84.25)**	**($43.58)**	**($26.00)**	**($80.66)**	**($107.94)**	**($478.75)**	**$1,322.25**
% Change	**26.68%**	**28.98%**	**17.30%**	**9.77%**	**-2.45%**	**-2.40%**	**9.93%**	**-10.85%**	**-12.14%**	**-10.03%**	**-6.80%**	**-18.22%**	**-19.75%**	**-12.74%**	**6.04%**
Base Rate	$2.54	$3.73	$4.72	$4.88	$4.62	$3.88	$24.38	$2.01	$0.59	$1.34	$1.27	$1.38	$1.57	$8.16	$32.54
% Change	0.62%	0.63%	0.63%	0.63%	0.63%	0.63%	0.63%	0.49%	0.21%	0.62%	0.63%	0.62%	0.63%	0.52%	0.60%
CGA & LDAC	$336.57	$654.24	$596.02	$374.20	($104.11)	($80.29)	$1,776.62	($138.32)	($84.84)	($44.92)	($27.27)	($82.05)	($109.51)	($486.92)	$1,289.71
% Change	40.54%	40.54%	22.63%	12.43%	-3.22%	-3.22%	12.85%	-16.76%	-20.96%	-20.96%	-15.61%	-38.11%	-38.11%	-22.95%	8.09%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 13 - Apr 14 vs Nov 14 - Apr 15 - Commercial Rate G-52

November 1, 2014 - April 30, 2015 / **May 1, 2014 - October 31, 2014**
Commercial Rate (G-52)

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Winter Nov-Apr	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Summer May-Oct	Total Nov-Oct
average Usage (Therms)		1,163	1,560	1,777	1,874	1,703	1,933	10,012	1,273	907	868	821	832	974	5,675	15,687
Winter:	7/1/2014															
Cust. Chg	$123.58	$123.58	$123.58	$123.58	$123.58	$123.58	$123.58	$741.48								
Headblock	$0.1701	$170.10	$170.10	$170.10	$170.10	$170.10	$170.10	$1,020.60								
Tailblock	$0.1154	$18.84	$64.67	$89.72	$100.83	$81.18	$107.70	$462.94								
HB Threshold	1,000															
Summer:																
Cust. Chg	$123.58								$122.81	$122.81	$123.58	$123.58	$123.58	$123.58	$739.94	$1,481.42
Headblock	$0.1250								$124.20	$112.70	$108.46	$102.63	$103.98	$121.73	$673.70	$1,694.30
Tailblock	$0.0720								$19.55	$0.00	$0.00	$0.00	$0.00	$0.00	$19.55	$482.49
HB Threshold	1,000															
Total Base Rate Amount		$312.52	$358.35	$383.40	$394.51	$374.86	$401.38	$2,225.02	$266.56	$235.51	$232.04	$226.21	$227.56	$245.31	$1,433.19	$3,658.21
CGA Rate - (Seasonal)		$1.2068	$1.2068	$1.2068	$1.2068	$1.2068	$1.2068	$1.2068	$0.5377	$0.5377	$0.5377	$0.5377	$0.3877	$0.3877	$0.4900	$0.9475
CGA amount		$1,403.85	$1,883.07	$2,145.08	$2,261.21	$2,055.76	$2,333.03	$12,082.00	$684.71	$487.90	$466.57	$441.47	$322.52	$377.54	$2,780.70	$14,862.70
LDAC		$0.0628	$0.0628	$0.0628	$0.0628	$0.0628	$0.0628	0.0628	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0530
LDAC amount		$73.05	$97.99	$111.63	$117.67	$106.98	$121.41	$628.73	$45.46	$32.39	$30.98	$29.31	$29.70	$34.76	$202.60	$831.33
Total Bill		**$1,789.42**	**$2,339.41**	**$2,640.11**	**$2,773.38**	**$2,537.61**	**$2,855.82**	**$14,935.75**	**$996.73**	**$755.80**	**$729.59**	**$696.99**	**$579.78**	**$657.61**	**$4,416.49**	**$19,352.24**

November 1, 2013 - April 30, 2014 / **May 1, 2013 - October 31, 2013**
Commercial Rate (G-52)

				Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Winter Nov-Apr	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Summer May-Oct	Total Nov-Oct
average Usage (Therms)				1,163	1,560	1,777	1,874	1,703	1,933	10,012	1,273	907	868	821	832	974	5,675	15,687
Winter:	7/1/2012	7/1/2013	7/1/2014															
Cust. Chg	122.22	$122.81	$123.58	$122.81	$122.81	$122.81	$122.81	$122.81	$122.81	$736.86								
Headblock	0.1683	$0.1691	$0.1701	169.10	169.10	169.10	169.10	169.10	169.10	$1,014.60								
Tailblock	0.1142	$0.1147	$0.1154	$18.73	$64.28	$89.18	$100.22	$80.69	$107.04	$460.13								
HB Thresh	1000	1,000	1,000															
Summer:																		
Cust. Chg	122.22	$122.81	$123.58								$122.22	$122.22	$122.81	$122.81	$122.81	$122.81	$735.68	$1,472.54
Headblock	0.1236	$0.1242	$0.1250								$123.60	$112.15	$107.77	$101.97	$103.32	$120.95	$669.76	$1,684.36
Tailblock	0.0712	$0.0715	$0.0720								$19.47	$0.00	$0.00	$0.00	$0.00	$0.00	$19.47	$479.60
HB Thresh	1000	1,000	1,000															
Total Base Rate Amount				$310.64	$356.19	$381.09	$392.13	$372.60	$398.95	$2,211.59	$265.29	$234.37	$230.58	$224.78	$226.13	$243.76	$1,424.90	$3,636.49
CGA Rate - (Seasonal)				$0.8807	$0.8807	$1.0108	$1.1009	$1.2809	$1.2809	$1.0904	$0.6661	$0.7020	$0.7020	$0.6569	$0.6569	$0.6569	$0.6731	$0.9394
CGA amount				$1,024.50	$1,374.23	$1,796.69	$2,062.78	$2,181.99	$2,476.29	$10,916.48	$848.21	$636.98	$609.14	$539.33	$546.46	$639.69	$3,819.81	$14,736.29
LDAC				$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	0.0357	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0295
LDAC amount				$41.53	$55.71	$63.46	$66.89	$60.81	$69.02	$357.41	$23.81	$16.97	$16.23	$15.35	$15.56	$18.21	$106.13	$463.54
Total Bill				**$1,376.67**	**$1,786.12**	**$2,241.23**	**$2,521.80**	**$2,615.41**	**$2,944.26**	**$13,485.48**	**$1,137.31**	**$888.32**	**$855.94**	**$779.47**	**$788.14**	**$901.66**	**$5,350.84**	**$18,836.32**

DIFFERENCE:

Total Bill	**$412.75**	**$553.29**	**$398.87**	**$251.59**	**($77.80)**	**($88.44)**	**$1,450.26**	**($140.58)**	**($132.52)**	**($126.35)**	**($82.48)**	**($208.36)**	**($244.04)**	**($934.35)**	**$515.92**
% Change	**29.98%**	**30.98%**	**17.80%**	**9.98%**	**-2.97%**	**-3.00%**	**10.75%**	**-12.36%**	**-14.92%**	**-14.76%**	**-10.58%**	**-26.44%**	**-27.07%**	**-17.46%**	**2.74%**
Base Rate	$1.88	$2.16	$2.31	$2.38	$2.26	$2.42	$13.43	$1.27	$1.13	$1.46	$1.43	$1.44	$1.55	$8.28	$21.71
% Change	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.48%	0.48%	0.63%	0.63%	0.63%	0.64%	0.58%	0.60%
CGA & LDAC	$410.87	$551.13	$396.56	$249.20	($80.06)	($90.86)	$1,436.84	($141.86)	($133.66)	($127.81)	($83.91)	($209.80)	($245.59)	($942.63)	$494.21
% Change	40.10%	40.10%	22.07%	12.08%	-3.67%	-3.67%	13.16%	-16.72%	-20.98%	-20.98%	-15.56%	-38.39%	-38.39%	-24.68%	3.35%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Residential Heating

	Winter 2013-14	Winter 2014-15
Customer Charge	$17.40	$17.51
First 100 Therms	$0.2752	$0.2769
Excess 100 Therms	$0.2274	$0.2288
LDAC	$0.0258	$0.0769
CGA	$1.1068	$1.2225
Total Adjust	$1.1326	$1.2994

		Winter 2013-14 CGA @	Winter 2014-15 CGA @	Total		Base Rate		CGA		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$1.1326	$1.2994	$0.17	15%						
Cooking alone	5	$24.44	$25.39	$0.95	4%	$0.12	0%	$0.58	2%	$0.26	1%
	10	$31.48	$33.27	$1.80	6%	$0.13	0%	$1.16	3%	$0.51	2%
	20	$45.56	$49.04	$3.48	8%	$0.14	0%	$2.31	5%	$1.02	2%
Water Heating alone	30	$59.63	$64.80	$5.17	9%	$0.16	0%	$3.47	5%	$1.53	3%
	45	$80.75	$88.44	$7.69	10%	$0.19	0%	$5.21	6%	$2.30	3%
	50	$87.79	$96.33	$8.54	10%	$0.20	0%	$5.79	6%	$2.56	3%
Heating Alone	80	$122.98	$135.73	$12.75	10%	$0.24	0%	$8.68	6%	$3.83	3%
	125	$203.06	$225.57	$22.51	11%	$0.33	0%	$15.39	7%	$6.80	3%
	150	$226.18	$251.55	$25.37	11%	$0.35	0%	$17.36	7%	$7.67	3%
	200	$294.18	$327.96	$33.78	11%	$0.42	0%	$23.14	7%	$10.22	3%

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Schedule 9

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Variance Analysis of the Components of the Winter 2013-14 Actual Results vs Proposed Winter 2014-15 Cost of Gas Rate

	WINTER 2013-14 ACTUAL RESULTS (6 months actual)			**WINTER 2014-15 (6 months Proposed)**		
Therm Sales	84,723,918			76,121,808		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 10,317,504	$ 0.1218		$ 9,596,261	$ 0.1261
Purchased Gas	70,885,890	$ 78,386,978	0.9252	56,471,705	55,657,311	0.7312
Storage Gas	19,557,350	8,429,820	0.0995	21,664,016	7,630,253	0.1002
Produced Gas	3,592,010	6,621,641	0.0782	2,867,227	5,182,397	0.0681
Hedging (Gain)/Loss		(1,179,241)	(0.0139)		193,505	0.0025
Total Volumes and Cost	94,035,250	$ 102,576,702	$ 1.2107	81,002,948	$ 78,259,727	$ 1.0281
Direct Costs						
Prior Period Balance		$ 5,119,793	$ 0.0604		14,889,808	$ 0.1956
Interest		461,060	0.0054		324,039	0.0043
Prior Period Adjustment		(43,153)	(0.0005)		-	-
Broker Revenues		(1,391,364)	(0.0164)		(1,099,927)	(0.0144)
Refunds from Suppliers		-	-		-	-
Fuel Financing		-	-		-	-
Transportation CGA Revenues		-	-		(353,484)	(0.0046)
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		(2,592,771)	(0.0306)		(2,674,599)	(0.0351)
Hedging Costs		-	-		197,835	0.0026
FPO Admin Costs		47,935	0.0006		50,689	0.0007
Indirect Costs						
Misc Overhead		10,735	0.0001		10,435	0.0001
Occupant Disallowance/Credits		-			-	-
Production & Storage		1,980,428	0.0234		1,980,428	0.0260
Other Indirect Gas Costs		1,212,720	0.0143		1,468,994	0.0193
Cashout, Broker penalty, Canadian Managed,…		(901,881)	(0.0106)		0	0
Total Adjusted Cost		$ 106,480,204	**$ 1.2568**		$ 93,053,946	**$ 1.2224**

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Schedule 10

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Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2014 - 2015 Winter Cost of Gas Filing
Capacity Assignment Calculations 2013-2014
Derivation of Class Assignments and Weightings

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

				Column A	**Column B**	**Column C**	**Column D**	**Column E**	**Column F**
				Design Day Demand. Dktherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg			692	780	0.6%		124	656
2	RATE R-3-Resi Htg			52,781	60,313	42.9%		3,735	56,578
3	RATE G-41 (T)			20,851	23,905	17.0%		964	22,941
4	RATE G-51 (S)			2,352	2,614	1.9%		650	1,964
5	RATE G-42 (V)			28,327	32,387	23.1%		1,886	30,501
6	RATE G-52			3,643	3,984	2.8%		1,418	2,566
7	RATE G-43			6,598	7,429	5.3%		1,185	6,244
8	RATE G-53			3,918	4,218	3.0%		1,961	2,257
9	RATE G-54			4,871	4,871	3.5%		4,871	0
10									
11	Total			124,034	140,501	100.0%		16,794	123,707
12									-
13	Residential Total			53,474	61,093	**43.482%**		3,860	57,233
14	LLF Total			55,776	63,721	**45.353%**		4,034	59,687
15	HLF Total			14,783	15,687	**11.165%**		8,900	6,787
16	Total			124,034	140,501	100.0%		16,794	123,707
17									
18	C&I Breakdown								
19	LLF Total							4,034	59,687
20	HLF Total							8,900	6,787
21	Total							12,934	66,474
22									
23	C&I Breakdown Percentage								
24	LLF Total							31.192%	89.790%
25	HLF Total							68.808%	10.210%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$5,282,957	53,718	$8.1955			
30	Storage			$5,642,086	28,115	$16.7232			
31									
32	Peaking			$4,848,410					
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)			$3,779,670					
34	Subtotal Peaking Costs			$8,628,079	58,667	$12.2557			
35	Total			$19,553,122	140,500	$11.5973			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			1,651,596	16,794	$8.1955			
39	Pipeline - Remaining			3,631,361	36,924	$8.1955			
40	Storage			5,642,086	28,115	$16.7232			
41	Peaking			8,628,079	58,667	$12.2557			
42	Total			19,553,122	140,500	$11.5973			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**43.482%**	718,147	7,302	$8.1955			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**43.482%**	1,578,985	16,055	$8.1955			
48	Storage	Line 40 * Line 13 Col C	**43.482%**	2,453,285	12,225	$16.7232			
49	Peaking	Line 41 * Line 13 Col C	**43.482%**	3,751,715	25,510	$12.2557			
50	Total		**43.482%**	8,502,113	61,093	$11.5973			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2014 - 2015 Winter Cost of Gas Filing
Capacity Assignment Calculations 2013-2014
Derivation of Class Assignments and Weightings

Line								
51								
52								**Ratios for COG**
53	C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46			933,449	9,491	$8.1955	
55	Pipeline - Remaining	Line 39 - Line 47			2,052,375	20,869	$8.1955	
56	Storage	Line 40 - Line 48			3,188,801	15,890	$16.7233	
57	Peaking	Line 41 - Line 49			4,876,364	33,157	$12.2557	
58	Total		**56.518%**		11,050,989	79,407	$11.5974	**1.0000**
59								
60								
61	LLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E			291,160	2,961	$8.1943	
63	Pipeline - Remaining	Line 55 * Line 24 Col F			1,842,818	18,738	$8.1955	
64	Storage	Line 56 * Line 24 Col F			2,863,210	14,268	$16.7228	
65	Peaking	Line 57 * Line 24 Col F			4,378,465	29,772	$12.2555	
66	Total		**47.9496%**		9,375,653	65,739	$11.8849	**1.0248**
67			31.192%		85%			(Line 66 / Line 58)
68								
69	HLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62			642,289	6,530	$8.1966	
71	Pipeline - Remaining	Line 55 - Line 63			209,557	2,131	$8.1948	
72	Storage	Line 56 - Line 64			325,591	1,622	$16.7279	
73	Peaking	Line 57 - Line 65			497,899	3,385	$12.2575	
74	Total		**8.5681%**		1,675,336	13,668	$10.2145	**0.8808**
75								(Line 74 / Line 58)
76								
77	Unit Cost				Residential	LLF C&I	HLF C&I	
78								
79	Pipeline			$	8.1955	$ 8.1955	$ 8.1955	
80	Storage			$	16.7232	$ 16.7232	$ 16.7232	
81	Peaking			$	-	$ -	$ -	
82	Total			$	11.5973	$ 11.8849	$ 10.2145	
83								
84								
85	Load Makeup				Residential	**LLF C&I**	**HLF C&I**	
86								
87	Pipeline				38.23%	**33.01%**	**63.37%**	
88	Storage				20.01%	**21.70%**	**11.87%**	
89	Peaking				41.76%	**45.29%**	**24.77%**	
90	Total				100.00%	**100.00%**	**100.00%**	
91								
92								
93	Supply Makeup				Residential	LLF C&I	HLF C&I	Total
94								
95	Pipeline				43.48%	40.39%	16.12%	100.00%
96	Storage				43.48%	50.75%	5.77%	100.00%
97	Peaking				43.48%	50.75%	5.77%	100.00%

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**							
2	**d/b/a Liberty Utilities**							
3	**2014-2015 Winter Calculation**							
4	**Correction Factor Calculation**							
5								
6								
7		d	e	f	g	h	i	
8	Data Source: Schedule 10B							Total
9		Nov	Dec	Jan	Feb	Mar	Apr	Sales
10								
11	G-41	946,981	1,845,123	2,776,142	2,964,971	2,393,754	1,910,631	12,837,603
12	G-42	926,482	1,537,420	2,138,159	2,150,855	1,820,478	1,623,549	10,196,945
13	G-43	96,997	134,506	191,924	185,450	165,068	148,978	922,923
14	High Winter Use	1,970,460	3,517,050	5,106,226	5,301,277	4,379,301	3,683,158	23,957,471
15								
16	G-51	142,363	196,019	248,643	291,526	297,572	260,446	1,436,570
17	G-52	193,360	253,274	298,416	311,964	355,383	321,882	1,734,278
18	G-53	34,404	40,744	46,454	58,794	68,795	55,019	304,210
19	G-54	527	932	2,474	2,982	2,121	1,546	10,581
21	Low Winter Use	370,654	490,968	595,986	665,266	723,871	638,893	3,485,638
22								
23	Gross Total	2,341,114	4,008,018	5,702,212	5,966,543	5,103,172	4,322,051	27,443,109
24								
25								
26	Total Sales				27,443,109			
27	Low Winter Use				3,485,638			
28	Winter Ratio for Low Winter Use				**0.8808**	Schedule 10A p 2, ln 74		
29	High Winter Use				23,957,471			
30	Winter Ratio for High Winter Use				**1.0248**	Schedule 10A p 2, ln 66		
31								
32	Correction Factor =	Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use						
33	Correction Factor =				**99.3532%**			
34								
35								
36	**Allocation Calculation for Miscellaneous Overhead**							
37								
38	Projected Winter Sales Volume				(11/1/14 - 4/30/15)		75,950,443	Sch.10B, ln 23
39	Projected Annual Sales Volume				(11/1/14 - 10/31/15)		95,853,149	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales						79.24%	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **2014 - 2015 Winter Cost of Gas Filing**
5
6 **Dry Therms**

Line		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Subtotal PK 14-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Subtotal OP 15	Total
7	**Firm Sales**															
8																
9	R-1	65,036	87,491	114,437	102,077	100,302	81,560	550,904	65,117	53,131	40,635	37,662	38,145	43,996	278,685	829,589
10	R-3	4,082,736	7,023,643	10,126,151	9,486,691	8,317,190	6,753,517	45,789,927	3,770,965	2,074,067	1,321,936	1,245,279	1,407,102	2,644,661	12,464,010	58,253,937
11	R-4	191,916	400,587	398,255	373,851	407,796	394,099	2,166,503	228,112	141,938	107,487	100,165	94,970	161,645	834,318	3,000,821
12	Total Residential.	4,339,688	7,511,721	10,638,842	9,962,619	8,825,287	7,229,176	48,507,334	4,064,194	2,269,136	1,470,059	1,383,106	1,540,216	2,850,302	13,577,013	62,084,346
13																
14	G-41	946,981	1,845,123	2,776,142	2,964,971	2,393,754	1,910,631	12,837,603	953,740	424,123	138,279	86,130	93,996	282,145	1,978,413	14,816,016
15	G-42	926,482	1,537,420	2,138,159	2,150,855	1,820,478	1,623,549	10,196,945	961,656	521,492	201,626	122,119	124,020	335,224	2,266,138	12,463,083
16	G-43	96,997	134,506	191,924	185,450	165,068	148,978	922,923	122,508	61,045	25,214	15,209	14,943	41,801	280,720	1,203,643
17	G-51	142,363	196,019	248,643	291,526	297,572	260,446	1,436,570	202,833	149,230	108,954	79,687	71,935	91,353	703,992	2,140,561
18	G-52	193,360	253,274	298,416	311,964	355,383	321,882	1,734,278	264,944	194,533	147,505	102,683	95,337	116,544	921,546	2,655,825
19	G-53	34,404	40,744	46,454	58,794	68,795	55,019	304,210	45,464	38,624	25,773	20,689	18,168	24,941	173,659	477,869
20	G-54	527	932	2,474	2,982	2,121	1,546	10,581	649	317	59	35	55	111	1,226	11,807
21	Total C/I	2,341,114	4,008,018	5,702,212	5,966,543	5,103,172	4,322,051	27,443,109	2,551,794	1,389,364	647,408	426,553	418,455	892,119	6,325,693	33,768,802
22																
23	**Sales Volume**	**6,680,802**	**11,519,739**	**16,341,054**	**15,929,162**	**13,928,459**	**11,551,226**	**75,950,443**	**6,615,988**	**3,658,500**	**2,117,467**	**1,809,659**	**1,958,671**	**3,742,422**	**19,902,706**	**95,853,149**
24																
25	Transportation Sales															
26																
27	G-41	498,850	920,801	1,280,881	1,548,302	1,480,570	1,176,001	6,905,405	1,139,576	292,994	170,880	121,840	156,880	334,153	2,216,322	9,121,727
28	G-42	966,341	1,776,074	2,498,802	2,789,187	2,562,667	2,013,586	12,606,656	1,136,781	670,013	367,121	252,158	308,234	484,232	3,218,541	15,825,196
29	G-43	689,783	998,423	1,158,491	1,340,397	1,321,509	1,292,126	6,800,729	912,587	859,610	576,419	391,971	384,857	462,604	3,588,047	10,388,777
30	G-51	96,824	132,147	181,369	177,989	218,216	171,775	978,321	115,523	93,024	86,907	76,762	70,458	80,838	523,513	1,501,833
31	G-52	318,247	432,046	508,657	571,948	654,954	478,876	2,964,728	379,136	320,646	286,511	268,224	264,822	301,244	1,820,583	4,785,312
32	G-53	801,279	895,743	1,067,264	1,196,006	1,213,462	1,070,350	6,244,105	788,696	683,937	565,131	569,663	591,320	658,932	3,857,679	10,101,784
33	G-54	1,670,914	1,657,345	1,735,059	1,526,876	1,260,842	1,556,037	9,407,073	1,597,103	1,569,455	1,564,067	1,612,111	1,593,833	1,601,649	9,538,217	18,945,290
34																
35	Total Trans. Sales	**5,042,238**	**6,812,578**	**8,430,524**	**9,150,704**	**8,712,219**	**7,758,752**	**45,907,017**	**6,069,402**	**4,489,678**	**3,617,035**	**3,292,730**	**3,370,405**	**3,923,654**	**24,762,903**	**70,669,919**
36																
37	Total All Sales	**11,723,040**	**18,332,318**	**24,771,579**	**25,079,866**	**22,640,679**	**19,309,978**	**121,857,459**	**12,685,389**	**8,148,178**	**5,734,502**	**5,102,389**	**5,329,076**	**7,666,075**	**44,665,609**	**166,523,068**

Schedule 11

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Normal and Design Year Volumes **Schedule 11A**

Volumes (Therms) **Normal Year**

For the Months of November 14 - April 15

	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	694,856	933,968	961,173	840,409	953,431	898,739	5,282,577
Niagara Supply	689,704	740,443	750,335	655,819	744,292	701,765	4,282,358
TGP Supply (Gulf)	5,030,346	3,214,961	3,257,912	2,848,386	3,231,671	4,110,233	21,693,509
Dracut Supply 1 - Baseload	-	2,833,266	4,784,937	3,138,027	-	-	10,756,230
Dracut Supply 2 - Swing	1,300,647	1,214,805	668,515	1,193,937	1,728,302	1,504,718	7,610,923
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	20,610	454,363	666,620	697,089	67,663	-	1,906,345
Propane Truck	-	-	635,615	72,785	-	-	708,400
PNTGS	60,358	83,376	93,792	77,288	73,814	50,929	439,557
TGP Supply (Z4)	1,774,680	1,906,182	1,931,648	1,689,072	1,916,090	1,841,666	11,059,338
Subtotal Pipeline Volumes	9,571,201	11,381,364	13,750,547	11,212,814	8,715,262	9,108,050	63,739,236
Storage Gas:							
TGP Storage	2,618,224	4,773,869	5,074,064	4,688,282	4,509,577	-	21,664,016
Produced Gas:							
LNG Vapor	20,610	454,363	717,779	697,089	22,298	20,971	1,933,110
Propane	-	-	784,441	72,785	76,890	-	934,116
Subtotal Produced Gas	20,610	454,363	1,502,221	769,875	99,188	20,971	2,867,227
Less - Gas Refills:							
LNG Truck	(20,610)	(454,363)	(666,620)	(697,089)	(67,663)	-	(1,906,345)
Propane	-	-	(635,615)	(72,785)	-	-	(708,400)
TGP Storage Refill	(3,151,143)	-	-	-	-	(1,501,643)	(4,652,786)
Subtotal Refills	(3,171,753)	(454,363)	(1,302,235)	(769,875)	(67,663)	(1,501,643)	(7,267,531)
Total Sendout Volumes	9,038,281	16,155,233	19,024,597	15,901,096	13,256,364	7,627,377	81,002,948

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
42 **Normal and Design Year Volumes** **Schedule 11B**

45 **Volumes (Therms)** **Design Year**

47 **For the Months of November 14 - April 15**

Line		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Peak Nov - Apr
51	Pipeline Gas:							
52	Dawn Supply	883,292	948,501	961,173	840,409	953,431	898,739	5,485,546
53	Niagara Supply	689,704	740,443	750,335	655,819	744,292	701,765	4,282,358
54	TGP Supply (Gulf)	5,025,929	3,214,961	3,257,912	2,848,386	3,231,671	4,262,269	21,841,129
55	Dracut Supply 1 - Baseload	-	2,833,266	4,784,937	3,138,027	-	-	10,756,230
56	Dracut Supply 2 - Swing	2,568,170	1,214,805	668,515	1,193,937	1,728,302	1,504,718	8,878,446
57	City Gate Delivered Supply	-	-	-	-	-	-	0
58	LNG Truck	20,610	89,496	869,707	858,418	67,663	-	1,905,893
59	Propane Truck	-	-	498,415	205,600	-	-	704,015
60	PNTGS	60,358	83,376	93,792	77,288	73,814	50,929	439,557
61	TGP Supply (Z4)	1,774,680	1,906,182	1,931,648	1,689,072	1,916,090	1,841,666	11,059,338
62	Subtotal Pipeline Volumes	11,022,743	11,031,030	13,816,434	11,506,957	8,715,262	9,260,086	65,352,512
63								
64	Storage Gas:							
65	TGP Storage	2,008,752	5,461,533	5,623,638	4,869,870	3,043,292	-	21,007,085
66								
67	Produced Gas:							
68	LNG Vapor	20,610	89,496	920,866	858,418	22,298	20,971	1,932,658
69	Propane	-	-	585,230	265,629	76,890	-	927,749
70	Subtotal Produced Gas	20,610	89,496	1,506,096	1,124,047	99,188	20,971	2,860,408
71								
72	Less - Gas Refills:							
73	LNG Truck	(20,610)	(89,496)	(869,707)	(858,418)	(67,663)	-	(1,905,893)
74	Propane	-	-	(498,415)	(205,600)	-	-	(704,015)
75	TGP Storage Refill	(2,542,408)	-	-	-	-	(1,501,643)	(4,044,051)
76	Subtotal Refills	(2,563,018)	(89,496)	(1,368,121)	(1,064,018)	(67,663)	(1,501,643)	(6,653,959)
77								
78	Total Sendout Volumes	10,489,088	16,492,563	19,578,047	16,436,856	11,790,079	7,779,414	82,566,046

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Capacity Utilization
Volumes (Therms)

	Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
Pipeline Gas:								
Dawn Supply	5,282,577	4,000	7,240,000	73%	5,485,546	4,000	7,240,000	76%
Niagara Supply	4,282,358	3,122	5,650,820	76%	4,282,358	3,122	5,650,820	76%
TGP Supply	32,752,847	21,596	39,088,760	84%	32,900,467	21,596	39,088,760	84%
Dracut Supply 1 & 2	18,367,153	50,000	90,500,000	20%	19,634,677	50,000	90,500,000	22%
LNG Truck	1,906,345	-	-	-	1,905,893	-	-	-
Propane Truck	708,400	-	-	-	704,015	-	-	-
PNGTS	439,557	1,000	1,810,000	24%	439,557	1,000	1,810,000	24%
Granite Ridge	-	-	-	-	-	-	-	-
Other Purchased Resources	-	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	63,739,236				65,352,512			
Storage Gas:								
TGP Storage	21,664,016		25,791,710	84%	21,007,085		25,791,710	81%
Produced Gas:								
LNG Vapor	1,933,110				1,932,658			
Propane	934,116.4				927,749			
Subtotal Produced Gas	2,867,227				2,860,408			
Less - Gas Refills:								
LNG Truck	(1,906,345)				(1,905,893)			
Propane	(708,400)				(704,015)			
TGP Storage Refill	(4,652,786)				(4,044,051)			
Subtotal Refills	(7,267,531)				(6,653,959)			
Total Sendout Volumes	81,002,948				82,566,046			

Liberty Utilities (EnergyNorth Natural Gas) Corp. **Schedule 11D**
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2014 / 15 Heating Season
(Therms)

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities

Requirements	
Firm Sales	1,065,130
Interruptible Sales	0
Firm Transportation	339,870
Interruptible Transportation	0
Total Requirements	1,405,000
Resources	
Purchased Pipeline Gas	689,500
Underground Storage Gas	281,000
Propane Air Production	319,200
LNG Produced Gas	115,300
Third-Party Supply	0
Total Resources	1,405,000

Please refer to Liberty's 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

F. Chico DaFonte
Vice President, Energy Procurement

Note: Forecasted Firm Transportation volumes are for customers using utility capacity only.

Schedule 12

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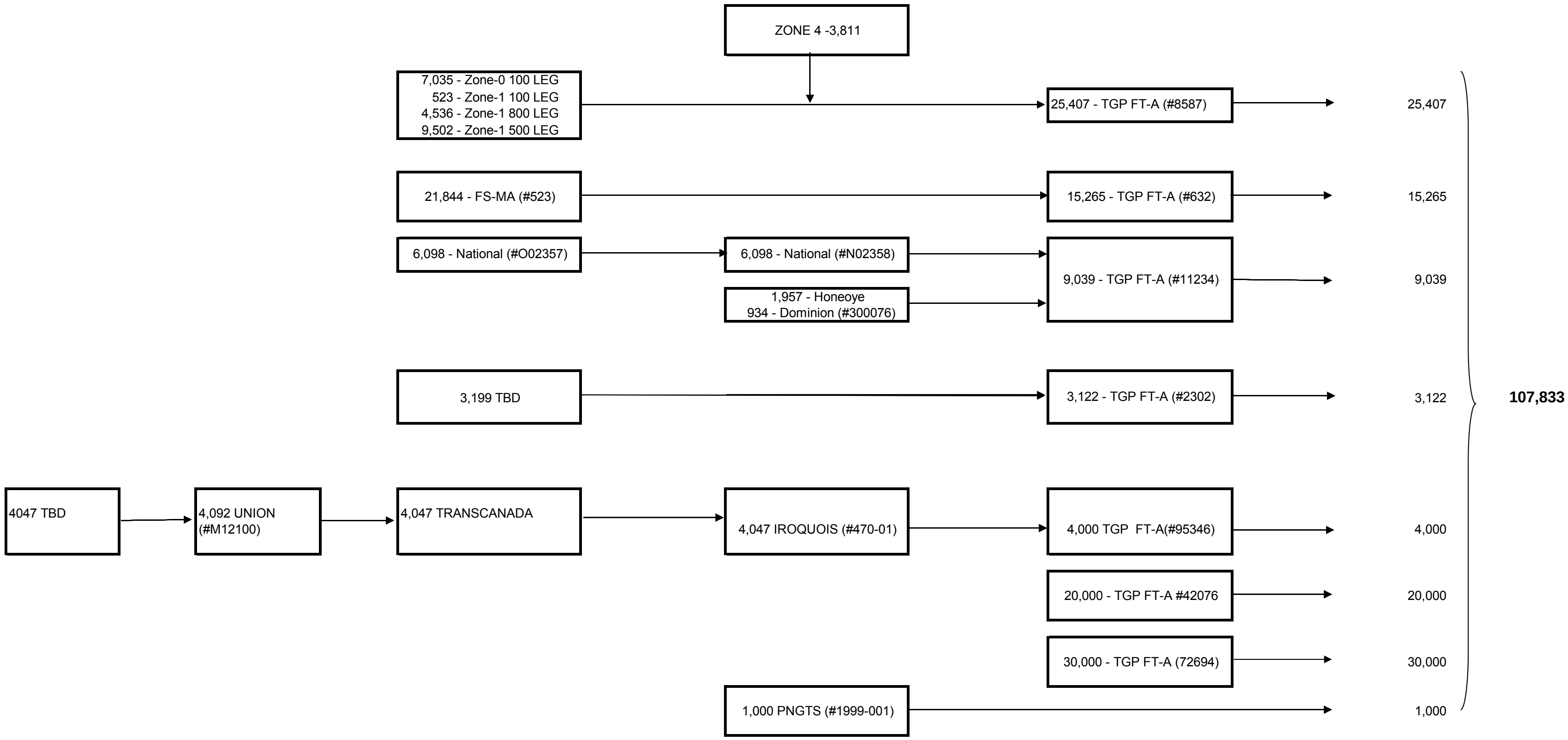
Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Niagara	-	-	Supply	3,199	1,167,635	3/31/2015	N/a	Terminates
ANE	-	-	Supply	4,047	611,097	Peak Only	N/a	Terminates
GDF Suez	FLS		Liquid Refill	Up to 5 trucks	250,000	3/31/2015 Peak Only	-	Terminates
Dracut or Z6	-	-	Supply	Up to 20,000 / day	1,412,000	4/30/2015	-	Terminates
TGP Long-Haul	-	-	Supply	21,596	3,908,876	4/30/2015	N/a	Terminates
Northern Transport			Trucking	28,500 Gallons	900,000 Gallons		N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2016	3/31/2013	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	4/1/2015	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2015	3/31/2013	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2015	3/31/2013	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	11/1/2017	10/31/2012	Evergreen Provision
Portland Natural Gas Transmission System	FT 1999-01	1999-001	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2015	10/31/2012	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2017	4/30/2016	Evergreen Provision
Union Gas Limited	M12	M12100	Transportation	4,092	1,493,580	10/31/2017	10/31/2015	Evergreen Provision

* MAQ is calculated on a 365 day calendar year.

