Schedules

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2015 - 2016 Winter Cost of Gas Filing

Table of Contents

Summary

Ln		Reference		PK 15-16
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**			
2	**d/b/a Liberty Utilities**			
3	**Peak 2015 - 2016 Winter Cost of Gas Filing**			
4	**Summary**			
5				PK 15-16
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	$	7,958,775
12	Supply Costs	Sch. 6, col (i), ln 44		51,450,609
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (k), ln 58	$	987,267
16	Commodity Costs:	Sch. 6, col (i), ln 47		5,489,978
17				
18	Produced Gas:	Sch. 6, col (i), ln 53	$	3,547,477
19				
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	176,262
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 172	$	-
22				
23	**Total Unadjusted Cost of Gas**		$	69,610,368
24				
25	**Adjustments**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$	(4,339,198)
28	Interest 05/01/15 - 10//31/15	Sch. 3, col (q) ln 193		(140,799)
29	Prior Period Adjustments	Sch. 4, ln 26 col (b)		-
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		(358,691)
31	Broker Revenues	Sch. 4, ln 26 col (d)		(1,917,919)
32	Fuel Financing	Sch. 4, ln 26 col (e)		-
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		35,761
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)		(3,512,739)
36	Hedging Costs	Sch. 4, ln 26 col (j)		-
37	FPO Premium - Collection			
38	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		49,565
39				
40	**Total Adjustments**		$	(10,184,020)
41				
42	**Total Anticipated Direct Costs**	lns 23 + 40	$	59 426 348
43				
44	**Anticipated Indirect Cost of Gas**			
45	**Working Capital**			
46	Total Unadjusted Anticipated Cost of Gas	Ln 23	$	69,610,368
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		88,467
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 100		(28,115)
52				
53	**Total Working Capital Allowance**	lns 50 + 51	$	60,352
54				
55	**Bad Debt**			
56	Total Unadjusted Anticipated Cost of Gas	ln 23	$	69,610,368
57	Less Refunds	ln 30		(358,691)
58	Plus Working Capital	ln 53		60,352
59	Plus Prior Period (Over) Under Recovery	ln 27		(4,339,198)
60	Subtotal		$	64,972,831
61	Bad Debt Percentage	per GTC 16(f)		3.47%
62				
63	Bad Debt Allowance	ln 60 * ln 61	$	2,254,557
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 181		720,643
65				
66	**Total Bad Debt Allowance**	lns 63 + 64	$	2 975 200
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		85,914
72	Divided by Total Sales	Sch. 10B, ln 23/1000		110,150
73	Ratio			78.00%
74				
75	**Miscellaneous Overhead**	lns 70 * 73	$	10,272
76				
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$	5,026,252
78				
79	**Total Cost of Gas**	lns 42 + 77	$	64,452,601
80				
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		85,749,300

Schedule 1

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 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-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10										1,581,922	1.7%
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	2,163,725	14,192,502	19,058,088	19,626,237	16,277,378	13,532,718	5,669,827	90,520,475
13	Lost Gas (Unaccounted for)		-	165,567	278,600	348,114	285,479	210,511	147,798		1,436,068
14	Company Use		-	16,816	28,296	35,356	28,995	21,380	15,011		145,854
15	Unbilled Therms		-	8,272,534	3,368,616	2,884,788	(1,631,478)	(3,008,127)	(4,216,505)	(5,669,827)	0
16											
17	**Total Firm Volumes**	Sch. 6, ln 92	-	10,618,641	17,868,013	22,326,346	18,309,233	13,501,142	9,479,022		92,102,397
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 63	-	836,662	921,223	935,514	851,729	878,077	844,268		5,267,474
22	Niagara Supply	Sch. 6, ln 64	-	653,294	719,148	730,305	664,495	685,467	659,233		4,111,942
23	TGP Supply (Direct)	Sch. 6, ln 65	-	4,768,976	3,122,500	3,170,940	2,887,067	2,976,256	4,151,689		21,077,429
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	2,751,782	4,657,201	3,180,032	-	-		10,589,015
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	1,584,778	3,727,982	3,922,369	3,133,775	536,760	91,462		12,997,126
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	-	2,789	2,972	1,083,386	691,663	81,435	-		1,862,243
28	Propane Truck	Sch. 6, ln 70	-	-	-	691,828	-	-	-		691,828
29	PNGTS	Sch. 6, ln 71	-	57,172	80,978	91,288	78,565	67,980	47,842		423,825
30	TGP Supply (Z4)	Sch. 6, ln 72	-	1,680,994	1,851,361	1,880,082	1,711,534	1,764,652	2,074,789		10,963,412
31	Subtotal Pipeline Volumes		-	9,584,666	13,177,947	17,162,912	13,198,860	6,990,626	7,869,283		67,984,295
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 77	-	4,585,608	4,690,065	5,075,164	5,110,373	6,589,118	3,345,413		29,395,741
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 80	-	2,789	2,972	1,171,656	691,663	2,833	19,700		1,891,611
38	Propane	Sch. 6, ln 81	-	-	-	691,828	-	-	-		691,828
39	Subtotal Produced Gas		-	2,789	2,972	1,863,484	691,663	2,833	19,700		2,583,439
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 86	-	(2,789)	(2,972)	(1,083,386)	(691,663)	(81,435)	-		(1,862,243)
43	Propane	Sch. 6, ln 87	-	-	-	(691,828)	-	-	-		(691,828)
44	TGP Storage Refill	Sch. 6, ln 88	-	(3,551,632)	-	-	-	-	(1,755,374)		(5,307,007)
45	Subtotal Refills		-	(3,554,421)	(2,972)	(1,775,213)	(691,663)	(81,435)	(1,755,374)		(7,861,078)
46											
47	Total Firm Sendout Volumes	lns 31 + 34 + 39 + 45	-	10,618,641	17,868,013	22,326,346	18,309,233	13,501,142	9,479,022		92,102,397
48											

REDACTED

Line	Description	Reference	Peak Costs May 14 - Oct 14	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Peak Period Nov - Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2015 - 2016 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-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Nov - Apr
49	**II. Gas Costs**										
50											
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		$ 1,353,884	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077		$ 9,586,347
74	Less Capacity Credit		(469 637)	(374 714)	(374 714)	(374 714)	(374 714)	(374 714)	(374 714)		(2 717 922)
75	Net Pipeline Demand Costs		$ 884,247	$ 997,363	$ 997,363	$ 997,363	$ 997,363	$ 997,363	$ 997,363		$ 6,868,425
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		$ -	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ -		$ 1,500,000
82	Less Capacity Credit		-	(81,930)	(81,930)	(81,930)	(81,930)	(81,930)	-		(409,650)
83	Net Peaking Supply Demand Costs		$ -	$ 218,070	$ 218,070	$ 218,070	$ 218,070	$ 218,070	$ -		$ 1,090,350
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		$ 715,401	$ 119,233	$ 119,233	$ 119,233	$ 119,233	$ 119,233	$ 119,233		$ 1,430,802
94	Less Capacity Credit		(248,159)	(32,563)	(32,563)	(32,563)	(32,563)	(32,563)	(32,563)		(443,535)
95	Net Storage Demand Costs		$ 467,242	$ 86,671	$ 86,671	$ 86,671	$ 86,671	$ 86,671	$ 86,671		$ 987,267
96											
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 2,069,285	$ 1,791,311	$ 1,791,311	$ 1,791,311	$ 1,791,311	$ 1,791,311	$ 1,491,311		$ 12,517,149
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(717 796)	(489 207)	(489 207)	(489 207)	(489 207)	(489 207)	(407 277)		(3 571 107)
99	Net Demand Charges		$ 1,351,489	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,084,034		$ 8,946,041
100											
101						**THIS PAGE HAS BEEN REDACTED**					

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Line	Description	Reference	Peak Costs May 14 - Oct 14	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Peak Period Nov - Apr
6											
7	For Month of:										
102	**B. Commodity Costs**										
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		$ -	$ 3,044,824	$ 10,770,106	$ 21,043,350	$ 15,257,252	$ 2,723,263	$ 2,153,821		$ 54,992,615
115											
116	Storage:										
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ 859,300	$ 878,874	$ 951,038	$ 957,636	$ 1,234,739	$ 608,392		$ 5,489,978
118											
119	Produced Gas Costs:										
120	LNG Vapor	Sch. 6, ln 50	[redacted]								
121	Propane	Sch. 6, ln 51									
122	Subtotal Produced Gas Costs		$ -	$ 3,446	$ 3,649	$ 2,643,842	$ 857,496	$ 4,908	$ 34,135		$ 3,547,477
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		$ -	$ (1,168,668)	$ (2,859)	$ (2,213,655)	$ (857,316)	$ (148,170)	$ (584,701)		$ (4,975,369)
130											
131	Total Supply Commodity Costs		$ -	$ 2,738,901	$ 11,649,770	$ 22,424,574	$ 16,215,068	$ 3,814,740	$ 2,211,648		$ 59,054,702
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		$ -	$ 194,353	$ 173,471	$ 198,595	$ 170,541	$ 130,872	$ 167,703		$ 1,035,536
140											
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ 62,085	$ 63,499	$ 68,713	$ 69,190	$ 89,210	$ 45,131		$ 397,827
142											
143	Total Supply Volumetric Trans. Costs	lns 139 + 141	$ -	$ 256,437	$ 236,970	$ 267,308	$ 239,731	$ 220,082	$ 212,834		$ 1,433,363
144											
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 2,995,339	$ 11,886,740	$ 22,691,882	$ 16,454,799	$ 4,034,822	$ 2,424,482		$ 60,488,065
146											
147											