Schedule 13

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2013 - Apr 2014 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	14,782,367	41.10%	74.24%
G-42	14,015,718	38.97%	45.09%
G-43	1,571,165	4.37%	16.22%
G-51	2,627,377	7.31%	65.79%
G-52	2,360,090	6.56%	31.26%
G-53	577,173	1.60%	6.13%
G-54	28,824	0.08%	0.17%
Total C/I	35,962,716	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	5,128,714	8.16%	25.76%
G-42	17,070,995	27.16%	54.91%
G-43	8,114,812	12.91%	83.78%
G-51	1,366,276	2.17%	34.21%
G-52	5,189,211	8.26%	68.74%
G-53	8,843,135	14.07%	93.87%
G-54	17,146,392	27.28%	99.83%
Total C/I	62,859,536	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	19,911,081	20.15%	100.00%
G-42	31,086,714	31.46%	100.00%
G-43	9,685,977	9.80%	100.00%
G-51	3,993,653	4.04%	100.00%
G-52	7,549,301	7.64%	100.00%
G-53	9,420,308	9.53%	100.00%
G-54	17,175,217	17.38%	100.00%
Total C/I	98,822,251	100.00%	

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Schedule 14

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak	Peak	Total	
	May 13 - Oct 13	**Nov 13-Apr 14**	**May 13 - Apr 14**	
	(Therms)	(Therms)	(Therms)	
Pipeline Deliveries	14,821,060	70,885,890	85,706,950	
All Others	965,570	23,149,360	24,114,930	
	15,786,630	94,035,250	109,821,880	
				Ratio
Total Winter Supplies				94,035,250
Total Pipeline Deliveries				85,706,950
Ratio Winter Supplies to Pipeline Supplies				1.097

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Schedule 15

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Schedule 15

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption

C&I Sales Normalized (Therms)	**Jul-13**	**Aug-13**	**Jul - Aug Total**	**Total Annual**	**% of Jul-Aug to Total**
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	162,797	151,043	313,840	14,782,367	2.12%
G-42	276,592	246,174	522,766	14,015,718	3.73%
G-43	57,914	19,658	77,572	1,571,165	4.94%
G-51	131,734	134,686	266,420	2,627,377	10.14%
G-52	132,847	123,592	256,439	2,360,090	10.87%
G-53	27,995	24,456	52,451	577,173	9.09%
G-54	815	819	1,634	28,824	5.67%
Total C/I	790,694	700,428	1,491,122	35,962,716	4.15%

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Schedule 16

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2014 - 2015 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**
5
6 **Underground Storage Gas**

Ln			May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
7			May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		286,533	556,561	867,551	1,224,288	1,492,654	1,761,020	2,029,386	1,767,564	1,290,177	782,770	313,942	(137,016)	286,533
10															
11	Injections (MMBtu)	Sch 11A ln 37 /10	278,140	327,214	356,737	268,366	268,366	268,366	-	-	-	-	-	150,164	1,917,353
12															
13	Subtotal		564,673	883,775	1,224,288	1,492,654	1,761,020	2,029,386	2,029,386	1,767,564	1,290,177	782,770	313,942	13,149	
14															
15	Storage Sale		-					-							
16															
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(8,112)	(16,224)	-	-	-	-	(261,822)	(477,387)	(507,406)	(468,828)	(450,958)	-	(2,190,738)
18															
19	Ending Balance (MMBtu)		556,561	867,551	1,224,288	1,492,654	1,761,020	2,029,386	1,767,564	1,290,177	782,770	313,942	(137,016)	13,149	13,149
20															
21															
22	Beginning Balance		$ 1,238,333	$ 2,456,163	$ 3,691,680	$ 4,861,194	$ 5,604,568	$ 6,342,575	$ 7,147,673	$ 6,225,512	$ 4,544,114	$ 2,756,985	$ 1,105,731	$ (482,581)	1,238,333
23															
24	Injections	ln 11 * ln 36	1,253,630	1,304,554	1,169,514	743,374	738,007	805,098	-	-	-	-	-	525,575	6,539,752
25															
26	Subtotal		$ 2,491,963	$ 3,760,718	$ 4,861,194	$ 5,604,568	$ 6,342,575	$ 7,147,673	$ 7,147,673	$ 6,225,512	$ 4,544,114	$ 2,756,985	$ 1,105,731	$ 42,994	
27															
28	Storage Sale		$ -					$ -							
29															
30	Withdrawals	ln 17 * ln 34	$ (35,799)	$ (69,038)	$ -	$ -	$ -	$ -	$ (922,161)	$ (1,681,398)	$ (1,787,129)	$ (1,651,253)	$ (1,588,312)	$ -	(7,735,090)
31															
32	Ending Balance		$ 2,456,163	$ 3,691,680	$ 4,861,194	$ 5,604,568	$ 6,342,575	$ 7,147,673	$ 6,225,512	$ 4,544,114	$ 2,756,985	$ 1,105,731	$ (482,581)	$ 42,994	$ 42,994
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$4.4131	$4.2553	$3.9706	$3.7548	$3.6016	$3.5221	$3.5221	$3.5221	$3.5221	$3.5221	$3.5221	$3.2699	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$4.5072	$3.9869	$3.2784	$2.7700	$2.7500	$3.0000	$3.5000	$4.5390	$4.6174	$4.6045	$4.5250	$3.5000	
37															
38	For Informational Purposes								Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Total
39	Summer Hedge Contracts - Vols Dth								-	-	-	-	-	-	-
40	Average Hedge Price								$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
41	NYMEX								$3.9895	$4.0837	$4.1591	$4.1467	$4.0703	$3.8261	
42															
43	Hedged Volumes at Hedged Price								$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX								-	-	-	-	-	-	-
45	Hedge (Savings)/Loss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
46															
47	Month Dollar Average	ln (22 + ln 32) /2				$ 5,232,881	$ 5,973,571	$ 6,745,124	$ 6,686,592	$ 5,384,813	$ 3,650,549	$ 1,931,358	$ 311,575	$ (219,793)	
48															
49	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
50															
51	Inventory Finance Charge	ln 47 * ln 49				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
52	Financial Expenses					0	0	0	0	0	0	0	0	0	
53	Total Inventory Finance Charges					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

54
55
38

Ln	Liquid Propane Gas (LPG)		May-14 (Actual)	Jun-14 (Actual)	Jul-14 (Actual)	Aug-14 (Estimate)	Sep-14 (Estimate)	Oct-14 (Estimate)	Nov-14 (Estimate)	Dec-14 (Estimate)	Jan-15 (Estimate)	Feb-15 (Estimate)	Mar-15 (Estimate)	Apr-15 (Estimate)	Total
43	Beginning Balance		36,478	50,350	74,841	95,369	95,369	95,369	95,369	95,369	95,369	80,486	80,486	72,797	36,478
45	Injections	Sch 11A ln 36 /10	13,872	24,491	20,528	-	-	-	-	-	63,561	7,279	-	-	129,731
47	Subtotal		50,350	74,841	95,369	95,369	95,369	95,369	95,369	95,369	158,930	87,765	80,486	72,797	
49	Withdrawals	Sch 11A ln 31 /10	-	-	-	-	-	-	-	-	(78,444)	(7,279)	(7,689)	-	(93,412)
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		50,350	74,841	95,369	95,369	95,369	95,369	95,369	95,369	80,486	80,486	72,797	72,797	72,797
56	Beginning Balance		$ 773,366	$ 969,598	$ 1,305,531	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 821,315	$ 753,201	$ 681,247	$ 773,366
58	Injections	ln 45 * ln 68	196,233	335,933	316,259	-	-	-	-	-	-	-	-	-	848,424
60	Subtotal		$ 969,598	$ 1,305,531	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 821,315	$ 753,201	$ 681,247	
62	Withdrawals	ln 51 * ln 66	-	-	-	-	-	-	-	-	(800,475)	(68,114)	(71,954)	-	(940,543)
64	Ending Balance		$ 969,598	$ 1,305,531	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 821,315	$ 753,201	$ 681,247	$ 681,247	$ 681,247
66	Average Rate For Withdrawals		$19.2572	$17.4441	$17.0054	$17.0054	$17.0054	$17.0054	$17.0054	$17.0054	$10.2044	$9.3581	$9.3581	$9.3581	
68	Propane Rate for Injections	Actual or Sch. 6, ln 151 * 10	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,621,790	$ 1,221,552	$ 787,258	$ 717,224	$ 681,247	
73	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Line	Liquid Natural Gas (LNG)		May-14 (Actual)	Jun-14 (Actual)	Jul-14 (Actual)	Aug-14 (Estimate)	Sep-14 (Estimate)	Oct-14 (Estimate)	Nov-14 (Estimate)	Dec-14 (Estimate)	Jan-15 (Estimate)	Feb-15 (Estimate)	Mar-15 (Estimate)	Apr-15 (Estimate)	Total
74	Beginning Balance		8,532	7,006	6,085	6,000	6,000	6,000	6,000	6,000	6,000	884	884	5,421	8,532
76	Injections	Sch 11A ln 35 /10	374	737	1,659	-	-	-	2,061	45,436	66,662	69,709	6,766	-	193,405
78	Subtotal		8,906	7,743	7,744	6,000	6,000	6,000	8,061	51,436	72,662	70,593	7,650	5,421	
80	Withdrawals	Sch 11A ln 30 /10	(1,900)	(1,658)	(1,744)	-	-	-	(2,061)	(45,436)	(71,778)	(69,709)	(2,230)	(2,097)	(198,613)
82	Ending Balance		7,006	6,085	6,000	6,000	6,000	6,000	6,000	6,000	884	884	5,421	3,324	3,324
85	Beginning Balance		$ 154,269	$ 139,466	$ 124,652	$ 113,388	$ 113,388	$ 113,388	$ 113,388	$ 94,401	$ 109,467	$ 16,965	$ 16,542	$ 63,602	$ 154,269
87	Injections	ln 76 * ln 97	23,012	19,157	21,688	-	-	-	13,440	844,024	1,284,910	1,303,906	73,223	-	3,583,361
89	Subtotal		$ 177,282	$ 158,623	$ 146,340	$ 113,388	$ 113,388	$ 113,388	$ 126,828	$ 938,426	$ 1,394,377	$ 1,320,871	$ 89,765	$ 63,602	
91	Withdrawals	ln 80 * ln 95	(37,816)	(33,971)	(32,952)	-	-	-	(32,427)	(828,959)	(1,377,411)	(1,304,329)	(26,163)	(24,606)	(3,698,634)
93	Ending Balance		$ 139,466	$ 124,652	$ 113,388	$ 113,388	$ 113,388	$ 113,388	$ 94,401	$ 109,467	$ 16,965	$ 16,542	$ 63,602	$ 38,996	$ 38,996
95	Average Rate For Withdrawals		$19.9059	$20.4860	$18.8972	$18.8980	$18.8980	$18.8980	$15.7335	$18.2444	$19.1899	$18.7111	$11.7334	$11.7334	
97	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	$61.5301	$25.9938	$13.0729	$13.0729	$13.0729	$13.0729	$6.5212	$18.5760	$19.2750	$18.7050	$10.8217	$4.7558	
100	Month Dollar Average	ln (85 + ln 93) /2				$ 113,388	$ 113,388	$ 113,388	$ 103,895	$ 101,934	$ 63,216	$ 16,754	$ 40,072	$ 51,299	
102	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
104	Inventory Finance Charge	ln 100 * ln 102				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
107	Total Fuel Financing	lns 53 + 75 + 104				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

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Schedule 17

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-14	5,042,238	$0.0077	$ 38,825
Dec-14	6,812,578	0.0077	52,457
Jan-15	8,430,524	0.0077	64,915
Feb-15	9,150,704	0.0077	70,460
Mar-15	8,712,219	0.0077	67,084
Apr-15	7,758,752	0.0077	59,742
Total	**45,907,017**		**$ 353,484**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed Third Revised Page 89 for calculation of rate.

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Schedule 18

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Liberty Utilities

Stephen R. Hall
Director, Regulatory & Government
O: 603-328.2721
E: Stephen.Hall@libertyutilities.com

August 26, 2014

Via Electronic Mail and U.S. Mail

Debra A. Howland
Executive Director
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

Re: DG 13-251: Liberty Utilities (EnergyNorth Natural Gas) Corp.
2013/2014 Winter Cost of Gas Reconciliation

Dear Ms. Howland:

On behalf of Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (the "Company"), enclosed for filing please find one redacted and seven confidential copies of the 2013/2014 Winter Period Cost of Gas reconciliation. This reconciliation compares the actual deferred gas costs to the projections submitted in the Company's 2013/2014 Winter Period Cost of Gas Filing submitted to the Commission on September 3, 2013.

Certain pages included in this filing contain confidential information, specifically, the Company's costs associated with the summary of supply and demand forecast, contracts ranked on a per-unit cost basis, adjustments to gas costs, details of demand costs per unit, details of demand rates per unit, details of commodity costs per unit and hedged contracts (including pricing terms). The Company requests confidential treatment of these materials pursuant to 201.06(a)(26) and will rely upon the procedures outlined in Puc 201.06 and 201.07 to protect confidentiality.

The filing shows an under collection for the 2013/2014 Winter Period of $14,889,808 summarized as follows:

Winter Period Beginning Balance	$	5,119,793
Prior Period Adjustment and Interest		34,959
Less: Cost of Gas Revenue Billed		(90,379,472)
Add: Cost of Gas Allowable 5/1/13 – 10/31/13		346,284
Add: Cost of Gas Allowable 11/1/13 – 4/30/14		99,768,244
Winter Period Ending Balance	$	14,889,808

The filing consists of a six-page summary and nine supporting schedules.

Summary:

- Page 1 compares the actual deferred gas costs to the projections submitted in the Company's filing including the beginning balance, prior period adjustments, interest, allowable gas costs and gas cost revenue. The result is a net under collection of $14,889,808;
- Page 2 compares the actual allowed Bad Debt and Working Capital costs to the filed projection submitted in the Company's filing resulting in an (over)/under collection of $(511,858) and $34,382, respectively, for a net under collection for all gas accounts of $14,412,332.
- Page 3 compares the actual demand charges of $10,317,504 to the $10,226,121 in demand charges estimated in the filing, resulting in an increase in demand costs of $91,383;
- Page 4 shows a similar comparison for commodity costs. The actual commodity costs were $91,357,317 compared to the $52,414,463 that was forecasted in the filing. The $38,942,854 increase in commodity costs was the direct result of sharp increases in gas prices in Tennessee's Zone 6 market area where the Company purchases a sizeable amount of its natural gas supplies. The price run up was attributable to a combination of increased demand from utilities and gas fired generators without a commensurate increase in supply. This supply restriction was caused in part by a reduction of LNG imports and a continued lack of new pipeline infrastructure needed to bring incremental shale gas supplies into New England. The results show that the total actual gas costs, demand and commodity were $39,034,237 higher than forecasted in the filing;
- Page 5 provides a variance analysis between actual costs and forecasted costs; and
- Page 6 shows the calculation of the actual transportation cost of gas and related revenue compared to the filing.

Schedules:

- Schedule 1 provides a monthly summary of the deferred gas cost account balances including beginning balances, actual gas cost allowable, gas cost collections, interest applied, and ending balances;
- Schedule 1A provides the same information for bad debts associated with the cost of gas;
- Schedules 2A and 2B provide the details of gas cost by source;
- Schedule 3 provides the detailed calculation of winter gas cost revenue billed by rate class;
- Schedule 3A provides a breakdown of the calculation of unbilled gas costs;
- Schedule 4 provides a monthly summary of the non-firm margin and capacity release credits to the winter cost of gas account;
- Schedule 5 provides the monthly summary of the deferred gas cost balances associated with gas working capital and shows the monthly beginning account balances, working capital allowable, the working capital revenue billed and the interest applied to derive the monthly ending balances;
- Schedule 6 shows the bad debt and working capital calculation that determines the amount of expense booked for those items;

- Schedule 7 provides the backup calculations for the revenue billed to recover working capital and bad debt by rate class;
- Schedule 8 provides a summary of the commodity costs and the related volumes; and
- Schedule 9 provides a summary of the monthly prime interest rates used to calculate the interest on the deferred balances.

Thank you for your assistance in this matter. Please do not hesitate to call if you have any questions.

Sincerely,

Stephen R. Hall

Stephen R. Hall

Enclosures

cc: Service List

2330

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
WINTER 2013-2014 COST OF GAS RESULTS
DG 13-251
NOVEMBER 2013 THROUGH APRIL 2014

REDACTED
2330 Cost of Gas Reconciliation Report
For the six months ended April 30, 2014 peak season

	Original Filing 1/	Actual		Difference
Peak Gas cost Account 1920-1740				
Balance 05/01/13 - (Over) / Under	$5,119,793	$5,119,793	2/	$0
Peak Gas Costs 5/1/13 - 10/31/13	$2,789,162	$3,151,895	3/	362,733
Fuel Financing 5/1/13 - 10/31/13	-	-	3/	-
Prior Period Adjustment 5/1/13-10/31/13	-	(42,610)	3/	(42,610)
Broker Revenue 5/1/13 - 10/31/13	(139,075)	(376,945)	3/	(237,870)
280 Day Margins 5/1/13 - 10/31/13	-	-	4/	-
IT Sales Margins 5/1/13 - 10/31/13	-	-	4/	-
Off System Sales Margin 5/1/13 - 10/31/13	(150,802)	(15,221)	4/	135,581
Capacity Release 5/1/13 - 10/31/13	(2,688,766)	(2,413,444)	4/	275,322
Interest 5/1/13 - 10/31/13	72,784	77,569	3/	4,785
Sum 5/1/13 - 10/31/13 costs	($116,697)	$381,244		$497,941
Beginning Balance 10/31/13 (Over)/Under	$5,003,096	$5,501,037		$497,941
Interest 11/1/13 - 4/30/14	46,805	385,289		338,484
Prior Period Adjustments	-	(543)		(543)
Interruptible and 280-Day Sales Margins 11/1/13 - 4/30/14	-	-		-
Hedging costs	197,835	-		(197,835)
Off System Sales Margin 11/1/13 -4/30/14	(119,091)	-		119,091
Capacity Release Credits 11/1/13 - 4/30/14	(59,410)	(164,106)		(104,696)
Other Transportation Related Margins	0	0		0
Fixed Price Option Admin Costs	45,056	47,935		2,879
Broker Revenues 11/1/13 - 4/30/14	(634,054)	(1,014,419)		(380,365)
Production & Storage	1,980,428	1,980,428		0
Misc Overhead	10,369	10,735		366
Fuel Financing 11/1/13 - 4/30/14	-	-		-
Transportation Cost of Gas Revenue	(93,511)	-		93,511
Total Adjustment to Costs	$1,374,427	$1,245,318		($129,109)
Gas Costs 11/1/13 - 4/30/14	$59,851,452	$98,522,925		$38,671,473
Total Gas Costs and Adjustments 11/13 - 04/14	$61,225,879	$99,768,244		$38,542,365
Gas Cost Billed	($66,228,975)	(90,379,472)		($24,150,497)
Total (Over) / Under 04/30/14	$0	$14,889,808		$14,889,808

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
WINTER 2013-2014 COST OF GAS RESULTS
DG 13-251
NOVEMBER 2013 THROUGH APRIL 2014

REDACTED
2330 Cost of Gas Reconciliation Report
For the six months ended April 30, 2014 peak season

	Original Filing 1/	Actual		Difference
Bad Debts Account 1920-1743				
Beginning Balance	$50,789	$50,789	sch 1a	$0
BD Costs 5/1/13 - 10/31/13	55,296	(172,867)	5/	(228,163)
Interest 5/1/12 - 10/31/12	1,208	(431)	5/	(1,639)
Beginning Balance 10/31/13 (Over)/Under	$107,293	($122,509)		($229,802)
Bad Debt Costs 11/1/13 - 4/30/14	1,288,137	1,197,629		(90,508)
Bad Debt CGA Billed	(1,396,391)	(1,584,854)		(188,463)
Adjustment	-	-		0
Interest	961	(2,124)		(3,085)
Total (Over) / Under 04/30/14	$0	($511,858)		($511,858)
Working Capital Account 1163-1422				
Beginning Balance	$11,247	$11,247	7/	$0
WC Costs 5/1/13 - 10/31/13	3,546	919	6/	(2,627)
Interest 5/1/13 - 10/31/13	210	180	6/	(30)
Beginning Balance 10/31/13 (Over)/Under	$15,003	$12,346		($2,657)
Working Capital Costs 11/1/13 - 4/30/14	76,063	125,003		48,940
Working Capital CGA Billed	(91,191)	(103,544)		(12,353)
Adjustment	-	-		0
Interest	125	577		452
Total (Over) / Under 04/30/14	$0	$34,382		$34,382
Total 1920-1740, 1920-1743, 1163-1422	$0	$14,412,332		$14,412,332

1/ As filed 09-03-13 in the Winter 2013-2014 Cost of Gas DG 13-251.
2/ Beg bal is the sum of the actual April 30, 2013 bal $2,343,441 less the May 2013 billings of $3,249,530, plus reverse of pr mo unbilled $6,098,408 less audit adjustments of -$62,208 & -$10
3/ The 5/1/13 - 10/31/13 costs are per Schedule 1, page 1, of the Summer 2013 Reconciliation filed on February 28, 2014 in DG 13-085.
4/ The 5/1/13 - 10/31/13 costs are per Schedule 4, of the Summer 2013 Reconciliation filed on February 28, 2014 in DG 13-085.
5/ The 5/1/13 - 10/31/13 costs are per Schedule 1A, page 1.
6/ The 5/1/13 - 10/31/13 costs are per Schedule 5, of the Summer 2013 Reconciliation filed on February 28, 2014 in DG 13-085.

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
WINTER 2013-2014 COST OF GAS RESULTS
DG 13-251
SUMMARY OF DEMAND CHARGES FOR PERIOD
NOVEMBER 2013 THROUGH APRIL 2014

	Filing (a)	1/ Actual May 13 - Oct 13 (b)	Actual Nov 13 - Apr 14 (c)	Actual Total Peak Demand (d)=(b)+(c)	Difference (e)=(d)-(a)
Supplies:					
BP/Nexen	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ICE					
Subtotal Supply Demand Charges	$6,369	$0	$10,800	$10,800	$4,431
Pipelines:					
Iroquois Gas Trans	$160,191	$0	$154,427	$154,427	($5,764)
TGP NET 33371	178,550	-	232,181	232,181	$53,631
TGP FTA Z5-Z6 2302	139,359	-	149,377	149,377	$10,018
TGP FTA Z0 - Z6 8587	3,121,464	-	2,568,279	2,568,279	($553,185)
TGP Dracut FTA Z6 - Z6 42076	586,152	-	521,110	521,110	($65,042)
TGP (Concord Lateral) Z6-Z6	4,089,120	1,682,857	1,933,632	3,616,489	($472,631)
Portland Natual Gas Pipeline	241,474	-	216,674	216,674	($24,800)
ANE (Uniongas and TransCanada)	317,817	-	35,157	35,157	($282,660)
TGP FTA 632	1,555,125	634,786	855,550	1,490,336	($64,789)
TGP FTA 11234	896,192	380,992	539,335	920,327	$24,135
National Fuel	276,642	112,152	114,564	226,716	($49,926)
Subtotal Pipeline Demand Charges	$11,562,086	$2,810,787	$7,320,286	$10,131,073	($1,431,013)
Peaking Supply					
Granite Ridge	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NJR / BG Energy					
GD Suez (formerly, Distrigas, aka DOMAC)					
Repsol					
JP Morgan					
Subtotal Peaking Supply	$700,000	($150,678)	$260,000	$109,322	($590,678)
Propane					
Energy North Propane	$0	$0	$0	$0	$0
Storage:					
Demand & Capacity Charges	$1,430,592	$590,490	$598,309	$1,188,799	($241,793)
Other:					
Capacity Managed	($3,472,926)	(98,704)	($1,023,787)	($1,122,491)	$2,350,436
Pipeline Refunds	$0	$0	$0	$0	$0
Total Demand Charges (Forward to Page 4)	$10,226,121	$3,151,895	$7,165,609	$10,317,504	$91,383

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2012 Cost of Gas Reconciliation, DG 12-067 filed March 1, 2013.

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
WINTER 2013-2014 COST OF GAS RESULTS
DG 13-251

SUMMARY OF COMMODITY COSTS FOR PERIOD

NOVEMBER 2013 THROUGH APRIL 2014

	Filing	Average Cost per Therm	Actual	Average Cost per Therm	Difference	
Demand Charges (Brought from Page 3):	**$10,226,121**		**$10,317,504**		**$91,383**	
TGP Gulf Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Dracut Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
PNGTS Comodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
TGP/Iroquois Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
TGP/Niagara Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
City Gate Delivered Supply						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Storage Gas - Commodity Withdrawn						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Propane P/S Plant Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Propane Tank Farm Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
LNG P/S Plant Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Hedging (Gains) Losses	[redacted]		[redacted]		[redacted]	
Other- Cashout, Broker Penalty, Canadian Managed, Non-Firm costs						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Prior period Adj	[redacted]		[redacted]		[redacted]	
Subtotal:						
Volumes (net of fuel retention)	77,133,381		94,035,250		16,901,869	
Cost	$ 52,414,463	0.6795	$ 91,357,317	0.9715	$ 38,942,854	0.2920
Total Demand and Commodity Costs	$ 62,640,584		$ 101,674,820		$ 39,034,236	
Demand (therms):	77,133,381		94,035,250		16,901,869	
Firm Gas Sales	76,131,660		84,723,918		8,592,258	
Lost Gas (Unaccounted For)	384,847		1,090,809		705,962	
Unbilled Therms	(3,920)		7,755,067		7,758,987	
Fuel Retention	-		-		-	
Company Use	620,794		465,457		(155,337)	
Total Demand	77,133,381		94,035,250		16,901,869	
						-

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
WINTER 2013-2014 COST OF GAS RESULTS
DG 13-251

Weather Variance - Volume Impact	**(A) Actual Volume**	**(B) Normal Volume**	**(C) Actual Rate**		**(A-B)*C Difference**
TGP Gulf	[redacted]				
TGP/Iroquios					
TGP/Niagra					
PNGTS					
Dracut					
City Gate Delivered Supply					
DOMAC					
Storage gas - commodity withdrawn					
Propane					
LNG					
Total Volume Weather Varaince	94,035,250	86,726,152		$	8,633,156

Demand Variance - Commodity Costs	**(A) Forecast Volume**	**(B) Actual Volume**	**(C) Forecast Rate**		**(B-A)*C Difference**
TGP Gulf	[redacted]				
TGP/Iroquios					
TGP/Niagra					
PNGTS Comodity					
City Gate Delivered Supply					
Dracut					
Storage Gas - Commodity Withdrawn					
Propane P/S Plant Commodity					
LNG P/S Plant Commodity					
Total Demand Variance (Less: Fuel Retention)	77,133,381	94,035,250		$	(7,484,643)
Demand Variance Net of Weather Variance					(16,117,798)

Rate Variance - Commodity Costs	**(A) Actual Volume**	**(B) Forecast Rate**	**(C) Actual Rate**		**(C-B)*A Difference**
TGP Gulf	[redacted]				
TGP/Iroquios					
TGP/Niagra					
PNGTS Comodity					
Dracut					
DOMAC					
Storage Gas - Commodity Withdrawn					
Propane P/S Plant Commodity					
LNG P/S Plant Commodity					
Total Commodity Cost Rate Variance	94,035,250			$	49,004,161
Demand Charge Variance (from page 3)					91,383
Other Rate Variance (from page 4)					
Hedging (Gains)/Losses					(1,747,078)
Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments					(829,587)
Total Rate Variance				$	46,518,879
Due to Weather Variance					8,633,156
Due to Demand Variance (from above)					(16,117,798)
Total Gas Cost Variance				$	39,034,236

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
WINTER 2013-2014 COST OF GAS RESULTS
DG 13-251

	FILING	ACTUAL
Cost of Propane	$ 576,011	$ 2,371,944
Cost of LNG	1,073,448	4,177,403
Total Costs	1,649,459	6,549,347
Percentage of Supplies Used For Pressure Support Purposes	9.9%	9.9%
Cost of Supplies Used For Pressure Support Purposes	163,296	648,385
Firm Therms Sold	75,425,285	84,723,918
Firm Therms Transported	42,504,877	43,880,783
Total Therms	117,930,162	128,604,701
Actual Liquid Cost/Therm	0.0014	0.0050
Firm Therms Transported	42,504,877	43,880,783
Liquid Costs Allocated to Transported Therms	58,856	221,233
Prior (Over) or under Collection	33,351	33,351
Total	92,207	254,584
Costs Recovered:		
Therms Transported	42,504,877	43,880,783
Recovery Rate	0.0022	0.0022
Costs Recovered	92,207	95,192
(Over) / Under Collection For Period	(0)	159,393

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 1920-1740

	FOR THE MONTH OF: **DAYS IN MONTH**	**Nov-13** **30**	**Dec-13** **31**	**Jan-14** **31**	**Feb-14** **28**	**Mar-14** **31**	**Apr-14** **30**	**May-14**	**Total**
1	BEGINNING BALANCE	$ 5,501,037	$ 10,592,944	$ 15,402,350	$ 30,446,083	$ 37,981,597	$ 35,699,889	$ 22,822,981	**$ 5,501,037**
2									
3	Add: Actual Costs	6,520,818	15,425,928	31,446,508	24,782,971	15,698,828	4,647,872		**98,522,925**
4									
5	Add. FPO Admin Costs	47,935	-	-	-	-	-		**47,935**
6	Add: MISC OH	1,789	1,789	1,789	1,789	1,789	1,789		**10,735**
7	Add: Production and Storage	330,071	330,071	330,071	330,071	330,071	330,071		**1,980,428**
8	Add: Fuel Financing	-	-	-	-	-	-		-
9	Reverse Fuel Finance Estimate	-	-	-	-	-	-		-
10	Add new Fuel Finance Estimate	-	-	-	-	-	-		-
11									
12	Less: CUSTOMER BILLINGS	(1,782,227)	(10,832,370)	(16,706,893)	(17,302,180)	(18,033,274)	(17,789,355)	(7,838,752)	**(90,285,051)**
13	Estimated Unbilled	-	-	-	-	-	-		-
14	Reverse Prior Month Unbilled		-	-	-	-	-	-	-
15	Sub-Total Accrued Customer Billings	(1,782,227)	(10,832,370)	(16,706,893)	(17,302,180)	(18,033,274)	(17,789,355)	(7,838,752)	**(90,285,051)**
16									
17	Less: REFUND	(543)	-	-	-	-	-		**(543)**
18									
19	Less: Broker Revenues	(32,195)	(96,625)	(60,516)	(331,915)	(365,464)	(127,704)	-	**(1,014,419)**
20									
21	NON FIRM MARGIN AND CREDITS	(15,208)	(55,216)	(30,416)	(30,416)	(15,208)	(17,642)	-	**(164,106)**
22									
23	ENDING BALANCE PRE INTEREST	**$ 10,571,477**	**$ 15,366,522**	**$ 30,382,893**	**$ 37,896,403**	**$ 35,598,339**	**$ 22,744,921**	**$ 14,984,230**	**$ 14,598,941**
24									
25	MONTH'S AVERAGE BALANCE	8,036,257	12,979,733	22,892,621	34,171,243	36,789,968	29,222,405		
26									
27	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
28									
29	INTEREST APPLIED	21,467	35,828	63,190	85,194	101,550	78,060		**385,289**
30									
31	ENDING BALANCE	**$ 10,592,944**	**$ 15,402,350**	**$ 30,446,083**	**$ 37,981,597**	**$ 35,699,889**	**$ 22,822,981**	**$ 14,984,230**	**$ 14,984,230**

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP

NOVEMBER 2013 THROUGH APRIL 2014
OFF PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 1920-1741

	FOR THE MONTH OF:	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Total**
	DAYS IN MONTH	**30**	**31**	**31**	**28**	**31**	**30**		
1	BEGINNING BALANCE	$ (440,205)	$ (1,148,525)	$ (1,151,695)	$ (1,154,874)	$ (1,157,753)	$ (1,160,949)	$ (1,164,050)	**(440,205)**
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		**$** -
4									
5	Add: MISC OH & PROD and STOR	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(2,492,244)	-	-	-	-	-	-	**(2,492,244)**
8	Estimated Unbilled		-	-	-	-	-		-
9	Reverse Prior Month Unbilled	1,786,043	-	-	-	-	-	-	**1,786,043**
10	Sub-Total Accrued Customer Billings	(706,201)	-	-	-	-	-	-	(706,201)
11									
12	Add: ADJUSTMENTS	-	-	-	-	-	-	-	-
13									
14	ENDING BALANCE PRE INTEREST	**$ (1,146,406)**	**$ (1,148,525)**	**$ (1,151,695)**	**$ (1,154,874)**	**$ (1,157,753)**	**$ (1,160,949)**	**$ (1,164,050)**	**$ (1,146,406)**
15									
16	MONTH'S AVERAGE BALANCE	(793,306)	(1,148,525)	(1,151,695)	(1,154,874)	(1,157,753)	(1,160,949)		
17									
18	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
19									
20	INTEREST APPLIED	(2,119)	(3,170)	(3,179)	(2,879)	(3,196)	(3,101)		**(17,644)**
21									
22	ENDING BALANCE	**$ (1,148,525)**	**$ (1,151,695)**	**$ (1,154,874)**	**$ (1,157,753)**	**$ (1,160,949)**	**$ (1,164,050)**	**$ (1,164,050)**	**$ (1,164,050)**

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
MAY 2013 THROUGH OCTOBER 2013
PEAK BAD DEBT
SCHEDULE 1A
ACCOUNTS 1920-1743 and 1163-1754

	FOR THE MONTH OF: DAYS IN MONTH	May-13 31	Jun-13 30	Jul-13 31	Aug-13 31	Sep-13 30	Oct-13 31		Total
1	BEGINNING BALANCE	$ 50,789	$ 14,855	$ (35,501)	$ (37,141)	$ (36,238)	$ (27,553)		**50,789**
2									
3	Add: COST ALLOW	48,938	(1,495)	32,490	31,237	41,088	60,255		**$ 212,513**
4									
5	Adjustment	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(25,276)	(48,833)	(34,030)	(30,233)	(32,318)	(155,004)		**(325,693)**
8	Estimated Unbilled	-	-	-	-	-	-		-
9	Reverse Prior Month Unbilled	(59,687)	-	-	-	-	-		**(59,687)**
10	Sub-Total Accrued Customer Billings	(84,963)	(48,833)	(34,030)	(30,233)	(32,318)	(155,004)		(385,380)
11									
12	ENDING BALANCE PRE INTEREST	**$ 14,765**	**$ (35,473)**	**$ (37,041)**	**$ (36,137)**	**$ (27,468)**	**$ (122,302)**		**$ (122,078)**
13									
14	MONTH'S AVERAGE BALANCE	32,777	(10,309)	(36,271)	(36,639)	(31,853)	(74,928)		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17									
18	INTEREST APPLIED	90	(28)	(100)	(101)	(85)	(207)		**$ (431)**
19									
20	ENDING BALANCE	**$ 14,855**	**$ (35,501)**	**$ (37,141)**	**$ (36,238)**	**$ (27,553)**	**$ (122,509)**		**$ (122,509)**