THIS PAGE HAS BEEN REDACTED

REDACTED

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 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-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Nov - Apr
148	**D. Supply and Demand Costs by Source**										
149											
150	Purchased Gas Demand Costs										
151	Pipeline Gas Demand Costs	lns 54 + 73	$ 1,353,884	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077		$ 9,586,347
152	Peaking Gas Demand Costs	ln 81	-	300,000	300,000	300,000	300,000	300,000	-		1,500,000
153	Subtotal Purchased Gas Demand Costs		$ 1,353,884	$ 1,672,077	$ 1,672,077	$ 1,672,077	$ 1,672,077	$ 1,672,077	$ 1,372,077		$ 11,086,347
154	Less Capacity Credit	lns 55 + 74 + 82	(469,637)	(456,644)	(456,644)	(456,644)	(456,644)	(456,644)	(374,714)		(3,127,572)
155	Net Purchased Gas Demand Costs		$ 884,247	$ 1,215,433	$ 1,215,433	$ 1,215,433	$ 1,215,433	$ 1,215,433	$ 997,363		$ 7,958,775
156											
157	Storage Gas Demand Costs										
158	Storage Demand	ln 93	$ 715,401	$ 119,233	$ 119,233	$ 119,233	$ 119,233	$ 119,233	$ 119,233		$ 1,430,802
159	Less Capacity Credit	ln 94	(248,159)	(32,563)	(32,563)	(32,563)	(32,563)	(32,563)	(32,563)		(443,535)
160	Net Storage Demand Costs		$ 467,242	$ 86,671	$ 86,671	$ 86,671	$ 86,671	$ 86,671	$ 86,671		$ 987,267
161											
162	**Total Demand Costs**	lns 155 + 160	$ 1,351,489	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,084,034		$ 8,946,041
163											
164	Purchased Gas Supply										
165	Commodity Costs	ln 114	$ -	$ 3,044,824	$ 10,770,106	$ 21,043,350	$ 15,257,252	$ 2,723,263	$ 2,153,821		$ 54,992,615
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		$ -	$ 2,070,508	$ 10,940,718	$ 19,028,290	$ 14,570,477	$ 2,705,965	$ 1,736,824		$ 51,052,782
172											
173	Storage Commodity Costs										
174	Commodity Costs	ln 117	$ -	$ 859,300	$ 878,874	$ 951,038	$ 957,636	$ 1,234,739	$ 608,392		$ 5,489,978
175	Transportation Costs	ln 141	-	62,085	63,499	68,713	69,190	89,210	45,131		397,827
176	Subtotal Storage Commodity Costs		$ -	$ 921,384	$ 942,373	$ 1,019,751	$ 1,026,825	$ 1,323,949	$ 653,523		$ 5,887,806
177											
178	Produced Gas Commodity Costs	ln 122	$ -	$ 3,446	$ 3,649	$ 2,643,842	$ 857,496	$ 4,908	$ 34,135		$ 3,547,477
179											
180	**Subtotal Commodity Costs**	lns 171 + 176 + 178	$ -	$ 2,995,339	$ 11,886,740	$ 22,691,882	$ 16,454,799	$ 4,034,822	$ 2,424,482		$ 60,488,065
181											
182	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ 2,732	$ 42,931	$ 57,724	$ 43,648	$ 28,790	$ 436		$ 176,262
183											
184	**Total Commodity Costs**	lns 180 + 182	$ -	$ 2,998,071	$ 11,929,671	$ 22,749,607	$ 16,498,447	$ 4,063,612	$ 2,424,919		$ 60,664,327
185											
186	**Total Demand Costs**	ln 99	$ 1,351,489	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,084,034		$ 8,946,041
187	**Total Supply Costs**	ln 184	-	2 998 071	11 929 671	22 749 607	16 498 447	4 063 612	2 424 919		60 664 327
188											
189	**Total Direct Gas Costs**	lns 186 + 187	$ 1 351 489	$ 4 300 174	$ 13 231 775	$ 24 051 710	$ 17 800 551	$ 5 365 716	$ 3 508 953		$ 69 610 369
190											
191						**THIS PAGE HAS BEEN REDACTED**					

THIS PAGE LEFT INTENTIONALLY BLANK

Schedule 2

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

3 **Peak 2015 - 2016 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	3,199	
12	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
13	Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
14	National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
15	Tenn Gas Pipeline - Demand	FS-MA 523	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 N02358	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	Firm Transportation	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	1,096,341	[redacted]
37	City Gate Delivered Supply		Pipeline	Dkt	-	
38	TGP Supply (Direct)		Pipeline	Dkt	2,107,743	
39	Niagara Supply		Pipeline	Dkt	411,194	
40	Dawn Supply		Pipeline	Dkt	526,747	
41	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,058,902	
42	PNGTS		Pipeline	Dkt	42,383	
43	Propane Truck		Pipeline	Dkt	69,183	
44	LNG Vapor (Storage)		Produced	Dkt	189,161	
45	LNG Truck		Pipeline	Dkt	186,224	
46	Dracut Supply 2 - Swing		Pipeline	Dkt	1,299,713	
47	TGP Storage		Storage	Dkt	2,939,574	
48	Propane		Produced	Dkt	69,183	
49						
50	**Supply Costs - Volumetric Transportation**					
51	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,058,902	[redacted]
52	Dracut Supply 2 - Swing		Pipeline	Dkt	1,299,713	
53	Niagara Supply		Pipeline	Dkt	411,194	
54	Dawn Supply		Pipeline	Dkt	526,747	
55	TGP Storage - Withdrawals		Pipeline	Dkt	2,939,574	
56	TGP Supply (Direct)		Pipeline	Dkt	2,107,743	

Schedule 3

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 2016 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line		Days in Month	Prior Period Bal Apr-15 Ending Bal Plus May Billings	May-15 31	Jun-15 30	Jul-15 31	Aug-15 31	Sep-15 30	Oct-15 31	Nov-15 30	Dec-15 31	Jan-16 31	Feb-16 29	Mar-16 31	Apr-16 30	May-16 31	Peak Period Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
10	**Account 1920 1740 COG (Over)/Under Balance Interest Calculation**																
12	**Beginning Balance**	Account 1920-1740 1/	**$ (4,339,198)**	$ (4,339,198)	$ (4,606,632)	$ (6,151,649)	$ (6,659,021)	$ (6,804,360)	$ (6,626,255)	$ (6,513,559)	$ (9,713,689)	$ (9,116,973)	$ (1,052,531)	$ 3,822,163	$ (340,887)	$ (3,584,196)	$ (4,339,198)
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		225,248	225,248	225,248	225,248	225,248	225,248	4,300,174	13,231,775	24,051,710	17,800,551	5,365,716	3,508,953	-	69,610,368
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	331,783	331,783	331,783	331,783	331,783	331,783		1,990,700
15	Projected Revenues w/o Int	ln 52 * 59		-	-	-	-	-	-	(982 467)	(9 617 926)	(13 110 930)	(13 518 804)	(11 114 659)	(9 144 267)	(4 070 369)	(61 559 422)
16	Projected Unbilled Revenue									(6 509 723)	(9 498 924)	(12 140 784)	(11 540 417)	(9 951 754)	(7 495 596)		(57 137 198)
17	Reverse Prior Month Unbilled										6,509,723	9,498,924	12,140,784	11,540,417	9,951,754	7,495,596	57,137,198
18	Prior Period Adjustment-Unbilled				-					-							-
19	Add Net Adjustments	Schedule 4		(480,352)	(1,755,916)	(714,964)	(352,032)	(29,229)	(94,443)	(318,253)	(333,763)	(552,246)	(342,774)	(339,351)	(390,701)	-	(5,704,023)
20	Gas Cost Billed	Account 1920-1740 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Monthly (Over)/Under Recovery		$ (4 339 198)	$ (4 594 302)	$ (6 137 299)	$ (6 641 364)	$ (6 785 804)	$ (6 608 341)	$ (6 495 449)	$ (9 692 045)	$ (9 091 020)	$ (1 038 515)	$ 3 818 592	$ (345 685)	$ (3 578 961)	$ (158 969)	$ (1 575)
22	Average Monthly Balance	(ln 12 + 21)/2		$ (4,466,750)	$ (5,371,965)	$ (6,396,507)	$ (6,722,412)	$ (6,706,350)	$ (6,560,852)	$ (8,102,802)	$ (9,402,355)	$ (5,077,744)	$ 1,383,030	$ 1,738,239	$ (1,959,924)	$ (1,871,583)	
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		$ (12,329)	$ (14,350)	$ (17,656)	$ (18,556)	$ (17,914)	$ (18,110)	$ (21,644)	$ (25,953)	$ (14,016)	$ 3,571	$ 4,798	$ (5,235)	$ -	$ (157,395)
28	**(Over)/Under Balance**	ln 21 + ln 26	$ (4 339 198)	$ (4 606 632)	$ (6 151 649)	$ (6 659 021)	$ (6 804 360)	$ (6 626 255)	$ (6 513 559)	$ (9 713 689)	$ (9 116 973)	$ (1 052 531)	$ 3 822 163	$ (340 887)	$ (3 584 196)	$ (158 969)	(158 969)
31	**Calculation of COG with Interest**																
33	**Beginning Balance**	ln 12	$ (4,339,198)	$ (4,339,198)	$ (4,606,632)	$ (6,151,649)	$ (6,659,021)	$ (6,804,360)	$ (6,626,255)	$ (6,513,559)	$ (9,722,078)	$ (9,139,489)	$ (1,092,708)	$ 3,767,473	$ (406,351)	$ (3,657,305)	$ (4,339,198)
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		225,248	225,248	225,248	225,248	225,248	225,248	4,300,174	13,231,775	24,051,710	17,800,551	5,365,716	3,508,953	-	69,610,368
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	331,783	331,783	331,783	331,783	331,783	331,783	-	1,990,700
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(983,562)	(9,628,644)	(13,125,541)	(13,533,869)	(11,127,044)	(9,154,457)	(4,074,905)	(61,628,022)
37	Projected Unbilled Revenue									(6 516 978)	(9 509 509)	(12 154 313)	(11 553 278)	(9 962 844)	(7 503 949)		(57 200 870)
38	Reverse Prior Month Unbilled										6,516,978	9,509,509	12,154,313	11,553,278	9,962,844	7,503,949	57,200,870
39	Add Net Adjustments	ln 19		(480,352)	(1,755,916)	(714,964)	(352,032)	(29,229)	(94,443)	(318,253)	(333,763)	(552,246)	(342,774)	(339,351)	(390,701)	-	(5,704,023)
40	Gas Cost Billed	ln 20	-							-	-	-	-	-	-	-	-
41	Add Interest	ln 26		-	-	-	-	-	-	(21,644)	(25,953)	(14,016)	3,571	4,798	(5,235)	-	(58,480)
42	**(Over)/Under Balance**		$ (4 339 198)	$ (4 594 302)	$ (6 137 299)	$ (6 641 364)	$ (6 785 804)	$ (6 608 341)	$ (6 495 449)	$ (9 722 038)	$ (9 139 411)	$ (1 092 602)	$ 3 767 591	$ (406 192)	$ (3 657 113)	$ (228 261)	$ (128 654)
44	Average Monthly Balance			$ (4,466,750)	$ (5,371,965)	$ (6,396,507)	$ (6,722,412)	$ (6,706,350)	$ (6,560,852)	$ (8,117,799)	$ (9,430,745)	$ (5,116,046)	$ 1,337,441	$ 1,680,641	$ (2,031,732)	$ (1,942,783)	
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		(12,329)	(14,350)	(17,656)	(18,556)	(17,914)	(18,110)	(21,685)	(26,031)	(14,122)	3,454	4,639	(5,427)	-	(158,087)
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ (4,339,198)	$ (4,606,632)	$ (6,151,649)	$ (6,659,021)	$ (6,804,360)	$ (6,626,255)	$ (6,513,559)	$ (9,722,078)	$ (9,139,489)	$ (1,092,708)	$ 3,767,473	$ (406,351)	$ (3,657,305)	$ (228,261)	(228,261)
51	Forecast Sendout Therms	Sch 1								10,618,641	17,868,013	22,326,346	18,309,233	13,501,142	9,479,022		92,102,397
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								1,368,529	13,397,306	18,262,892	18,831,041	15,482,182	12,737,522	5,669,827	85,749,300
53	Less Forecast Unaccounted For	Sch 1								165,567	278,600	348,114	285,479	210,511	147,798		1,436,068
54	Less Forecast Company Use	Sch 1								16,816	28,296	35,356	28,995	21,380	15,011		145,854
55	Unbilled Volumes									9,067,730	4,163,811	3,679,984	-836,282	-2,212,931	-3,421,310	-5,669,827	4,771,175
56	Gross Unbilled									9,067,730	13,231,541	16,911,525	16,075,243	13,862,312	10,441,003	4,771,175	
59	COB w/o Interest	Sch. 3, pg. 4, ln 211 col. (c)								$0.7179	$0.7179	$0.7179	$0.7179	$0.7179	$0.7179	$0.7179	
61	COG With Interest	Sch 3 pg 4 ln 211 col (d)								$0 7187	$0 7187	$0 7187	$0 7187	$0 7187	$0 7187	$0 7187	