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP

NOVEMBER 2013 THROUGH APRIL 2014
PEAK BAD DEBT
SCHEDULE 1A
ACCOUNTS 1920-1743 and 1163-1754

	FOR THE MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Total
	DAYS IN MONTH	30	31	31	28	31	30		
1	BEGINNING BALANCE	$ (122,509)	$ (74,761)	$ (112,094)	$ (68,789)	$ (86,901)	$ (190,324)	$ (392,847)	**(122,509)**
2									
3	Add: COST ALLOW	85,163	187,771	373,487	296,360	191,393	63,456		**$ 1,197,629**
4									
5	Adjustment	-	-	-	-	-	-	-	-
6									
7	Less: CUSTOMER BILLINGS	(37,152)	(224,846)	(329,932)	(314,279)	(294,433)	(265,201)	(119,010)	**(1,584,854)**
8	Estimated Unbilled	-	-	-	-	-	-		-
9	Reverse Prior Month Unbilled	-	-	-	-	-	-	-	-
10	Sub-Total Accrued Customer Billings	(37,152)	(224,846)	(329,932)	(314,279)	(294,433)	(265,201)	(119,010)	(1,584,854)
11									
12	ENDING BALANCE PRE INTEREST	**$ (74,498)**	**$ (111,836)**	**$ (68,540)**	**$ (86,707)**	**$ (189,942)**	**$ (392,069)**	**$ (511,858)**	**$ (509,734)**
13									
14	MONTH'S AVERAGE BALANCE	(98,504)	(93,299)	(90,317)	(77,748)	(138,422)	(291,197)		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17									
18	INTEREST APPLIED	(263)	(258)	(249)	(194)	(382)	(778)		**$ (2,124)**
19									
20	ENDING BALANCE	**$ (74,761)**	**$ (112,094)**	**$ (68,789)**	**$ (86,901)**	**$ (190,324)**	**$ (392,847)**	**$ (511,858)**	**$ (511,858)**

REDACTED

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
GAS COSTS BY SOURCE
SCHEDULE 2A

	FOR THE MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
1	**DEMAND**							
2								
3	ALBERTA NORTHEAST	[redacted]						
4	BP/NORTHEAST GAS MARKETS							
5	CANADIAN CAPACITY MANAGED							
6	TOTAL CANADIAN DEMAND	$ (116,505.97)	$ (137,675.29)	$ (176,167.13)	$ (237,029.94)	$ (318,040.20)	$ (28,010.93)	**$ (1,013,429.46)**
7								
8	PEAKING SUPPLY	(206,666.66)	(206,666.66)	(206,666.66)	(206,666.66)	(206,666.66)	(206,666.66)	**(1,239,999.96)**
9								
10	TRANSPORT CAPACITY	1,264,356.72	1,266,614.29	1,183,379.54	1,189,717.15	1,058,164.92	1,183,590.61	**7,145,823.23**
11	CAPACITY RELEASE ADJUSTMENT	15,208.00	55,216.00	30,416.00	30,416.00	15,208.00	17,641.73	**164,105.73**
12	TOTAL TRANSPORT	$ 1,279,564.72	$ 1,321,830.29	$ 1,213,795.54	$ 1,220,133.15	$ 1,073,372.92	$ 1,201,232.34	**$ 7,309,928.96**
13								
14	STORAGE FIXED COSTS	99,659.21	100,127.27	99,700.98	99,700.98	99,560.41	99,560.41	**598,309.26**
15								
16	LNG	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00	-	**1,500,000.00**
17								
18	PROPANE	-	-	-	-	-	-	**-**
19								
20	PIPELINE REFUNDS	-	-	-	-	-	-	**-**
21								
22	OTHER	1,800.00	1,800.00	1,800.00	1,800.00	1,800.00	1,800.00	**10,800.00**
23								
24								
25								
26	**TOTAL DEMAND**	**$ 1,357,851.30**	**$ 1,379,415.61**	**$ 1,232,462.73**	**$ 1,177,937.53**	**$ 950,026.47**	**$ 1,067,915.16**	**$ 7,165,608.80**
27								
28	**COMMODITY**							
29								
30	ALBERTA NORTHEAST / BP	[redacted]						
31	ALBERTA NORTHEAST / Emera							
32	SHELL CANADA							
33	TOTAL CANADIAN COMMODITY							
34								
35	PIPELINE TRANSPORT	[redacted]						
36	DRACUT SUPPLY							
37	PNGTS							
38								
39	GAS SUPPLY	[redacted]						
40								
41	STORAGE	[redacted]						
42								
43	LNG	[redacted]						
44								
45	PROPANE	[redacted]						
46								
47	**OTHER COST ADJUSTMENTS**							
48	CANDIAN CAPACITY MANAGED	[redacted]						
49	SUPPLIER CASHOUT							
50	NET OTHER COST ADJUSTMENTS							
51								
52	**SUBTOTAL COMMODITY COST**	**$ 5,162,966.69**	**$ 14,046,512.49**	**$ 30,214,045.22**	**$ 23,605,033.92**	**$ 14,748,801.65**	**$ 3,579,956.62**	**$ 91,357,316.59**
53								
54	OFF SYSTEM SALES COST	[redacted]						
55	OFF SYSTEM SALES COST - PPA							
56	NON-FIRM COST							
57								
58	**TOTAL COMMODITY COST**	**$ 5,162,966.69**	**$ 14,046,512.49**	**$ 30,214,045.22**	**$ 23,605,033.92**	**$ 14,748,801.65**	**$ 3,579,956.62**	**$ 91,357,316.59**

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP

NOVEMBER 2013 THROUGH APRIL 2014
GAS COSTS SUMMARY
SCHEDULE 2A

	FOR THE MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
67								
68	**Total Peak Demand**	**$ 1,357,851.30**	**$ 1,379,415.61**	**$ 1,232,462.73**	**$ 1,177,937.53**	**$ 950,026.47**	**$ 1,067,915.16**	**$ 7,165,608.80**
69	**Off-Peak Demand**	-	-	-	-	-	-	-
70	**Total Demand**	**$ 1,357,851.30**	**$ 1,379,415.61**	**$ 1,232,462.73**	**$ 1,177,937.53**	**$ 950,026.47**	**$ 1,067,915.16**	**$ 7,165,608.80**
71								
72	**Total Peak Commodity**	**$ 5,162,966.69**	**$ 14,046,512.49**	**$ 30,214,045.22**	**$ 23,605,033.92**	**$ 14,748,801.65**	**$ 3,579,956.62**	**$ 91,357,316.59**
73	**Off-Peak Commodity**	-	-	-	-	-	-	-
74	**Total Commodity**	**$ 5,162,966.69**	**$ 14,046,512.49**	**$ 30,214,045.22**	**$ 23,605,033.92**	**$ 14,748,801.65**	**$ 3,579,956.62**	**$ 91,357,316.59**
75								
76	**Firm Sendout Costs**	**$ 6,520,817.99**	**$ 15,425,928.10**	**$ 31,446,507.95**	**$ 24,782,971.45**	**$ 15,698,828.12**	**$ 4,647,871.78**	**$ 98,522,925.39**

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

	FOR THE MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
1	**DEMAND**							
2	**Supply**							
3	Alberta Northeast	[redacted]						
4	Northeast Gas Markets/BP							
5	**Subtotal Canadian Supply**	$ 1,653.78	$ 1,814.24	$ 1,962.36	$ 1,640.37	$ 1,667.81	$ 1,618.48	$ 10,357.04
6	**Peaking Suppy**							
7	Repsol	[redacted]						
8	Granite Ridge							
9	BG Energy							
10	NJR Energy							
11	**Subtotal Peaking Supply**	$ (206,666.66)	$ (206,666.66)	$ (206,666.66)	$ (206,666.66)	$ (206,666.66)	$ (206,666.66)	$ (1,239,999.96)
12								
13	**Transport Capacity**							
14	Iroquois 470-01-RTS	$ 20,934.57	$ 26,698.46	$ 26,698.46	$ 26,698.46	$ 26,698.46	$ 26,698.46	$ 154,426.87
15	National Fuel N02358	19,095.31	19,065.06	18,978.10	18,978.10	18,947.86	19,499.81	114,564.24
16	PNGTS FT-1999-001	40,245.60	15,445.60	40,245.60	40,245.60	40,245.60	40,245.60	216,673.60
17	Transcanada	-	-	-	-	-	-	-
18	TGP 632 FTA	126,898.72	131,899.06	125,296.59	132,865.53	139,029.01	123,521.07	779,509.98
19	TGP 2302 FTA Zone 5-6	24,986.15	25,257.16	25,105.43	24,354.89	25,054.85	24,618.90	149,377.38
20	TGP 8587 FTA	493,322.45	524,113.53	421,966.00	424,405.54	267,618.97	436,852.66	2,568,279.15
21	TGP 11234 FTA	84,470.45	80,889.19	81,824.54	79,861.92	83,071.41	65,951.93	476,069.44
22	TGP 33371 NET	40,093.33	40,429.65	40,429.65	39,292.33	40,399.30	31,536.45	232,180.71
23	TGP 72694 NET	316,914.14	320,628.58	320,647.17	320,826.78	319,703.46	334,911.46	1,933,631.59
24	TGP 42076 FTA	97,396.00	82,188.00	82,188.00	82,188.00	97,396.00	79,754.27	521,110.27
25	Union Gas	-	-	-	-	-	-	-
26	**Subtotal Transport Capacity**	$ 1,264,356.72	$ 1,266,614.29	$ 1,183,379.54	$ 1,189,717.15	$ 1,058,164.92	$ 1,183,590.61	$ 7,145,823.23
27								
28	**Storage Fixed**							
29	Sempra	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Dominion 300076-Storage	2,058.02	2,664.75	2,650.91	2,650.91	2,647.47	2,647.47	15,319.53
31	NFG Deliverability FSS 2357	33,713.48	33,660.13	33,506.70	33,506.70	33,453.35	33,453.35	201,293.71
32	Tenn Reservation FSMA 523	55,143.32	55,058.00	54,798.98	54,798.98	54,715.20	54,715.20	329,229.68
33	Honeoye Storage SS-NY	8,744.39	8,744.39	8,744.39	8,744.39	8,744.39	8,744.39	52,466.34
34	**Subtotal Storage**	$ 99,659.21	$ 100,127.27	$ 99,700.98	$ 99,700.98	$ 99,560.41	$ 99,560.41	$ 598,309.26
35								
36	**LNG / DISTRIGAS**	[redacted]						
37	**LNG/ DISTRIGAS FLS160**							
38	**Transgas Trucking**							
39	**Subtotal Distrigas**	$ 300,000.00	$ 300,000.00	$ 300,000.00	$ 300,000.00	$ 300,000.00	$ -	$ 1,500,000.00
40								
41	**Propane**							
42	**En Propane**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43								
44	**Intercontinental Exchange**	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	10,800.00
45								
46	**Capacity Managed - Canadian**	[redacted]						
47								
48	**PNGTS Refund per RP02-13**	[redacted]						
49	**TGP Pipeline Refund** PK	$ -	$ -	$ -	$ -	$ -	$ -	-
50	**TGP Pipeline Refund** OP	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Demand Subtotal**	$ 1,342,643.30	$ 1,324,199.61	$ 1,202,046.73	$ 1,147,521.53	$ 934,818.47	$ 1,050,273.43	$ 7,001,503.07
52								
53	**Capacity Release Adjustment**							
54	PNGTS FT-1999-001	[redacted]						
55	TGP 72694 NET-NE							
56	TGP 42076 FTA							
57	Iriquois Gas Transmission System 470-							
58	TGP FT-A 11234							
59	**Total Capacity Release Adjustment**							
60								
61	**TOTAL DEMAND**	$ 1,357,851.30	$ 1,379,415.61	$ 1,232,462.73	$ 1,177,937.53	$ 950,026.47	$ 1,067,915.16	$ 7,165,608.80

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP **REDACTED**
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

62	**FOR THE MONTH OF:**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Total**
63								
64	**COMMODITY**							
65								
66	**Canadian Supply**							
67	VPEM	[redacted]						
68	ANE Union/Dawn/Iroquois (BG)							
69	Shell Canada							
70	**Subtotal Canadian Commodity**							
71								
72	**Pipeline Transport**							
73	ANE Union/Dawn	[redacted]						
74								
75	Dominion							
76	El Paso							
77	Iroquois							
78	National Fuel							
79	PNGTS							
80	**Subtotal TGP Transportation**							
81	**Total Transportation**							
82								
83	**City Gate Delivery**							
84	VPEM	[redacted]						
85								
86	**Dracut Supply (citygate)**							
87								
88	**PNGTS Supply**							
89	Emera							
90	Shell							
91								
92	**Subtotal PNGTS**							
93								
94	**Gas Supply**							
95	Andarko	[redacted]						
96	J Aron							
97	BG Energy							
98	Barclay							
99	BP Energy							
100	Chevron							
101	Cheniere							
102	Conoco							
103	EServices							
104	StatOil							
105	EnCan							
106	Emera							
107	Gulf							
108	Hess							
109	L. Dreyfus							
110	Macquarie							
111	Merrill							
112	NJR Energy							
113	Repsol							
114	South Jersey							
115	Shell US							
116	Spark							
117	Tenaska							
118	Vitol							
119	VPEM							
120	United							
121	**Total Other TGP Supply**							
122								
123	**Peaking Supply**							
124	Granite Ridge (formerly AES)	[redacted]						
125								
126	NYMEX Hedging (Gains) Losses							
127								
128	**STORAGE WITHDRAWALS**							
129								
130	**STORAGE INJECTIONS**							
131								
132	DISTRIGAS (FLS187)							
133	LNG VAPOR							
134	LNG BOIL OFF							
135	**Subtotal LNG**							
136	**PROPANE**							
137	Country Gas							
138	Propane Storage Withdrawal							
139	Energy North Propane							
140	**Subtotal Propane**							
141								
142	Broker Cashout							
143	Other Taxes W. Virginia/ICE							
144	**Subtotal Cashouts**							
145								
146	Capacity Managed - Canadian							
147	Broker Inventory							
148	**Subtotal Capacity Managed**							
149								
150	**TOTAL COMMODITY**							
151								
152	Off System Gas Sales Cost							
153	Off System Sales Costs - PPA							
154	NON-FIRM COST							
155								
156	**NET COMMODITY COST**	**$ 5,162,966.69**	**$ 14,046,512.49**	**$ 30,214,045.22**	**$ 23,605,033.92**	**$ 14,748,801.65**	**$ 3,579,956.62**	**$ 91,357,316.59**

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

			Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
157	**FOR THE MONTH OF:**		**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**Total**
158									
159	Peak Demand 1920-1740		$ 1,357,851.30	$ 1,379,415.61	$ 1,232,462.73	$ 1,177,937.53	$ 950,026.47	$ 1,067,915.16	$ 7,165,608.80
160	Peak Commodity 1920-1740		5,162,966.69	14,046,512.49	30,214,045.22	23,605,033.92	14,748,801.65	3,579,956.62	91,357,316.59
161	Total Peak Gas Costs		**$ 6,520,817.99**	**$ 15,425,928.10**	**$ 31,446,507.95**	**$ 24,782,971.45**	**$ 15,698,828.12**	**$ 4,647,871.78**	**$ 98,522,925.39**
162									
163	Off-Peak Demand 1920-1741	OP	-	-	-	-	-	-	-
164	Off-Peak Comm 1920-1741	OP	-	-	-	-	-	-	-
165	Total Off-Peak Gas Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
166									
167	Firm Sendout Costs		**$ 6,520,817.99**	**$ 15,425,928.10**	**$ 31,446,507.95**	**$ 24,782,971.45**	**$ 15,698,828.12**	**$ 4,647,871.78**	**$ 98,522,925.39**

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
SCHEDULE 3
WINTER CGAC GAS REVENUES BILLED

	FOR MONTH OF:	prior collections	prior collections	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	ubsequent collection	Total
		OffPeak	Peak	Peak	Peak	Peak	Peak	Peak	Peak	Peak
1	**VOLUMES BILLED**									
2	**RESIDENTIAL**									
3	R-1	-	68,903	109,936	142,489	139,871	128,583	124,305	-	**714,087**
4	R-1 FPO	-	1,487	9,965	13,012	12,846	11,845	11,238	-	**60,393**
5	R-3	-	3,444,904	6,675,714	9,197,608	8,734,802	8,030,937	6,770,194	-	**42,854,159**
6	R-3 FPO	-	167,776	934,129	1,283,231	1,245,401	1,109,993	982,832	-	**5,723,362**
7	R-4	-	26,665	272,890	441,703	572,480	632,815	680,476	-	**2,627,029**
8	R-4 FPO	-	3,174	52,182	83,103	99,638	100,222	99,577	-	**437,896**
9	Total Residential	-	3,712,909	8,054,816	11,161,146	10,805,038	10,014,395	8,668,622	-	
10	**COMMERCIAL/INDUSTRIAL**									
11	G41 - G43	-	1,678,054	3,888,569	5,952,172	5,496,316	5,373,904	4,787,553	-	**27,176,568**
12	G41 - G43 (FPO)	-	23,949	183,100	270,425	279,342	250,071	232,816	-	**1,239,703**
13	Total G41- G43	-	1,702,003	4,071,669	6,222,597	5,775,658	5,623,975	5,020,369	-	
14	G51 - G63	-	368,790	569,460	673,920	688,521	612,339	845,274	-	**3,758,304**
15	G51 - G63 (FPO)	-	5,405	21,891	29,840	27,341	21,227	26,713	-	**132,417**
16	Total G51-G63	-	374,195	591,351	703,760	715,862	633,566	871,987	-	
17	Total Sales Volumes	-	5,789,107	12,717,836	18,087,503	17,296,558	16,271,936	14,560,978	-	**84,723,918**
18	**TRANSPORTATION**									
19	G41 - G43	-	2,116,369	4,064,127	5,305,709	5,271,149	4,837,495	4,146,128	-	**25,740,977**
20	G51 - G63	-	2,865,928	3,022,735	3,170,084	3,118,697	2,873,054	3,089,308	-	**18,139,806**
21	Total Transportation Volumes	0	4,982,297	7,086,862	8,475,793	8,389,846	7,710,549	7,235,436	0	**43,880,783**
22	**Total Volumes**	**0**	**10,771,404**	**19,804,698**	**26,563,296**	**25,686,404**	**23,982,485**	**21,796,414**	**0**	**128,604,701**
23										
34	**REVENUES**									
43	**Winter Gas Cost Rev filed**	**$ 94,421**	**$ 1,782,227**	**$ 10,832,370**	**$ 16,706,893**	**$ 17,302,180**	**$ 18,033,274**	**$ 17,789,355**	**$ 7,838,752**	**$ 90,379,472**
51										
52	Winter Gas Costs Billed (Acct 1920-1740)	**$ 94,421**	**$ 1,782,227**	**$ 10,832,370**	**$ 16,706,893**	**$ 17,302,180**	**$ 18,033,274**	**$ 17,789,355**	**$ 7,838,752**	**$ 90,379,472**
55										
56										
57	Total Sales COG Billed	**$ 94,421**	**$ 1,782,227**	**$ 10,832,370**	**$ 16,706,893**	**$ 17,302,180**	**$ 18,033,274**	**$ 17,789,355**	**$ 7,838,752**	**$ 90,379,472**
58										
59	Plus: Working Capital Gas Cost Billed	-	2,398	14,742	21,612	20,582	19,263	17,361	7,586	**103,544**
60	Plus: Bad Debt Cost Billed	-	37,152	224,846	329,932	314,279	294,433	265,201	119,010	**1,584,854**
61	Plus: Broker Revenues	-	32,195	96,625	60,516	331,915	365,464	127,704	-	**1,014,419**
62										
63	**Total Winter Gas Costs Billed**	**$ 94,421**	**$ 1,853,971**	**$ 11,168,584**	**$ 17,118,953**	**$ 17,968,957**	**$ 18,712,434**	**$ 18,199,621**	**$ 7,965,348**	**$ 93,082,290**

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
SCHEDULE 3A- CALCULATION OF UNBILLED GAS COSTS (ACCRUED COG)

	FOR MONTH OF:	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
1	Firm Gas Purchases		11,566,590	17,854,690	21,609,750	18,179,170	17,099,890	7,725,160	94,035,250
2	Firm Sales		5,789,107	12,717,836	18,087,503	17,296,558	16,271,936	14,560,978	84,723,918
3	Company Use		15,652	137,105	62,404	59,119	53,284	137,892	465,457
4	Unaccounted For %		1.16%	1.16%	1.16%	1.16%	1.16%	1.16%	
5	Unaccounted For Gas		134,172	207,114	250,673	210,878	198,359	89,612	1,090,809
6	COG Factor- Gas Cost Only		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
7	COG Factor- Bad Debt Factor		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
8	COG Factor- Working Capital Factor		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
9									
10	Unbilled Volume								
11	Beginning Bal		-	5,627,659	10,420,293	13,629,463	14,242,078	14,818,389	
12	Incremental Unbilled		5,627,659	4,792,635	3,209,170	612,615	576,311	(7,063,322)	
13	Ending Balance	-	5,627,659	10,420,293	13,629,463	14,242,078	14,818,389	7,755,067	
14									
15	COG Factor- Gas Cost Only		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
16	Gross Unbilled Gas Cost	$1,786,043	$0	$0	$0	$0	$0	$0	
17									
18	Monthly Incremental Gas Cost		($1,786,043)	$0	$0	$0	$0	$0	
19									
20	COG Factor- Bad Debt Only		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
21	Gross Unbilled Bad Debt Cost	$24,921	$0	$0	$0	$0	$0	$0	
22									
23	Monthly Incremental Bad Debt Cost		($24,921)	$0	$0	$0	$0	$0	
24									
25	COG Factor- Working Capital Only		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
26	Gross Unbilled Working Capital Cost	$1,478	$0	$0	$0	$0	$0	$0	
27									
28	Monthly Incremental Working Capital Cost		($1,478)	$0	$0	$0	$0	$0	

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
SCHEDULE 4 - NONFIRM MARGIN

	FOR THE MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
1	INTERRUPTIBLE	[redacted]						
2								
3	280 DAY	[redacted]						
4								
5	OFF SYSTEM GAS SALES MARGIN	[redacted]						
6	PROPANE OFF SYSTEM SALES MARGIN							
7								
8	CAPACITY RELEASE CREDIT	[redacted]						
9								
10	TOTAL NON FIRM MARGIN AND CREDITS	**$ (15,208)**	**$ (55,216)**	**$ (30,416)**	**$ (30,416)**	**$ (15,208)**	**$ (17,642)**	**$ (164,106)**

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
PEAK PERIOD WORKING CAPITAL
ACCOUNT 1163-1422
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	Nov-13 30	Dec-13 31	Jan-14 31	Feb-14 28	Mar-14 31	Apr-14 30	May-14	Total
1	BEGINNING BALANCE	$ 12,346	$ 18,257	$ 23,106	$ 41,509	$ 52,502	$ 53,317	$ 41,967	**$ 12,346**
2									
3	Add: COST ALLOW	8,268	19,534	39,926	31,458	19,932	5,884		**125,003**
4									
5	Less: CUSTOMER BILLINGS	(2,398)	(14,742)	(21,612)	(20,582)	(19,263)	(17,361)	(7,586)	**(103,544)**
6	Estimated Unbilled	-	-	-	-	-	-		-
7	Reverse Prior Month Unbilled	-	-	-	-	-	-	-	-
8	Subtotal: Accrued Customer Billings	(2,398)	(14,742)	(21,612)	(20,582)	(19,263)	(17,361)	(7,586)	**(103,544)**
9									
10	Adjustment	-	-	-	-	-	-	-	-
11									
12	ENDING BALANCE PRE INTEREST	**18,216**	**23,049**	**41,420**	**52,385**	**53,171**	**41,840**	**34,382**	**33,805**
13									
14	MONTH'S AVERAGE BALANCE	15,281	20,653	32,263	46,947	52,837	47,579		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17	INTEREST APPLIED	41	57	89	117	146	127		**577**
18	ENDING BALANCE	**$ 18,257**	**$ 23,106**	**$ 41,509**	**$ 52,502**	**$ 53,317**	**$ 41,967**	**$ 34,382**	**$ 34,382**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2013 THROUGH APRIL 2014
OFF PEAK WORKING CAPITAL
ACCOUNT 1163-1424
SCHEDULE 5

	FOR THE MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Total
	DAYS IN MONTH	30	31	31	28	31	30		
1	BEGINNING BALANCE	$ 45	$ (555)	$ (557)	$ (559)	$ (560)	$ (562)	$ (564)	45
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		$ -
4									0
5	Less: CUSTOMER BILLINGS	(2,640)	-	-	-	-	-	-	(2,640)
6	Estimated Unbilled	-	-	-	-	-	-		-
7	Reverse Prior Month Unbilled	2,041	-	-	-	-	-	-	2,041
8	Subtotal: Accrued Customer Billings	(599)	-	-	-	-	-	-	(599)
9									
10	ENDING BALANCE PRE INTEREST	(554)	(555)	(557)	(559)	(560)	(562)	(564)	(554)
11									
12	MONTH'S AVERAGE BALANCE	(255)	(555)	(557)	(559)	(560)	(562)		
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
15	INTEREST APPLIED	(1)	(2)	(2)	(1)	(2)	(2)		(10)
16	ENDING BALANCE	$ (555)	$ (557)	$ (559)	$ (560)	$ (562)	$ (564)	$ (564)	$ (564)

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
1	Demand	$ 1,342,643	$ 1,324,200	$ 1,202,047	$ 1,147,522	$ 934,818	$ 1,050,273	$ 7,001,503
2	Commodity	5,162,967	14,046,512	30,214,045	23,605,034	14,748,802	3,579,957	91,357,317
3	Total Gas Costs	$ 6,505,610	$ 15,370,712	$ 31,416,092	$ 24,752,555	$ 15,683,620	$ 4,630,230	$ 98,358,820
4								
5	Lead Lag Days	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	
6	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7								
8	Working Capital Rate 1/	0.00127	0.00127	0.00127	0.00127	0.00127	0.00127	
9								
10	Total Working Capital Costs	$ 8,268	$ 19,534	$ 39,926	$ 31,458	$ 19,932	$ 5,884	$ 125,003
11								
12	Prior Period Undercollection	853,299	853,299	853,299	853,299	853,299	853,299	5,119,793
13								
14	Subtotal Gas Costs, Working Capital & Under Collection	7,367,177	16,243,545	32,309,317	25,637,312	16,556,851	5,489,413	103,603,615
15								
16	Bad Debt Rate 1/	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	
17								
18	Total Bad Debt Cost	$ 85,163	$ 187,771	$ 373,487	$ 296,360	$ 191,393	$ 63,456	$ 1,197,629

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total
1	Demand	$ 1,026,824	$ (132,814)	$ 914,092	$ 889,206	$ 1,181,310	$ 1,285,245	$ 5,163,863
2	Commodity	1,432,978	48,732	716,061	677,716	882,526	1,745,372	5,503,385
3	Total Gas Costs	$ 2,459,802	$ (84,082)	$ 1,630,153	$ 1,566,922	$ 2,063,836	$ 3,030,617	$ 10,667,248
4								
5	Lead Lag Days	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	
6	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7								
8	Working Capital Rate 1/	0.00127	0.00127	0.00127	0.00127	0.00127	0.00127	
9								
10	Total Working Capital Costs	$ 3,126	$ (107)	$ 2,072	$ 1,991	$ 2,623	$ 3,852	$ 13,557
11								
12	Prior Period Undercollection	8,694	8,694	8,694	8,694	8,694	8,694	52,165
13								
14	Subtotal Gas Costs, Working Capital & Under Collection	2,471,622	(75,495)	1,640,919	1,577,608	2,075,153	3,043,163	10,732,970
15								
16	Bad Debt Rate 1/	0.0198	0.0198	0.0198	0.0198	0.0198	0.0198	
17								
18	Total Bad Debt Cost	$ 48,938	$ (1,495)	$ 32,490	$ 31,237	$ 41,088	$ 60,255	$ 212,513

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	
1	Monthly Revenue	$ 7,975,784	$ 4,902,619	$ 3,921,830	$ 3,810,815	$ 3,893,794	$ 4,686,169	
2	Charge Off	137,803	201,344	425,767	637,217	3,467	395	

	FOR MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Total
3	Monthly Revenue	$ 7,058,250	$ 14,038,800	$ 17,885,973	$ 19,875,904	$ 18,997,363	$ 15,278,233	122,325,536
4	Charge Off	-	-	4,172	-	2,509	1,375	1,414,050
5								
6								
7	Bad Debt Rate							0.0116

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
SCHEDULE 7
WORKING CAPITAL & BAD DEBT COLLECTED

	FOR MONTH OF:	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Total
17									
18	**WORKING CAPITAL RATES**	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
25									
34	**WORKING CAPITAL COLLECTED**	**$ 2,397.94**	**$ 14,742.30**	**$ 21,611.99**	**$ 20,581.70**	**$ 19,262.92**	**$ 17,361.29**	**$ 7,585.75**	**$ 103,543.89**
35									
36	**BAD DEBT RATES**	$ 0.0183	$ 0.0183	$ 0.0183	$ 0.0183	$ 0.0183	$ 0.0183	$ 0.0183	
43									
52	**BAD DEBTS COLLECTED**	**$ 37,151.63**	**$ 224,845.97**	**$ 329,932.33**	**$ 314,279.00**	**$ 294,433.43**	**$ 265,201.35**	**$ 119,010.39**	**$ 1,584,854.10**

LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
COMMODITY AND RELATED VOLUMES
SCHEDULE 8

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	FOR THE MONTH OF:	Nov-13		Dec-13		Jan-14		Feb-14		Mar-14		Apr-14		Total	
		Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	**Dollar**	**Volume Dkt**
	TENNESEE COMMODITY														
1	Gas Supply	[redacted]													
2	Off System Sales Gas Costs														
3	Pipeline Transport														
4	Storage Injections														
5	TOTAL TENNESSEE														
6															
7															
8															
9	City Gate Supply	[redacted]													
10															
11	Dracut Supply	[redacted]													
12															
13															
14	<u>**CANADIAN COMMODITY**</u>														
15	PNGTS Supply	[redacted]													
16	TOTAL PNGTS														
17															
18	BP	[redacted]													
19	SJR														
20	Hess														
21	TOTAL TGP/Niagara														
22															
23	ANE Dawn-Iroquois	[redacted]													
24	ANE Union/Transgas Transporation														
25	TOTAL TGP/Iroquois Commodity														
26															
27															
28	**LNG**														
29	Distrigas (FCS 064)	[redacted]													
30															
31	LNG Vapor - P/S Plant	[redacted]													
32	LNG Injections														
33	Subtotal LNG														
34															
35															
36	**Propane**														
37	Off System Sales	[redacted]													
38	Propane Sendout - P/S Plant														
39	EN Propane - Tank Farm														
40	Total Propane														
41															
42															
43	Storage Withdrawals	[redacted]													
44															
45															
46	Hedging (Gains) Loses	[redacted]													
47															
48	Supplier Cashouts	[redacted]													
49															
50	Capacity Managed - Canadian	[redacted]													
51															
52	Taxes	[redacted]													
53															
54	Non-Firm Costs	[redacted]													
55															
56															
57	**NET COMMODITY COST**	**$ 5,162,967**	**1,156,659**	**$ 14,046,512**	**1,785,469**	**$ 30,214,045**	**2,160,975**	**$ 23,605,034**	**1,817,917**	**$ 14,748,802**	**1,709,989**	**$ 3,579,957**	**772,516**	**$ 91,357,317**	**9,403,525**

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LIBERTY UTILITIES (ENERGY NORTH NATURAL GAS) CORP
D/B/A LIBERTY UTILITIES
NOVEMBER 2013 THROUGH APRIL 2014
MONTHLY PRIME RATES
SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
Nov-13	11/01 - 11/30	**3.25%**	30	3.2500%
Dec-13	12/01 - 012/31	**3.25%**	31	3.2500%
Jan-14	01/01 - 01/31	**3.25%**	31	3.2500%
Feb-14	02/01 - 02/28	**3.25%**	28	3.2500%
Mar-14	03/01 - 03/31	**3.25%**	31	3.2500%
Apr-14	04/01 - 04/30	**3.25%**	30	3.2500%

Schedule 19

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Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

Rate Case Expense Factors for Residential Customers

Rate Case Expense (Balance 05/31/14)	$	(123,489)
Temporary Rate Reconciliation - DG 10-017		-
Stipulation per Settlement Argument - DG 10-017		-
Reconciliation DG 08-009 and Merger Incentive DG 06-707		-
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	(123,489)
Off-peak 2014 Rate Case Expense Factor	$	-
Off-peak 2014 Projected Volumes (Aug-Oct)		-
Off-peak 2013 Rate Case Expense Projected Collection (Aug-Oct)		-
Off-peak 2013 Rate Case Expense Projected Interest (Aug-Oct)		-
Total Net Rate Case Expense/Temporary Rate Reconciliation Recoverable		(123,489)
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		-
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		-
		-
Total Volumes		
Rate Case Expense Factor	$	-

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**	**Customer Charge**	**First Block**	**Last Block**	**Total**	
2	R-3 Base Rates	$ 17.5100	$ 0.2769	$ 0.2288		
3	R-4 Rate at 40% of R-3	$ 7.0000	$ 0.1108	$ 0.0915		
4	Program Subsidy	$ 10.5100	$ 0.1661	$ 0.1373		
5	Average Annual Therms		572	203	775	
6						
7	Peak Period RLIAP Subsidy	$ 63.06	$ 95.04	$ 27.85	$ 185.96	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 17.5100	$ 0.2769	$ 0.2288		
11	R-4 Rate at 40% of R-3	$ 7.0000	$ 0.1108	$ 0.0915		
12	Program Subsidy	$ 10.5100	$ 0.1661	$ 0.1373		
13	Average Annual Therms		118	52	170	
14						
15	Off Peak Period RLIAP Subsidy	$ 63.06	$ 19.63	$ 7.15	$ 89.84	
16						
17	Estimated Annual Subsidy	$ 126.12	$ 114.68	$ 35.01	$ 275.80	
18						
19	Number of Estimated 2013/14 Participants				5,261	1/
20						
21	Annual Subsidy times Number of Participants (Ln 17 * Ln 19)				$ 1,450,987	
22	Prior Year Ending Balance - RLIAP Page 2				(275,120)	
23	Estimated Annual Administrative Costs				-	
24	Total Program Costs				$ 1,175,867	
25						
26	Estimated weather normalized firm therms billed for the					
27	twelve months ended 10/31/15 sales and transportation				166,523,068	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0071**	

1/ Estimated number of participants for 2014-15 is based on the actual number participants as of June 2014, as provided in the RLIAP Quarterly Report as revised and filed on August 4, 2014.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2013 THROUGH OCTOBER 2014
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (323,989)	$ (394,567)	$ (450,439)	$ (520,401)	$ (556,903)	$ (548,389)	$ (514,936)	$ (444,636)	$ (402,289)	$ (369,379)	$ (333,980)	$ (300,204)	$ (323,989)
4														
5	Add: Actual Costs	10,270	92,113	130,320	161,602	188,760	198,094	164,814	81,159	74,784	73,146	73,355	81,583	1,330,000
6														
7	Less: Collected Revenue	(79,889)	(146,821)	(198,944)	(196,714)	(178,723)	(163,223)	(93,191)	(37,683)	(40,811)	(36,779)	(38,733)	(55,706)	(1,267,215)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ (393,608)	$ (449,275)	$ (519,063)	$ (555,514)	$ (546,866)	$ (513,518)	$ (443,313)	$ (401,159)	$ (368,315)	$ (333,011)	$ (299,358)	$ (274,327)	**$ (261,204)**
12														
13	Month's Average Balance	$ (358,798)	$ (421,921)	$ (484,751)	$ (537,958)	$ (551,885)	$ (530,953)	$ (479,125)	$ (422,897)	$ (385,302)	$ (351,195)	$ (316,669)	$ (287,266)	
14														
15	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16														
17	Interest Applied	$ (958)	$ (1,165)	$ (1,338)	$ (1,389)	$ (1,523)	$ (1,418)	$ (1,323)	$ (1,130)	$ (1,064)	$ (969)	$ (846)	$ (793)	**(13,916)**
18														
19	Ending Balance	**$ (394,567)**	**$ (450,439)**	**$ (520,401)**	**$ (556,903)**	**$ (548,389)**	**$ (514,936)**	**$ (444,636)**	**$ (402,289)**	**$ (369,379)**	**$ (333,980)**	**$ (300,204)**	**$ (275,120)**	**$ (275,120)**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential Non-Heating and Heating Classes
November 1, 2014 - October 31, 2015
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Actual DSM Expenditures Low-Income	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Monthly Federal Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Residential Therm Sales	Residential Therm Sales	# of Days
May 14	Actual	146,281	($0.0197)	(83,103)	97,125	396,516	26,108	12,063	497,865	322,073	3.25%	889	498,754	3,349,634	4,218,439	31
June 14	Actual	498,754	($0.0197)	(38,207)	97,125	120,074	10,012	12,064	602,696	550,725	3.25%	1,471	604,167	1,984,898	1,942,868	30
July 14	Forecast	604,167	($0.0197)	(24,677)	224,848	0	0		804,338	704,252	3.25%	1,944	806,282	1,252,661	0	31
August 14	Forecast	806,282	($0.0197)	(20,816)	350,189	0	0		1,135,654	970,968	3.25%	2,680	1,138,334	1,056,675	0	31
September 14	Forecast	1,138,334	($0.0197)	(22,519)	224,848	0	0		1,340,662	1,239,498	3.25%	3,311	1,343,973	1,143,113	0	30
October 14	Forecast	1,343,973	($0.0197)	(33,363)	224,848	0	0		1,535,458	1,439,716	3.25%	3,974	1,539,432	1,693,533	0	31
November 14	Forecast	1,539,432	($0.0646)	(280,344)	224,848	0	0		1,483,936	1,511,684	3.25%	4,038	1,487,974	4,339,688	0	30
December 14	Forecast	1,487,974	($0.0646)	(485,257)	224,848	0	0		1,227,565	1,357,770	3.25%	3,748	1,231,313	7,511,721	0	31
January 15	Forecast	1,231,313	($0.0646)	(687,269)	201,226	0	0		745,269	988,291	3.25%	2,728	747,997	10,638,842	0	31
February 15	Forecast	747,997	($0.0646)	(643,585)	201,226	0	0		305,638	526,818	3.25%	1,313	306,951	9,962,619	0	28
March 15	Forecast	306,951	($0.0646)	(570,114)	201,226	0	0		(61,936)	122,507	3.25%	338	(61,598)	8,825,287	0	31
April 15	Forecast	(61,598)	($0.0646)	(467,005)	201,226	0	0		(327,377)	(194,488)	3.25%	(520)	(327,897)	7,229,176	0	30
May 15	Forecast	(327,897)	($0.0646)	(262,547)	201,226	0	0		(389,218)	(358,557)	3.25%	(990)	(390,207)	4,064,194	0	31
June 15	Forecast	(390,207)	($0.0646)	(146,586)	201,226	0	0		(335,568)	(362,888)	3.25%	(969)	(336,537)	2,269,136	0	30
July 15	Forecast	(336,537)	($0.0646)	(94,966)	201,226	0	0		(230,277)	(283,407)	3.25%	(782)	(231,059)	1,470,059	0	31
August 15	Forecast	(231,059)	($0.0646)	(89,349)	201,226	0	0		(119,182)	(175,121)	3.25%	(483)	(119,666)	1,383,106	0	31
September 15	Forecast	(119,666)	($0.0646)	(99,498)	201,226	0	0		(17,938)	(68,802)	3.25%	(184)	(18,122)	1,540,216	0	30
October 15	Forecast	(18,122)	($0.0646)	(184,130)	201,226	0	0		(1,025)	(9,573)	3.25%	(26)	(1,052)	2,850,302	0	31
November 15	Forecast	(1,052)	($0.0646)	(280,344)	201,226	0	0		(80,170)	(40,611)	3.25%	(108)	(80,278)	4,339,688	0	30
December 15	Forecast	(80,278)	($0.0646)	(485,257)	201,226	0	0		(364,310)	(222,294)	3.25%	(614)	(364,923)	7,511,721	0	31

unearned incentives for 2013-2015 were budgeted at 70% of target

Estimated Residential Conservation Charge Effective November 1, 2014 - October 31, 2015		
Beginning Balance	$	1,539,432
Program Budget Nov 14-Oct 15		**2,461,954**
Projected Interest		8,211
Projected Budget with Interest	$	4,009,597
Total Charges	**$**	**4,009,597**
Projected Therm Sales		**62,084,346**
Residential Rate		**$0.0646**
Total Charges with Interest	**$**	**4,010,649**
Projected Therm Sales		**62,084,346**
Residential Rate		**$0.0646**

Residential Non Heating Therm Sales	1%	**957,206**	**829,589**	0%
Residential Heating Therm Sales	37%	**58,518,868**	**61,254,757**	37%
C&I Therm Sales	63%	**100,542,745**	**104,438,722**	63%
Total Therms	100%	**160,018,819**	**166,523,068**	100%
		Budget **2014**	Budget **2015**	
Low-Income Program Budget		**$ 923,250**	**$ 921,250**	
Other Refund		-	-	
Total Shared Budget		**$ 923,250**	**$ 921,250**	
Residential Program Budget		**$ 1,821,000**	**$ 1,912,550**	
Residential Program Incentive @ 70%		**$219,540**	**$158,693**	
Total Residential Program Budget		**$ 2,040,540**	**$ 2,071,243**	
Commercial/Industrial Program Budget		**$ 2,425,501**	**$ 2,493,010**	
Commercial/Industrial Program Incentive at 70%		**$194,040**	**$139,609**	
Total Commercial/Industrial Program Budget		**$ 2,619,541**	**$ 2,632,619**	
Total Program Budget		**$ 5,583,331**	**$ 5,625,112**	
Shared Expenses Allocation to Residential		$ 343,155	$ 343,467	
Shared Expenses Allocation to C&I		580,095	577,783	
Total Allocated Shared Expenses		**$ 923,250**	**$ 921,250**	
Total Residential (including allocation of Shared Budget)		$ 2,383,695	$ 2,414,710	
Total C&I (including allocation of Shared Budget)		3,199,636	3,210,402	
Total Budget		**$ 5,583,331**	**$ 5,625,112**	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2014 - October 31, 2015
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures		Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Fed Reserve Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Commercial/ Industrial Therm Sales	Actual Commercial/ Industrial Therm Sales	# of Days
						C&I	Low-Income									
May 14	Actual	1,148,181	($0.0264)	(215,505)	136,875	153,152	34,608	12,063	1,132,499	1,140,340	3.25%	3,148	1,135,647	6,537,363	8,211,791	31
June 14	Actual	1,135,647	($0.0264)	(81,390)	136,875	67,639	13,272	12,063	1,147,231	1,141,439	3.25%	3,049	1,150,280	5,092,563	3,053,714	30
July 14	Forecast	1,150,280	($0.0264)	(105,831)	281,855	0	0		1,326,304	1,238,292	3.25%	3,418	1,329,722	4,008,754	0	31
August 14	Forecast	1,329,722	($0.0264)	(101,681)	419,210	0	0		1,647,250	1,488,486	3.25%	4,109	1,651,359	3,851,567	0	31
September 14	Forecast	1,651,359	($0.0264)	(109,729)	281,855	0	0		1,823,485	1,737,422	3.25%	4,641	1,828,126	4,156,413	0	30
October 14	Forecast	1,828,126	($0.0264)	(131,680)	281,855	0	0		1,978,301	1,903,214	3.25%	5,253	1,983,555	4,987,864	0	31
November 14	Forecast	1,983,555	($0.0502)	(370,644)	281,855	0	0		1,894,766	1,939,160	3.25%	5,180	1,899,946	7,383,352	0	30
December 14	Forecast	1,899,946	($0.0502)	(543,194)	281,855	0	0		1,638,607	1,769,276	3.25%	4,884	1,643,491	10,820,596	0	31
January 15	Forecast	1,643,491	($0.0502)	(709,463)	267,533	0	0		1,201,561	1,422,526	3.25%	3,927	1,205,487	14,132,736	0	31
February 15	Forecast	1,205,487	($0.0502)	(758,886)	267,533	0	0		714,135	959,811	3.25%	2,393	716,528	15,117,247	0	28
March 15	Forecast	716,528	($0.0502)	(693,533)	267,533	0	0		290,529	503,528	3.25%	1,390	291,919	13,815,391	0	31
April 15	Forecast	291,919	($0.0502)	(606,456)	267,533	0	0		(47,004)	122,457	3.25%	327	(46,677)	12,080,802	0	30
May 15	Forecast	(46,677)	($0.0502)	(432,784)	267,533	0	0		(211,928)	(129,302)	3.25%	(357)	(212,285)	8,621,196	0	31
June 15	Forecast	(212,285)	($0.0502)	(295,128)	267,533	0	0		(239,879)	(226,082)	3.25%	(604)	(240,483)	5,879,041	0	30
July 15	Forecast	(240,483)	($0.0502)	(214,075)	267,533	0	0		(187,024)	(213,754)	3.25%	(590)	(187,615)	4,264,443	0	31
August 15	Forecast	(187,615)	($0.0502)	(186,708)	267,533	0	0		(106,789)	(147,202)	3.25%	(406)	(107,195)	3,719,283	0	31
September 15	Forecast	(107,195)	($0.0502)	(190,201)	267,533	0	0		(29,863)	(68,529)	3.25%	(183)	(30,046)	3,788,860	0	30
October 15	Forecast	(30,046)	($0.0502)	(241,752)	267,533	0	0		(4,264)	(17,155)	3.25%	(47)	(4,311)	4,815,773	0	31
November 15	Forecast	(4,311)	($0.0502)	(370,644)	267,533	0	0		(107,422)	(55,867)	3.25%	(149)	(107,571)	7,383,352	0	30
December 15	Forecast	(107,571)	($0.0502)	(543,194)	267,533	0	0		(383,232)	(245,401)	3.25%	(677)	(383,909)	10,820,596	0	31

unearned incentives for 2013-2015 were budgeted at 70% of target

Estimated C&I Conservation Charge November 1, 2014 - October 31, 2015	
Beginning Balance	1,983,555
Program Budget Nov 14-Oct 15	**3,239,045**
Projected Interest	15,913
Program Budget with Interest	5,238,512
Total Charges	**$5,238,512**
Projected Therm Sales	**104,438,722**
C&I Rate	$0.0502
Total Charges with Interest	**$5,242,824**
Projected Therm Sales	**104,438,722**
C&I Rate	**$0.0502**
C&I Rate from Prior Programs (1)	**$0.0000**
Combined C&I Rate	**$0.0502**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2014 - October 31, 2015
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	C&I	Low-Income	Total	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Plus Interest Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Therm Sales	Actual Therm Sales	# of Days
May 14	Actual	1,294,462	n/a	(298,608)	234,000	396,516	153,152	60,716	610,384	24,126	1,630,364	1,462,413	**3.25%**	4,037	1,634,401	9,886,997	12,430,230	31
June 14	Actual	1,634,401	n/a	(119,597)	234,000	120,074	67,639	23,284	210,997	24,127	1,749,927	1,692,164	3.25%	4,520	1,754,447	7,077,460	4,996,582	30
July 14	Forecast	1,754,447	n/a	(130,509)	506,703	0	0	0	0		2,130,641	1,942,544	3.25%	5,362	2,136,003	5,261,414	0	31
August 14	Forecast	2,136,003	n/a	(122,498)	769,398	0	0	0	0		2,782,904	2,459,454	3.25%	6,789	2,789,692	4,908,241	0	31
September 14	Forecast	2,789,692	n/a	(132,249)	506,703	0	0	0	0		3,164,147	2,976,920	3.25%	7,952	3,172,099	5,299,526	0	30
October 14	Forecast	3,172,099	n/a	(165,042)	506,703	0	0	0	0		3,513,760	3,342,929	3.25%	9,227	3,522,987	6,681,398	0	31
November 14	Forecast	3,522,987	n/a	(650,988)	506,703	0	0	0	0		3,378,702	3,450,845	3.25%	9,218	3,387,920	11,723,040	0	30
December 14	Forecast	3,387,920	n/a	(1,028,451)	506,703	0	0	0	0		2,866,172	3,127,046	3.25%	8,632	2,874,803	18,332,318	0	31
January 15	Forecast	2,874,803	n/a	(1,396,733)	468,759	0	0	0	0		1,946,830	2,410,817	3.25%	6,655	1,953,485	24,771,579	0	31
February 15	Forecast	1,953,485	n/a	(1,402,471)	468,759	0	0	0	0		1,019,773	1,486,629	3.25%	3,706	1,023,479	25,079,866	0	28
March 15	Forecast	1,023,479	n/a	(1,263,646)	468,759	0	0	0	0		228,592	626,036	3.25%	1,728	230,320	22,640,679	0	31
April 15	Forecast	230,320	n/a	(1,073,461)	468,759	0	0	0	0		(374,381)	(72,031)	3.25%	(192)	(374,574)	19,309,978	0	30
May 15	Forecast	(374,574)	n/a	(695,331)	468,759	0	0	0	0		(601,145)	(487,860)	3.25%	(1,347)	(602,492)	12,685,389	0	31
June 15	Forecast	(602,492)	n/a	(441,714)	468,759	0	0	0	0		(575,447)	(588,969)	3.25%	(1,573)	(577,020)	8,148,178	0	30
July 15	Forecast	(577,020)	n/a	(309,041)	468,759	0	0	0	0		(417,302)	(497,161)	3.25%	(1,372)	(418,674)	5,734,502	0	31
August 15	Forecast	(418,674)	n/a	(276,057)	468,759	0	0	0	0		(225,971)	(322,323)	3.25%	(890)	(226,861)	5,102,389	0	31
September 15	Forecast	(226,861)	n/a	(289,699)	468,759	0	0	0	0		(47,800)	(137,331)	3.25%	(367)	(48,167)	5,329,076	0	30
October 15	Forecast	(48,167)	n/a	(425,881)	468,759	0	0	0	0		(5,289)	(26,728)	3.25%	(74)	(5,363)	7,666,075	0	31
November 15	Forecast	(5,363)	n/a	(650,988)	468,759	0	0	0	0		(187,592)	(96,477)	3.25%	(258)	(187,849)	11,723,040	0	30
December 15	Forecast	(187,849)	n/a	(1,028,451)	468,759	0	0	0	0		(747,541)	(467,695)	3.25%	(1,291)	(748,832)	18,332,318	0	31

unearned incentives for 2013-2015 were budgeted at 70% of target

Residential (R-1 & R-3) and C & I Conservation Charge November 1, 2014 - October 31, 2015		
Beginning Balance	$	3,522,987
Program Budget Nov 14-Oct 15	$	5,700,999
Projected Interest	$	24,124
Program Budget with Interest	$	9,248,109
Total Charges		**$9,248,109**

History:

Residential (R-1 & R-3) and C & I Conservation Charge Effective November 1, 2013 - October 31, 2014

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Schedule 20

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Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual Environmental increase	$995,500	
DG 10-17 Base Rate Revision Collections	($78,892)	
Environmental Subtotal	$916,608	
Overall Annual Net Increase to Rates	$916,608	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/15 - sales and transportation	166,523,068	therms
Surcharge per therm	$0.0055	per therm
Total Environmental Surcharge	$0.0055	

LIBERTYUTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

CONCORD FORMER MGP

LINE
NO.

1. SITE LOCATION: One Gas Street, Concord, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: EnergyNorth Natural Gas, Inc. (ENGI) received a Notice Letter from the New Hampshire Department of Environmental Services (NHDES) in September 1992. The Notice related primarily to contamination identified in the pond adjacent to Exit 13 off Interstate 93, although it was broad enough to also include the former manufactured gas plant (MGP) site itself.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond, as the NHDOT began site preparation work for the reconfiguration of that interchange. Subsequent investigations by ENGI and others indicate that contaminants originating from the MGP on Gas Street are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI has continued to monitor groundwater semiannually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003 and 2007, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit. These sample results will be evaluated over time to address the efficacy of the existing Exit 13 pond remedy, and determine if additional treatment may be necessary. A groundwater sampling round for the MGP site was conducted in August 2010 and included monitoring wells located on the MGP site itself as well as a number of wells located offsite. In addition, a Supplemental Data Collection Work Plan for the collection of off-ENGI-owned property data was submitted to NHDES in August 2010. ENGI participated in a site walk in July 2011 with NHDES to review the supplemental investigation locations proposed in the August 2010 Work Plan. NHDES agreed with the approach and all proposed investigation locations. ENGI submitted a revised Work Plan with revised sampling locations to NHDES in November 2011; the revision was necessary because site access was not granted by the property owners for some of the originally proposed locations. NHDES approved the revised Work Plan, and asked that ENGI notify them when samples were collected on NHDOT's former Johnson and Dix property, which was completed in July 2012. A letter summarizing the preliminary findings of this work was written to NHDES on November 27, 2012. The report

summarizing these investigation activities was submitted to NHDES in August 2013, in preparation for submittal of the Remedial Action Plan. **This Supplement Data Collection Report was accepted by NHDES on October 24, 2013, and ENGI was authorized to prepare a RAP and Groundwater Management Permit application, which is currently being prepared for submittal in September 2014.**

The New Hampshire Department of Transportation (NHDOT) contacted ENGI in August 2001 and February 2002 regarding possible coal tar-related impacts in a sewer line on a parcel adjacent to the former gas plant. NHDOT is currently conducting groundwater monitoring as part of a Groundwater Management Zone Permit on this parcel. ENGI met with NHDOT and NHDES in January 2003 to review the results of its 2002 site investigation. Limited coal tar impacts were observed in groundwater and subsurface soils at select locations.

On July 15, 2003, NHDES issued a letter to ENGI requesting submission of a schedule and scope of work for a site investigation of the MGP site by mid-September 2003. ENGI proposed a May 2005 date for submission of a Site Investigation Report for the MGP site on Gas Street to NHDES by way of a letter dated October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will be required. NHDES accepted the report on August 12, 2005, and requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. The document was submitted in November 2005. Site investigation activities at and downgradient of the MGP were conducted in 2006. ENGI submitted an additional supplemental scope of work to further delineate MGP impacts on May 31, 2007 and NHDES subsequently approved the scope on June 5, 2007. ENGI bid the NHDES-approved scope of work in June 2008 and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. The Additional Supplemental Site Investigation Report was submitted to NHDES in September 2009. ENGI met with NHDES to discuss the report findings and strategy for moving forward in October 2009. NHDES issued an approval letter for the Supplemental Site Investigation Report on February 9, 2010. The correspondence approved the report and requested that certain additional activities be completed by ENGI. These requested activities include the following: a) preparation and submission of an Initial Response Action Work Plan to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots and tar wells at the MGP property on Gas Street; b) evaluation of the groundwater conditions in the vicinity of the "Tar Pond" which is depicted on a referenced NHDOT site plan; and c) evaluation of potential indoor air impacts at select locations identified during the additional SSI work.

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of the Work Plan on September 16, 2010. ENGI obtained access to 4 properties in the vicinity of the site in order to conduct the supplemental investigation activities, which included soil, ground water and soil vapor sampling, along with further investigation of the brick tar sewer. The investigation work was completed in July 2012, and summarized in a Supplement Data Collection Report that was submitted in August 2013.

On June 16, 2013, wind during a thunderstorm caused a tree to fall on the northern side of the roof of the Holder House located on the former Concord MGP property. Damage to the slate roof and brick was sustained. In a letter dated February 24, 2014 NHDES stated that the holder structure "...serves as a physical barrier to prevent infiltration of precipitation into the foundation and thereby limits the amount of MGP byproducts that may be released to the environment." ENGI is in the process of repairing the structure to prevent these potential releases.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the future. In 2006, NHDES requested ENGI address the residual contamination in the pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results were to be used to prepare the Remedial Action Plan (RAP) which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design. ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project moved into the remedial design phase. The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of

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the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. ENGI met with the regulatory permitting agencies in October 2010. The agencies requested that ENGI modify the remedial design to include an upland cap versus a wetland cap to minimize the impacts of the project. The cap was redesigned and ENGI met with the stakeholders in December 2010. At a subsequent meeting in January 2011, the City of Concord requested that the design be further modified to relocate the City's storm water outfall location. ENGI met with the City in March 2011 to present the feasibility evaluation that was conducted for several alternatives, and concluded that the original design was the appropriate design. The City is currently evaluating the draft design plans, and has committed to following up with ENGI following their internal discussions.

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond.

During May 19, 2009 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. ENGI met with NHDES in October 2009 to present the results of the sediment investigation, and submitted the sediment sampling data report to NHDES in October 2009. The investigation indicated limited site-related impacts to the shallow near-shore sediments of the Merrimack River. Based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river. ENGI met with NHDES on February 20, 2013 to discuss all sampling activities to date, summarized in an SIR Addendum Report, submitted in June 2013.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the MGP site. ENGI submitted the scope to NHDES in May 2004 and implemented the work between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was subsequently approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. In addition, ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. **The NHDES-approved investigation activities were completed in July 2012, as described above.**

ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit was renewed in October

CONCORD FORMER MGP

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2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI undertook a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT and ENGI. ENGI met with these parties on several occasions in the last twelve months to discuss the proposed remedy and the required access. The most recent meeting with the City was on March 14, 2011, when the City stated that they would hold internal discussions and contact National Grid when they are ready to reconvene the group. Efforts to re-engage the City are ongoing as of February 2013. A renewal application for the Groundwater Management Permit was submitted on July 20, 2012, and the renewed permit was granted by NHDES on December 11, 2012. Groundwater and surface water monitoring continues under this permit every May and November. **The Company reinitiated discussion with the City in July 2014 regarding access to the site to implement the approved design of the wetland cap. These discussions are ongoing.**

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Concord MGP operated from approximately 1850 to 1952, when the natural gas pipeline was extended to Concord. The plant was constructed and operated by predecessors of the Concord Gas Company, which later became known as the Concord Natural Gas Company. By virtue of a merger, ENGI acquired Concord Natural Gas. As has been reported previously by ENGI, it filed a contribution claim in the United States District Court for the District of New Hampshire against the successor to the United Gas Improvement Company. In that claim, ENGI alleged that under the federal Superfund statute, the United Gas Improvement Company exercised control over the operations of the Concord Gas Plant to the extent that the United Gas Improvement Company should be considered an "operator" under the statute. That matter was settled in 1997.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Numerous confidential settlements with insurance carriers and with one private party have been entered into. *Insurance recovery efforts at the Concord Site are complete.*

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

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1. SITE LOCATION: The former MGP was located on Messer Street in Laconia. Sometime in the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford. At the time of the disposal, the property was utilized as a gravel pit, and the disposal reportedly occurred with the permission of the gravel pit owner. The property currently comprises part of a residential neighborhood.

2. DATE SITE WAS FIRST INVESTIGATED: In 1994 and 1995, Public Service Company of New Hampshire (PSNH), one of the former owners and operators of the Laconia Manufactured Gas Plant (MGP), conducted limited site investigations at the plant. In 1996, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and its parent company, Northeast Utilities Services Company (NU), and to EnergyNorth Natural Gas, Inc. (ENGI), another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnipesaukee River. Please contact PSNH and refer to PSNH filings with NHDES for complete information on the nature and extent of site contamination at the MGP. Residual materials from the former MGP were disposed of at the Liberty Hill disposal area, and MGP-related constituents have been detected in soil and ground water.

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4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: Based on the settlement with PSNH that has previously been reported to the Commission, ENGI has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area. Please contact PSNH and refer to PSNH filings with NHDES for complete information on material developments and interactions with environmental authorities.

With respect to the Liberty Hill disposal area, in October 2004, ENGI notified NHDES of the possible existence of this disposal site; the site was assigned disposal site number 200411113 by NHDES. NHDES collected drinking water samples from two residential wells in the vicinity in December 2004 and from three additional residential wells in June and July 2005; no MGP-related contaminants were detected. In January 2005, NHDES requested that ENGI conduct a preliminary site investigation on the two residential properties. ENGI submitted a scope of work for the investigation to NHDES on March 2, 2005. The investigation began in July 2005 and was completed in June 2006 with the submission of the Site Investigation Report.

Additional site investigations were conducted in 2006 and summarized in the December 20, 2006 Interim Data Report #2 submitted to NHDES. Based upon the results of the investigations, remediation is required at the site. In response, a Remedial Action Plan (RAP) was submitted to NHDES on February 28, 2007. The RAP presented NHDES with several remedial alternatives to address soil and groundwater contamination at the site. The February 2007 RAP identified soil excavation (to a depth of 3 feet), construction of a containment wall and impermeable cap on the four residential properties purchased by ENGI as the recommended alternative. In September 2007, NHDES responded to the February 2007 RAP and required that ENGI evaluate additional remedial alternatives that included further soil removal. In November 2007, a RAP Addendum was submitted to NHDES. The revised RAP recommended a remedial alternative that included removal of tar-saturated soils to a depth of approximately 45 feet, construction of a containment wall and impermeable cap on the four residential properties owned by ENGI. On February 29, 2008, NHDES issued a letter to ENGI indicating that NHDES had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the NHDES requirements and that a final decision would be reached following a public meeting and comment period.

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modelling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. ENGI submitted the second RAP Addendum to NHDES on August 17, 2009 and presented the findings at a public meeting held in Gilford on September 10, 2009. In October 2009, NHDES hired a third party consultant to review the RAP cost estimates and the results were presented in a report to NHDES in April 2010. In October 2010, NHDES issued a Preliminary Decision on RAP Addendum No. 2, in which NHDES indicated that it did not concur with ENGI's recommended remedial alternative and further recommended the complete removal of coal tar-impacted soils at the site. On January 28, 2011, ENGI submitted a comment letter to NHDES further explaining its rationale for the remedial alternative recommended in RAP Addendum No. 2. On November 2, 2011 NHDES announced a Final Decision indicating that it did not concur with ENGI's recommended remedial approach and selecting the full removal option as the remedy for the site. On December 2, 2011, ENGI filed an appeal of the NHDES Final Decision with the New Hampshire Waste Management Council. In March 2012, ENGI attended the Pre-Conference Hearing with the Council related to the appeal. Hearings on the matter were scheduled for October 18 and November 15, 2012. On July 26, 2012, the Hearing Officer granted an Assented to Motion to Continue the hearing until a date after January 3, 2013.

During the period of time the appeal was subject to the continuance, the company, the New Hampshire Department of Justice and NHDES engaged in settlement discussions on a confidential basis. At the conclusion of those negotiations, NHDES and the company agreed on a final remedy for the site, which was approved by NHDES. That approval allowed ENGI to withdraw its appeal as of December 19, 2012, and proceed with implementation of the remedy. The town of Gilford was briefed on the agreed-upon remedy concurrently with NHDES approval and ENGI's withdrawal of the appeal.

ENGI has also performed numerous other activities requested by NHDES between 2008 and 2011, including remediation of the groundwater seep area near Jewett Brook in accordance with NHDES-approved September 2008 Initial Response Action Plan; evaluation of options for providing financial assurances to NHDES for the site remediation activities; coal tar recovery; semi-annual groundwater and surface water sampling activities; and drinking water well sampling. Groundwater sampling is reported to the NHDES in semi-annual reports. In addition, ENGI developed a Liberty Hill Road site website to assist in updating interested parties.

In conjunction with the Site Investigation work, ENGI has acquired 4 properties on Liberty Hill Road to facilitate remediation activities, and eliminate any potential risk to residents associated with a significant remediation and construction project. The properties were obtained based upon arms-length negotiations, and in one instance to settle potential litigation.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: On December 10, 2012, ENGI submitted a Conceptual Remedial Design Report to NHDES describing the approach for full removal. NHDES approved this Conceptual RAP Addendum design on December 18, 2012, and ENGI withdrew their appeal before the New Hampshire Waste Management Council on December 19, 2012. A public meeting was held in the Town of Gilford to present the approved Conceptual Remedial Design on January 23, 2013. The pre-design investigation to confirm extent and depth of contamination commenced on February 20, 2013 and was completed first week in April 2013. **A public meeting was held on September 25, 2013 to present the design to the Town. The Remedial Design Report was finalized and approved by NHDES in December 2013. Plans and Specifications were developed concurrently, and the bidding process commenced in September 2013 with a Request for Information to ten (10) prospective contractors. On October 28, six (6) contractors were selected to participate in the bidding for the construction, with bids due back on December 6, 2013. On January 9, 2014, three (3) of the bidders were interviewed and Charter Environmental of Boston, MA (the Contractor) was selected for the project. A public meeting took**

place on February 12, 2014 to further explain details of the anticipated construction and to introduce the project team to the community. The Contractor mobilized to the site and began set-up in May 2014, with the first load of soil being hauled from the site on June 6, 2014. Construction has begun to remove tar-impacted soil on the south side of the site with little to no impact to the surrounding community. To date, approximately one third of the soil destined for treatment from the site has been removed and treated. The north side of the site will be remediated during the construction season of 2015, with the entire project expected to be complete in the Fall 2015.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc. (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Laconia MGP, which began operating in 1894, was included in that transaction. Gas manufacturing took place at the property until 1952, when the MGP was converted to propane. Half of the property is now owned by Robert Irwin and maintained as an open field, and the other half is owned by PSNH, which operates an electric substation on the parcel.

   The Liberty Hill Road parcel on which disposal was believed to have occurred was utilized as a gravel pit at the time of the disposal. It was subdivided in May 1970, and currently constitutes part of a residential subdivision.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: ENGI and PSNH entered into a confidential settlement in 1999. Under this agreement, PSNH took the lead on the MGP site investigation and remediation and all communications with NHDES. ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal.

   Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003 the United States District Court certified a question to the New Hampshire Supreme Court asking what "trigger of coverage" should be applied to the insurance policies issued by Lloyds of London to ENGI's predecessor, Gas Service, Inc. In May, 2004 the Supreme Court responded that a "continuous injury-in-fact" trigger should be applied. The federal court conducted a jury trial against Lloyds of London - the only remaining defendant – in October 5, 2004. At the end of that trial the jury returned a verdict in favor of ENGI. Subsequent to the verdict, ENGI and Lloyds of London entered into a confidential settlement.

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With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated. The Company does not expect to pursue any insurance litigation.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

MANCHESTER FORMER MGP

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1. SITE LOCATION: 130 Elm Street, Manchester, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: The New Hampshire Department of Environmental Services (NHDES) compiled a list of all former Manufactured Gas Plants (MGPs) in New Hampshire that were not already subject to a site investigation or remediation. In March of 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites. EnergyNorth Natural Gas, Inc. (ENGI) received a "Notification of Site Listing and Request for Site Investigation" for the former Manchester MGP from NHDES, which designated the site DES #200003011.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - On behalf of ENGI, Harding ESE, Inc. (Harding ESE), submitted a Scoping Phase Field Investigation Scope of Work to NHDES in March 2000.

   - NHDES approved the Scoping Phase Field Investigation Scope of Work in June 2000.

   - During the summer and fall of 2000, ENGI and Harding ESE conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Manchester MGP and the nearby Merrimack River.

   - On August 31, 2000 an underground tank containing MGP residuals was discovered at the site. As required by NHDES regulations, the tank contents were removed and disposed of subject to a permit from NHDES. Harding ESE, on behalf of ENGI, submitted a summary report to NHDES in January 2001 documenting the response action.

   - ENGI and Harding ESE submitted the Scoping Phase Field Investigation Report to NHDES in February 2001.

- NHDES provided comments to ENGI and Harding ESE in April 2001 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

- ENGI responded to NHDES' comments on the Scoping Phase Investigation Report and indicated that ENGI planned to solicit bids for the Phase II Scope of Work.

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments. In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage. In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence. NHDES approved the ravine sign language in April 2002.

- On May 1, 2002, ENGI issued a Request for Proposals to eight environmental consultants for the Phase II Site Investigation and Risk Characterization. ENGI received six proposals for the Phase II work in June 2002.

- In June 2002, the City of Manchester approved the ravine fence location and granted access to City property to install. The work was completed in August 2002.

- URS Consultants were awarded the contract to undertake the next phase of work. A Phase II Site Investigation Scope of Work was submitted in September 2002.

- Phase II field investigations began in the fall of 2002.

- In June 2003, the City of Manchester approved a proposal to construct a minor league ballpark, retail shops, parking garage, hotel and high-rise condominium complex on the Singer Park site, in the same general areas that MGP impacts were detected in ongoing Phase II investigations. Following supplemental ravine investigations during the spring and summer of 2003, the Drainage Ravine Engineering Evaluation was submitted to NHDES in January 2004, and presented four potential remedial alternatives for the ravine, which is located on a portion of Singer Park.

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers from April 2003 until the regular meetings ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment were being addressed concurrently and that ENGI avoided incurring costs associated with another entity's contamination.

- ENGI entered into confidential agreements with Manchester Parkside Place (the owner of the ravine property) for access and cleanup of MGP byproducts in the ravine in January 2005.

- In January 2005, ENGI submitted a Remedial Design Report to NHDES selecting excavation and off-site disposal of source material and impacted soils as the remedial alternative for the ravine. NHDES approved of this alternative via a letter dated February 7, 2005. Eleven contractors were invited to bid on the ravine remediation in January 2005. The contract was awarded to the low bidder (ENTACT) in February 2005. Remediation of the ravine began in March and was completed in July 2005. A remedial completion report was submitted to NHDES on September 2, 2005.

- ENGI submitted a Phase II Site Investigation Report to NHDES in March 2004. The report concluded that MGP impacts (including impacted soil and groundwater and separate phase coal tar) were present in the subsurface beneath the 130 Elm Street property, portions of Singer Park at depth and the Merrimack River sediment. Further investigations were recommended by ENGI to further assess the nature and extent of this contamination and a work plan proposing those investigations was submitted to NHDES in May 2004 and approved in July 2004. These supplemental investigations were completed and documented in the Supplemental Phase II Investigation Report and the Stage I Ecological Screening Report for the Merrimack River, submitted to NHDES in February and March 2005, respectively. The reports concluded that Remedial Action Plans for the upland and Merrimack River portions of the site were required. On September 15, 2005, NHDES issued a letter accepting the reports and requested ENGI prepare a Remedial Action Plan (RAP) to address impacted sediments in the Merrimack River, as well as MGP-related impacts on the upland portion of the site. Preparation of the RAPs began in August 2006.