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

Line		Days in Month	Prior Period Bal Apr-15 Ending Bal + May Collections	May-15 31	Jun-15 30	Jul-15 31	Aug-15 31	Sep-15 30	Oct-15 31	Nov-15 30	Dec-15 31	Jan-16 31	Feb-16 29	Mar-16 31	Apr-16 30	May-16 31	Peak Period Total
74	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	( )	(k)	(l)	(m)	(n)	(o)	(p)
76	**Account 1163 1422 Working Capital (Over)/Under Balance Interest Calculation**																
78	**Beginning Balance**	Account 1163-1422 1/	**$ (28,115)**	$ (28,115)	$ (27,906)	$ (27,694)	$ (27,484)	$ (27,273)	$ (27,059)	$ (26,847)	$ (28,762)	$ (24,311)	$ (9,151)	$ 865	$ (1,606)	$ (3,674)	$ (28,115)
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%		286	286	286	286	286	286	5,465	16,816	30,567	22,622	6,819	4,459	-	88,467
84	Projected Revenues w/o Int.	ln 121 * ln 125		-	-	-	-	-	-	(958)	(9,378)	(12,784)	(13,182)	(10,838)	(8,916)	(3,969)	(60,025)
85	Projected Unbilled Revenue									(6,347)	(9,262)	(11,838)	(11,253)	(9,704)	(7,309)		(55,713)
86	Reverse Prior Month Unbilled										6,347	9,262	11,838	11,253	9,704	7,309	55,713
88	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Working Capital Billed	Account 1163-1422 2/	-														-
92	Monthly (Over)/Under Recovery		$ (28 115)	$ (27 829)	$ (27 620)	$ (27 408)	$ (27 197)	$ (26 987)	$ (26 773)	$ (28 687)	$ (24 238)	$ (9 105)	$ 875	$ (1 605)	$ (3 667)	$ (335)	$ 327
94	Average Monthly Balance	(ln 78 + ln 92)/2		$ (27,972)	$ (27,763)	$ (27,551)	$ (27,340)	$ (27,130)	$ (26,916)	$ (27,767)	$ (26,500)	$ (16,708)	$ (4,138)	$ (370)	$ (2,637)	$ (2,005)	
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		$ (77)	$ (74)	$ (76)	$ (75)	$ (72)	$ (74)	$ (74)	$ (73)	$ (46)	$ (11)	$ (1)	$ (7)	$ -	$ (662)
100	**(Over)/Under Balance**	ln 92 + ln 98	$ (28 115)	$ (27 906)	$ (27 694)	$ (27 484)	$ (27 273)	$ (27 059)	$ (26 847)	$ (28 762)	$ (24 311)	$ (9 151)	$ 865	$ (1 606)	$ (3 674)	$ (335)	(335)

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 2016 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**	In 78	$ (28,115)	$ (28,115)	$ (27,906)	$ (27,694)	$ (27,484)	$ (27,273)	$ (27,059)	$ (26,847)	$ (28,762)	$ (24,312)	$ (9,151)	$ 864	$ (1,606)	$ (3,675)	$ (28,115)
106	Forecast Working Cap tal	In 82		286	286	286	286	286	286	5,465	16,816	30,567	22,622	6,819	4,459	-	88,467
107	Projected Rev. with interest	In 121 * In 127		-	-	-	-	-	-	(958)	(9,378)	(12,784)	(13,182)	(10,838)	(8,916)	(3,969)	(60,025)
108	Projected Unbilled Revenue									(6,347)	(9,262)	(11,838)	(11,253)	(9,704)	(7,309)		(55,713)
109	Reverse Prior Month Unbilled										6,347	9,262	11,838	11,253	9,704	7,309	55,713
110	Add Net Adjustments	In 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Cap tal Billed	In 90	-	-	-	-	-	-	-								-
112	Add Interest	In 98		-	-	-	-	-	-	(74)	(73)	(46)	(11)	(1)	(7)	-	(212)
113	Monthly (Over)/Under Recovery		$ (28 115)	$ (27 829)	$ (27 620)	$ (27 408)	$ (27 197)	$ (26 987)	$ (26 773)	$ (28 762)	$ (24 312)	$ (9 151)	$ 864	$ (1 606)	$ (3 675)	$ (335)	$ 115
114																	
115	Average Monthly Balance			$ (27,972)	$ (27,763)	$ (27,551)	$ (27,340)	$ (27,130)	$ (26,916)	$ (27,804)	$ (26,537)	$ (16,731)	$ (4,143)	$ (371)	$ (2,640)	$ (2,005)	
116																	
117	Interest Applied	In 96 * In 115 / 365 * Days of Month		(77)	(74)	(76)	(75)	(72)	(74)	(74)	(73)	(46)	(11)	(1)	(7)	-	$ (662)
118																	
119	**(Over)/Under Balance**	-In 112 +In 113 + In 117	$ (28,115)	$ (27,906)	$ (27,694)	$ (27,484)	$ (27,273)	$ (27,059)	$ (26,847)	$ (28,762)	$ (24,312)	$ (9,151)	$ 864	$ (1,606)	$ (3,675)	$ (335)	$ (335)
120																	
121	Forecast Therm Sales	In 52								1,368,529	13,397,306	18,262,892	18,831,041	15,482,182	12,737,522	5,669,827	85,749,300
122	Unbilled Therm	In 55								9,067,730	4,163,811	3,679,984	(836,282)	(2,212,931)	(3,421,310)		
123	Gross Unbi led									9,067,730	13,231,541	16,911,525	16,075,243	13,862,312	10,441,003		
124																	
125	Working Cap Rate w/out Int	Sch 3 pg 4 In 228 col (c)								$0 0007	$0 0007	$0 0007	$0 0007	$0 0007	$0 0007	$0 0007	
126																	
127	Working Cap tal Rate w/ Int.	Sch. 3, pg. 4, In 228 col. (d)								$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	

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			Prior Period Bal														
131			Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	DemandPeriod
132		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	29	31	30	31	Total
133	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	( )	(k)	(l)	(m)	(n)	(o)	(p)
134																	
135	**Account 1920 1743 Bad Debt (Over)/Under Balance Interest Calculation**																
136																	
137	Forecast Direct Gas Costs	In 34		$ 225,248	$ 225,248	$ 225,248	$ 225,248	$ 225,248	$ 225,248	$ 4,300,174	$13,231,775	$24,051,710	$17,800,551	$ 5,365,716	$ 3,508,953	$ -	69,610,368
138	Forecast Working Cap tal	In 106		286	286	286	286	286	286	(22 650)	16 816	30 567	22 622	6 819	4 459		60 352
139	Prior Period Balance	In 42								(723 200)	(723 200)	(723 200)	(723 200)	(723 200)	(723 200)		(4 339 198)
140	Total Forecast Direct Gas Costs & Working Cap tal			225,534	225,534	225,534	225,534	225,534	225,534	3,554,325	12,525,391	23,359,078	17,099,974	4,649,335	2,790,212	-	69,670,720
141																	
142	**Beginning Balance**	Account 1920-1743 1/	**$ 720,643**	$ 720,643	$ 730,469	$ 740,257	$ 750,137	$ 760,044	$ 769,911	$ 779,873	$ 541,789	$ 366,545	$ 414,570	$ 382,749	$ 82,953	$ (144,513)	$ 720,643
143																	
144	Forecast Bad Debt	In 140 * 0.0347		7,826	7,826	7,826	7,826	7,826	7,826	123,335	434,631	810,560	593,369	161,332	96,820		2,267,004
145																	
146	Projected Revenues w/o int	In 183 * In 187		-	-	-	-	-	-	(47,625)	(466,226)	(635,549)	(655,320)	(538,780)	(443,266)	(197,310)	(2,984,076)
147	Projected Unbilled Revenue									(315,557)	(460,458)	(588,521)	(559,418)	(482,408)	(363,347)		(2,769,710)
148	Reverse Prior Month Unbilled										315,557	460,458	588,521	559,418	482,408	363,347	2,769,710
149																	
150	Bad Debt Bi led	Account 1920-1743 2/	-		-	-	-	-	-		-	-	-	-	-	-	-
151																	
152	Add Net Adjustments		-	-	-	-	-	-	-		-	-	-	-	-	-	-
153																	
154	Monthly (Over)/Under Recovery		$ 720,643	$ 728,469	$ 738,295	$ 748,083	$ 757,963	$ 767,870	$ 777,737	$ 540,026	$ 365,293	$ 413,493	$ 381,721	$ 82,311	$ (144,431)	$ 21,524	$ 3,571
155																	
156	Average Monthly Balance	(In 142 + In 154)/2		$ 724,556	$ 734,382	$ 744,170	$ 754,050	$ 763,957	$ 773,824	$ 659,950	$ 453,541	$ 390,019	$ 398,146	$ 232,530	$ (30,739)	$ (61,494)	
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	In 156 * In 158 / 365 * Days of Month		$ 2,000	$ 1,962	$ 2,054	$ 2,081	$ 2,041	$ 2,136	$ 1,763	$ 1,252	$ 1,077	$ 1,028	$ 642	$ (82)		$ 17,953
161																	
162	**(Over)/Under Balance**	In 154 + In 160	$ 720 643	$ 730 469	$ 740 257	$ 750 137	$ 760 044	$ 769 911	$ 779 873	$ 541 789	$ 366 545	$ 414 570	$ 382 749	$ 82 953	$ (144 513)	$ 21 524	21 524
163																	
164																	
165	**Calculation of Bad Debt with Interest**																
166																	
167	**Beginning Balance**	In 142	$ 720,643	$ 720,643	$ 730,469	$ 740,257	$ 750,137	$ 760,044	$ 769,911	$ 779,873	$ 540,747	$ 363,743	$ 409,573	$ 375,953	$ 74,830	$ (153,567)	$ 720,643
168	Forecast Bad Debt	In 144		7,826	7,826	7,826	7,826	7,826	7,826	123,335	434,631	810,560	593,369	161,332	96,820	-	2,267,004
169	Projected Revenues with int.	In 183 * In 189		-	-	-	-	-	-	(47,762)	(467,566)	(637,375)	(657,203)	(540,328)	(444,540)	(197,877)	(2,992,651)
170	Projected Unbilled Revenue									(316,464)	(461,781)	(590,212)	(561,026)	(483,795)	(364,391)		(2,777,669)
171	Reverse Prior Month Unbilled										316,464	461,781	590,212	561,026	483,795	364,391	2,777,669
172	Bad Debt Bi led	In 150	-		-	-	-	-	-	-	-	-	-	-	-	-	0
173	Add Interest	In 160		-	-	-	-	-	-	1 763	1 252	1 077	1 028	642	(82)	-	5 679
174	Add Net Adjustments	In 152	-							-	-	-	-	-	-	-	0
175	Monthly (Over)/Under Recovery		$ 720,643	$ 728,469	$ 738,295	$ 748,083	$ 757,963	$ 767,870	$ 777,737	$ 540,746	$ 363,747	$ 409,573	$ 375,953	$ 74,830	$ (153,567)	$ 12,947	$ 675
176																	
177	Average Monthly Balance			$ 724,556	$ 734,382	$ 744,170	$ 754,050	$ 763,957	$ 773,824	$ 660,309	$ 452,247	$ 386,658	$ 392,763	$ 225,392	$ (39,369)	$ (70,310)	
178																	
179	Interest Applied	In 158 * In 177 / 365 * Days of Month		2,000	1,962	2,054	2,081	2,041	2,136	1,764	1,248	1,077	1,028	642	(82)	-	$ 17,950
180																	
181	**(Over)/Under Balance**	-In 173 +In 175 + In 179	$ 720,643	$ 730,469	$ 740,257	$ 750,137	$ 760,044	$ 769,911	$ 779,873	$ 540,747	$ 363,743	$ 409,573	$ 375,953	$ 74,830	$ (153,567)	$ 12,947	$ 12,947
182																	
183	Forecast Term Sales	In 52								1,368,529	13,397,306	18,262,892	18,831,041	15,482,182	12,737,522	5,669,827	85,749,300
184	Unbilled Therm	In 55								9,067,730	4,163,811	3,679,984	(836,282)	(2,212,931)	(3,421,310)		
185	Gross Unbi led									9 067 730	13 231 541	16 911 525	16 075 243	13 862 312	10 441 003		
186																	
187	COG Rate Without Interest	Sch. 3, pg. 4, In 245 col. (c)								$0.0348	$0.0348	$0.0348	$0.0348	$0.0348	$0.0348	$0.0348	
188																	
189	COG With Interest	Sch. 3, pg. 4, In 245 col. (d)								$0.0349	$0.0349	$0.0349	$0.0349	$0.0349	$0.0349	$0.0349	

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

193	**Total Interest**	Ins 46 + 117 + 179	$ -	$ (10 407)	$ (12 462)	$ (15 678)	$ (16 550)	$ (15 946)	$ (16 048)	$ (19 995)	$ (24 856)	$ (13 091)	$ 4 471	$ 5 280	$ (5 516)	$ -	$ (140 799)

			COG Rate	COG Rate
195	**Calculation of COG**		Without Interest	W th Interest
196	(a)	(b)	(c)	(d)
197	(Over)Under Recovery Balance	In 12, col. (g)	$ (4,339,198)	$ (4,339,198)
198				
199	Unadjusted Forecast of Gas Costs	In 13, col. (g)	69,610,368	69,610,368
200				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 2016 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

201	Production & Storage and Misc Overhead	ln 14, col. (q)	1,990,700	1,990,700
203	Adjustments	ln 19, col. (q)	(5,704,023)	(5,704,023)
205	Interest Nov -Apr	ln 46, col. (q)	-	$ 69 852
207	Total Gas To Be Recovered		$ 61,557,848	$ 61,627,700
209	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	85,749,300	85,749,300
211	Preliminary COG Rate	ln. 207 / ln. 209	$0 7179	$0 7187
212				
213				
			Working Capital Rate without interest	Working Capital Rate with Interest
214	**Calculation of Working Capital Rate**			
215	(a)	(b)	(c)	(d)
216	(Over)Under Recovery Balance	ln 78, col. (q)	$ (28,115)	$ (28,115)
218	Unadjusted Working Capital Forecast	ln 82, col. (q)	88,467	88,467
220	Adjustments without interest	ln 88 col (q)	-	-
222	Interest Nov -Apr	ln 117, col. (q)	-	$ 38
224	Total Gas To Be Recovered		$ 60,352	$ 60,390
226	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	85,749,300	85,749,300
228	Preliminary Working Capital COG Rate		$0 0007	$0 0007
229				
230				
			Bad Debt Rate without Interest	Bad Debt Rate with interest
231	**Calculation of Bad Debt Rate**			
232	(a)	(b)	(c)	
233	(Over)Under Recovery Balance	ln 142, col. (q)	$ 720,643	$ 720,643
235	Unadjusted Bad Debt Forecast	ln 144, col. (q)	2,267,004	2,267,004
237	Adjustments without interest	ln 152, col. (q)	-	-
239	Interest Nov -Apr	ln 179, col. (q)	-	$ 3 974
241	Total Gas To Be Recovered		$ 2 987 647	$ 2 991 621
243	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	85,749,300	85,749,300
245	Preliminary Bad Debt COG Rate		$0 0348	$0 0349

Schedule 4

Line													
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**												**REDACTED**
2													
3	**Peak 2015 - 2016 Winter Cost of Gas Filing**												
4	**Adjustments to Gas Costs**												
5													
6	**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**	
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)	
8													
9	May-15	$ -	$ -	(241,578)	$ -	$ -	[redacted]			$ -	$ -	$ (480,352)	
10	Jun-15	-	-	(1,226,659)	-	-				-	-	(1,755,916)	
11	Jul-15 1/	-	-	(36,072)	-	-				-	-	(714,964)	
12	Aug-15 1/	-	-	(46,486)	-	-				-	-	(352,032)	
13	Sep-15 1/	-	-	-	-	-				-	-	(29,229)	
14	Oct-15 1/	-	-	(73,766)	-	-				-	-	(94,443)	
15	Nov-15 1/	-	(59,318)	(38,655)	-	4,135				-	49,565	(318,253)	
16	Dec-15 1/	-	(59,492)	-	-	5,438				-	-	(333,763)	
17	Jan-16 1/	-	(59,671)	(209,259)	-	6,517				-	-	(552,246)	
18	Feb-16 1/	-	(59,857)	-	-	7,134				-	-	(342,774)	
19	Feb-16 1/	-	(60,056)	-	-	6,724				-	-	(339,351)	
20	Mar-16 1/	-	(60,297)	(45,444)	-	5,814				-	-	(390,701)	
21													
22	Subtotal May 15 - Oct 15	$ -	$ -	$ (1,624,561)	$ -	$ -	$ -	$ -	$ (1,802,375)	$ -	$ -	$ (3,426,935)	
23													
24	Subtotal Nov 15 - Apr 16	$ -	$ (358,691)	$ (293,358)	$ -	$ 35,761	$ -	$ -	$ (1,710,365)	$ -	$ 49,565	$ (2,277,088)	
25													
26	Total Peak Period	$ -	$ (358,691)	$ (1,917,919)	$ -	$ 35,761	$ -	$ -	$ (3,512,739)	$ -	$ 49,565	$ (5,704,023)	
27													