- Additional Merrimack River investigations were completed in 2007 and the Remedial Design Report for dredging approximately 9,000 cubic yards of coal tar-impacted sediments from the river was submitted to NHDES on May 11, 2007. ENGI applied for, and was granted, a Dredge and Fill Permit for the remedial dredging from NHDES and the United States Army Corps of Engineers on May 18, 2007. Dredging of the river commenced in June 2007 and was substantially completed by the end of the year. Final site restoration activities associated with

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the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

- Certain pre-design investigations were completed on the upland portion of the site in 2008/2009. ENGI also completed interim Phase I Corrective Actions at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale dense non-aqueous phase (DNAPL) recovery, and design for repair/replacement of a deteriorated portion of the site drainage system located within a known LNAPL area of the site. Limited surface soil removal activities were conducted during the summer/fall of 2008 in an area with detected Upper Concentration Limit exceedences in shallow soils.

- ENGI was issued a Groundwater Management Zone (GMZ) permit No. GWP-200003011-M-001 for the former MGP site on June 15, 2009. The permit establishes a groundwater management zone in the vicinity of the former MGP site with associated notification/groundwater monitoring requirements. Groundwater monitoring events to support this GMZ permit have been ongoing, every April and October.

- ENGI submitted an RAP for the upland portion of the site to NHDES on June 30, 2010. The remedial objectives for the site include control of mobile DNAPL, reduction in contaminant mass (where practicable), and management of residual contamination through the use of administrative controls. The recommended remedial alternative includes removal of the contents of certain subsurface structures where removal is anticipated to provide a reduction in the potential for the further release of DNAPL to the subsurface; NAPL recovery from the subsurface; construction of a barrier wall proximate to the Merrimack River to mitigate potential DNAPL migration; and use of administrative controls to address potential human exposure to residual soil and groundwater contamination. Additional investigation activities were recommended to support the preparation of Design Plans and Construction Specifications following NHDES approval of the RAP and to confirm the appropriateness of certain remedial alternatives recommended in the RAP.

- In Fall 2010, ENGI performed storm drain rehabilitation activities on a deteriorated portion of the site drainage system that is located within a known LNAPL area. This work was performed to mitigate the migration of LNAPL to the Merrimack River via the storm drain system. These activities were mainly completed in late 2010.

- In April 2011, NHDES approved of the upland RAP and requested that ENGI proceed with the additional investigation activities recommended in the June 2010 RAP. In addition, ENGI was contacted by both the developer and condominium association associated with the property directly downgradient of the site regarding potential impacts to the property, as well as the proposed remedy; ENGI met with both parties in early and mid-2011.

- After meeting with the developer of the property directly downgradient of the site at the potential location of the barrier wall regarding potential impacts to the property in September/October 2011, access was obtained to conduct certain approved pre-design off-site investigation activities as recommended in the June 2010 RAP. The off-property investigations were substantially completed in December 2011. A meeting was held with NHDES in December 2011 to discuss the results. A Remedial Design Report for the off-site property is currently being finalized.

- On-site pre-design investigation activities were conducted during the spring and summer of 2012 including: additional groundwater quality monitoring, former gas holder foundation test pit excavations, supplemental LNAPL delineation, cyanide source investigation test pit excavations, cyanide delineation and source investigation monitoring well installation, and storm drain inspection.

- **Further storm drain inspections occurred during July and August 2013. The remedial design and construction specifications report was drafted including a summary of the design investigation activities and findings. The remedial design includes the monitoring and practicable recovery of NAPL at strategic on-site and off-site locations, as well as excavation of subsurface structures with concurrent source removal if encountered. The Remedial Design Report also summarizes the results of cyanide source investigation and delineation work, with further source delineation work anticipated. Submittal of the Remedial Design Report is anticipated during September 2014. In addition to routine Groundwater Management Permit (GMP) sampling and reporting, an application for GMP renewal was also submitted to NHDES during June 2014.**

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan (RAP) for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. A RAP for the upland portion of the site was submitted to NHDES for review on June 30, 2010. NHDES issued its approval of the RAP for the upland portion of the site in a letter dated April 11, 2011. **The Remedial Design Report**

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summarizing the activities for addressing on-site and off-site impacts is currently being finalized.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The former Manchester MGP is believed to have started producing coal gas in 1852. Gas was produced at the site by the Manchester Gas Company and its predecessors until the MGP was shut down in 1952 when natural gas was supplied to the city via pipeline. ENGI is the successor by merger to the Manchester Gas Company. ENGI continues to own and operate the 130 Elm Street property as an operations center.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: In late 2000, ENGI filed suit against UGI Utilities, Inc. in the United States District Court for the District of New Hampshire, alleging that during much of the early part of the 20th century, a predecessor to that entity "operated" the Manchester Gas Plant, as defined by the Comprehensive Environmental Response, Compensation and Liability Act (commonly referred to as "CERCLA" or "Superfund"). This claim was similar to a claim litigated and ultimately settled by the parties in the late 1990s, related to the former gas plant in Concord, NH. The case went to trial in June 2003 and was settled after 8 days of trial.

   Insurance recovery efforts are complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier paid ENGI's attorneys fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States District Court, on allocation of coverage, and the scope and meaning of NH RSA 491:22-a, as it relates to awards of attorneys fees. EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007). As to allocation, the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done; the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

MANCHESTER FORMER MGP

LINE
NO.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

NASHUA FORMER MGP

LINE
NO.

1. SITE LOCATION: 38 Bridge Street, Nashua, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: At the end of 1998, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Nashua Manufactured Gas Plant (MGP) to the former plant owners/operators: EnergyNorth Natural Gas, Inc. d/b/a National Grid (ENGI), and Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities Services Company (NU). NHDES designated the site DES #199810022.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - Prior to the time NHDES issued its notice letter to ENGI, the US Environmental Protection Agency (EPA) was remediating contamination (asbestos) at the former Johns Manville plant located adjacent to, and downstream from the 38 Bridge Street property. In the course of that work, EPA detected what it determined to be MGP related residuals in Nashua River sediments containing asbestos. EPA sought reimbursement from ENGI and PSNH of only those incremental additional costs it incurred to dispose of sediments containing MGP related wastes in addition to asbestos. ENGI and PSNH entered into a settlement agreement with the EPA at the end of September 2000. Under the terms of the agreement, each company received a release from liability associated with the so-called Nashua River Superfund Site and contribution protection against future claims associated with that site. The settlement agreement made it clear that EPA does not contend that ENGI or PSNH contributed any asbestos to the Nashua River.

   - In response to the 1998 notice from NHDES, QST Environmental, Inc. (QST, subsequently Environmental Science and Engineering, Inc. (ESE), and later Harding ESE, Inc. (Harding ESE)), submitted a Scoping Phase Field Investigation Scope of Work to NHDES on behalf of ENGI in February 1999.

   - In response to comments from NHDES, QST and ENGI refined the Scope of Work for the Scoping Phase Field Investigation and resubmitted to NHDES in April 1999.

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NO.

- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.
- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.
- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.
- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.
- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.
- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.
- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.
- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.
- ENGI submitted a letter to NHDES in August 2000 discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and PSNH/NU, along with a proposed schedule for implementation of the work.
- NHDES approved the Revised Phase II Work Plan for the site at the end of August 2000.
- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.
- ENGI submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

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NO.

- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH reached agreement in late 2000 regarding sharing of costs for the remediation work and transfer of management of the remediation work to ENGI.

- Harding ESE implemented the Phase II Work Plan during the fall and winter of 2000/2001. Work entailed a comprehensive field program that included the advancement of river borings and collection of sediment samples as well as the installation of borings and monitoring wells on and off the property.

- NHDES provided comments on the Phase II Work Plan addendum in February 2001.

- Harding ESE responded to NHDES comments on the Phase II Work Plan addendum in March 2001.

- In May 2001, ENGI submitted to NHDES a Draft Site Conceptual Model to assist with finalization of the Phase II Work Plan Addendum and met with NHDES to discuss.

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June 2001.

- In July 2001, ENGI and Harding ESE met with NHDES to review the Site Conceptual Model and proposed Phase II supplemental investigation activities.

- ENGI and NHDES met in August 2001 to discuss the overall site objectives.

- In September 2001, Harding ESE, on behalf of ENGI, submitted a Phase IIB Supplemental Site Investigation (SI) Scope of Work to NHDES.

- NHDES provided verbal approval for the Phase IIB Supplemental SI, and Harding ESE initiated the field program on behalf of ENGI in October 2001.

- NHDES provided written approval of the Phase IIB Supplemental SI in October 2001. A modification to the proposed scope of work relating to investigations adjacent to the gas lines was proposed and verbal approval was obtained from NHDES on November 19, 2001.

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NO.

- Property owners north of the Nashua River did not provide access to install monitoring wells proposed in the Phase IIB SOW. Harding ESE completed all on-site work outlined in the Phase IIB SOW in February 2002.

- ENGI received access from PSNH to install Phase IIB monitoring wells west of the site in March 2002.

- Harding ESE installed additional groundwater monitoring wells west of the site in March and sampled all newly installed monitoring wells in April 2002. All work outlined in the Phase IIB SOW was completed except for the proposed monitoring wells north of the Nashua River where access was denied.

- The Phase II Report was submitted to NHDES in February 2003. The report was approved by NHDES in August 2003. At the time of approval, NHDES required ENGI to begin work on the Remedial Action Plan for the site, due in 2004.

- ENGI met with NHDES on November 3, 2003, to review the proposed remedial schedule, which called for the Remedial Action Plan to be submitted in July 2004, and remediation to occur in 2005. NHDES approved the schedule by letter dated December 1, 2003. In that letter they concurred with ENGI's request to divide the site into terrestrial and aquatic portions, to facilitate remediation of sediments concurrent with re-armoring of ENGI's gas mains crossing the river.

- By way of a May 5, 2004 letter, ENGI requested that NHDES waive the Remedial Action Plan (RAP) requirement for the aquatic portion of the site and allow ENGI to proceed with capping sediments in conjunction with gas main rearmoring, which was scheduled for completion in 2004. NHDES approved the request by letter dated May 14, 2004.

- ENGI held pre-application meetings with state and federal agencies (NHDES Wetlands Bureau, United States Army Corps of Engineers, United States Department of Fish and Wildlife, United States Environmental Protection Agency and National Oceanic and Atmospheric Administration) in June 2004. These meetings were held in advance of permit application submission for the capping/rearmoring project, to review the project and expedite the approval process. The application was submitted to these agencies as well as the City of Nashua on July 1, 2004. On July 6, 2004, NHDES deemed the permit application administratively complete. The hearing was closed on July 26, 2004 and the permit was issued in September 2004. The capping and re-armoring was

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completed in October 2004 and the Remedial Completion Report, submitted to NHDES in January 2005, was subsequently approved.

- In October 2005, ENGI submitted the Terrestrial Remedial Action Plan to NHDES, and the document was deemed complete by NHDES in March 2006. NHDES requested supplemental information to be submitted before ENGI proceeded with remediation, and in 2007 ENGI gathered the requested data.

- In November 2007, ENGI submitted a Workplan for DNAPL Recovery Pilot Test to NHDES and the document was approved by NHDES on November 14, 2007.

- ENGI applied for three permits required for the implementation of the NHDES-approved DNAPL pilot testing activities: Nashua Conservation Commission Permit, Nashua Zoning Board of Appeals Permit and NHDES Dredge and Fill Permit. ENGI attended numerous hearings related to obtaining the permits and obtained the three permits on April 21, 2008, April 23, 2008 and May 31, 2008, respectively.

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and the first three quarters of 2009.

- In Spring 2009, ENGI began trenching and final system installation activities for the DNAPL recovery pilot testing. The trenching, pump installations and system electrical work were completed in July 2009. Electrical service was installed in late August 2009. The system was started up in November 2009 and has been operational since that time. **The system has recovered 234 gallons of DNAPL as of July 2014.**

- In September 2010, ENGI submitted an Installation Summary and DNAPL Recovery Pilot test summary report to NHDES. This report recommended that DNAPL extraction activities continue. In October 2010, a work plan for an off-site groundwater investigation program to support the delineation of a Groundwater Management Zone was submitted to NHDES. This work plan was approved by NHDES in a letter dated November 5, 2010. Access negotiations and environmental permitting for the NHDES-approved investigation were completed in June 2011.

- The NHDES-approved subsurface soil and groundwater investigation program was initiated on September 26, 2011. The goal of this program was to delineate a Groundwater Management Zone for the site, and allow for the filing of a Groundwater Management Permit (GMP). Due to known asbestos in the off-site area to be investigated, ENGI submitted an "In-active Asbestos Disposal Site (ADS) Work Plan"; NHDES approved the asbestos work plan in October 2011. Soil boring and well installation work was performed between October and December 2011. An In-active ADS Site Completion Report was submitted to and accepted by NHDES on May 4, 2012. Groundwater sampling events were conducted in February and May 2012. A meeting to discuss the preliminary results of the Groundwater Management Zone (GMZ) investigation program with NHDES took place on August 16, 2012. It was agreed that two more rounds of groundwater sampling should occur before a delineation of the GMZ is considered.

- On November 27, 2012 and December 6, 2012, 8.25 feet and 10.83 feet of DNAPL appeared in MW-106, situated in the foot print of historical Holder #2. A weekly monitoring and removal plan was initiated at this time and is ongoing as of July 2013. To date, 109 gallons of DNAPL has been removed manually, in addition to the system removal discussed above.

- In January 2013, a Supplemental Investigation Report (SIR) and DNAPL Recovery System Pilot Test Progress report was submitted to NHDES reporting on additional investigation activities, including the installation of sixteen additional wells in 2011, and the May and September 2012 (second and third of three) rounds of sampling to define groundwater quality and hydrogeologic conditions at the site, so that the GMZ can be delineated. Additionally, the report includes information regarding DNAPL recovery system O&M activities and DNAPL recovery rates demonstrating that the system still effectively recovers DNAPL. A meeting with NHDES took place on March 22, 2013 to discuss these results and next steps.

- NHDES responded to the January 2013 submittal via letter dated May 21, 2013 accepting the SI Report and authorizing ENGI to proceed with the delineation of the GMZ in order to submit a Groundwater Management Permit (GMP) application, and the preparation of a revised Remedial Action Plan (RAP) for the terrestrial portion of the site.

- ENGI responded to the NHDES letter on June 19 with a schedule targeting December 31, 2013 for submittal of the GMP application and revised RAP.

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- **In December 2013 ENGI submitted a request to revise the RAP. The purpose of the request was to summarize activities conducted since submittal of the 2013 Supplemental Investigation Report and to propose a revision to the approved RAP for the area on site known as "Holder # 2."**
- **The RAP submitted in 2005 selected asphalt capping in the area of Holder #2. The entire area of the Holder was not designated to be capped with asphalt. At the time of the preparation of the RAP, separate phase NAPL was not considered to be present in recoverable quantities in Holder #2. In order to address what appears to be a limited area and quantity of NAPL in a monitoring well in Holder #2, continued manual NAPL recovery from two additional wells in the Holder #2 area was proposed as part of the GMP monitoring program.**
- **In addition to the NAPL recovery activity, the area of asphalt capping was proposed to be expanded to include all of former Holder #2. This expansion of paving will also address the asbestos contaminated material (ACM) present in this area of the site. The asphalt cap detail presented in the proposed RAP revision will be modified (as necessary) to address the relevant solid waste regulations for ACM in soil.**
- **On June 4, 2014, the NHDES approved of the requested RAP revision and required that a RAP Summary Report, with the necessary engineering details for the selected remedies, be provided. ENGI plans to submit this RAP Summary Report by December 31, 2014.**
- **The GMP Application was submitted in March 2014. The GMP proposed a list of monitoring wells and analytical methods in order to monitor the Groundwater Management Zone.**
- **On June 5, 2014, the NHDES approved the GMP application. This Permit was issued for a period of 5 years requiring the monitoring of groundwater quality, assessing and recovering any free product found, and visually inspecting the Nashua River sediment cap area. During the first year of the Permit, monitoring events will be conducted in October 2014 and April 2015. Annual summary reports are to be submitted to the NHDES in January of each year.**

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

NASHUA FORMER MGP

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5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. DNAPL recovery is on-going. **A Groundwater Management Permit was granted on June 5, 2014, and a Remedial Action Plan involving the asphalt capping of the site will be submitted by December 31, 2014.**

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Nashua Gas Light Company built the original coal gas facility in 1852 or 1853. In 1889, the Nashua Gas Light Company merged with the Nashua Electric Company to form the Nashua Light, Heat and Power Company (NHLPC). In 1914, the NLHPC merged with the Manchester Traction Light & Power Company, and PSNH acquired the facility in 1926. The MGP facility was upgraded and expanded. In 1945, PSNH divested the gas operations to Gas Service, Inc. Gas production was eliminated in 1952 when natural gas was supplied to the city via pipeline. In 1981, Gas Service, Inc. merged with Manchester Gas Company to form ENGI. ENGI currently owns the majority of the former gas plant property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: The EPA made a claim against ENGI and PSNH related to the so-called Nashua River Asbestos Site located adjacent to the former MGP. EPA was removing asbestos from the Nashua River, when some was found to be mixed with wastes allegedly from the MGP. Without admitting any facts or liability, by agreement effective December 21, 2000, ENGI resolved EPA's claim in exchange for a payment of $387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

   ENGI and PSNH have entered into a confidential Site Responsibility and Indemnity Agreement effective as of September 15, 2000, which governs the financial and decision-making responsibilities of the two companies through the remainder of site study and remediation. Under this agreement, ENGI will take the lead on site investigation and remediation.

   Numerous, confidential insurance settlements have been entered into. A jury trial commenced against the London Market Insurers and Century Indemnity on November 1, 2005. On November 14, 2005, the jury returned a verdict in favor of EnergyNorth finding that the defendants were obligated to indemnify EnergyNorth for response costs incurred at the site. The Court then awarded ENGI its reasonable costs and attorneys fees to be

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paid by the defendants. Subsequent to the verdict, the London Market and ENGI entered into a confidential settlement. Century appealed to the First Circuit Court of Appeals in the summer of 2006. However, on the day its brief was due at the First Circuit, Century withdrew its appeal. Because the site has not yet been remediated, the jury was not asked to make a damage determination. Future proceedings will take place after the remedy has been approved by the NHDES to determine the indemnification amounts to be paid by Century. The New Hampshire Supreme Court's ruling and guidance on the proper manner in which costs are to be allocated among insurers (discussed in more detail in the Manchester MGP summary) will be used in the calculation of that figure.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

DOVER FORMER MGP

LINE
NO.

1. SITE LOCATION: Intersection of Cocheco Street and Portland Street, Dover, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: In 1999, NHDES sent notice letters to current and former site owners and operators including: Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities (NU).; EnergyNorth Natural Gas, Inc. (ENGI); Northern Utilities, Inc.; and Central Vermont Public Service Company (CVPS). It is the company's understanding that NHDES sent a notice to the current site owner, Estelle Maglaras, earlier. NHDES designated the site DES #198401047.

3. NATURE AND SCOPE OF SITE CONTAMINATION: According to the August 2002 Supplemental Site Investigation Report, the evaluation of the nature and extent of MGP impacts to the site has been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cocheco River. These residuals, which include tars, oils, and purifier waste, have been found in surface soil, subsurface soil, groundwater, and river sediment.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - During late 1999 and early 2000, PSNH/NU took the lead on preparation of a Site Investigation Report. PSNH/NU submitted the report to NHDES and the other potentially responsible parties (PRPs) in February 2000.

   - The PRPs held meetings and discussions during 2000 regarding site responsibility and liability.

   - Following an October meeting between NHDES, PSNH/NU, ENGI, and CVPS, Metcalf & Eddy, Inc. (M&E) submitted a Supplemental Site Investigation Work Plan to NHDES on behalf of PSNH/NU, ENGI, and CVPS to NHDES in December 2000.

   - NHDES provided written comments on the Supplemental Site Investigation Work Plan in April, 2001.

   - M&E submitted a letter response to NHDES comments on the Work Plan to NHDES in early June 2001.

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- NHDES approved the Supplemental Site Investigation Work Plan and letter addendum in late June 2001.

- PSNH/NU, in conjunction with CVPS and ENGI, submitted the M&E Supplemental Site Investigation Report to the DES on August 9, 2002.

- Since 2002, PSNH has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. **Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.**

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Supplemental Site Investigation completed. Please contact PSNH or NHDES for current status.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Dover MGP, which began operation in 1850, was included in that transaction. GSI operated the Dover MGP until 1956, when it was sold to Allied New Hampshire Gas Company (Allied). Approximately 10 months after that sale, the MGP was shut down when natural gas arrived in Dover. Allied merged into Northern Utilities in 1969, and Northern Utilities continued to own the property until 1978. At that time, the property was sold to Estelle Maglaras, the current owner. The majority of the property is used by the Maglaras family as a marina and boatyard. Northern Utilities, Inc. maintains a regulator station on a small portion of the former MGP property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Mediation between PSNH, ENGI, CVPS and Northern Utilities for allocation was undertaken in the fall of 2001 but was not successful. Since that time, PSNH reached a confidential settlement and allocation with CVPS, and has taken the lead on site investigation and remediation activities. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments. PSNH and ENGI have attempted to negotiate an allocation but thus far have been unsuccessful.

   Insurance recovery efforts are complete, and resulted in several confidential settlements as well as a judgment in favor of coverage. Trial was conducted in the United States District Court in February, 2005. At the close of the defendant's case, the court directed a verdict in ENGI's favor on the issue of coverage determining that the defendant is liable for environmental costs related to the site. In May, 2005, the court ordered Century Indemnity to reimburse ENGI's attorneys' fees and costs associated with the litigation. In June 2005, the Court issued an Amended Judgment awarding fees to ENGI. Century appealed the Amended Judgment and oral argument was heard in January 2006. Century's appeal was

DOVER FORMER MGP

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denied by the Court in June 2006, and ENGI was ultimately awarded its attorneys fees associated with that appeal.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY UTILITIES

KEENE FORMER MGP

LINE
NO.

1. SITE LOCATION: 207 and 227 Emerald Street, Keene, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: Information on site investigation activities comes from reports prepared by Public Service Company of New Hampshire (PSNH). It is apparent the New Hampshire Department of Environmental Services (NHDES) first investigated Mill Creek adjacent to the former Keene Manufactured Gas Plant (MGP) in 1986. PSNH, a former owner and operator, and its parent company, Northeast Utilities Service Company (NU), conducted several site assessments of the former MGP during the early and mid-1990s. PSNH/NU completed a Site Investigation in 1996 in response to a notice letter from the NHDES, which designated the site DES # 199412009. PSNH/NU has had responsibility for site management and interactions with NHDES since that time. Although it does not appear to have been actively involved in the site study, Keene Gas Corporation (KGC) received a notice letter from NHDES in January 1999. In response to a request from PSNH/NU, NHDES sent a notice letter to EnergyNorth Natural Gas, Inc. (ENGI) in April 2001. ENGI responded to the NHDES on April 27, 2001, indicating that it would continue to coordinate with PSNH and that it was evaluating its potential liability, if any, at the site.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site in sediments of the adjacent Mill Creek and Ashuelot River. Removal of impacted sediment areas constituting readily apparent harm and restoration of the creek bed and portions of the river bed is the likely remedial alternative for the aquatic portion of the site.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI entered into a confidential agreement with PSNH relative to the development and execution of a Remedial Action Plan (RAP) for the aquatic portion of the site in January 2005. Subsequently, in March 2005, ENGI and PSNH/NU submitted a Scope of Work for the ecological evaluation of the Ashuelot River Sediments to NHDES, and met with NHDES on April 25, 2005 to discuss the conceptual RAP (consisting of sediment removal and stream bed restoration) for Mill Creek/Ashuelot River. NHDES approved the scope of the ecological evaluation, and it was conducted in 2005. In February 2006, PSNH submitted a scope of work for a supplemental investigation of the Ashuelot River, which was approved by NHDES in April 2006. This work was completed and in February 2007 NHDES requested the preparation of a Remedial Action Plan (RAP) for Mill Creek and a portion of the Ashuelot River. NHDES files indicate that PSNH submitted the RAP in 2008 and completed permitting and obtaining access from private property owners for the Mill Creek and Ashuelot River remediation activities in 2010. Subsequently, a remedial contractor was a selected, and

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NO.

Phase II RAP implementation is underway. According to NHDES files, remedial actions in the Mill Creek and Ashuelot River continued in late 2011/2012. According to NHDES files, remedial actions in the Mill Creek and Ashuelot River continued through 2011. **In October 2012, NU/PSNH completed the remediation project. The tri-annual groundwater monitoring program/reporting continues**.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Remediation of the terrestrial portion of the site was completed by PSNH/NU in 2004/2005. An ecological risk assessment in support of a Remedial Action Plan for the Ashuelot River and Mill Creek portions of the site was conducted jointly by ENGI and PSNH/NU in 2005. A supplemental investigation of the Ashuelot River to support the preparation of a Remedial Action Plan (RAP) was completed in 2007 and NHDES has requested PSNH/NU submit the RAP for Mill Creek and portions of the Ashuelot River in 2007. NHDES files indicate that the RAP was submitted by PSNH in 2008 and that NHDES commented and approved the Phase II RAP. NHDES and other public information sources indicate that remedial and wetland permitting is complete, necessary approvals and site access agreements with impacted landowners are complete, a remedial contractor has been selected, and Phase II RAP implementation is on-going. PSNH has taken the lead on investigation at this Site, and has conducted this work without ENGI's active involvement. NHDES is aware of the situation. **Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.**

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: Given its status at the site, ENGI has not yet conducted a thorough evaluation of its history. It is known that the plant became operational in approximately 1860 and operated as a manufactured gas plant until 1952, after which it was converted to butane and later to propane. Gas Service, Inc., a predecessor of ENGI, owned the former MGP between October 1945 and its closure in 1952. Gas Service continued to own the property until it was sold to KGC in 1979. KGC continues to operate a propane-air plant at the site. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on site history, use and ownership.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Insurance recovery claims are underway, and confidential settlements have been entered into with all but one defendant. The case is currently stayed. Trial had been scheduled for October 2006 against the sole remaining insurance company defendant, Century Indemnity, however that trial was put off while awaiting a ruling on an issue of law in the Manchester MGP litigation by the New Hampshire Supreme Court.

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NO.

The Supreme Court has since ruled on the appropriate method of allocating indemnification obligations among multiple insurers and the applicability of the New Hampshire attorneys fees statute, RSA 491:22-a, which is relevant to the Keene case. In that case, EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007), the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

ENGI intervened in Docket DE 98-123, the proceeding in which the Commission considered the proposed transfer of operating assets from Keene Gas Corporation (KGC) to New Hampshire Gas Corporation (NHGC). ENGI opposed the proposed transfer because it was concerned that the transfer was likely to create a significant, and possibly insurmountable, obstacle to the potential for KGC customers to share in responsibility for any costs associated with environmental liabilities at the Keene MGP site. At the time, ENGI had not been named as a potentially responsible party for the Keene MGP site, nor had it been notified by any PRP of any claimed liability for the site. Nevertheless, ENGI was aware of the possibility that it would receive such a notice at some point in the future. In the KGC/NHGC proceeding, ENGI proposed that the Commission condition any approval of the proposed transfer on NHGC's willingness to assume responsibility for KGC's liability with regard to the site. The Commission ultimately approved the transfer of assets without imposing such a condition, finding among other things that liability for environmental contamination at the Keene MGP site remained speculative at that time and that assignment of any such liability to various parties was not appropriate for determination by the Commission.

On August 30, 2013, ENGI received a Demand Letter from PSNH for reimbursement of clean-up costs at the Keene former MGP plant. On February 27, 2014, ENGI and PSNH entered into a cost allocation settlement that resolved the matter that resulted from a mediation. Under that agreement, ENGI will pay some of the remediation expense incurred by PSNH.

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD POND - REMEDIATION
PROJECT DEF056

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013070439	$80.00					80.00			80.00
2	GEI CONSULTANTS, INC.	57590		$6,436.35				6,436.35			6,436.35
3	CLEAN HARBORS	1000064818					$495.00	495.00			495.00
4	GEI CONSULTANTS, INC.	57756		$1,562.79				1,562.79			1,562.79
5	GEI CONSULTANTS, INC.	57963		1,043.75				1,043.75			1,043.75
6	[redacted]										
7	CLEAN HARBORS	1000168171					787.01	787.01			787.01
8	GEI CONSULTANTS, INC.	58178		2,280.85				2,280.85			2,280.85
9	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 10 13					1,351.09	1,351.09			1,351.09
10	GEI CONSULTANTS, INC.	58276		1,268.00				1,268.00			1,268.00
11	[redacted]										
12	GEI CONSULTANTS, INC.	58515		4,247.97				4,247.97			4,247.97
13	CLEAN HARBORS	1000253110					418.00	418.00			418.00
14	GEI CONSULTANTS, INC.	58623		4,860.15				4,860.15			4,860.15
15	NH DEPT OF ENVIRONMENTAL SERVICES	4042					3,784.67	3,784.67			3,784.67
16	GEI CONSULTANTS, INC.	58855		2,590.70				2,590.70			2,590.70
17	GEI CONSULTANTS, INC.	59012		1,056.70				1,056.70			1,056.70
18	[redacted]										
19	GEI CONSULTANTS, INC.	59125		965.27				965.27			965.27
20	NH DEPT OF ENVIRONMENTAL SERVICES	199212014					553.93	553.93			553.93
21	GEI CONSULTANTS, INC.	59376		1,180.63				1,180.63			1,180.63
22	[redacted]										
23	GEI CONSULTANTS, INC.	59604		5,351.28				5,351.28			5,351.28
24								0.00			0.00
25								0.00			0.00
26								0.00			0.00
27								0.00			0.00
28								0.00			0.00
29								0.00			0.00
30								0.00			0.00
31								0.00			0.00
32	Environmental Staff Time							0.00			0.00
	Total Pool Activity		**80.00**	**32,844.44**	**0.00**	**0.00**	**7,389.70**	**40,314.14**	**0.00**	**(7,990.07)**	**32,324.07**

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
PROJECT DEF077

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CASEY MARY						57.56	57.56			57.56
3	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 7 13					215.29	215.29			215.29
4	GZA GEOENVIRONMENTAL INC	0671173		20,264.54				20,264.54			20,264.54
5	CLEAN HARBORS	1000064809					897.60	897.60			897.60
6	GZA GEOENVIRONMENTAL INC	0668374		33,089.83				33,089.83			33,089.83
7	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 10 13					255.65	255.65			255.65
8	[redacted]										
9	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 1 14					3,153.10	3,153.10			3,153.10
10	GZA GEOENVIRONMENTAL INC	679457		23,721.56				23,721.56			23,721.56
11	CLEAN HARBORS	1000310043					468.56	468.56			468.56
12	[redacted]										
13	GZA GEOENVIRONMENTAL INC	681517		48,669.86				48,669.86			48,669.86
14	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 4 14					3,711.40	3,711.40			3,711.40
15	[redacted]										
16	CLEAN HARBORS	1000484020					330.00	330.00			330.00
17								0.00			0.00
18								0.00			0.00
19								0.00			0.00
20	Environmental Staff Time						838.22	838.22			838.22
	Total Pool Activity		**0.00**	**125,745.79**	**0.00**	**0.00**	**9,927.38**	**135,673.17**	**0.00**	**(12,318.55)**	**123,354.62**

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL - REMEDIATION
PROJECT DEF086

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	100 % RECOVERABLE EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	PUBLIC SERVICE OF NEW HAMPSHIRE	56399816065 06 13					11.96	11.96			11.96
2	PUBLIC SERVICE OF NEW HAMPSHIRE	56220916084 06 13					11.96	11.96			11.96
3	CASEY MARY	6-1 THRU 6-30-13					59.25	59.25			59.25
4	OSTROW & PARTNERS INC	07 13 01					479.50	479.50			479.50
5	PUBLIC SERVICE OF NEW HAMPSHIRE	56399816065 07 13					24.79	24.79			24.79
6	PUBLIC SERVICE OF NEW HAMPSHIRE	56220916084 07 13					24.16	24.16			24.16
7	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013070442	200.00					200.00			200.00
8	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 200411113 3 13					7,407.49	7,407.49			7,407.49
9	GEI CONSULTANTS, INC.	57589		31,757.06				31,757.06			31,757.06
10	MILL CITY ENVIRONMENTAL CORP.	3799					8,790.00	8,790.00			8,790.00
11	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013080686	880.00					880.00			880.00
12	OSTROW & PARTNERS INC	08 13 01					401.25	401.25			401.25
13	GEI CONSULTANTS, INC.	57755		10,260.00				10,260.00			10,260.00
14	CASEY MARY	8-1 THRU 8-31-13					90.14	90.14			90.14
15	COVINO ENVIROMENTAL ASSOCIATES, INC.	0037346					1,719.00	1,719.00			1,719.00
16	CLEAN HARBORS	1000113555					1,826.83	1,826.83			1,826.83
17	OSTROW & PARTNERS INC	09 13 01					323.00	323.00			323.00
18	GEI CONSULTANTS, INC.	57962		34,361.88				34,361.88			34,361.88
19	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013100896	1,560.00					1,560.00			1,560.00
20	CASEY MARY	9-1 THRU 9-30-13					152.28	152.28			152.28
21	CASEY MARY	07/01 THRU 07/29FY13					108.35	108.35			108.35
22	OSTROW & PARTNERS INC	10 13 01					557.75	557.75			557.75
23	CLEAN HARBORS	1000162499					409.20	409.20			409.20
24	GZA GEOENVIRONMENTAL INC	674560		6,757.50				6,757.50			6,757.50
25	PUBLIC SERVICE OF NEW HAMPSHIRE	56399816065 09 13					62.95	62.95			62.95
26	GEI CONSULTANTS, INC.	58177		51,165.13				51,165.13			51,165.13
27	NH DEPT OF ENVIRONMENTAL SERVICES	14262 10 13					2,151.86	2,151.86			2,151.86
28	Granite State Salvage (metals recovery)	Receipt					(310.35)	(310.35)			(310.35)
29	CASEY MARY	10/01 THRU 10/31/13					77.54	77.54			77.54
30	GEI CONSULTANTS, INC.	58275		58,587.86				58,587.86			58,587.86
31	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013111084	3,173.20					3,173.20			3,173.20
32	CASEY MARY	11/01 THRU 11/30/13					93.40	93.40			93.40
33	DEVINE, MILLIMET & BRANCH, PA	391734	3,997.43					3,997.43			3,997.43
34	GEI CONSULTANTS, INC.	58514		8,994.19				8,994.19			8,994.19
35	OSTROW & PARTNERS INC	12 13 01					1,262.00	1,262.00			1,262.00
36	DE MAXIMIS, INC.	132358		9,457.93				9,457.93			9,457.93
37	DE MAXIMIS, INC.	132113		1,708.88				1,708.88			1,708.88
38	GEI CONSULTANTS, INC.	58622		10,133.75				10,133.75			10,133.75
39	OSTROW & PARTNERS INC	11 13 01					1,496.75	1,496.75			1,496.75
40	OSTROW & PARTNERS INC	1 14 01					1,262.00	1,262.00			1,262.00
41	NH DEPT OF ENVIRONMENTAL SERVICES	14262					10,198.15	10,198.15			10,198.15
42	DE MAXIMIS, INC.	140180		4,737.41				4,737.41			4,737.41
43	DE MAXIMIS, INC.	132573		4,848.41				4,848.41			4,848.41
44	CASEY MARY	02/11 THRU 02/12/14					23.94	23.94			23.94
45	BLUE CHIP FILMS LLC	1170					1,225.00	1,225.00			1,225.00
46	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2014021508	615.00					615.00			615.00
47	GEI CONSULTANTS, INC.	58854		12,996.00				12,996.00			12,996.00
48	DE MAXIMIS, INC.	140471		12,727.36				12,727.36			12,727.36
49	CASEY MARY	02/01 THRU 02/28/14					110.10	110.10			110.10
50	OSTROW & PARTNERS INC	03 14 01					3,140.00	3,140.00			3,140.00
51	GEI CONSULTANTS, INC.	59011		33,308.23				33,308.23			33,308.23