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

THIS PAGE HAS BEEN REDACTED

Schedule 5

Line												REDACTED
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**											
2	**d/b/a Liberty Utilities**											
3	**Peak 2015 - 2016 Winter Cost of Gas Filing**											
4	**Demand Costs**											
5												
6				Deferred							Peak	
7				to Peak							Nov-Apr	
8		Peak	Reference	May 15 -Oct 15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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			$ 1,353,884	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 1,372,077	$ 9,586,347	
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			$ -	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ -	$ 1,500,000	
38												
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 1,353,884	$ 1,672,077	$ 1,672,077	$ 1,672,077	$ 1,672,077	$ 1,672,077	$ 1,372,077	$ 11,086,347	
40												
41	Less Transportation Capacity Credit			$ (469,637)	$ (456,644)	$ (456,644)	$ (456,644)	$ (456,644)	$ (456,644)	$ (374,714)	$ (3,127,572)	
42												
43	**Total Supply, Pipeline & Peaking Demand**			$ 884,247	$ 1,215,433	$ 1,215,433	$ 1,215,433	$ 1,215,433	$ 1,215,433	$ 997,363	$ 7,958,775	
44												
45												
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 51 x days	$ 10,437	$ 1,740	$ 1,740	$ 1,740	$ 1,740	$ 1,740	$ 1,740	$ 20,875	
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**			$ 715,401	$ 119,233	$ 119,233	$ 119,233	$ 119,233	$ 119,233	$ 119,233	$ 1,430,802	
55												
56	Less Transportation Capacity Credit			$ (248,159)	$ (32,563)	$ (32,563)	$ (32,563)	$ (32,563)	$ (32,563)	$ (32,563)	$ (443,535)	
57												
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 467,242	$ 86,671	$ 86,671	$ 86,671	$ 86,671	$ 86,671	$ 86,671	$ 987,267	
59												
60	**Total Demand Charges**		ln 39 + ln 54	$ 2,069,285	$ 1,791,311	$ 1,791,311	$ 1,791,311	$ 1,791,311	$ 1,791,311	$ 1,491,311	$ 12,517,149	
61												
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (717,796)	$ (489,207)	$ (489,207)	$ (489,207)	$ (489,207)	$ (489,207)	$ (407,277)	$ (3,571,107)	
63												
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 1,351,489	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,302,104	$ 1,084,034	$ 8,946,041	
65												
66							THIS PAGE HAS BEEN REDACTED					

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2015 - 2016 Winter Cost of Gas Filing
<u>Demand Volumes</u>

		Peak	Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply									
	Niagara Supply			3,199	3,199	3,199	3,199	3,199	3,199
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)		Firm Transportation	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 N02358	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	245,380	245,380	245,380	245,380	245,380	245,380
	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 523	21,844	21,844	21,844	21,844	21,844	21,844
	Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA 523	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **Demand Rates**

Line	Description	Contract	Rate	Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Nov - Apr
5					**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**Nov - Apr**
6	**Tariff Rates**				30	31	31	29	31	30	182
7					Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
8	**Supply**										
9	Niagara Supply		[redacted]		[redacted]						
10											
11	**Pipeline**										
12	Iroquois Gas Trans Service	RTS 470-01	$6.5971	First Revised Sheet No. 4	$0.2199	$0 2128	$0 2128	$0.2275	$0.2128	$0.2199	$0.2176
13											
14	Tenn Gas Pipeline	95346 Z5-Z6	$7.3963	Seventh Rev Sheet No. 14	$0.2465	$0 2386	$0 2386	$0.2550	$0.2386	$0.2465	$0.2440
15											
16	Tenn Gas Pipeline	2302 Z5-Z6	$7.3963	Seventh Rev Sheet No. 14	$0.2465	$0 2386	$0 2386	$0.2550	$0.2386	$0.2465	$0.2440
17											
18	Tenn Gas Pipeline	8587 Z0-Z6	$23.9536	FT-A (Z0 - Z6)	$0.7985	$0.7727	$0.7727	$0.8260	$0.7727	$0.7985	$0.7902
19											
20	Tenn Gas Pipeline	8587 Z1-Z6	$21.2648	FT-A (Z1 - Z6)	$0.7088	$0.6860	$0.6860	$0.7333	$0.6860	$0.7088	$0.7015
21											
22	Tenn Gas Pipeline	8587 Z4-Z6	$8.4181	FT-A (Z4 - Z6)	$0.2806	$0 2716	$0 2716	$0.2903	$0.2716	$0.2806	$0.2777
23											
24	TGP Dracut	42076 FTA Z6-Z6	$4.9101	Seventh Rev Sheet No. 14	$0.1637	$0.1584	$0.1584	$0.1693	$0.1584	$0.1637	$0.1620
25											
26	TGP Concord Lateral	Firm Transportatioı	$12.2103	Per contract	$0.4070	$0 3939	$0 3939	$0.4210	$0.3939	$0.4070	$0.4028
27											
28	Portland Natural Gas	FT-1999-001	$25.9843	Part 4.1 v.5.0.0	$0.8661	$0 8382	$0 8382	$0.8960	$0.8382	$0.8661	$0.8572
29											
30	Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.4181	Seventh Rev Sheet No. 14	$0.2806	$0 2716	$0 2716	$0.2903	$0.2716	$0.2806	$0.2777
31											
32	Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.4181	Seventh Rev Sheet No. 14	$0.2806	$0 2716	$0 2716	$0.2903	$0.2716	$0.2806	$0.2777
33											
34	Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.3963	Seventh Rev Sheet No. 14	$0.2465	$0 2386	$0 2386	$0.2550	$0.2386	$0.2465	$0.2440
35											
36	National Fuel	FST N02358	$3.7805	4.010 Version 12.0.0 Pg 1	$0.1260	$0.1220	$0.1220	$0.1304	$0.1220	$0.1260	$0.1247
37											
38	ANE Union Gas		$2.6040								
39	TransCanada Pipelines Limited		$15.05290	Union Parkway to Iroquois							
40	Delivery Pressure Demand Charge		1.0123	Union Parkway to Iroquois							
41	Sub Total Demand Charges		18.6692								
42	Conversion rate GJ to MMBTU		1.0551								
43	Conversion rate to US$		1.2019	updated 7/28/15							
44	Demand Rate/US$		$16.3894		$0.5463	$0 5287	$0 5287	$0.5652	$0.5287	$0.5463	$0.5406
45											
46	**Peaking**										
47	Granite Ridge Demand		[redacted]		[redacted]						
48	GDF Suez Demand NSB041										
49											
50	**Storage**										
51	Dominion - Demand	GSS 300076	$1.8625	Rec No 10.30 Ver 14.0.0	$0.0621	$0.0601	$0.0601	$0.0642	$0.0601	$0.0621	$0.0613
52	Dominion - Capacity	GSS 300076	$0.0145	Rec No 10.30 Ver 14.0.0	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
53			$1.8770		$0.0626	$0.0605	$0.0605	$0.0647	$0.0605	$0.0626	$0.0618
54											
55	Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0 2071	$0 2071	$0.2213	$0.2071	$0.2140	$0.2113
56											
57	National Fuel - Demand	FSS-1 2357	$2.4826	4.020 Version 8.0.0 Pg 1	$0.0828	$0.0801	$0.0801	$0.0856	$0.0801	$0.0828	$0.0817
58	National Fuel - Capacity	FSS-1 2357	$0.0381	4.020 Version 8.0.0 Pg 1	$0.0013	$0.0012	$0.0012	$0.0013	$0.0012	$0.0013	$0.0013
59			$2.5207		$0.0840	$0.0813	$0.0813	$0.0869	$0.0813	$0.0840	$0.0830
60											
61	Tenn Gas Pipeline	FS-MA 523	$1.5400	Tenth Rev Sheet No.61	$0.0513	$0.0497	$0.0497	$0.0531	$0.0497	$0.0513	$0.0507
62	Tenn Gas Pipeline - Space	FS-MA 523	$0.0211	Tenth Rev Sheet No.61	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007
63			$1.5611		$0.0520	$0.0504	$0.0504	$0.0538	$0.0504	$0.0520	$0.0514
64											
65					**THIS PAGE HAS BEEN REDACTED**						

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)

RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule (1)	Rate Component (2)	Base Tariff Rate [1] (3)	Current Acct 858 Base (4)	Current EPCA Base (5)	TCRA [5] Surcharge (6)	EPCA [6] Surcharge (7)	Current Rate [7] (8)	FERC ACA (9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0678	$0.0014	($0.0042)	($0.0009)	$1.8625	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0152	$0.0000	$0.0012	$0.0318	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	$0.0012	$0.0166	[8]
	GSS-TE Surcharge [3]	-	$0.0046	-	($0.0006)	-	$0.0040	-
	From Customers Balance	$0.6163	$0.0146	$0.0003	($0.0009)	$0.0010	$0.6313	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0678	$0.0014	($0.0042)	($0.0009)	$2.2754	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0152	$0.0000	$0.0012	$0.0318	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	$0.0012	$0.0166	[8]
	Authorized Overruns	$1.0657	$0.0146	$0.0003	($0.0009)	$0.0010	$1.0807	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0000	($0.0001)	$0.0000	$0.0757	-
	Injection Charge	$0.0154	-	$0.0152	$0.0000	$0.0012	$0.0318	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	$0.0012	$0.0166	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0146	$0.0003	($0.0009)	$0.0010	$0.6313	[8]
	Excess Injection Charge	$0.2245	-	$0.0152	$0.0000	$0.0012	$0.2409	-

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 1.67% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 1.95%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6147. Daily Capacity Release Rate for GSS-E per Dt is $1.0641.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.
[7] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[8] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

934
x 1.8625
1739.58

Contract Summary

General Information

Contract Number	Customer	Contract Type
EN-11234	Energy North Natural Gas Inc.	Firm

Contract Dates

Effective Date (mm/dd/yy)	Termination Date (mm/dd/yy)
05/01/10	01/01/20

Transaction Types and Rates

Transaction Type	Volumetric Charge	Other Rate	Fuel %	Invoice Qty Type
Storage Injection	$ 0.0000	$ 0.0000	0	Sch Qty

Transaction Type	Volumetric Charge	Other Rate	Fuel %	Invoice Qty Type
Storage Withdrawal	$ 0.0000	$ 0.0000	0	Sch Qty

Transaction Type	Volumetric Charge	Other Rate	Fuel %	Invoice Qty Type
Authorized Injection Overrun	$ 0.0000	$ 0.0000	0	Sch Qty

Transaction Type	Volumetric Charge	Other Rate	Fuel %	Invoice Qty Type
Authorized Withdrawal Overrun	$ 0.0000	$ 0.0000	0	Sch Qty

Storage and Other Rates

☐ Use Monthly Storage Rate ($/Dth/Month)

Monthly Storage Rate Table

From	To
05/01/10	01/01/20

☐ Use Monthly Flat Fee ($/Month)

Monthly Flat Storage Fee Table

From	To	Rate
05/01/10	01/01/20	8,744.3

	Rate	Amount
☐ Use Daily Storage Rate ($/Dth/Day)	0	
☐ Use Injection Deliverability Rate	0	0
☐ Use Withdrawal Deliverability Rate	0	0

------------- 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)

Same 1/23/13

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/]
	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
.0014
.0405

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 0.46%.
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.

.46 on both INJ & wd

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	0.0000	$3.9653	
		(Min)	0.0000	0.0000	0.0000	$0.0000	
	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/

Commodity is charged on both FNJ & w/d

.0135
.0014
.0149

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 0.54% and the Transportation LAUF Retention for all applicable rate schedules is 0.42%. 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.

FNJ Fuel = .54
.42
.96

* No Fuel when w/d

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/
FT	Recourse Reservation Rate		
	-- Maximum	$25.9843	---------
	-- Minimum	$00.0000	---------
	Seasonal Recourse Reservation Rate		
	-- Maximum	$49.3701	---------
	-- Minimum	$00.0000	---------
	Recourse Usage Rate		
	-- Maximum	$00.0000	2/
	-- Minimum	$00.0000	2/
FT-FLEX	Recourse Reservation Rate		
	--Maximum	$17.4406	---------
	--Minimum	$00.0000	---------
	Recourse Usage Rate		
	--Maximum	$00.2809	2/
	--Minimum	$00.0000	2/

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

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

Rates get updated in April

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

Seventh Revised Sheet No. 14
Superseding
Sixth Revised Sheet No. 14

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

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

Daily Base Reservation Rate 1/

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

Maximum Reservation Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7528		$11.9778	$16.0978	$16.3820	$17.9965	$19.1000	$23.9536
L		$5.1117						
1	$8.6400		$8.2838	$11.0107	$15.5810	$15.3455	$17.3010	$21.2648
2	$16.0979		$10.9448	$5.7118	$5.3421	$6.8241	$9.3706	$12.0846
3	$16.3820		$8.6778	$5.7576	$4.1649	$6.3761	$11.4990	$13.2812
4	$20.7887		$19.1685	$7.3298	$11.1182	$5.4628	$5.9046	$8.4181
5	$24.7798		$17.4243	$7.6869	$9.2927	$6.0642	$5.6908	$7.3963
6	$28.6592		$20.0071	$13.7822	$15.1790	$10.7337	$5.6659	$4.9101

Notes:
1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0403.

Pipeline Safety/Green House Gas

Flat rate across all zones

Issued: September 30, 2014
Effective: November 1, 2014

Docket No. RP14-1306-000
Accepted: October 30, 2014

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	0	L	1	2	3	4	5	6
				DELIVERY ZONE				
0	$0.0047		$0.0130	$0.0192	$0.0234	$0.2766	$0.2640	$0.3139
L		$0.0027						
1	$0.0057		$0.0096	$0.0162	$0.0194	$0.2354	$0.2400	$0.2738
2	$0.0182		$0.0102	$0.0027	$0.0043	$0.0772	$0.1229	$0.1360
3	$0.0222		$0.0184	$0.0041	$0.0017	$0.1027	$0.1415	$0.1543
4	$0.0265		$0.0220	$0.0102	$0.0120	$0.0483	$0.0677	$0.1088
5	$0.0299		$0.0271	$0.0115	$0.0133	$0.0674	$0.0668	$0.0826
6	$0.0361		$0.0315	$0.0158	$0.0178	$0.1029	$0.0564	$0.0349

Notes:

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

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

3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of
* $0.0015.

* Flat across All zones

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.8100	$2.8100 1/		
Space Rate	$0.0286	$0.0286 1/		
Injection Rate	$0.0073	$0.0073	0.80%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.3372	$0.3372 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.5400	$1.5400 1/		
Space Rate	$0.0211	$0.0211 1/		
Injection Rate	$0.0087	$0.0087	0.80%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1848	$0.1848 1/		

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.01%.

No Fuel charged on W/D
Fuel is charged on INJ

NO ACA on INJ or W/D
NO EPCR, NO PS/GHG

Issued: February 27, 2015
Effective: April 1, 2015

Docket No.
Accepted:

FUEL AND EPCR

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.48%		1.05%	1.46%	1.75%	2.05%	2.29%	2.68%
L		0.35%						
1	0.55%		0.82%	1.26%	1.48%	1.77%	2.09%	2.36%
2	1.46%		0.86%	0.34%	0.46%	0.67%	0.99%	1.26%
3	1.75%		1.48%	0.46%	0.28%	0.85%	1.12%	1.41%
4	2.05%		1.65%	0.86%	0.98%	0.47%	0.60%	0.88%
5	2.33%		2.09%	0.99%	1.13%	0.60%	0.59%	0.70%
6	2.74%		2.36%	1.26%	1.41%	0.84%	0.52%	0.37%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0049		$0.0189	$0.0292	$0.0363	$0.0439	$0.0499	$0.0599
L		$0.0016						
1	$0.0066		$0.0132	$0.0242	$0.0296	$0.0368	$0.0451	$0.0518
2	$0.0292		$0.0142	$0.0015	$0.0043	$0.0095	$0.0174	$0.0238
3	$0.0363		$0.0296	$0.0043	$0.0000	$0.0139	$0.0206	$0.0275
4	$0.0439		$0.0340	$0.0141	$0.0172	$0.0045	$0.0079	$0.0148
5	$0.0499		$0.0451	$0.0174	$0.0206	$0.0078	$0.0077	$0.0103
6	$0.0599		$0.0518	$0.0238	$0.0275	$0.0138	$0.0058	$0.0021

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.26%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.26%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

Final Mainline Transportation Tolls Effective July 1, 2015 and
Final Abandonment Surcharges Effective January 1, 2015

Storage Transportation Service

Line No	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
1	Centram MDA	5.23197	0.17201	0.25380	0.0083
2	Union WDA	39.71839	1.30581	2.29401	0.0754
3	Union NDA	16.92748	0.55652	0.85092	0.0280
4	Union EDA	11.84212	0.38933	0.52893	0.0174
5	KPUC EDA	11.39043	0.37448	0.50032	0.0164
6	GMIT EDA	19.47488	0.64027	1.01224	0.0333
7	Enbridge CDA	5.88532	0.19349	0.15176	0.0050
8	Enbridge CDA (Amended)	6.05839	0.19918	0.16269	0.0053
9	Enbridge EDA	15.16514	0.49858	0.73933	0.0243
10	Cornwall	15.38840	0.50592	0.75348	0.0248
11	Philipsburg	19.52568	0.64194	1.01543	0.0334

Firm Transportation - Short Notice

Line No	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
12	Kirkwall to Thorold CDA	6.98093	0.22951	0.18094	0.0059
13	Union Parkway Belt to Goreway CDA	5.19730	0.17087	0.07829	0.0026
14	Union Parkway Belt to Victoria Square #2 CDA	6.07695	0.19979	0.13244	0.0044
15	Union Parkway Belt to Schomberg #2 CDA	6.13839	0.20181	0.12891	0.0042

Enhanced Market Balancing Service

Line No	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
16	Union Parkway Belt to Union EDA	13.02633	0.42826	0.52893	0.0174

Delivery Pressure

Line No	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
17	Average Delivery Pressure Toll	1.01227	0.03328

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

Union Dawn Receipt Point Surcharge

Line No	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
18	Union Dawn Receipt Point Surcharge	0.10724	0.00353

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
19	SNB Toll		
Note:	This SNB Toll is a representative toll for the Eastern Region.	3.42005	0.1124

Energy Deficient Gas Allowance (EDGA) Service

Line No	Particulars	Capacity Charge ($/GJ/D)
	(a)	(b)
20	Western Section	1.52481
21	Eastern Section	0.41865