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL - REMEDIATION
PROJECT DEF086

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	100 % RECOVERABLE EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
52	DE MAXIMIS, INC.	140635		15,225.02				15,225.02			15,225.02
53	SOPHWELL INC	1804					89.00	89.00			89.00
54	CASEY MARY	03/01 THRU 03/31/14					162.13	162.13			162.13
55	OSTROW & PARTNERS INC	02 14 01					1,888.00	1,888.00			1,888.00
56	OSTROW & PARTNERS INC	04 14 01					636.00	636.00			636.00
57	NH DEPT OF ENVIRONMENTAL SERVICES	200411113					2,925.56	2,925.56			2,925.56
58	GEI CONSULTANTS, INC.	59124		30,820.19				30,820.19			30,820.19
59	CASEY MARY	04/01 THRU 04/30/14					301.53	301.53			301.53
60	DE MAXIMIS, INC.	140868		10,099.60				10,099.60			10,099.60
61	AON REED STENHOUSE INC	3450000334004					6,654.00	6,654.00			6,654.00
62	CHARTER ENVIRONMENTAL INC	APP 1 2-1055			343,439.77			343,439.77			343,439.77
63	OSTROW & PARTNERS INC	05 14 01					1,105.50	1,105.50			1,105.50
64	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2014051315	205.00					205.00			205.00
65	CASEY MARY	05/14 THRU 05/14/14					17.67	17.67			17.67
66	GEI CONSULTANTS, INC.	59375		18,339.10				18,339.10			18,339.10
67	AIRLOGICS LLC	687502			12,410.00			12,410.00			12,410.00
68	BLUE CHIP FILMS LLC	1185					1,362.50	1,362.50			1,362.50
69	CASEY MARY	05/21 THRU 05/22/14					205.38	205.38			205.38
70	DRAGONFLY AERIALS LLC	64					460.00	460.00			460.00
71	CASEY MARY	05/28 THRU 05/28/14					14.11	14.11			14.11
72	CASEY MARY	05/01 THRU 05/31/14					635.77	635.77			635.77
73	DE MAXIMIS, INC.	141112		17,617.39				17,617.39			17,617.39
74	ESMI OF NH	1011315			143,691.03			143,691.03			143,691.03
75	OSTROW & PARTNERS INC	06 14 01					1,653.25	1,653.25			1,653.25
76	CHARTER ENVIRONMENTAL INC	APP 2 2-1055			479,537.63			479,537.63			479,537.63
77	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2014061537	328.00					328.00			328.00
78	AIRLOGICS LLC	688716			8,100.00			8,100.00			8,100.00
79	DE MAXIMIS, INC.	141408		41,053.59				41,053.59			41,053.59
80								0.00			0.00
81								0.00			0.00
82								0.00			0.00
83								0.00			0.00
84								0.00			0.00
85								0.00			0.00
86	Environmental Staff Time						34,760.51	34,760.51			34,760.51
	Total Pool Activity		**10,958.63**	**424,956.48**	**987,178.43**	**0.00**	**96,061.16**	**1,519,154.70**	**0.00**	**0.00**	**1,519,154.70**

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
PROJECT DEF057

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013070441	720.00					720.00			720.00
2	GZA GEOENVIRONMENTAL INC	0671172		9427.22				9,427.22			9,427.22
3	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 20003011 3 13					359.22	359.22			359.22
4	CLEAN HARBORS	1000064807					587.40	587.40			587.40
5	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013080685	187.50					187.50			187.50
6	[redacted]										
7	GZA GEOENVIRONMENTAL INC	0668375		6501.96				6,501.96			6,501.96
8	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013091242	560.00					560.00			560.00
9	CASEY MARY	07/01 THRU 07/29					27.87	27.87			27.87
10	[redacted]										
11											
12	GZA GEOENVIRONMENTAL INC	672995		14,386.83				14,386.83			14,386.83
13	GZA GEOENVIRONMENTAL INC	676916		37,853.12				37,853.12			37,853.12
14	ESMI OF NH	1010774					6,007.16	6,007.16			6,007.16
15	[redacted]										
16	GZA GEOENVIRONMENTAL INC	678444		3,633.77				3,633.77			3,633.77
17	CLEAN HARBORS	1000310044					1,347.28	1,347.28			1,347.28
18	[redacted]										
19	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 20003011 3 13					97.83	97.83			97.83
20	GZA GEOENVIRONMENTAL INC	684967		11,090.85				11,090.85			11,090.85
21	[redacted]										
22											
23											
24								0.00			0.00
25								0.00			0.00
26								0.00			0.00
27								0.00			0.00
28								0.00			0.00
29								0.00			0.00
30								0.00			0.00
31								0.00			0.00
32	Environmental Staff Time						111.54	111.54			111.54
	Total Pool Activity		**1,467.50**	**82,893.75**	**0.00**	**0.00**	**8,538.30**	**92,899.55**	**0.00**	**(39,932.61)**	**52,966.94**

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - REMEDIATION
PROJECT DEF054

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 199810022 3/13					3,595.22	3,595.22			3,595.22
2	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11038		5,749.52				5,749.52			5,749.52
3	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11094		4,042.43				4,042.43			4,042.43
4	[redacted]										
5	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11171		4,294.34				4,294.34			4,294.34
6	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 199810022 10/13					1,448.72	1,448.72			1,448.72
7	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11286		6,477.23				6,477.23			6,477.23
8	[redacted]										
9	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11211		3,956.22				3,956.22			3,956.22
10	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11308		8,769.51				8,769.51			8,769.51
11	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11355		9,337.16				9,337.16			9,337.16
12	[redacted]										
13	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11405		1,913.77				1,913.77			1,913.77
14	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11450		2,437.58				2,437.58			2,437.58
15	CASEY MARY	04/01 THRU 04/30/14					16.95	16.95			16.95
16	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11454		4,408.94				4,408.94			4,408.94
17	[redacted]										
18	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11518		2,869.33				2,869.33			2,869.33
19	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11494		2,346.49				2,346.49			2,346.49
20								0.00			0.00
21								0.00			0.00
22								0.00			0.00
23								0.00			0.00
24	Environmental Staff Time						1,733.88	1,733.88			1,733.88
	Total Pool Activity		**-**	**56,602.52**	**-**	**-**	**6,794.77**	**63,397.29**	**-**	**(27,447.20)**	**35,950.09**

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - REMEDIATION
PROJECT DEF055

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	[redacted]										
2											
3											
4											
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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
PROJECT DEF064

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CASEY MARY						$9.61	9.61			9.61
2	CASEY MARY						$12.43	12.43			12.43
3	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2013080687	$400.00					400.00			400.00
4	CASEY MARY						$21.91	21.91			21.91
5	ALLEGRA MARKETING PRINT MAIL	26070					$116.00	116.00			116.00
6	CASEY MARY						42.38	42.38			42.38
7	CASEY MARY						931.24	931.24			931.24
8	ISH INC - MGP CONSORTIUM ANNUAL DUES	MGP140602					2,500.00	2,500.00			2,500.00
9								-			0.00
10								-			0.00
11								-			0.00
12								-			0.00
13								-			0.00
14								-			0.00
15								-			0.00
16	Environmental Staff Time						9,105.54	9,105.54			9,105.54
	Total Pool Activity		**400.00**	**-**	**-**	**-**	**12,739.11**	**13,139.11**	**-**	**-**	**13,139.11**

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
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Concord Pond

		internal order no. 500061 (formerly acc no. 1796)														DEF056	
		(thru 3/98) pool #1	(4/98 - 9/98) pool #2	(10/98 - 9/15/99 pool #3	(9/99 - 9/00) pool #4	(9/03 - 9/04) pool #5	(9/04 - 9/05) pool #6	(9/05 - 9/06) pool #7	(9/06 - 9/07) pool #8	(9/07 - 9/08) pool #9	(9/08 - 9/09) pool #10	(9/09 - 9/10) pool #11	(9/10 - 9/11) pool #12	(9/11 - 9/12) pool #13	(9/12 - 9/13) pool #14	(9/13 - 9/14) pool #15	subtotal
1	Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	6,704,682
	Remediation costs (i.o. 500005)	-	-	-	-												-
A	Subtotal - remediation costs	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	6,704,682
																	-
	Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(2,159,273)
	Cash recoveries (i.o. 500004)	(445,985)	-	-	-												(445,985)
	Recovery costs (i.o. 500004)	623,784	-	-	-				-	-	-	-	-	-	-	-	623,784
	Transfer Credit from Gas Restructuring																-
B	Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(1,981,474)
																	-
A-B	Total net expenses to recover	520,030	1,409,330	1,654,552	95,798	60,293	21,613	81,979	142,350	95,374	115,579	136,936	216,743	81,238	59,069	32,324	4,723,208
																	-
																	-
	Surcharge revenue:																-
Act	June 1998 - October 1998	(54,889)	-	-	-												(54,889)
Act	November 1998 - October 1999	(287,010)	(251,133)	-	-												(538,143)
Act	November 1999 - October 2000	(178,131)	(266,400)	(316,340)	-												(760,871)
Act	November 2000 - October 2001	-	(292,420)	(334,194)	(13,925)												(640,539)
Act	November 2001 - October 2002	-	(281,914)	(318,686)	(24,514)												(625,114)
Act	November 2002 - October 2003	-	(258,347)	(334,331)	(15,197)												(607,874)
Act	November 2003 - October 2004	-	(14,567)	(276,773)	(14,567)												(305,907)
Act	November 2004- October 2005	-	-	(56,719)	(14,180)	(14,180)											(85,078)
Act	November 2005- October 2006	-	-	-	(6,875)	(6,875)											(13,750)
Act	November 2006- October 2007	-	-	-	-	-	-	(14,091)									(14,091)
Act	November 2007- October 2008																-
Act	November 2012- October 2013												(5,002)	(5,002)			(10,003)
Act	November 2013- October 2014												(11,887)	(11,887)			(23,774)
Act	Nov 2009-Oct 2010 Base Rate Rev												($4,423)				(4,423)
Act	Nov 2010-Oct 2011 Base Rate Rev												($32,310)				(32,310)
Act	Nov 2011-Oct 2012 Base Rate Rev												($28,448)				(28,448)
Act	Nov 2012-Oct 2013 Base Rate Rev												($2,143)	($2,143)			(4,286)
Act	Nov 2013-Oct 2014 Base Rate Rev																-
	AES collections					(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,725)	(13,950)	(162,694)
	Gas Street overcollection	-	(23,511)														(23,511)
	Prior Period Pool under/overcollection		-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	-	-	-	-	-	-	
																	0
																	-
C	Surcharge Subtotal	(520,030)	(1,388,292)	(1,616,004)	(50,710)	(9,559)	39,108	34,729	104,437	234,166	(12,904)	(13,145)	(97,433)	(32,769)	(13,725)	(13,950)	(3,935,705)
D	Net balance to be recovered (A-B+C)	-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	329,540	102,675	123,791	119,310	48,469	45,345	18,374	787,503
E	Allocation of Litigated Recovery					-		-		(329,540)	(102,675)	(123,791)	(65,100)	-	-	-	(621,106)
	Surcharge calculation																
	Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	-	54,210	48,469	45,345	18,374	166,397
	remaining life	-	-	-	-	24	36	48	60	72	84	84	48	60	72	84	
	one year	-	-	-	-	12	12	12	12	12	12	12	12	12	12	12	
F	amortization	-	-	-	-	-	-	-		-	-	-	13,553	9,694	7,557	2,625	33,429
	Required annual increase in rates:																
	smaller of D or F	-	-	-	-	-	-	-		-	-	-	13,553	9,694	7,557	2,625	33,429
	forecasted therm sales	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$0.0000	$0.0000	$0.0002

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Laconia & Liberty Hill

		i.o. no. 500005 (through 9/15/99) pool #1	(9/99 - 9/00) pool #2	(9/00 - 9/01) pool #3	(9/04 - 9/05) pool #4	(9/05 - 9/06) pool #5	(9/06 - 9/07) pool #6	(9/07 - 9/08) pool #7 Incl. Audit Corr	(9/08 - 9/09) pool #8 Incl. Audit Corr	(9/09 - 9/10) pool #9	(9/10 - 9/11) pool #10	(9/11 - 9/12) pool #11	(9/12 - 9/13) pool #12	DEF086 (9/13 - 9/14) pool #13	subtotal
1	Remediation costs (i.o. 500061)	-	-		-									[redacted]	
	Remediation costs (i.o. 500005)	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986		
A	Subtotal - remediation costs	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986		
	Cash recoveries (i.o. 500061)	-	-	-	-	-	-	-	-						
	Cash recoveries (i.o. 500004)	-	-	-	-	-	-	-	-						
	Recovery costs (i.o. 500004)	-	-	-			11,643	21,729	-	-					
	Transfer Credit from Gas Restructurinc						-	-	-						
B	Subtotal - net recoveries	-	-	-	-	-	11,643	21,729	-	-	-	-	-		
A-B	Total net expenses to recover	1,027,747	3,513,285	700,000	9,702	2,330,555	2,100,842	449,954	607,876	262,678	210,532	269,281	642,986		
	Surcharge revenue:														
Act	June 1998 - October 1998	-	-	-	-	-		-	-	-	-	-	-	-	-
Act	November 1998 - October 1999	-	-	-	-	-		-	-	-	-	-	-	-	-
Act	November 1999 - October 2000	(151,933)	-	-	-	-		-	-	-	-	-	-	-	(151,933)
Act	November 2000 - October 2001	(153,172)	(543,065)	-	-	-		-	-	-	-	-	-	-	(696,237)
Act	November 2001 - October 2002	(159,343)	(527,057)	(110,314)	-	-		-	-	-	-	-	-	-	(796,714)
Act	November 2002 - October 2003	(151,969)	(547,087)	(106,378)	-	-		-	-	-	-	-	-	-	(805,434)
Act	November 2003 - October 2004	(131,103)	(466,143)	(101,969)											(699,215)
Act	November 2004- October 2005	(127,617)	(439,570)	(85,078)											(652,264)
Act	November 2005- October 2006	(141,176)	(453,736)	(96,247)	-	-		-	-	-	-	-	-	-	(691,159)
Act	November 2006- October 2007	-	(549,539)	(98,635)	-	(309,996)									(958,171)
Act	November 2007- October 2008														-
Act	November 2012- October 2013											(20,006)			(20,006)
Act	November 2013- October 2014											(23,774)	(71,323)		(95,097)
Act	Nov 2009-Oct 2010 Base Rate Rev										($4,296)				(4,296)
Act	Nov 2010-Oct 2011 Base Rate Rev										($31,384)				(31,384)
Act	Nov 2011-Oct 2012 Base Rate Rev										($27,632)				(27,632)
Act	Nov 2012-Oct 2013 Base Rate Rev										$0	($14,208)			(14,208)
Act	Nov 2013-Oct 2014 Base Rate Rev											($27,903)	($27,903)	($27,903)	(83,708)
	AES collections														-
	Gas Street overcollection														-
	Prior Period Pool under/overcollection		11,434	(1,477)	99,902	109,604	2,130,162	4,231,004		-	-	(21,057)	-	-	
C	Surcharge Subtotal	(1,016,313)	(3,514,762)	(600,098)	99,902	(200,393)	2,130,162	4,231,004	-	-	(63,313)	(106,948)	(99,225)	(27,903)	(5,727,458)
D	Net balance to be recovered (A-B+C)	11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	4,680,958	607,876	262,678	147,219	162,333	543,761	[redacted]	
E	Allocation of Litigated Recovery							(4,680,958)	(607,876)	(262,678)	(168,276)	-	-		
	Surcharge calculation														
	Unrecovered costs (D+E)	-	-	-	-			-	-	-	-	162,333	543,761		
	remaining life	-	-	-	36	48	60	72	84	84	48	60	72		
	one year	-	-	-	12	12	12	12	12	12	12	12	12		
F	amortization	-	-	-	-	-	-	-	-	-	-	32,467	90,627		
	Required annual increase in rates:														
	smaller of D or F	-	-	-	-	-		-	-	-	-	32,467	90,627	[redacted]	
	forecasted therm sales	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0006	[redacted]	

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular

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Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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Manchester

		(9/00 - 9/01) pool #1	(9/02 - 9/03) pool #2	(9/02 - 9/03) pool #3 (withdrawn 2/1/04)	(9/03 - 9/04) pool #4	(9/04 - 9/05) pool #5	(9/05 - 9/06) pool #6	(9/06 - 9/07) pool #7	(9/07 - 9/08) pool #8 Incl. Audit Corr	(9/08 - 9/09) pool #9	(9/09 - 9/10) pool #10	(9/10 - 9/11) pool #11	(9/11 - 9/12) pool #12	(9/12 - 9/13) pool #13	DEF057 (9/13 - 9/14) pool #14	subtotal
1	Remediation costs (i.o. 500061)	-	-		335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	9,885,837
	Remediation costs (i.o. 500005)	495,106	329,986													825,092
A	Subtotal - remediation costs	495,106	329,986	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	10,710,929
	Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(270,732)	(39,933)	(2,544,325)
	Cash recoveries (i.o. 500004)	-	-													-
	Recovery costs (i.o. 500004)	-	-		1,242,326			2,546	-							1,244,872
	Transfer Credit from Gas Restructuring							-	-							-
B	Subtotal - net recoveries	-	-	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(234,648)	(65,324)	(270,732)	(39,933)	(1,299,453)
A-B	Total net expenses to recover	495,106	329,986	-	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	137,589	442,298	(188,619)	52,967	9,411,476
																-
																-
	Surcharge revenue:															-
Act	June 1998 - October 1998	-	-	-	-											-
Act	November 1998 - October 1999	-	-	-	-											-
Act	November 1999 - October 2000	-	-	-	-											-
Act	November 2000 - October 2001	-	-	-	-											-
Act	November 2001 - October 2002	(73,543)	-	-	-											(73,543)
Act	November 2002 - October 2003	(75,984)	-	-	-											(75,984)
Act	November 2003 - October 2004	(72,835)	(24,416)	(41,325)	-											(138,576)
Act	November 2004- October 2005	(70,898)	(42,539)	-	(212,695)	-			-	-	-	-	-	-	-	(326,132)
Act	November 2005- October 2006	(54,998)	(41,249)	-	(206,243)	(261,242)			-	-	-	-	-	-	-	(563,732)
Act	November 2006- October 2007	(70,454)	(56,363)	-	(211,361)	(281,815)	(42,272)									(662,265)
Act	November 2007- October 2008															-
Act	November 2012- October 2013												(40,012)			(40,012)
Act	November 2013- October 2014												(47,548)			(47,548)
Act	Nov 2009-Oct 2010 Base Rate Rev											$0				-
Act	Nov 2010-Oct 2011 Base Rate Rev											$0				-
Act	Nov 2011-Oct 2012 Base Rate Rev											$0				-
Act	Nov 2012-Oct 2013 Base Rate Rev											$0	($23,337)			(23,337)
Act	Nov 2013-Oct 2014 Base Rate Rev															-
	AES collections															-
	Gas Street overcollection															-
	Prior Period Pool under/overcollection		76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	-	-	-				
C	Surcharge Subtotal	(418,713)	(88,173)	200,488	(429,812)	604,796	2,552,371	2,882,534	3,225,936	-	-	-	(110,898)	-	-	(1,951,130)
D	Net balance to be recovered (A-B+C)	76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	6,486,145	312,185	328,678	137,589	331,400	(188,619)	52,967	7,460,346
E	Allocation of Litigated Recovery			-	-	-			(6,486,145)	(312,185)	(328,678)	(129,877)	-	-	-	(7,256,885)
	Surcharge calculation															
	Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-	7,713	331,400	(188,619)	52,967	203,461
	remaining life	-	-	-	24	36	48	60	70	84	84	48	60	72	84	
	one year	-	-	-	12	12	12	12	12	12	12	12	12	12	12	
F	amortization	-	-	-	-	-	-	-	-	-	-	1,928	66,280	(31,437)	7,567	
	Required annual increase in rates:															
	smaller of D or F	-	-	-	-	-	-		-	-	-	1,928	66,280	-	7,567	75,775
	forecasted therm sales	160,018,819	#########	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0004	$0.0000	$0.0000	$0.0005

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EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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		Nashua														
								Corrected per 2/08 Audit							DEF054	
		(9/00 - 9/01) pool #1	(9/01 - 9/02) pool #2	(9/02 - 9/03) pool #3	(9/03 - 9/04) pool #4	(9/04 - 9/05) pool #5	(9/05 - 9/06) pool #6	(9/06 - 9/07) pool #7	(9/07 - 9/08) pool #8	(9/08 - 9/09) pool #9	(9/09 - 9/10) pool #10	(9/10 - 9/11) pool #11	(9/11 - 9/12) pool #12	(9/12 - 9/13) pool #13	(9/13 - 9/14) pool #14	subtotal
1	Remediation costs (i.o. 500061)	-	-	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	1,246,178
	Remediation costs (i.o. 500005)	1,233,726	362,663	175,178												1,771,567
A	Subtotal - remediation costs	1,233,726	362,663	175,178	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	3,017,745
																-
	Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(420,686)
	Cash recoveries (i.o. 500004)	-	-	-												-
	Recovery costs (i.o. 500004)	-	-	-			5,449	12,938	-	-						18,388
	Transfer Credit from Gas Restructuring							-	-	-						-
B	Subtotal - net recoveries	-	-	-	-		(13,131)	8,787	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(402,298)
																-
A-B	Total net expenses to recover	1,233,726	362,663	175,178	10,841	206,367	10,223	18,524	97,191	16,289	98,975	33,351	396,411	(80,241)	35,950	2,615,447
	Surcharge revenue:															
Act	June 1998 - October 1998	-	-	-	-											-
Act	November 1998 - October 1999	-	-	-	-											-
Act	November 1999 - October 2000	-	-	-	-											-
Act	November 2000 - October 2001	-	-	-	-											-
Act	November 2001 - October 2002	(183,857)	-	-	-											(183,857)
Act	November 2002 - October 2003	(182,362)	(60,787)	-	-											(243,150)
Act	November 2003 - October 2004	(174,804)	(43,701)	(29,134)	-											(247,639)
Act	November 2004- October 2005	(170,156)	(42,539)	(28,359)	-											(241,054)
Act	November 2005- October 2006	(164,995)	(54,998)	(27,499)	-	(27,499)			-	-	-	-	-	-	-	(274,991)
Act	November 2006- October 2007	(169,089)	(56,363)	(28,181)	-	(28,181)	-									(281,815)
Act	November 2007- October 2008															-
Act	November 2012- October 2013												(40,012)			(40,012)
Act	November 2013- October 2014												(35,661)			(35,661)
Act	Nov 2009-Oct 2010 Base Rate Rev											$0				-
Act	Nov 2010-Oct 2011 Base Rate Rev											$0				-
Act	Nov 2011-Oct 2012 Base Rate Rev											$0				-
Act	Nov 2012-Oct 2013 Base Rate Rev											$0	($20,916)			(20,916)
Act	Nov 2013-Oct 2014 Base Rate Rev															-
	AES collections															-
	Gas Street overcollection															-
	Prior Period Pool under/overcollection		188,463	292,737	354,741	365,582	516,269	526,492	545,015	-	-	-	(2,447)	-	-	
C	Surcharge Subtotal	(1,045,263)	(69,925)	179,564	354,741	309,902	516,269	526,492	545,015	-	-	-	(99,037)	-	-	(1,569,095)
D	Net balance to be recovered (A-B+C)	188,463	292,737	354,741	365,582	516,269	526,492	545,015	642,206	16,289	98,975	33,351	297,374	(80,241)	35,950	1,046,352
E	Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	(16,289)	(98,975)	(35,798)	-	-	-	(793,268)
	Surcharge calculation															
	Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-		297,374	(80,241)	35,950	253,083
	remaining life	-	-	12	24	36	48	60	72	84	84	72	60	72	84	
	one year	-	12	12	12	12	12	12	12	12	12	12	12	12	12	
F	amortization	-	-	-	-	-	-	-	-	-	-	-	59,475	(13,374)	5,136	
	Required annual increase in rates:															
	smaller of D or F	-	-	-	-	-	-		-	-	-	-	59,475	(13,374)	5,136	51,237
	forecasted therm sales	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0004	($0.0001)	$0.0000	$0.0003

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Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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		Dover											
												DEF059	
		(9/02 - 9/03) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	(9/08 - 9/09) pool #6	(9/09 - 9/10) pool #7	(9/10 - 9/11) pool #8	(9/11 - 9/12) pool #9	(9/12 - 9/13) pool #10	(9/13 - 9/14) pool #11	subtotal
1	Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	-	-	-	-	-	-	21,142
	Remediation costs (i.o. 500005)	181,066											181,066
A	Subtotal - remediation costs	181,066	18,854	2,288	-	-	-	-	-	-	-	-	202,208
	Cash recoveries (i.o. 500061)	-					-	-	-	-	-	-	-
	Cash recoveries (i.o. 500004)	-											-
	Recovery costs (i.o. 500004)	-											-
	Transfer Credit from Gas Restructuring												-
B	Subtotal - net recoveries	-	-	-	-	-	-	-	-	-	-	-	-
A-B	Total net expenses to recover	181,066	18,854	2,288	-	-	-	-	-	-	-	-	202,208
	Surcharge revenue:												
Act	June 1998 - October 1998	-											-
Act	November 1998 - October 1999	-											-
Act	November 1999 - October 2000	-											-
Act	November 2000 - October 2001	-											-
Act	November 2001 - October 2002	-											-
Act	November 2002 - October 2003	-											-
Act	November 2003 - October 2004	(29,134)											(29,134)
Act	November 2004- October 2005	(28,359)											(28,359)
Act	November 2005- October 2006	(27,499)	-			-	-	-	-	-	-	-	(27,499)
Act	November 2006- October 2007	(28,181)	-	-									(28,181)
Act	November 2007- October 2008												-
Act	November 2012- October 2013												-
Act	November 2013- October 2014												-
Act	Nov 2009-Oct 2010 Base Rate Rev												-
Act	Nov 2010-Oct 2011 Base Rate Rev												-
Act	Nov 2011-Oct 2012 Base Rate Rev												-
Act	Nov 2012-Oct 2013 Base Rate Rev												-
Act	Nov 2013-Oct 2014 Base Rate Rev												-
	AES collections												-
	Gas Street overcollection												-
	Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034	-	-	-	-	-	-	
C	Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	-	-	-	-	-	-	(113,174)
D	Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	-	-	-	-	-	-	89,034
E	Allocation of Litigated Recovery		-		-	(89,034)	-	-	-	-	-	-	(89,034)
	Surcharge calculation												
	Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	-	-
	remaining life	24	36	48	60	72	84	84	84	84	84	84	
	one year	12	12	12	12	12	12	12	12	12	12	12	
F	amortization	-	-	-	-	-	-	-	-	-	-	-	
	Required annual increase in rates:												
	smaller of D or F	-	-	-		-	-	-	-	-	-	-	-
	forecasted therm sales	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

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Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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		Keene											
												DEF055	
		(9/03 - 9/04) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	(9/08 - 9/09) pool #6	(9/09 - 9/10) pool #7	(9/10 - 9/11) pool #8	(9/11 - 9/12) pool #9	(9/12 - 9/13) pool #10	(9/13 - 9/14) pool #11	subtotal
1	Remediation costs (i.o. 500061)	-										[redacted]	
	Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400		
A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400		
	Cash recoveries (i.o. 500061)	-											
	Cash recoveries (i.o. 500004)	-											
	Recovery costs (i.o. 500004)			18,831	823	-	-	-	-				
	Transfer Credit from Gas Restructuring				-	-	-						
B	Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-		
A-B	Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400		
													-
													-
	Surcharge revenue:												-
Act	June 1998 - October 1998	-											-
Act	November 1998 - October 1999	-											-
Act	November 1999 - October 2000	-											-
Act	November 2000 - October 2001	-											-
Act	November 2001 - October 2002	-											-
Act	November 2002 - October 2003	-											-
Act	November 2003 - October 2004	-											-
Act	November 2004- October 2005	-	-				-	-	-	-	-	-	-
Act	November 2005- October 2006	-	-				-	-	-	-	-	-	-
Act	November 2006- October 2007	-	-	(14,091)									(14,091)
Act	November 2007- October 2008												-
Act	November 2012- October 2013												-
Act	November 2013- October 2014												-
Act	Nov 2009-Oct 2010 Base Rate Rev												-
Act	Nov 2010-Oct 2011 Base Rate Rev												-
Act	Nov 2011-Oct 2012 Base Rate Rev												-
Act	Nov 2012-Oct 2013 Base Rate Rev												-
Act	Nov 2013-Oct 2014 Base Rate Rev												-
	AES collections												-
	Gas Street overcollection												-
	Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	-	-	-	-	
C	Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	-	-	-	-	(14,091)
D	Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	-	488	1,400	[redacted]	
E	Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	-		
	Surcharge calculation												
	Unrecovered costs (D+E)	-	-	-			-	-	-	488	1,400		
	remaining life	24	36	48	60	72	84	84	84	60	72		
	one year	12	12	12	12	12	12	12	12	12	12		
F	amortization	-	-	-	-	-	-	-	-	98	233		
	Required annual increase in rates:												
	smaller of D or F	-	-	-			-	-	-	98	233	[redacted]	
	forecasted therm sales	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]	

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Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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	Concord											
			Corrected per 1/24/07 Audit	Corrected per 2/08 Audit							DEF077	
	(9/03 - 9/04) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	(9/08 - 9/09) pool #6	(9/09 - 9/10) pool #7	(9/10 - 9/11) pool #8	(9/11 - 9/12) pool #9	(9/12 - 9/13) pool #10	(9/13 - 9/14) pool #11	subtotal
1 Remediation costs (i.o. 500061)	-											-
Remediation costs (i.o. 500005)	22,191	220,932	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	1,220,346
A Subtotal - remediation costs	22,191	220,932	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	1,220,346
												-
Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(163,566)
Cash recoveries (i.o. 500004)	-											-
Recovery costs (i.o. 500004)					1,432	(1,007)						425
Transfer Credit from Gas Restructuring			-									-
B Subtotal - net recoveries	-	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(163,140)
A-B Total net expenses to recover	22,191	220,932	22,106	61,665	(3,163)	92,679	46,190	168,338	257,528	45,384	123,355	1,057,205
												-
												-
Surcharge revenue:												-
Act June 1998 - October 1998	-											-
Act November 1998 - October 1999	-											-
Act November 1999 - October 2000	-											-
Act November 2000 - October 2001	-											-
Act November 2001 - October 2002	-											-
Act November 2002 - October 2003	-											-
Act November 2003 - October 2004	-											-
Act November 2004- October 2005												-
Act November 2005- October 2006	-	(27,499)			-	-	-	-	-	-	-	(27,499)
Act November 2006- October 2007	-	(28,181)	-									(28,181)
Act November 2007- October 2008												-
Act November 2012- October 2013								(20,006)	(20,006)			(40,012)
Act November 2013- October 2014								(11,887)	(23,774)			(35,661)
Act Nov 2009-Oct 2010 Base Rate Rev								($1,891)				(1,891)
Act Nov 2010-Oct 2011 Base Rate Rev								($13,816)				(13,816)
Act Nov 2011-Oct 2012 Base Rate Rev								($12,164)				(12,164)
Act Nov 2012-Oct 2013 Base Rate Rev								($6,794)	($6,794)			(13,588)
Act Nov 2013-Oct 2014 Base Rate Rev												-
AES collections												-
Gas Street overcollection												-
Prior Period Pool under/overcollection		22,191	187,442	209,549	271,214	-	-	-	-	-	-	
C Surcharge Subtotal	-	(33,490)	187,442	209,549	271,214	-	-	(66,558)	(50,574)	-	-	(172,813)
D Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	92,679	46,190	101,780	206,954	45,384	123,355	884,392
												-
E Allocation of Litigated Recovery	-	-	-	-	(268,051)	(92,679)	(46,190)	(12,960)	-	-	-	(419,879)
												-
Surcharge calculation												-
Unrecovered costs (D+E)	-	-	-		-	-	-	88,820	206,954	45,384	123,355	464,513
remaining life	36	48	60		72	84	84	48	60	72	84	
one year	12	12	12		12	12	12	12	12	12	12	
F amortization	-	-	-		-	-	-	22,205	41,391	7,564	17,622	
Required annual increase in rates:												
smaller of D or F	-	-	-		-	-	-	22,205	41,391	7,564	17,622	88,782
forecasted therm sales	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0003	$0.0000	$0.0001	$0.0006

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	General															
				Corrected per 1/24/07 Audit								DEF064				2014 MGP Remediation
	(9/02 - 9/03) pool #1	(9/03 - 9/04) pool #2	(9/04 - 9/05) pool #3	(9/05 - 9/06) pool #4	(9/06 - 9/07) pool #5	(9/07 - 9/08) pool #6	(9/08 - 9/09) pool #7	(9/09 - 9/10) pool #8	(9/10 - 9/11) pool #9	(9/11 - 9/12) pool #10	(9/12 - 9/13) pool #11	(9/13 - 9/14) pool #12	subtotal			subtotal
1 Remediation costs (i.o. 500061)	-												-			
Remediation costs (i.o. 500005)	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	853,590			[redacted]
A Subtotal - remediation costs	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	853,590			
Cash recoveries (i.o. 500061)	-				-	-	-						-			
Cash recoveries (i.o. 500004)	-												-			
Recovery costs (i.o. 500004)				290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	346,520			
Transfer Credit from Gas Restructuring	(3,331)			-									(3,331)			
B Subtotal - net recoveries	(3,331)	-	-	290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	343,189			
A-B Total net expenses to recover	(123)	538,903	208,128	324,511	53,844	(164,988)	(2,931)	4,199	69,286	78,967	73,846	13,139	1,196,779			
																-
Surcharge revenue:																
Act June 1998 - October 1998	-	-											-			(54,889)
Act November 1998 - October 1999	-	-											-			(538,143)
Act November 1999 - October 2000	-	-											-			(912,804)
Act November 2000 - October 2001	-	-											-			(1,336,776)
Act November 2001 - October 2002	-	-											-			(1,679,228)
Act November 2002 - October 2003	-	-											-			(1,732,442)
Act November 2003 - October 2004	(8,265)	-											(8,265)			(1,428,735)
Act November 2004- October 2005		(70,898)											(70,898)			(1,403,787)
Act November 2005- October 2006		(68,748)	(27,499)			-	-	-	-	-	-	-	(96,247)			(1,694,877)
Act November 2006- October 2007		(77,499)	(28,181)	(49,318)									(154,998)			(2,141,793)
Act November 2007- October 2008													-			-
Act November 2012- October 2013									(5,002)	(5,002)			(10,003)			(160,048)
Act November 2013- October 2014									(11,887)	(11,887)	(11,887)		(35,661)			(273,404)
Act Nov 2009-Oct 2010 Base Rate Rev													-			(10,611)
Act Nov 2010-Oct 2011 Base Rate Rev													-			(77,509)
Act Nov 2011-Oct 2012 Base Rate Rev													-			(68,244)
Act Nov 2012-Oct 2013 Base Rate Rev													-			(76,335)
Act Nov 2013-Oct 2014 Base Rate Rev																(83,708)
AES collections		-											-			(162,694)
Gas Street overcollection													-			(23,511)
Prior Period Pool under/overcollection		(8,388)	313,370	465,817	741,010	794,853	-	-	-	-	-	-				
C Surcharge Subtotal	(8,265)	(225,533)	257,689	416,499	741,010	794,853	-	-	(16,889)	(16,889)	(11,887)	-	(376,073)		(13,859,539)	(13,859,539)
D Net balance to be recovered (A-B+C)	(8,388)	313,370	465,817	741,010	794,853	629,865	(2,931)	4,199	52,397	62,078	61,959	13,139	820,706	4,960,120	21,707,305	[redacted]
														-		
E Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	2,931	(4,199)	(16,426)	-	-	-	(647,559)	(428,437)	(15,614,032)	
														-		
Surcharge calculation														-		
Unrecovered costs (D+E)	-	-	-	-		-	-	-	35,971	62,078	61,959	13,139	173,147	5,664,284	6,093,272	
remaining life		36	48	60	72	84	84	84	48	60	72	84				
one year		12	12	12	12	12	12	12	12	12	12	12				
F amortization		-	-	-	-	-	-	-	8,993	12,416	10,327	1,877				
Required annual increase in rates:																
smaller of D or F	-	-	-	-		-	-	-	8,993	12,416	10,327	1,877	33,612	892,565	995,500	
forecasted therm sales	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819	160,018,819			**160,018,819**
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$0.0001	$0.0000	$0.0002			**$0.0062**

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Cash Recoveries[1]

	(9/11 - 9/12) Concord Pond	(9/10 - 9/11) Concord Ponc	(9/09 - 9/10) Concord Pond	(9/08 - 9/09) Concord Pond	(9/07 - 9/08) Concord Pond	(9/06 - 9/07) Concord Pond	(9/05 - 9/06) Concord Pond	(9/04- 9/05) Concord Pond	(9/03 - 9/04) Concord Pond	(9/11 - 9/12) Laconia	(9/10 - 9/11) Laconia	(9/09 - 9/10) Laconia	(9/08 - 9/09) Laconia	(9/07 - 9/08) Laconia	(9/06 - 9/07) Laconia
1 Remediation costs (i.o. 500061)	-	-	-	-	-		-	-	-	-	-	-	-	-	
Remediation costs (i.o. 500005)	-	-	-	-	-		-	-	-	-	-	-	-	-	
A Subtotal - remediation costs	-	-	-	-	-		-	-	-	-	-	-	-	-	
Cash recoveries (i.o. 500061)															
Cash recoveries (i.o. 500004)				-	568	-	-	-	(648,000)	-	-	-	-	-	-
Recovery costs (i.o. 500004)				-	-	-	73	-	658,508				-	-	45
Transfer Credit from Gas Restructurinc				-	-	-	-	-	-						
B Subtotal - net recoveries	-	-	-	-	568	-	73	-	10,508	-	-	-	-	-	45
A-B Total net expenses to recover	-	-	-	-	568	-	73	-	10,508	-	-	-	-	-	45
Surcharge revenue:															
Act June 1998 - October 1998	-	-	-	-	-		-	-	-						
Act November 1998 - October 1999	-	-	-	-	-		-	-	-						
Act November 1999 - October 2000	-	-	-	-	-		-	-	-						
Act November 2000 - October 2001	-	-	-	-	-		-	-	-						
Act November 2001 - October 2002	-	-	-	-	-		-	-	-						
Act November 2002 - October 2003	-	-	-	-	-		-	-	-						
Act November 2003 - October 2004	-	-	-	-	-		-	-	-						
Act November 2004- October 2005															
Act November 2005- October 2006															
Act November 2006- October 2007															
Act November 2007- October 2008															
Act November 2012- October 2013															
Act November 2013- October 2014															
Act Nov 2009-Oct 2010 Base Rate Rev															
Act Nov 2010-Oct 2011 Base Rate Rev															
Act Nov 2011-Oct 2012 Base Rate Rev															
Act Nov 2012-Oct 2013 Base Rate Rev															
Act Nov 2013-Oct 2014 Base Rate Rev															
AES collections	-	-	-	-	-		-	-	-						
Gas Street overcollection	-	-	-	-	-		-	-	-						
Prior Period Pool under/overcollection															
C Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D Net balance to be recovered (A-B+C)	-	-	-	-	568	-	73	-	10,508	-	-	-	-	-	45
E Allocation of Litigated Recovery															
Surcharge calculation															
Unrecovered costs (D+E)															
remaining life															
one year															
F amortization															
Required annual increase in rates:															
smaller of D or F															
forecasted therm sales															
surcharge per therm															

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Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

EnergyNorth Natural Gas, Inc.
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		Corrected per 1/24/07 Audit (9/05 - 9/06) Laconia	(9/04 - 9/05) Laconia	(9/03 - 9/04) Laconia	(9/11 - 9/12) Manchester	(9/10 - 9/11) Manchester	(9/09 - 9/10) Manchester	(9/08 - 9/09) Manchester	(9/07 - 9/08) Manchester	(9/06 - 9/07) Manchester	Corrected per 1/24/07 Audit (9/05 - 9/06) Manchester	(9/04 - 9/05) Manchester	(9/03 - 9/04) Manchester	(9/11 - 9/12) Nashua	(9/10 - 9/11) Nashua	(9/09 - 9/10) Nashua	(9/08 - 9/09) Nashua	(9/07 - 9/08) Nashua
1	Remediation costs (i.o. 500061)		-	-	-	-								-	-	-	-	-
	Remediation costs (i.o. 500005)		-	-										-	-	-	-	-
A	Subtotal - remediation costs		-	-										-	-	-	-	-
	Cash recoveries (i.o. 500061)																	
	Cash recoveries (i.o. 500004)	-	(23,619)	(2,677,000)				9,679	-	(630,000)	(1,725,792)	(754,938)	-	-	-	-		(1,032,186)
	Recovery costs (i.o. 500004)	22,240	486,894	1,492,967	-	-	-	(2,008,365)	77,222	195,929	941,433	307,062	951,425					561,030
	Transfer Credit from Gas Restructuring																	
B	Subtotal - net recoveries	22,240	463,275	(1,184,033)	-	-	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	-	-	(471,155)
A-B	Total net expenses to recover	22,240	463,275	(1,184,033)	-	-	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	-	-	(471,155)
	Surcharge revenue:																	
Act	June 1998 - October 1998				-	-	-	-	-		-	-						
Act	November 1998 - October 1999				-	-	-	-	-	-	-	-						
Act	November 1999 - October 2000				-	-	-	-	-	-	-	-						
Act	November 2000 - October 2001				-	-	-	-	-	-	-	-						
Act	November 2001 - October 2002				-	-	-	-	-	-	-	-						
Act	November 2002 - October 2003				-	-	-	-	-	-	-	-						
Act	November 2003 - October 2004				-	-	-	-	-	-	-	-						
Act	November 2004- October 2005																	
Act	November 2005- October 2006										-	-						
Act	November 2006- October 2007																	
Act	November 2007- October 2008																	
Act	November 2012- October 2013																	
Act	November 2013- October 2014																	
Act	Nov 2009-Oct 2010 Base Rate Rev																	
Act	Nov 2010-Oct 2011 Base Rate Rev																	
Act	Nov 2011-Oct 2012 Base Rate Rev																	
Act	Nov 2012-Oct 2013 Base Rate Rev																	
Act	Nov 2013-Oct 2014 Base Rate Rev																	
	AES collections				-	-	-	-	-	-								
	Gas Street overcollection				-	-	-	-	-	-								
	Prior Period Pool under/overcollection										-	-						
											-	-						
C	Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D	Net balance to be recovered (A-B+C)	22,240	463,275	(1,184,033)	-	-	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	-	-	(471,155)
E	Allocation of Litigated Recovery																	
	Surcharge calculation																	
	Unrecovered costs (D+E)																	
	remaining life																	
	one year																	
F	amortization																	
	Required annual increase in rates:																	
	smaller of D or F																	
	forecasted therm sales																	
	surcharge per therm																	

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular

ıe following protective orders:
er No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
er No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

Natural Gas, Inc.
ıl Remediation - MGPs

		(9/06 - 9/07) Nashua	(9/05 - 9/06) Nashua	(9/04 - 9/05) Nashua	(9/03 - 9/04) Nashua	(9/11 - 9/12) Dover	(9/10 - 9/11) Dover	(9/09 - 9/10) Dover	(9/08 - 9/09) Dover	(9/07 - 9/08) Dover	(9/06 - 9/07) Dover	(9/05 - 9/06) Dover	(9/04 - 9/05) Dover	(9/03 - 9/04) Dover	(9/10 - 9/11) Keene	(9/10 - 9/11) Keene
1	Remediation costs (i.o. 500061)			-		-	-	-	-	-		-	-		-	-
	Remediation costs (i.o. 500005)			-		-	-	-	-	-		-	-			
A	Subtotal - remediation costs			-		-	-	-	-	-		-	-			
	Cash recoveries (i.o. 500061)															
	Cash recoveries (i.o. 500004)	(544,402)	(625,000)	(782,450)	(795,000)	-	-	-	-	(2,133)	-	(237,489)	(7,150)	(645,500)	-	-
	Recovery costs (i.o. 500004)	78,298	645,302	537,552	655,683				(92,947)	-	14,848	117,621	517,891	500,868		
	Transfer Credit from Gas Restructuring															
B	Subtotal - net recoveries	(466,104)	20,302	(244,898)	(139,317)	-	-	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	-	-
A-B	Total net expenses to recover	(466,104)	20,302	(244,898)	(139,317)	-	-	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	-	-
	Surcharge revenue:															
Act	June 1998 - October 1998															
Act	November 1998 - October 1999															
Act	November 1999 - October 2000															
Act	November 2000 - October 2001															
Act	November 2001 - October 2002															
Act	November 2002 - October 2003															
Act	November 2003 - October 2004															
Act	November 2004- October 2005															
Act	November 2005- October 2006															
Act	November 2006- October 2007															
Act	November 2007- October 2008															
Act	November 2012- October 2013															
Act	November 2013- October 2014															
Act	Nov 2009-Oct 2010 Base Rate Rev															
Act	Nov 2010-Oct 2011 Base Rate Rev															
Act	Nov 2011-Oct 2012 Base Rate Rev															
Act	Nov 2012-Oct 2013 Base Rate Rev															
Act	Nov 2013-Oct 2014 Base Rate Rev															
	AES collections															
	Gas Street overcollection															
	Prior Period Pool under/overcollection															
C	Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-		
D	Net balance to be recovered (A-B+C)	(466,104)	20,302	(244,898)	(139,317)	-	-	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)	-	-
E	Allocation of Litigated Recovery															
	Surcharge calculation															
	Unrecovered costs (D+E)															
	remaining life															
	one year															
F	amortization															
	Required annual increase in rates:															
	smaller of D or F															
	forecasted therm sales															
	surcharge per therm															

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EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
Tariff page 91

		(9/09 - 9/10) Keene	(9/08 - 9/09) Keene	(9/07 - 9/08) Keene	(9/06 - 9/07) Keene	(9/05 - 9/06) Keene	(9/04 - 9/05) Keene	(9/03 - 9/04) Keene	(9/06 - 9/07) General	2012 subtotal	MGP TOTAL
1	Remediation costs (i.o. 500061)					-	-			-	[redacted]
	Remediation costs (i.o. 500005)					-	-			-	[redacted]
A	Subtotal - remediation costs					-	-			-	[redacted]
											[redacted]
	Cash recoveries (i.o. 500061)									-	[redacted]
	Cash recoveries (i.o. 500004)	-	116			(700,000)	(211,213)	0	(10,760,900)	(22,792,408)	[redacted]
	Recovery costs (i.o. 500004)			1,559	28,211	309,618	56,392	121,018		7,178,376	[redacted]
	Transfer Credit from Gas Restructuring									-	[redacted]
B	Subtotal - net recoveries	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	[redacted]
										-	[redacted]
A-B	Total net expenses to recover	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	[redacted]
	Surcharge revenue:										
Act	June 1998 - October 1998									-	(54,889)
Act	November 1998 - October 1999									-	(538,143)
Act	November 1999 - October 2000									-	(912,804)
Act	November 2000 - October 2001									-	(1,336,776)
Act	November 2001 - October 2002									-	(1,679,228)
Act	November 2002 - October 2003									-	(1,732,442)
Act	November 2003 - October 2004									-	(1,428,735)
Act	November 2004- October 2005									-	(1,403,787)
Act	November 2005- October 2006										(1,694,877)
Act	November 2006- October 2007										(2,141,793)
Act	November 2007- October 2008										-
Act	November 2012- October 2013										(160,048)
Act	November 2013- October 2014										(273,404)
Act	Nov 2009-Oct 2010 Base Rate Rev										(10,611)
Act	Nov 2010-Oct 2011 Base Rate Rev										(77,509)
Act	Nov 2011-Oct 2012 Base Rate Rev										(68,244)
Act	Nov 2012-Oct 2013 Base Rate Rev										(76,335)
Act	Nov 2013-Oct 2014 Base Rate Rev										(83,708)
	AES collections									-	(162,694)
	Gas Street overcollection									-	(23,511)
	Prior Period Pool under/overcollection									-	
										-	
C	Surcharge Subtotal				-	-	-	-		-	(13,859,539)
										-	[redacted]
										-	[redacted]
D	Net balance to be recovered (A-B+C)	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	[redacted]
E	Allocation of Litigated Recovery									15,614,032	
										-	
	Surcharge calculation										
	Unrecovered costs (D+E)										
	remaining life										
	one year										
F	amortization										
	Required annual increase in rates:										
	smaller of D or F										
	forecasted therm sales										
	surcharge per therm										

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular

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EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
Tariff page 91

Expense and Collection Summary per Year

		(thru 3/98)	(4/98 - 9/98)	(10/98 - 9/15/99)	(9/99 - 9/00)	(9/00 - 9/01)	(9/01 - 9/02)	(9/02 - 9/03)	(9/03 - 9/04)	(9/04 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	(9/10 - 9/11)	(9/11 - 9/12)	(9/12 - 9/13)	(9/13 - 9/14)	Total
1	Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	686,515	993,434	279,595	196,611	[redacted]
	Remediation costs (i.o. 500005)	-	-	1,027,747	3,513,285	2,428,832	362,663	689,437	571,259	445,367	2,444,366	2,229,625	255,263	658,324	316,280	459,550	651,906	803,846	1,801,404	
A	Subtotal - remediation costs	1,422,811	1,843,806	3,181,982	3,642,287	2,428,832	362,663	689,437	977,731	2,682,050	3,442,003	2,956,367	4,845,887	1,177,231	991,045	1,146,065	1,645,340	1,083,441	1,998,015	
	Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(105,062)	(528,258)	(87,688)	
	Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	
	Recovery costs (i.o. 500004)	623,784	-	-	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	-	(14,068)	(1,358)	2,500,000	
	Transfer Credit from Gas Restructuring	-	-	-	-	-	-	(3,331)	-	-	-	-	-	-	-	-	-	-	-	
B	Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(3,331)	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(310,226)	(119,129)	(529,616)	2,412,312	
A-B	Total net expenses to recover	520,030	1,409,330	2,682,299	3,609,083	2,428,832	362,663	686,106	1,835,026	2,808,471	1,903,772	(8,887,756)	3,340,669	(949,571)	877,655	835,839	1,526,211	553,825.34	4,410,326.68	
	Surcharge revenue:																			
Act	June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
Act	November 1998 - October 1999	(287,010)	(251,133)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
Act	November 1999 - October 2000	(178,131)	(266,400)	(468,273)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
Act	November 2000 - October 2001	-	(292,420)	(487,366)	(556,990)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,336,776)
Act	November 2001 - October 2002	-	(281,914)	(478,029)	(551,571)	(367,714)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,679,228)
Act	November 2002 - October 2003	-	(258,347)	(486,300)	(562,284)	(364,725)	(60,787)	-	-	-	-	-	-	-	-	-	-	-	-	(1,732,442)
Act	November 2003 - October 2004	-	(14,567)	(407,875)	(480,710)	(349,608)	(43,701)	(132,274)	-	-	-	-	-	-	-	-	-	-	-	(1,428,735)
Act	November 2004- October 2005	-	-	(184,336)	(453,749)	(326,132)	(42,539)	(99,258)	(297,773)	-	-	-	-	-	-	-	-	-	-	(1,403,787)
Act	November 2005- October 2006	-	-	(141,176)	(460,610)	(316,240)	(54,998)	(96,247)	(281,866)	(343,739)	-	-	-	-	-	-	-	-	-	(1,694,877)
Act	November 2006- October 2007	-	-	-	(549,539)	(338,178)	(56,363)	(112,726)	(288,860)	(366,359)	(429,768)	-	-	-	-	-	-	-	-	(2,141,793)
Act	November 2007- October 2008															-	-	-	-	-
Act	November 2012- October 2013											-	-	-	-	(30,009)	(130,039)	-	-	(160,048)
Act	November 2013- October 2014															(35,661)	(154,533)	(83,210)	-	(273,404)
Act	Nov 2009-Oct 2010 Base Rate Rev															(10,611)	-	-	-	(10,611)
Act	Nov 2010-Oct 2011 Base Rate Rev															(77,509)	-	-	-	(77,509)
Act	Nov 2011-Oct 2012 Base Rate Rev															(68,244)	-	-	-	(68,244)
Act	Nov 2012-Oct 2013 Base Rate Rev															(8,937)	(67,398)	-	-	(76,335)
Act	Nov 2013-Oct 2014 Base Rate Rev															-	(27,903)	(27,903)	(27,903)	(83,708)
	AES collections	-	-	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,725)	(13,950)	(162,694)
	Gas Street overcollection	-	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
	Prior Period Pool under/overcollection																			
C	Surcharge Subtotal	(520,030)	(1,388,292)	(2,653,355)	(3,615,454)	(2,062,596)	(258,389)	(440,504)	(902,092)	(721,725)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(244,193)	(393,610)	(124,837)	(41,853)	(13,859,539)
D	Net balance to be recovered (A-B+C)	-	21,038	28,944	(6,371)	366,236	104,274	245,602	932,934	2,086,746	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	591,646	1,132,601	428,988	4,368,474	[redacted]
E	Allocation of Litigated Recovery																			
	Surcharge calculation																			
	Unrecovered costs (D+E)																			
	remaining life																			
	one year																			
F	amortization																			
	Required annual increase in rates:																			
	smaller of D or F																			
	forecasted therm sales																			
	surcharge per therm																			

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular

Schedule 21

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Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2014-15

Rate: $0.21 /MMBtu

	Rate	Volume	Total	
Injection Cost	$0.0087	**373,371**	$3,248	
Fuel (1.07%)	$0.0401	**373,371**	$14,982	
Withdrawal Cost	$0.0087	**203,547**	$1,771	
Delivery Rate	$0.0506	203,547	$10,306	
FTA Demand Charge	$0.2754	203,547	$56,064	
FTA Commodity Charge	$0.1140	203,547	$23,204	
Fuel (1.39%)	$0.0521	203,547	$10,610	
		Total Cost	$120,184	
	Absolute Value of the	Sendout Error	**576,918**	MMBtu
		Rate	$ 0.21	/MMBTU

NOTES:	See Tennessee Gas Pipeline Tariff Pages in Tab 6		
	TGP FSMA Injection Charge	$0.0087	/ MMBtu
	TGP FSMA Withdrawal Charge	$0.0087	/ MMBtu
	TGP FSMA Deliverability Charge	$1.54	/ MMBtu per month
		$0.0506	/ MMBtu per day
	TGP Z4-6 Demand Charge	$8.3778	/ MMBtu per month
		$0.2754	/ MMBtu per day
	TGP Z4-6 Commodity Charge	$0.1140	/ MMBtu

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2014-15

Estimated Monthly Imbalances

Date	Forecasted DD	Actual DD	Forecaster Error DD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Nov	830	802	28	1,659,374	1,614,738	44,636	89,272	66,954	22,318
Dec	1,170	1,156	14	2,391,176	2,367,950	23,226	126,086	74,656	51,430
Jan	1,310	1,295	15	2,623,439	2,598,554	24,885	77,974	51,430	26,544
Feb	1,188	1,173	15	2,379,705	2,355,411	24,294	100,609	62,452	38,157
Mar	1,102	1,065	37	1,903,221	1,850,355	52,866	73,333	63,099	10,234
Apr	506	500	6	860,437	854,116	6,320	42,134	24,227	17,907
May	181	211	-30	406,956	418,501	-11,545	15,393	1,924	13,469
Jun	47	40	7	286,931	284,755	2,176	5,284	3,730	1,554
Jul	1	1	0	299,341	299,341	0	0	0	0
Aug	1	2	-1	299,214	299,326	-112	112	0	112
Sep	149	146	3	386,980	385,926	1,054	7,379	4,216	3,162
Oct	387	382	5	797,494	792,311	5,183	42,503	23,843	18,660
Total	**6,872**	**6,773**	**99**	**14,294,268**	**14,121,284**	**172,985**	**580,078**	**376,531**	**203,547**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2014-15
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Apr 1, 13	26	25	1	38,302	37,249	1,053	1,053	1,053	0
Apr 2, 13	33	32	1	45,675	44,622	1,053	1,053	1,053	0
Apr 3, 13	30	28	2	42,515	40,409	2,107	2,107	2,107	0
Apr 4, 13	22	19	3	34,088	30,928	3,160	3,160	3,160	0
Apr 5, 13	22	22	0	34,088	34,088	0	0	0	0
Apr 6, 13	28	30	-2	40,409	42,515	-2,107	2,107	0	2,107
Apr 7, 13	17	17	0	28,822	28,822	0	0	0	0
Apr 8, 13	11	12	-1	22,502	23,555	-1,053	1,053	0	1,053
Apr 9, 13	10	11	-1	21,448	22,502	-1,053	1,053	0	1,053
Apr 10, 13	12	14	-2	23,555	25,662	-2,107	2,107	0	2,107
Apr 11, 13	22	24	-2	34,088	36,195	-2,107	2,107	0	2,107
Apr 12, 13	29	29	0	41,462	41,462	0	0	0	0
Apr 13, 13	18	19	-1	29,875	30,928	-1,053	1,053	0	1,053
Apr 14, 13	21	22	-1	33,035	34,088	-1,053	1,053	0	1,053
Apr 15, 13	17	17	0	28,822	28,822	0	0	0	0
Apr 16, 13	9	7	2	20,395	18,288	2,107	2,107	2,107	0
Apr 17, 13	15	13	2	26,715	24,608	2,107	2,107	2,107	0
Apr 18, 13	9	8	1	20,395	19,341	1,053	1,053	1,053	0
Apr 19, 13	2	2	0	13,021	13,021	0	0	0	0
Apr 20, 13	20	20	0	31,982	31,982	0	0	0	0
Apr 21, 13	22	22	0	34,088	34,088	0	0	0	0
Apr 22, 13	20	23	-3	31,982	35,142	-3,160	3,160	0	3,160
Apr 23, 13	21	22	-1	33,035	34,088	-1,053	1,053	0	1,053
Apr 24, 13	8	3	5	19,341	14,075	5,267	5,267	5,267	0
Apr 25, 13	13	14	-1	24,608	25,662	-1,053	1,053	0	1,053
Apr 26, 13	13	15	-2	24,608	26,715	-2,107	2,107	0	2,107
Apr 27, 13	11	11	0	22,502	22,502	0	0	0	0
Apr 28, 13	8	7	1	19,341	18,288	1,053	1,053	1,053	0
Apr 29, 13	8	4	4	19,341	15,128	4,213	4,213	4,213	0
Apr 30, 13	9	8	1	20,395	19,341	1,053	1,053	1,053	0
May 1, 13	6	6	0	13,190	13,190	0	0	0	0
May 2, 13	8	10	-2	13,959	14,729	-770	770	0	770
May 3, 13	11	11	0	15,114	15,114	0	0	0	0
May 4, 13	12	14	-2	15,499	16,268	-770	770	0	770
May 5, 13	10	13	-3	14,729	15,883	-1,154	1,154	0	1,154
May 6, 13	5	6	-1	12,805	13,190	-385	385	0	385
May 7, 13	0	0	0	10,881	10,881	0	0	0	0
May 8, 13	1	1	0	11,266	11,266	0	0	0	0
May 9, 13	3	5	-2	12,035	12,805	-770	770	0	770
May 10, 13	0	0	0	10,881	10,881	0	0	0	0
May 11, 13	0	2	-2	10,881	11,650	-770	770	0	770
May 12, 13	9	11	-2	14,344	15,114	-770	770	0	770
May 13, 13	15	16	-1	16,653	17,038	-385	385	0	385
May 14, 13	14	16	-2	16,268	17,038	-770	770	0	770
May 15, 13	5	8	-3	12,805	13,959	-1,154	1,154	0	1,154
May 16, 13	1	0	1	11,266	10,881	385	385	385	0
May 17, 13	7	8	-1	13,575	13,959	-385	385	0	385
May 18, 13	4	5	-1	12,420	12,805	-385	385	0	385
May 19, 13	5	5	0	12,805	12,805	0	0	0	0
May 20, 13	0	0	0	10,881	10,881	0	0	0	0
May 21, 13	5	9	-4	12,805	14,344	-1,539	1,539	0	1,539
May 22, 13	2	10	-8	11,650	14,729	-3,079	3,079	0	3,079
May 23, 13	0	0	0	10,881	10,881	0	0	0	0
May 24, 13	10	10	0	14,729	14,729	0	0	0	0
May 25, 13	23	21	2	19,732	18,962	770	770	770	0
May 26, 13	16	15	1	17,038	16,653	385	385	385	0
May 27, 13	7	6	1	13,575	13,190	385	385	385	0
May 28, 13	2	2	0	11,650	11,650	0	0	0	0
May 29, 13	0	1	-1	10,881	11,266	-385	385	0	385
May 30, 13	0	0	0	10,881	10,881	0	0	0	0
May 31, 13	0	0	0	10,881	10,881	0	0	0	0
Jun 1, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 2, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 3, 13	1	0	1	9,388	9,077	311	311	311	0
Jun 4, 13	5	3	2	10,632	10,010	622	622	622	0
Jun 5, 13	2	0	2	9,699	9,077	622	622	622	0
Jun 6, 13	2	2	0	9,699	9,699	0	0	0	0
Jun 7, 13	11	11	0	12,497	12,497	0	0	0	0
Jun 8, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 9, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 10, 13	1	4	-3	9,388	10,321	-932	932	0	932
Jun 11, 13	7	6	1	11,253	10,942	311	311	311	0
Jun 12, 13	5	2	3	10,632	9,699	932	932	932	0
Jun 13, 13	7	7	0	11,253	11,253	0	0	0	0
Jun 14, 13	2	0	2	9,699	9,077	622	622	622	0
Jun 15, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 16, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 17, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 18, 13	3	3	0	10,010	10,010	0	0	0	0
Jun 19, 13	1	0	1	9,388	9,077	311	311	311	0
Jun 20, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 21, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 22, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 23, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 24, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 25, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 26, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 27, 13	0	2	-2	9,077	9,699	-622	622	0	622
Jun 28, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 29, 13	0	0	0	9,077	9,077	0	0	0	0
Jun 30, 13	0	0	0	9,077	9,077	0	0	0	0
Jul 1, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 2, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 3, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 4, 13	0	0	0	9,591	9,591	0	0	0	0

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Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2014-15
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jul 5, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 6, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 7, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 8, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 9, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 10, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 11, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 12, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 13, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 14, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 15, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 16, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 17, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 18, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 19, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 20, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 21, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 22, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 23, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 24, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 25, 13	1	1	0	11,602	11,602	0	0	0	0
Jul 26, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 27, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 28, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 29, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 30, 13	0	0	0	9,591	9,591	0	0	0	0
Jul 31, 13	0	0	0	9,591	9,591	0	0	0	0
Aug 1, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 2, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 3, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 4, 13	0	1	-1	9,648	9,760	-112	112	0	112
Aug 5, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 6, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 7, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 8, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 9, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 10, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 11, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 12, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 13, 13	1	1	0	9,760	9,760	0	0	0	0
Aug 14, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 15, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 16, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 17, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 18, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 19, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 20, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 21, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 22, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 23, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 24, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 25, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 26, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 27, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 28, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 29, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 30, 13	0	0	0	9,648	9,648	0	0	0	0
Aug 31, 13	0	0	0	9,648	9,648	0	0	0	0
Sep 1, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 2, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 3, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 4, 13	7	7	0	13,614	13,614	0	0	0	0
Sep 5, 13	5	5	0	12,911	12,911	0	0	0	0
Sep 6, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 7, 13	7	7	0	13,614	13,614	0	0	0	0
Sep 8, 13	4	8	-4	12,560	13,965	-1,405	1,405	0	1,405
Sep 9, 13	3	3	0	12,208	12,208	0	0	0	0
Sep 10, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 11, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 12, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 13, 13	3	2	1	12,208	11,857	351	351	351	0
Sep 14, 13	6	8	-2	13,262	13,965	-703	703	0	703
Sep 15, 13	3	3	0	12,208	12,208	0	0	0	0
Sep 16, 13	11	12	-1	15,019	15,371	-351	351	0	351
Sep 17, 13	12	12	0	15,371	15,371	0	0	0	0
Sep 18, 13	5	5	0	12,911	12,911	0	0	0	0
Sep 19, 13	2	1	1	11,857	11,506	351	351	351	0
Sep 20, 13	1	1	0	11,506	11,506	0	0	0	0
Sep 21, 13	0	0	0	11,154	11,154	0	0	0	0
Sep 22, 13	10	7	3	14,668	13,614	1,054	1,054	1,054	0
Sep 23, 13	14	13	1	16,073	15,722	351	351	351	0
Sep 24, 13	10	10	0	14,668	14,668	0	0	0	0
Sep 25, 13	7	6	1	13,614	13,262	351	351	351	0
Sep 26, 13	6	4	2	13,262	12,560	703	703	703	0
Sep 27, 13	8	7	1	13,965	13,614	351	351	351	0
Sep 28, 13	7	7	0	13,614	13,614	0	0	0	0
Sep 29, 13	9	11	-2	14,317	15,019	-703	703	0	703
Sep 30, 13	9	7	2	14,317	13,614	703	703	703	0
Oct 1, 13	0	1	-1	12,784	13,821	-1,037	1,037	0	1,037
Oct 2, 13	0	0	0	12,784	12,784	0	0	0	0
Oct 3, 13	1	1	0	13,821	13,821	0	0	0	0
Oct 4, 13	3	5	-2	15,894	17,967	-2,073	2,073	0	2,073
Oct 5, 13	5	5	0	17,967	17,967	0	0	0	0
Oct 6, 13	9	11	-2	22,114	24,187	-2,073	2,073	0	2,073
Oct 7, 13	3	2	1	15,894	14,857	1,037	1,037	1,037	0
Oct 8, 13	13	14	-1	26,261	27,297	-1,037	1,037	0	1,037