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

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/Month)	Daily Equivalent FT for IT / STFT ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
1	Union NCDA	Union Parkway Belt	-	0.2792	-	0.0104
2	Union NCDA	Union CDA (Amended)	-	0.3277	-	0.0135
3	Union NCDA	Union ECDA	-	0.2883	-	0.0110
4	Union NCDA	Enbridge Parkway CDA	-	0.2792	-	0.0104
5	Union NCDA	Enbridge CDA (Amended)	-	0.2737	-	0.0101
6	Union NDA	Empress	-	1.4286	-	0.1224
7	Union NDA	TransGas SSDA	-	1.1879	-	0.1005
8	Union NDA	Centram SSDA	-	1.0893	-	0.0916
9	Union NDA	Centram MDA	-	0.9409	-	0.0781
10	Union NDA	Centrat MDA	-	0.8727	-	0.0719
11	Union NDA	Union WDA	-	0.6155	-	0.0486
12	Union NDA	Nipigon WDA	-	0.5101	-	0.0390
13	Union NDA	Union NDA	-	0.0927	-	0.0012
14	Union NDA	Calstock NDA	-	0.3266	-	0.0224
15	Union NDA	Tunis NDA	-	0.1989	-	0.0108
16	Union NDA	GMIT NDA	-	0.1848	-	0.0095
17	Union NDA	Union SSMDA	-	0.8518	-	0.0700
18	Union NDA	Union NCDA	-	0.3072	-	0.0187
19	Union NDA	Union CDA	-	0.4349	-	0.0295
20	Union NDA	Enbridge CDA	-	0.4132	-	0.0277
21	Union NDA	Union EDA	-	0.4902	-	0.0342
22	Union NDA	Enbridge EDA	-	0.4480	-	0.0306
23	Union NDA	KPUC EDA	-	0.5277	-	0.0373
24	Union NDA	GMIT EDA	-	0.5801	-	0.0418
25	Union NDA	Enbridge SWDA	-	0.5522	-	0.0394
26	Union NDA	Union SWDA	-	0.5543	-	0.0396
27	Union NDA	Chippawa	-	0.4975	-	0.0348
28	Union NDA	Cornwall	-	0.4798	-	0.0333
29	Union NDA	East Hereford	-	0.6919	-	0.0512
30	Union NDA	Emerson 1	-	0.9514	-	0.0791
31	Union NDA	Emerson 2	-	0.9514	-	0.0791
32	Union NDA	Iroquois	-	0.4600	-	0.0316
33	Union NDA	Kirkwall	-	0.4398	-	0.0299
34	Union NDA	Napierville	-	0.5713	-	0.0410
35	Union NDA	Niagara Falls	-	0.4961	-	0.0347
36	Union NDA	North Bay Junction	-	0.1893	-	0.0099
37	Union NDA	Philipsburg	-	0.5817	-	0.0419
38	Union NDA	Spruce	-	0.8727	-	0.0719
39	Union NDA	St. Clair	-	0.5274	-	0.0406
40	Union NDA	Welwyn	-	1.0893	-	0.0916
41	Union NDA	Dawn Export	-	0.5522	-	0.0394
42	Union NDA	Union Parkway Belt	-	0.4170	-	0.0280
43	Union NDA	Union CDA (Amended)	-	0.4534	-	0.0311
44	Union NDA	Union ECDA	-	0.4238	-	0.0286
45	Union NDA	Enbridge Parkway CDA	-	0.4170	-	0.0280
46	Union NDA	Enbridge CDA (Amended)	-	0.4128	-	0.0276
47	Union Parkway Belt	Empress	72.71500	2.3906	4.38333	0.1441
48	Union Parkway Belt	TransGas SSDA	62.22550	2.0458	3.71915	0.1223
49	Union Parkway Belt	Centram SSDA	57.92793	1.9045	3.44704	0.1133
50	Union Parkway Belt	Centram MDA	51.42698	1.6908	3.03541	0.0998
51	Union Parkway Belt	Centrat MDA	50.92176	1.6741	3.00341	0.0987
52	Union Parkway Belt	Union WDA	39.71839	1.3058	2.29401	0.0754
53	Union Parkway Belt	Nipigon WDA	35.11878	1.1546	2.00276	0.0658
54	Union Parkway Belt	Union NDA	16.92748	0.5565	0.85092	0.0280
55	Union Parkway Belt	Calstock NDA	27.12102	0.8917	1.49639	0.0492
56	Union Parkway Belt	Tunis NDA	20.82538	0.6847	1.09773	0.0361
57	Union Parkway Belt	GMIT NDA	16.14638	0.5308	0.80147	0.0263
58	Union Parkway Belt	Union SSMDA	24.24117	0.7970	1.31401	0.0432
59	Union Parkway Belt	Union NCDA	8.49264	0.2792	0.31683	0.0104
60	Union Parkway Belt	Union CDA	4.76720	0.1567	0.08094	0.0027
61	Union Parkway Belt	Enbridge CDA	5.88532	0.1935	0.15176	0.0050
62	Union Parkway Belt	Union EDA	11.84212	0.3893	0.52893	0.0174
63	Union Parkway Belt	Enbridge EDA	15.16514	0.4986	0.73933	0.0243
64	Union Parkway Belt	KPUC EDA	11.39043	0.3745	0.50032	0.0164
65	Union Parkway Belt	GMIT EDA	19.47488	0.6403	1.01224	0.0333
66	Union Parkway Belt	Enbridge SWDA	9.52802	0.3133	0.38239	0.0126
67	Union Parkway Belt	Union SWDA	9.61501	0.3161	0.38790	0.0128
68	Union Parkway Belt	Chippawa	7.30852	0.2403	0.24188	0.0080
69	Union Parkway Belt	Cornwall	15.38840	0.5059	0.75348	0.0248
70	Union Parkway Belt	East Hereford	24.00088	0.7891	1.29882	0.0427
71	Union Parkway Belt	Emerson 1	47.97256	1.5772	2.81666	0.0926
72	Union Parkway Belt	Emerson 2	47.97256	1.5772	2.81666	0.0926
73	Union Parkway Belt	Iroquois	14.36427	0.4723	0.68863	0.0226
74	Union Parkway Belt	Kirkwall	4.96613	0.1633	0.09354	0.0031
75	Union Parkway Belt	Napierville	19.10349	0.6281	0.98870	0.0325
76	Union Parkway Belt	Niagara Falls	7.25103	0.2384	0.23822	0.0078

unıongas

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	$2.604	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$2.193			
Kirkwall to Parkway	$0.411			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$3.244	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$6.250	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$6.250			
Parkway (TCPL) to Parkway (Cons) (2)		0.155%		

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".		$0.086
Dawn to Kirkwall				$0.072
Kirkwall to Parkway				$0.014
Parkway to Dawn				$0.086
Parkway (TCPL) Overrun (4)	n/a	0.694%		n/a
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.107

BANK OF CANADA
BANQUE DU CANADA

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 (http://www.bankofcanada.ca/terms/#fx-rates) 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
Use cash rate
Convert
Answer:
0.75
Exchange Rate:
0.7517
Summary:
On 26 August 2015, 1.00 Canadian Dollar(s) = 0.75 U.S. dollar(s), at an exchange rate of 0.7517 (using nominal rate).

See Also

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

Why is the Currency I'm Looking for Not Listed Here?

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

Are the Exchange Rates Shown Here Accepted by Canada Revenue Agency?

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

Schedule 6

Line		Reference							
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**							**REDACTED**	Schedule 6
2	**d/b/a Liberty Utilities**								Page 1 of 5
3	**Peak 2015 - 2016 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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		$ 3,044,824	$ 10,770,106	$ 21,043,350	$ 15,257,252	$ 2,723,263	$ 2,153,821	$ 54,992,615
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**		$ 256,437	$ 236,970	$ 267,308	$ 239,731	$ 220,082	$ 212,834	$ 1,433,363
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		$ (1,168,668)	$ (2,859)	$ (2,213,655)	$ (857,316)	$ (148,170)	$ (584,701)	$ (4,975,369)
43									
44	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 34 + ln 42	$ 2,132,593	$ 11,004,217	$ 19,097,002	$ 14,639,667	$ 2,795,175	$ 1,781,955	$ 51,450,609
45									
46	**Storage Gas**								
47	TGP Storage - Withdrawals	ln 77 * ln 157	$ 859,300	$ 878,874	$ 951,038	$ 957,636	$ 1,234,739	$ 608,392	$ 5,489,978
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	$ 3,446	$ 3,649	$ 2,643,842	$ 857,496	$ 4,908	$ 34,135	$ 3,547,477
54									
55									
56	**Total Commodity Gas & Trans. Costs**	ln 44 + ln 47 + ln 53	$ 2,995,339	$ 11,886,740	$ 22,691,882	$ 16,454,799	$ 4,034,822	$ 2,424,482	$ 60,488,065
57									$ 92,102,397
58					**THIS PAGE HAS BEEN REDACTED**				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
d/b/a Liberty Utilities
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line									
5									Peak
6	For Month of:	Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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		836,662	921,223	935,514	851,729	878,077	844,268	5,267,474
64	Niagara Supply		653,294	719,148	730,305	664,495	685,467	659,233	4,111,942
65	TGP Supply (Direct)		4,768,976	3,122,500	3,170,940	2,887,067	2,976,256	4,151,689	21,077,429
66	Dracut Supply 1 - Baseload		-	2,751,782	4,657,201	3,180,032	-	-	10,589,015
67	Dracut Supply 2 - Swing		1,584,778	3,727,982	3,922,369	3,133,775	536,760	91,462	12,997,126
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		2,789	2,972	1,083,386	691,663	81,435	-	1,862,243
70	Propane Truck		-	-	691,828	-	-	-	691,828
71	PNGTS		57,172	80,978	91,288	78,565	67,980	47,842	423,825
72	TGP Supply (Z4)		1,680,994	1,851,361	1,880,082	1,711,534	1,764,652	2,074,789	10,963,412
73									
74	Subtotal Pipeline Volumes		9,584,666	13,177,947	17,162,912	13,198,860	6,990,626	7,869,283	67,984,295
75									
76	**Storage Gas**								
77	TGP Storage		4,585,608	4,690,065	5,075,164	5,110,373	6,589,118	3,345,413	29,395,741
78									
79	**Produced Gas**								
80	LNG Vapor		2,789	2,972	1,171,656	691,663	2,833	19,700	1,891,611
81	Propane		-	-	691,828	-	-	-	691,828
82									
83	Subtotal Produced Gas		2,789	2,972	1,863,484	691,663	2,833	19,700	2,583,439
84									
85	**Less - Gas Refill**								
86	LNG Truck		(2,789)	(2,972)	(1,083,386)	(691,663)	(81,435)	-	(1,862,243)
87	Propane		-	-	(691,828)	-	-	-	(691,828)
88	TGP Storage Refill		(3,551,632)	-	-	-	-	(1,755,374)	(5,307,007)
89									
90	Subtotal Refills		(3,554,421)	(2,972)	(1,775,213)	(691,663)	(81,435)	(1,755,374)	(7,861,078)
91									
92	**Total Sendout Volumes**		10,618,641	17,868,013	22,326,346	18,309,233	13,501,142	9,479,022	92,102,397
93									
94									
95									

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line									
5									Peak
6	For Month of:	Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
96	**Gas Costs and Volumetric Transportation Rates**								
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	**$1.7962**	**$0.9621**	**$1.2547**	**$1.2395**	**$1.8195**	**$1.8045**	**$1.4794**
132									
133	**Propane Truck**	Propane WACOG	**$1.2349**	**$1.2349**	**$1.2349**	**$1.2349**	**$1.2349**	**$1.2349**	**$1.2349**
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	**$1.2356**	**$1.2279**	**$1.2524**	**$1.2398**	**$1.7328**	**$1.7328**	**$1.4035**
146									
147	**Propane**	Sch 16, ln 66 /10	**$1.2349**	**$1.2349**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.5453**
148									
149	**Storage Refill**								
150	**LNG Truck**	ln 131	**$1.7962**	**$0.9621**	**$1.2547**	**$1.2395**	**$1.8195**	**$1.8045**	**$1.4035**
151	**Propane**	ln 133	**$1.2349**	**$1.2349**	**$1.2349**	**$1.2349**	**$1.2349**	**$1.2349**	**$1.5453**
152									
153						**THIS PAGE HAS BEEN REDACTED**			