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2014-15
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Oct 9, 13	14	15	-1	27,297	28,334	-1,037	1,037	0	1,037
Oct 10, 13	10	12	-2	23,151	25,224	-2,073	2,073	0	2,073
Oct 11, 13	7	6	1	20,041	19,004	1,037	1,037	1,037	0
Oct 12, 13	13	14	-1	26,261	27,297	-1,037	1,037	0	1,037
Oct 13, 13	17	17	0	30,407	30,407	0	0	0	0
Oct 14, 13	11	7	4	24,187	20,041	4,147	4,147	4,147	0
Oct 15, 13	9	8	1	22,114	21,077	1,037	1,037	1,037	0
Oct 16, 13	8	11	-3	21,077	24,187	-3,110	3,110	0	3,110
Oct 17, 13	4	2	2	16,931	14,857	2,073	2,073	2,073	0
Oct 18, 13	11	11	0	24,187	24,187	0	0	0	0
Oct 19, 13	9	8	1	22,114	21,077	1,037	1,037	1,037	0
Oct 20, 13	16	16	0	29,371	29,371	0	0	0	0
Oct 21, 13	12	10	2	25,224	23,151	2,073	2,073	2,073	0
Oct 22, 13	16	15	1	29,371	28,334	1,037	1,037	1,037	0
Oct 23, 13	21	18	3	34,554	31,444	3,110	3,110	3,110	0
Oct 24, 13	22	21	1	35,591	34,554	1,037	1,037	1,037	0
Oct 25, 13	26	26	0	39,737	39,737	0	0	0	0
Oct 26, 13	19	16	3	32,481	29,371	3,110	3,110	3,110	0
Oct 27, 13	22	22	0	35,591	35,591	0	0	0	0
Oct 28, 13	27	24	3	40,774	37,664	3,110	3,110	3,110	0
Oct 29, 13	28	28	0	41,810	41,810	0	0	0	0
Oct 30, 13	23	27	-4	36,627	40,774	-4,147	4,147	0	4,147
Oct 31, 13	8	9	-1	21,077	22,114	-1,037	1,037	0	1,037
Nov 1, 13	8	8	0	23,961	23,961	0	0	0	0
Nov 2, 13	13	12	1	31,932	30,338	1,594	1,594	1,594	0
Nov 3, 13	32	30	2	62,220	59,032	3,188	3,188	3,188	0
Nov 4, 13	32	32	0	62,220	62,220	0	0	0	0
Nov 5, 13	27	23	4	54,250	47,873	6,377	6,377	6,377	0
Nov 6, 13	12	9	3	30,338	25,555	4,782	4,782	4,782	0
Nov 7, 13	21	20	1	44,685	43,091	1,594	1,594	1,594	0
Nov 8, 13	27	26	1	54,250	52,656	1,594	1,594	1,594	0
Nov 9, 13	26	25	1	52,656	51,061	1,594	1,594	1,594	0
Nov 10, 13	23	21	2	47,873	44,685	3,188	3,188	3,188	0
Nov 11, 13	24	21	3	49,467	44,685	4,782	4,782	4,782	0
Nov 12, 13	36	36	0	68,597	68,597	0	0	0	0
Nov 13, 13	35	33	2	67,003	63,815	3,188	3,188	3,188	0
Nov 14, 13	27	28	-1	54,250	55,844	-1,594	1,594	0	1,594
Nov 15, 13	21	23	-2	44,685	47,873	-3,188	3,188	0	3,188
Nov 16, 13	21	24	-3	44,685	49,467	-4,782	4,782	0	4,782
Nov 17, 13	12	17	-5	30,338	38,308	-7,971	7,971	0	7,971
Nov 18, 13	18	15	3	39,902	35,120	4,782	4,782	4,782	0
Nov 19, 13	33	31	2	63,815	60,626	3,188	3,188	3,188	0
Nov 20, 13	35	35	0	67,003	67,003	0	0	0	0
Nov 21, 13	31	25	6	60,626	51,061	9,565	9,565	9,565	0
Nov 22, 13	26	24	2	52,656	49,467	3,188	3,188	3,188	0
Nov 23, 13	34	35	-1	65,409	67,003	-1,594	1,594	0	1,594
Nov 24, 13	46	44	2	84,538	81,350	3,188	3,188	3,188	0
Nov 25, 13	38	35	3	71,785	67,003	4,782	4,782	4,782	0
Nov 26, 13	25	26	-1	51,061	52,656	-1,594	1,594	0	1,594
Nov 27, 13	26	24	2	52,656	49,467	3,188	3,188	3,188	0
Nov 28, 13	41	40	1	76,568	74,974	1,594	1,594	1,594	0
Nov 29, 13	43	44	-1	79,756	81,350	-1,594	1,594	0	1,594
Nov 30, 13	37	36	1	70,191	68,597	1,594	1,594	1,594	0
Dec 1, 13	33	30	3	69,268	64,291	4,977	4,977	4,977	0
Dec 2, 13	30	28	2	64,291	60,973	3,318	3,318	3,318	0
Dec 3, 13	30	28	2	64,291	60,973	3,318	3,318	3,318	0
Dec 4, 13	30	31	-1	64,291	65,950	-1,659	1,659	0	1,659
Dec 5, 13	19	27	-8	46,041	59,314	-13,272	13,272	0	13,272
Dec 6, 13	27	27	0	59,314	59,314	0	0	0	0
Dec 7, 13	37	37	0	75,904	75,904	0	0	0	0
Dec 8, 13	37	38	-1	75,904	77,563	-1,659	1,659	0	1,659
Dec 9, 13	32	33	-1	67,609	69,268	-1,659	1,659	0	1,659
Dec 10, 13	41	40	1	82,540	80,881	1,659	1,659	1,659	0
Dec 11, 13	42	42	0	84,199	84,199	0	0	0	0
Dec 12, 13	47	48	-1	92,494	94,153	-1,659	1,659	0	1,659
Dec 13, 13	51	51	0	99,130	99,130	0	0	0	0
Dec 14, 13	44	50	-6	87,517	97,471	-9,954	9,954	0	9,954
Dec 15, 13	44	41	3	87,517	82,540	4,977	4,977	4,977	0
Dec 16, 13	54	51	3	104,107	99,130	4,977	4,977	4,977	0
Dec 17, 13	47	49	-2	92,494	95,812	-3,318	3,318	0	3,318
Dec 18, 13	41	37	4	82,540	75,904	6,636	6,636	6,636	0
Dec 19, 13	35	32	3	72,586	67,609	4,977	4,977	4,977	0
Dec 20, 13	29	27	2	62,632	59,314	3,318	3,318	3,318	0
Dec 21, 13	22	22	0	51,019	51,019	0	0	0	0
Dec 22, 13	29	33	-4	62,632	69,268	-6,636	6,636	0	6,636
Dec 23, 13	33	31	2	69,268	65,950	3,318	3,318	3,318	0
Dec 24, 13	47	42	5	92,494	84,199	8,295	8,295	8,295	0
Dec 25, 13	48	46	2	94,153	90,835	3,318	3,318	3,318	0
Dec 26, 13	39	46	-7	79,222	90,835	-11,613	11,613	0	11,613
Dec 27, 13	38	37	1	77,563	75,904	1,659	1,659	1,659	0
Dec 28, 13	34	31	3	70,927	65,950	4,977	4,977	4,977	0
Dec 29, 13	31	30	1	65,950	64,291	1,659	1,659	1,659	0
Dec 30, 13	50	45	5	97,471	89,176	8,295	8,295	8,295	0
Dec 31, 13	49	46	3	95,812	90,835	4,977	4,977	4,977	0
Jan 1, 14	48	47	1	94,153	92,494	1,659	1,659	1,659	0
Jan 2, 14	58	61	-3	110,743	115,720	-4,977	4,977	0	4,977
Jan 3, 14	66	64	2	124,015	120,697	3,318	3,318	3,318	0
Jan 4, 14	48	49	-1	94,153	95,812	-1,659	1,659	0	1,659
Jan 5, 14	33	32	1	69,268	67,609	1,659	1,659	1,659	0
Jan 6, 14	36	35	1	74,245	72,586	1,659	1,659	1,659	0
Jan 7, 14	57	57	0	109,084	109,084	0	0	0	0
Jan 8, 14	50	48	2	97,471	94,153	3,318	3,318	3,318	0
Jan 9, 14	48	48	0	94,153	94,153	0	0	0	0
Jan 10, 14	35	35	0	72,586	72,586	0	0	0	0
Jan 11, 14	20	20	0	47,700	47,700	0	0	0	0
Jan 12, 14	31	28	3	65,950	60,973	4,977	4,977	4,977	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2014-15
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jan 13, 14	24	20	4	54,337	47,700	6,636	6,636	6,636	0
Jan 14, 14	27	26	1	59,314	57,655	1,659	1,659	1,659	0
Jan 15, 14	28	30	-2	60,973	64,291	-3,318	3,318	0	3,318
Jan 16, 14	31	30	1	65,950	64,291	1,659	1,659	1,659	0
Jan 17, 14	32	31	1	67,609	65,950	1,659	1,659	1,659	0
Jan 18, 14	33	34	-1	69,268	70,927	-1,659	1,659	0	1,659
Jan 19, 14	35	35	0	72,586	72,586	0	0	0	0
Jan 20, 14	41	43	-2	82,540	85,858	-3,318	3,318	0	3,318
Jan 21, 14	51	56	-5	99,130	107,425	-8,295	8,295	0	8,295
Jan 22, 14	59	57	2	112,402	109,084	3,318	3,318	3,318	0
Jan 23, 14	57	54	3	109,084	104,107	4,977	4,977	4,977	0
Jan 24, 14	54	51	3	104,107	99,130	4,977	4,977	4,977	0
Jan 25, 14	42	41	1	84,199	82,540	1,659	1,659	1,659	0
Jan 26, 14	45	46	-1	89,176	90,835	-1,659	1,659	0	1,659
Jan 27, 14	46	44	2	90,835	87,517	3,318	3,318	3,318	0
Jan 28, 14	49	50	-1	95,812	97,471	-1,659	1,659	0	1,659
Jan 29, 14	49	48	1	95,812	94,153	1,659	1,659	1,659	0
Jan 30, 14	42	42	0	84,199	84,199	0	0	0	0
Jan 31, 14	35	33	2	72,586	69,268	3,318	3,318	3,318	0
Feb 1, 14	30	29	1	64,291	62,632	1,659	1,659	1,659	0
Feb 2, 14	29	28	1	62,632	60,973	1,659	1,659	1,659	0
Feb 3, 14	37	41	-4	75,904	82,540	-6,636	6,636	0	6,636
Feb 4, 14	37	35	2	75,904	72,586	3,318	3,318	3,318	0
Feb 5, 14	43	44	-1	85,858	87,517	-1,659	1,659	0	1,659
Feb 6, 14	47	51	-4	92,494	99,130	-6,636	6,636	0	6,636
Feb 7, 14	48	44	4	94,153	87,517	6,636	6,636	6,636	0
Feb 8, 14	45	41	4	89,176	82,540	6,636	6,636	6,636	0
Feb 9, 14	42	41	1	84,199	82,540	1,659	1,659	1,659	0
Feb 10, 14	49	53	-4	95,812	102,448	-6,636	6,636	0	6,636
Feb 11, 14	54	52	2	104,107	100,789	3,318	3,318	3,318	0
Feb 12, 14	47	46	1	92,494	90,835	1,659	1,659	1,659	0
Feb 13, 14	35	35	0	72,586	72,586	0	0	0	0
Feb 14, 14	38	38	0	77,563	77,563	0	0	0	0
Feb 15, 14	37	38	-1	75,904	77,563	-1,659	1,659	0	1,659
Feb 16, 14	47	44	3	92,494	87,517	4,977	4,977	4,977	0
Feb 17, 14	49	50	-1	95,812	97,471	-1,659	1,659	0	1,659
Feb 18, 14	39	45	-6	79,222	89,176	-9,954	9,954	0	9,954
Feb 19, 14	32	33	-1	67,609	69,268	-1,659	1,659	0	1,659
Feb 20, 14	28	27	1	60,973	59,314	1,659	1,659	1,659	0
Feb 21, 14	30	31	-1	64,291	65,950	-1,659	1,659	0	1,659
Feb 22, 14	28	27	1	60,973	59,314	1,659	1,659	1,659	0
Feb 23, 14	31	27	4	65,950	59,314	6,636	6,636	6,636	0
Feb 24, 14	44	41	3	87,517	82,540	4,977	4,977	4,977	0
Feb 25, 14	47	46	1	92,494	90,835	1,659	1,659	1,659	0
Feb 26, 14	52	50	2	100,789	97,471	3,318	3,318	3,318	0
Feb 27, 14	53	49	4	102,448	95,812	6,636	6,636	6,636	0
Feb 28, 14	52	52	0	100,789	100,789	0	0	0	0
Mar 1, 14	38	35	3	65,269	60,883	4,386	4,386	4,386	0
Mar 2, 14	44	40	4	74,041	68,193	5,848	5,848	5,848	0
Mar 3, 14	54	52	2	88,660	85,736	2,924	2,924	2,924	0
Mar 4, 14	44	42	2	74,041	71,117	2,924	2,924	2,924	0
Mar 5, 14	49	50	-1	81,350	82,812	-1,462	1,462	0	1,462
Mar 6, 14	49	48	1	81,350	79,888	1,462	1,462	1,462	0
Mar 7, 14	39	37	2	66,731	63,807	2,924	2,924	2,924	0
Mar 8, 14	35	29	6	60,883	52,112	8,772	8,772	8,772	0
Mar 9, 14	37	34	3	63,807	59,421	4,386	4,386	4,386	0
Mar 10, 14	29	29	0	52,112	52,112	0	0	0	0
Mar 11, 14	27	23	4	49,188	43,340	5,848	5,848	5,848	0
Mar 12, 14	33	34	-1	57,959	59,421	-1,462	1,462	0	1,462
Mar 13, 14	50	49	1	82,812	81,350	1,462	1,462	1,462	0
Mar 14, 14	30	30	0	53,574	53,574	0	0	0	0
Mar 15, 14	29	26	3	52,112	47,726	4,386	4,386	4,386	0
Mar 16, 14	45	44	1	75,503	74,041	1,462	1,462	1,462	0
Mar 17, 14	46	44	2	76,965	74,041	2,924	2,924	2,924	0
Mar 18, 14	37	37	0	63,807	63,807	0	0	0	0
Mar 19, 14	30	29	1	53,574	52,112	1,462	1,462	1,462	0
Mar 20, 14	28	26	2	50,650	47,726	2,924	2,924	2,924	0
Mar 21, 14	32	31	1	56,498	55,036	1,462	1,462	1,462	0
Mar 22, 14	29	26	3	52,112	47,726	4,386	4,386	4,386	0
Mar 23, 14	40	40	0	68,193	68,193	0	0	0	0
Mar 24, 14	41	42	-1	69,655	71,117	-1,462	1,462	0	1,462
Mar 25, 14	34	34	0	59,421	59,421	0	0	0	0
Mar 26, 14	40	39	1	68,193	66,731	1,462	1,462	1,462	0
Mar 27, 14	29	28	1	52,112	50,650	1,462	1,462	1,462	0
Mar 28, 14	19	19	0	37,492	37,492	0	0	0	0
Mar 29, 14	22	24	-2	41,878	44,802	-2,924	2,924	0	2,924
Mar 30, 14	27	29	-2	49,188	52,112	-2,924	2,924	0	2,924
Mar 31, 14	29	28	1	52,112	50,650	1,462	1,462	1,462	0
Apr 1, 14	25	22	3	37,249	34,088	3,160	3,160	3,160	0
Apr	506	500	6	860,437	854,116	6,320	42,134	24,227	17,907
May	181	211	-30	406,956	418,501	-11,545	15,393	1,924	13,469
Jun	47	40	7	286,931	284,755	2,176	5,284	3,730	1,554
Jul	1	1	0	299,341	299,341	0	0	0	0
Aug	1	2	-1	299,214	299,326	-112	112	0	112
Sep	149	146	3	386,980	385,926	1,054	7,379	4,216	3,162
Oct	387	382	5	797,494	792,311	5,183	42,503	23,843	18,660
Nov	830	802	28	1,659,374	1,614,738	44,636	89,272	66,954	22,318
Dec	1,170	1,156	14	2,391,176	2,367,950	23,226	126,086	74,656	51,430
Jan	1,310	1,295	15	2,623,439	2,598,554	24,885	77,974	51,430	26,544
Feb	1,188	1,173	15	2,379,705	2,355,411	24,294	100,609	62,452	38,157
Mar	1,102	1,065	37	1,903,221	1,850,355	52,866	73,333	63,099	10,234
Total	6,872	6,773	99	14,294,268	14,121,284	172,985	580,078	376,531	203,547
Datacheck	0	0	0	0	0	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		140,500	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 95346	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
		TGP FT-A (Z6-Z6) 72694	30,000		
10			79,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3 of 3: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		32,667	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$2,000,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,980,428		Summary Page Line 68
26	Granite Ridge		$0		Attachment B Page 3 Line 1
27	Total		$3,980,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$121.85		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$20.31**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	77%	53%
Storage	10%	21%
Peaking	12%	26%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2014:

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	ANE *	Supply at Waddington		4,000		$13.8539		10/31/2017	X
	Iroquois	RTS to Wright	470-01	4,047		$6.5971		11/1/2017	
	TGP	NET-NE	95346	4,000		$7.3560		11/30/2015	
	BP Canada Energy Co.**	Supply at Niagara		3,199		$0.0000		3/31/2015	X
	TGP	FT-A (Z5-Z6)	2302	3,122		$7.3560		10/31/2015	
	TGP	FT-A (Z0-Z6)	8587	7,035		$23.9133		10/31/2015	
	TGP	FT-A (Z1-Z6)	8587	14,561		$21.2245		10/31/2015	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4.8698		10/31/2015	
	TGP	FT-A (Z6-Z6)	72694	30,000		$12.1700		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523***	21,844	1,560,391	$1.5400	$0.0211	10/31/2015	
	TGP	FT-A (Z4-Z6)	632	15,265		$8.3778		10/31/2015	
	TGP	FT-A (Z4-Z6)	8587	3,811		$8.3778		10/31/2015	
	National Fuel	FSS-1 (Storage)	O02357***	6,098	670,800	$2.4826	$0.0381	3/31/2012	
	National Fuel	FST (Transport)	N02358	6,098		$3.7805		3/31/2012	
	TGP	FT-A (Z4-Z6)	11234	6,150		$8.3778		10/31/2012	
	Honeoye	SS-NY (Storage)	SS-NY***	1,957	245,280	$4.4683	$0.0000	4/1/2012	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$7.3560		10/31/2012	
	Dominion	GSS (Storage)	300076***	934	102,700	$1.8438	$0.0145	3/31/2012	
	TGP	FT-A (Z4-Z6)	11234	932		$8.3778		10/31/2012	
Peaking									
	Energy North	LNG/Propane****		32,667	-	$20.3100	$0.0000		X
	TGP	FT-A (Z6-Z6)	72694	-	-	$12.1700	$0.0000	10/31/2029	X

* Volumes and Demand Charges are based on MMBtu at the border.
**BP commodity price is based on Inside FERC at Niagara plus $.01 per Dth.
***All gas transferred for storage contracts will be based on LDC's monthly WACOG.
****All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention. Demand charge applicable for 6 months.

Note: **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/08. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the Energy North Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $40.2456/dth.

ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

		Volume	Rate	Monthly Cost	Months/Year	Annual Cost	
1		[redacted]					
2							
3							
4	Concord Lateral	[redacted]					
5	GDF Suez						
6							
7	Subtotal					**$2,000,000**	*
8							
9	**Total**					**$2,000,000**	
10							

* Contract currently being negotiated for an effective date of November 1, 2014

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Schedule 22

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ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	53.0%	21.0%	26.0%	100.0%
G-51	Low Annual /Low Winter Use	77.4%	10.3%	12.3%	100.0%
G-42	Medium Annual / High Winter	53.0%	21.0%	26.0%	100.0%
G-52	High Annual / Low Winter Use	77.4%	10.3%	12.3%	100.0%
G-43	High Annual / High Winter	53.0%	21.0%	26.0%	100.0%
G-53	High Annual / Load Factor < 90%	77.4%	10.3%	12.3%	100.0%
G-54	High Annual / Load Factor < 90%	77.4%	10.3%	12.3%	100.0%

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	Storage	Peaking	Total
G-41	**LAHW**	Low Annual C&I - High Winter Use	53.0%	21.0%	26.0%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	77.4%	10.3%	12.3%	200.0%
G-42	**MAHW**	Medium C&I - High Winter Use	53.0%	21.0%	26.0%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	77.4%	10.3%	12.3%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	53.0%	21.0%	26.0%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	77.4%	10.3%	12.3%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	77.4%	10.3%	12.3%	100.0%

HLF	High Load Factor	77%	10%	12%	100%
LLF	Low Load Factor	53%	21%	26%	100%
	Total	56%	20%	24%	100%

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD		Base load	72 Heat load	Total
HLF	R-1 RNSH	124	655	780
LLF	R-3 RSH	3,735	56,577	60,312
LLF	G-41 SL	964	22,941	23,905
HLF	G-51 SH	650	1,964	2,614
LLF	G-42 ML	1,886	30,501	32,387
HLF	G-52 MH	1,418	2,566	3,984
LLF	G-43 LL	1,185	6,245	7,429
HLF	G-53 LLL90	1,961	2,257	4,218
HLF	G-54 LLG90	4,871	-	4,871
	TOTAL	16,794	123,706	140,500

HLF	9,024	7,442	16,466
LLF	7,770	116,264	124,034
Total	16,794	123,706	140,500

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	124	328	452	149	178	780
R-3 RSH	3,735	28,321	32,056	12,858	15,398	60,312
G-41 SL	964	11,484	12,448	5,214	6,243	23,905
G-51 SH	650	983	1,633	446	534	2,614
G-42 ML	1,886	15,268	17,154	6,932	8,301	32,387
G-52 MH	1,418	1,285	2,703	583	698	3,984
G-43 LL	1,185	3,126	4,311	1,419	1,700	7,429
G-53 LLL90	1,961	1,130	3,091	513	614	4,218
G-54 LLG90	4,871	-	4,871	-	-	4,871
TOTAL	16,794	61,924	78,718	28,115	33,667	140,500

HLF	9,024	3,725	12,750	1,691	2,025	16,466
LLF	7,770	58,199	65,968	26,424	31,642	124,034
Total	16,794	61,924	78,718	28,115	33,667	140,500

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	58.0%	19.1%	22.9%	100.0%
R-3 RSH	53.2%	21.3%	25.5%	100.0%
G-41 SL	52.1%	21.8%	26.1%	100.0%
G-51 SH	62.5%	17.1%	20.4%	100.0%
G-42 ML	53.0%	21.4%	25.6%	100.0%
G-52 MH	67.8%	14.6%	17.5%	100.0%
G-43 LL	58.0%	19.1%	22.9%	100.0%
G-53 LLL90	73.3%	12.2%	14.6%	100.0%
G-54 LLG90	100.0%	0.0%	0.0%	100.0%
TOTAL	56.0%	20.0%	24.0%	100.0%

High Load Factor	77%	10%	12%	100%
Low Load Factor	53%	21%	26%	100%
Total	56%	20%	24%	100%

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Design DD 72

	Daily Baseload * 1000	March Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total
R-1 RNSH	124	7.888	568	692
R-3 RSH	3,735	681.198	49,046	52,781
G-41 SL	964	276.214	19,887	20,851
G-51 SH	650	23.644	1,702	2,352
G-42 ML	1,886	367.239	26,441	28,327
G-52 MH	1,418	30.897	2,225	3,643
G-43 LL	1,185	75.187	5,413	6,598
G-53 LLL90	1,961	27.177	1,957	3,918
G-54 LLG90	4,871	-	-	4,871
TOTAL	16,794	1,580.224	107,240	124,034

	Baseload as % of Total Class Load	Heat Load as % of Total
R-1 RNSH	18%	0.530%
R-3 RSH	7%	45.735%
G-41 SL	5%	18.545%
G-51 SH	28%	1.587%
G-42 ML	7%	24.656%
G-52 MH	39%	2.074%
G-43 LL	18%	5.048%
G-53 LLL90	50%	1.825%
G-54 LLG90	100%	0.000%
TOTAL		100.000%

Allocate Design Day Sendout to Rate Classes

	Base Load	Heat Load	Total
R-1 RNSH	124	655	780
R-3 RSH	3,735	56,577	60,312
G-41 SL	964	22,941	23,905
G-51 SH	650	1,964	2,614
G-42 ML	1,886	30,501	32,387
G-52 MH	1,418	2,566	3,984
G-43 LL	1,185	6,245	7,429
G-53 LLL90	1,961	2,257	4,218
G-54 LLG90	4,871	-	4,871
TOTAL	16,794	123,706	140,500

HLF	9,024	90	6,452	15,476
LLF	7,770	1,491	100,788	108,558
Total	16,794	1,580	107,240	124,034

Design Day from 2012-2013 Resource Plan	**140,500**
Design Day from Billing Calculation	124,034
Variance	16,466

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-13	Sep-13	Oct-13	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	7	11	14	14	13	12	8	6	4	4	4	4	102	3.857	0.124
LLF	R-3 RSH	353	733	990	998	871	756	413	206	121	111	120	152	5,823	115.791	3.735
LLF	G-41 SL	103	245	367	377	336	294	150	50	35	25	27	40	2,048	29.878	0.964
HLF	G-51 SH	27	42	50	51	46	47	34	26	20	20	21	21	404	20.146	0.650
LLF	G-42 ML	193	390	527	504	465	415	253	128	57	60	72	108	3,171	58.462	1.886
HLF	G-52 MH	55	74	83	83	78	91	65	54	45	43	59	32	763	43.958	1.418
LLF	G-43 LL	74	116	142	154	120	102	100	54	50	24	25	43	1,003	36.726	1.185
HLF	G-53 LLL90	75	83	93	101	91	102	78	17	64	58	66	61	888	60.789	1.961
HLF	G-54 LLL110	163	153	148	138	103	138	140	10	158	144	139	149	1,582	150.998	4.871
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	0	0.000	0.000
	TOTAL	1,049	1,846	2,414	2,421	2,123	1,956	1,242	550	553	488	532	610	15,785	520.606	16.794
	HLF	327	363	387	388	331	390	325	113	291	269	289	267	3,739	279.748	9.024
	LLF	722	1,483	2,026	2,033	1,792	1,566	917	438	263	219	243	343	12,045	240.857	7.770

Baseload (= the lesser of actual volumes or the average of July and August volumes)

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-13	Sep-13	Oct-13	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	4	4	4	3	4	4	4	4	4	4	4	4	45
LLF	R-3 RSH	112	116	116	105	116	112	116	112	121	111	112	116	1,363
LLF	G-41 SL	29	30	30	27	30	29	30	29	35	25	27	30	352
HLF	G-51 SH	19	20	20	18	20	19	20	19	20	20	19	20	237
LLF	G-42 ML	57	58	58	53	58	57	58	57	57	60	57	58	688
HLF	G-52 MH	43	44	44	40	44	43	44	43	45	43	43	32	518
LLF	G-43 LL	36	37	37	33	37	36	37	36	50	24	25	37	432
HLF	G-53 LLL90	59	61	61	55	61	59	61	17	64	58	59	61	716
HLF	G-54 LLL110	146	151	148	136	103	138	140	10	158	144	139	149	1,582
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	534	552	548	498	503	525	541	356	584	519	514	538	6,130
	HLF	271	280	276	253	232	262	269	93	291	269	264	266	3,098
	LLF	233	241	241	218	241	233	241	233	263	219	220	241	2,836

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
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Heating Volumes (= Actual Volumes - Baseload)

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-13	Sep-13	Oct-13	Total
HLF	R-1 RNSH	3	7	10	11	9	8	5	3	0	0	0	1	57
LLF	R-3 RSH	241	617	875	894	755	644	297	93	0	0	8	36	4,460
LLF	G-41 SL	74	215	337	350	306	265	120	21	0	0	0	11	1,697
HLF	G-51 SH	7	22	30	33	26	27	14	6	0	0	1	0	167
LLF	G-42 ML	137	332	469	451	407	358	195	71	0	0	15	49	2,483
HLF	G-52 MH	12	30	39	44	34	49	21	11	0	0	17	0	245
LLF	G-43 LL	38	79	105	121	83	66	64	19	0	0	0	6	571
HLF	G-53 LLL90	16	22	32	46	30	43	17	0	0	0	7	1	172
HLF	G-54 LLL110	17	2	0	2	0	0	0	0	0	0	0	0	0
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	516	1,295	1,866	1,922	1,619	1,431	701	195	(31)	(31)	18	73	9,655

HLF	56	83	111	135	99	127	56	20	0	0	25	1	641
LLF	489	1,242	1,786	1,815	1,551	1,333	676	205	0	0	23	102	9,210
Actual BDD	592.0	978.5	1295.0	1216.5	1108.0	809.0	377.0	119.5	12.5	1.0	69.5	260.0	6838.5

Heat Factors

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-13	Sep-13	Oct-13	Total
HLF	R-1 RNSH	0.0053	0.0075	0.0080	0.0090	0.0079	0.0105	0.0121	0.0212	0.0000	0.0000	0.0038	0.0021	
LLF	R-3 RSH	0.4068	0.6305	0.6754	0.7346	0.6812	0.7960	0.7879	0.7824	0.0000	0.0000	0.1121	0.1400	
LLF	G-41 SL	0.1246	0.2197	0.2602	0.2876	0.2762	0.3276	0.3182	0.1793	0.0000	0.0000	0.0000	0.0407	
HLF	G-51 SH	0.0124	0.0222	0.0230	0.0270	0.0236	0.0335	0.0361	0.0527	0.0000	0.0000	0.0191	0.0015	
LLF	G-42 ML	0.2307	0.3388	0.3620	0.3705	0.3672	0.4425	0.5172	0.5947	0.0000	0.0000	0.2150	0.1888	
HLF	G-52 MH	0.0210	0.0308	0.0302	0.0359	0.0309	0.0603	0.0547	0.0948	0.0000	0.0000	0.2427	0.0000	
LLF	G-43 LL	0.0646	0.0807	0.0813	0.0994	0.0752	0.0820	0.1691	0.1554	0.0000	0.0000	0.0000	0.0236	
HLF	G-53 LLL90	0.0272	0.0230	0.0246	0.0378	0.0272	0.0531	0.0463	0.0000	0.0000	0.0000	0.0963	0.0021	
HLF	G-54 LLL110	0.0290	0.0017	0.0000	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
HLF	G-63 LLG110	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
	TOTAL	0.8709	1.3233	1.4407	1.5802	1.4615	1.7683	1.8593	1.6294	-2.4800	-31.0000	0.2573	0.2796	

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
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Actual BillingDD	**592.0**	**978.5**	**1,295.0**	**1,216.5**	**1,108.0**	**809.0**	**377.0**	**119.5**	**12.5**	**1.0**	**69.5**	**260.0**	**6838.5**
Norm Billing DD	**566.4**	**890.1**	**1149.2**	**1132.0**	**962.3**	**702.6**	**376.3**	**145.9**	**31.1**	**10.0**	**67.5**	**272.3**	**6305.6**

Normal Volumes (= Heating Volumes * Normal EDD/Actual EDD + Baseload)

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-13	Sep-13	Oct-13	Total
HLF	**R-1 RNSH**	7	11	13	14	11	11	8	7	4	4	4	4	98
LLF	**R-3 RSH**	342	677	892	936	771	671	412	226	121	111	120	154	5,434
LLF	**G-41 SL**	99	225	329	353	296	259	150	55	35	25	27	41	1,893
HLF	**G-51 SH**	27	40	47	49	43	43	34	27	20	20	21	21	390
LLF	**G-42 ML**	187	360	474	472	412	367	253	143	57	60	71	110	2,968
HLF	**G-52 MH**	54	71	79	80	74	85	65	56	45	43	59	32	743
LLF	**G-43 LL**	72	109	130	146	109	93	100	58	50	24	25	43	959
HLF	**G-53 LLL90**	74	81	89	98	87	96	78	17	64	58	65	61	869
HLF	**G-54 LLL110**	163	152	148	138	103	138	140	10	158	144	139	149	1,581
HLF	**G-63 LLG110**	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	1,027	1,730	2,204	2,287	1,910	1,768	1,240	593	507	209	532	614	14,620

HLF	324	356	375	378	318	373	325	117	291	269	288	267	3,681
LLF	701	1,371	1,825	1,907	1,588	1,391	915	483	263	219	242	348	11,254

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Schedule 23

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Fixed Price Option

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6.0%				$0.3927	$0.3722	$ 943.37	$ 926.93	$ 16.44	1.77%	$0.3927	$0.3736	$ 1,570.86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9.0%				$0.4724	$0.4628	$ 679.85	$ 672.22	$ 7.63	1.13%	$0.4724	$0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20.0%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10.90%	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10.22%
4	Nov 01 - Apr 02	24.0%				$0.5141	$0.4818	$ 790.65	$ 760.55	$ 30.10	3.96%	$0.5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3.52%
5	Nov 02 - Apr 03	24.0%	$0.0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (19.11)	-2.27%	$0.5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	23.0%	$0.0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 35.09	3.25%	$0.8759	$0.8352	$ 1,798.38	$ 1,740.30	$ 58.08	3.34%
7	Nov 04 - Apr 05	29.6%	$0.0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142.96	$ 1,189.55	$ (46.60)	-3.92%	$0.9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3.51%
8	Nov 05 - Apr 06	29.8%	$0.0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 150.00	10.90%	$1.3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9.61%
9	Nov 06 - Apr 07	15.1%	$0.0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415.80	$ 93.99	6.64%	$1.2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	15.8%	$0.0200	14,078,553	$ 281,571	$1.2043	$1.1746	$ 1,433.09	$ 1,405.40	$ 27.69	1.97%	$1.2044	$1.1725	$ 2,232.39	$ 2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	15.2%	$0.0200	13,041,335	$ 260,827	$1.2835	$1.0888	$ 1,555.31	$ 1,373.85	$ 181.46	13.21%	$1.2836	$1.0958	$ 2,467.49	$ 2,199.54	$ 267.95	12.18%
12	Nov 09 - Apr 10	11.4%	$0.0200	8,405,413	$ 168,108	$0.9863	$0.9416	$ 1,250.80	$ 1,209.12	$ 41.69	3.45%	$0.9865	$0.9408	$ 1,984.29	$ 1,919.03	$ 65.26	3.40%
13	Nov 10 - Apr 11	12.6%	$0.0200	10,379,804	$ 207,596	$0.8420	$0.8029	$ 1,175.03	$ 1,138.58	$ 36.45	3.20%	$0.8434	$0.8030	$ 1,880.96	$ 1,823.34	$ 57.63	3.16%
14	Nov 11 - Apr 12	11.9%	$0.0200	7,835,197	$ 156,704	$0.8126	$0.7309	$ 1,165.61	$ 1,089.44	$ 76.17	6.99%	$0.8129	$0.7327	$ 1,845.28	$ 1,730.88	$ 114.40	6.61%
15	Nov 12 - Apr 13	10.9%	$0.0200	8,179,524	$ 163,590	$0.6919	$0.7680	$ 743.03	$ 792.48	$ (49.45)	-6.24%	$0.6936	$0.7724	$ 1,989.86	$ 2,132.90	$ (143.03)	-6.71%
16	Nov 13 - Apr 14	10.5%	$0.0200	8,930,779	$ 178,616	$0.9095	$1.1068	$886.96	$1,014.97	$ (128.01)	-12.61%	$0.9108	$1.1178	$2,476.20	$2,862.29	$ (386.09)	-13.49%
17	Nov 14 - Apr 15					$1.2425	$1.2225	$1,135.85	$1,122.87	$ 12.98	1.16%						
18	Total									$ 366.66						$ 268.91	

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Schedule 24

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2014 - 2015 Winter Cost of Gas Filing
Short-Term Debt Limitations

		For Purposes of Fuel Financing
Total Direct Gas Costs	$	89,594,088
Total Indirect Gas Costs		3,459,857
Total Gas Costs	$	93,053,946
% of Debt to Total Gas Costs		30%
Short Term Debt	$	27,916,184

		For Purposes Other Than Fuel Financing
12/1/2014 Projected Net Plant	**$**	**296,319,143**
% of Debt to Net Plant		20%
Short Term Debt	$	59,263,829

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Schedule 25

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
2014 - 2015 Winter Cost of Gas Filing

Company Allowance Calculation

	Jul-2013	Aug-2013	Sep-2013	Oct-2013	Nov-2013	Dec-2013	Jan-2014	Feb-2014	Mar-2014	Apr-2014	May-2014	Jun-2014	Total
Total Sendout- Therms	4,788,440	5,367,750	6,004,200	10,028,830	18,196,700	25,634,070	29,638,250	25,203,610	24,370,650	12,901,430	7,508,340	5,662,830	175,305,100
Total Throughput- Therms	5,187,207	4,863,981	5,321,015	6,009,137	10,771,404	19,804,698	26,563,296	25,686,404	23,982,485	21,796,414	12,430,231	7,738,177	170,154,449
Variance	(398,767)	503,769	683,185	4,019,693	7,425,296	5,829,372	3,074,954	(482,794)	388,165	(8,894,984)	(4,921,891)	(2,075,347)	5,150,651
Company Allowance													**2.94%**

Lost and Unaccounted For Gas ("LAUF") Calculation

	Jul-2013	Aug-2013	Sep-2013	Oct-2013	Nov-2013	Dec-2013	Jan-2014	Feb-2014	Mar-2014	Apr-2014	May-2014	Jun-2014	Total
Total Sendout- Therms	4,788,440	5,367,750	6,004,200	10,028,830	18,196,700	25,634,070	29,638,250	25,203,610	24,370,650	12,901,430	7,508,340	5,662,830	175,305,100
Total Throughput- Therms	5,187,207	4,863,981	5,321,015	6,009,137	10,771,404	19,804,698	26,563,296	25,686,404	23,982,485	21,796,414	12,430,231	7,738,177	170,154,449
Company Use	2,257	2,959	4,806	6,159	15,652	137,105	62,404	59,119	53,284	137,892	9,662	5,049	496,348
Variance	(401,024)	500,810	678,379	4,013,534	7,409,644	5,692,267	3,012,550	(541,913)	334,881	(9,032,876)	(4,931,553)	(2,080,396)	4,654,303
LAUF													**2.65%**

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