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**
5

Line	For Month of:	Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
154									
155									
156	**TGP Storage**								Average Rate
157	**Commodity Costs - Storage withdrawal**	Sch 16, ln 34 /10	$0.1874	$0.1874	$0.1874	$0.1874	$0.1874	$0.1819	$0.1865
158									
159	TGP - Max Commodity - Z 4-6	Tenth Rev Sheet No. 15	$0.01088	$0.01088	$0.01088	$0.01088	$0.01088	$0.01088	$0.01088
160	TGP - Max Comm. ACA Rate - Z 4-6	Tenth 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		$0.01102	$0.01102	$0.01102	$0.01102	$0.01102	$0.01102	$0.01102
162	TGP - Fuel Charge % - Z 4-6	Ninth Rev Sheet No. 32	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%	0.88%
163	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00165	$0.00165	$0.00165	$0.00165	$0.00165	$0.00160	$0.00164
164	TGP - Withdrawal Charge	Tenth 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)**		$0.01354	$0.01354	$0.01354	$0.01354	$0.01354	$0.01349	$0.01353
166									
167	**Total TGP - Comm. & Vol. Trans. Rate**	ln 157 + ln 165	**$0.20093**	**$0.20093**	**$0.20093**	**$0.20093**	**$0.20093**	**$0.19535**	**$0.20000**
168									
169									
156	**Per Unit Volumetric Transportation Rates**								
157	**Dawn Supply Volumetric Transportation Charge**								
158	**Commodity Costs**	ln 102	**$0.3146**	**$0.3394**	**$0.3467**	**$0.3546**	**$0.3548**	**$0.3054**	**$0.3359**
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 7/28/15	1.2019	1.2019	1.2019	1.2019	1.2019	1.2019	1.2019
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	1.46%	1.75%	2.11%	2.27%	2.11%	2.12%	1.97%
165	TransCanada Fuel * Percentage	ln 158 x ln 164	$0.00461	$0.00594	$0.00732	$0.00806	$0.00749	$0.00648	$0.00665
166	Subtotal TransCanada		**$0.00461**	**$0.00594**	**$0.00732**	**$0.00806**	**$0.00749**	**$0.00648**	**$0.00665**
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	Fifth Revised Sheet 4A	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
169	IGTS - Z1 RTS Deferred Asset Surcharge	Fifth 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	Tenth Rev Sheet No. 15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
172	IGTS -Fuel Use Factor - Percentage	Fifth 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	**$0.00315**	**$0.00339**	**$0.00347**	**$0.00355**	**$0.00355**	**$0.00305**	**$0.00336**
174	TGP FTA Fuel Charge % Z 5-6	Ninth Rev Sheet No. 32	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%
175	TGP FTA Fuel * Percentage	ln 158 x ln 174	**$0.00220**	**$0.00238**	**$0.00243**	**$0.00248**	**$0.00248**	**$0.00214**	**$0.00235**
176	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01053**	**$0.01229**	**$0.01379**	**$0.01467**	**$0.01410**	**$0.01225**	**$0.01294**
177									
178									
179	**Niagara Supply Volumetric Transportation Charge**								
180	**Commodity Costs**	Ln 107	[redacted]						
181									
182	TGP FTA - FTA Z 5-6 Comm. Rate	Tenth Rev Sheet No. 15	$0.00826	$0.00826	$0.00826	$0.00826	$0.00826	$0.00826	$0.00826
183	TGP FTA - FTA Z 5-6 - ACA Rate	Tenth 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		**$0.00840**	**$0.0084**	**$0.0084**	**$0.0084**	**$0.0084**	**$0.0084**	**$0.0084**
185	TGP FTA Fuel Charge % Z 5-6	Ninth Rev Sheet No. 32	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%
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**			

Ln									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**							**REDACTED**	Schedule 6 Page 5 of 5
2	**d/b/a Liberty Utilities**								
3	**Peak 2015 - 2016 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
191									
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	Tenth Rev Sheet No. 15	$0.03139	$0.03139	$0.03139	$0.03139	$0.03139	$0.03139	$0.03139
197	TGP - Max Commodity ACA Rate - Z 0-6	Tenth 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		$0.03153	$0.03153	$0.03153	$0.03153	$0.03153	$0.03153	$0.03153
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		**$0.01028**	**$0.01028**	**$0.01028**	**$0.01028**	**$0.01028**	**$0.01028**	**$0.01028**
201	TGP - Max Comm. Base Rate - Z 1-6	Tenth Rev Sheet No. 15	$0.02738	$0.02738	$0.02738	$0.02738	$0.02738	$0.02738	$0.02738
202	TGP - Max Commodity ACA Rate - Z 1-6	Tenth 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		$0.02752	$0.02752	$0.02752	$0.02752	$0.02752	$0.02752	$0.02752
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		**$0.01855**	**$0.01855**	**$0.01855**	**$0.01855**	**$0.01855**	**$0.01855**	**$0.01855**
206	TGP - Fuel Charge % - Z 0 -6	Ninth Rev Sheet No. 32	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%
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		0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%
209	TGP - Fuel Charge % - Z 1 -6	Ninth Rev Sheet No. 32	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%	2.36%
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		1.59%	1.59%	1.59%	1.59%	1.59%	1.59%	1.59%
212	TGP - Fuel Charge % - Z 0-6	ln 194 x ln 208	**$0.00255**	**$0.00269**	**$0.00278**	**$0.00277**	**$0.00273**	**$0.00259**	**$0.00268**
213	TGP - Fuel Charge % - Z 1-6	ln 194 x ln 211	**$0.00464**	**$0.00489**	**$0.00505**	**$0.00504**	**$0.00498**	**$0.00472**	**$0.00489**
214	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.03601**	**$0.03640**	**$0.03666**	**$0.03664**	**$0.03654**	**$0.03614**	**$0.03640**
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	Tenth Rev Sheet No. 15	$0.00349	$0.00349	$0.00349	$0.00349	$0.00349	$0.00349	$0.00349
220	TGP - Max Commodity ACA Rate - Z 6-6	Tenth 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		**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**
222	TGP - Fuel Charge % - Z 6-6	Ninth Rev Sheet No. 32	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%
223	TGP - Fuel Charge	ln 217 x ln 222	**$0.00076**	**$0.00080**	**$0.00083**	**$0.00082**	**$0.00081**	**$0.00077**	**$0.00080**
224	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00439**	**$0.00443**	**$0.00446**	**$0.00445**	**$0.00444**	**$0.00440**	**$0.00443**
225									
226									
227	**TGP Dracut**								
228	**Commodity Costs - NYMEX Price**	Ln 112	[redacted]						
229									
230	TGP - Trans Charge - Comm. - Z 6-6	Tenth Rev Sheet No. 15	$0.00349	$0.00349	$0.00349	$0.00349	$0.00349	$0.00349	$0.00349
231	TGP - Trans Charge - ACA Rate - Z6-6	Tenth 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		**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**	**$0.00363**
233	TGP - Fuel Charge % - Z 6-6	Ninth Rev Sheet No. 32	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%
234	TGP - Fuel Charge	ln 228 x ln 233	[redacted]						
235	**Total Volumetric Transportation Rate - TGP Dracut**								
236									
237					**THIS PAGE HAS BEEN REDACTED**				

Schedule 7

Ln		Reference		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Peak Strip Average
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**									
2	**d/b/a Liberty Utilities**									
3	**Peak 2015 - 2016 Winter Cost of Gas Filing**									
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**									
5										Peak
6	For Month of:	Reference		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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)			2.9163	3.0743	3.1769	3.1714	3.1281	2 9695	$ 3.0727
10	NYMEX	ln 201	**Filed COG**	2.9163	3.0743	3.1769	3.1714	3.1281	2 9695	$ 3.0727
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		2,068	32,879	43,465	33,270	22,170	362	134,214
24	Market Priced Volumes (Dth)			782 303	1 091 385	1 298 168	1 038 440	485 486	574 303	5 270 085
25	Total Volumes (Dth)	Sch 6, lns 63 - 68 / 10		784,371	1,124,264	1,341,633	1,071,710	507,656	574,665	5,404,299
26										
27										Weighted Average
28	Hedge Price	ln 170		$ 4 2374	$ 4.3800	$ 4 5050	$ 4.4833	$ 4.4267	$ 4.1752	$ 4.4511
29	NYMEX Price	ln 10		$ 2 9163	$ 3.0743	$ 3.1769	$ 3.1714	$ 3.1281	$ 2 9695	$ 3.1378
30										
31	Hedged Volumes at Hedged Price	ln 23 * ln 28		$ 8,763	$ 144,010	$ 195,810	$ 149,161	$ 98,139	$ 1,511	$ 597,394
32	Less Hedged Volumes at NYMEX	ln 24 * ln 29		6,031	101,079	138,085	105,512	69,349	1,075	421,132
33										
34	Hedge Contract (Savings)/Loss	ln 31 - ln 32		$ 2,732	$ 42,931	$ 57,724	$ 43,648	$ 28,790	$ 436	$ 176,262
35										
36	Total Financial Hedge	ln 23		20,680	328,790	434,650	332,700	221,700	3,620	1,342,140
37	Total Underground Storage	Sch 6, Ln 77		4,585,608	4,690,065	5,075,164	5,110,373	6,589,118	3,345,413	29,395,741
38	Sub Total			4,606,288	5,018,855	5,509,814	5,443,073	6,810,818	3,349,033	30,737,881
39	Total Throughput	Sch 6, ln 92		10,618,641	17,868,013	22,326,346	18,309,233	13,501,142	9,479,022	92,102,397
40	Hedge Percentage	ln 38 / ln 39		43%	28%	25%	30%	50%	35%	33%

REDACTED

42	Hedged Volumes (Dth)											
43	Hedge #	1	Trade Date	18-Jun-14	Swaps	[redacted]						
44	Hedge #	2	Trade Date	18-Jul-14	Swaps							
45	Hedge #	3	Trade Date	3-Jul-14	Swaps							
46	Hedge #	4	Trade Date		Swaps							
47	Hedge #	5	Trade Date		Swaps							
48	Hedge #	6	Trade Date		Swaps							
49	Hedge #	7	Trade Date		Swaps							
50	Hedge #	8	Trade Date		Swaps							
51	Hedge #	9	Trade Date		Swaps							
52	Hedge #	10	Trade Date		Swaps							
53	Hedge #	11	Trade Date		Swaps							
54	Hedge #	12	Trade Date		Swaps							
55	Hedge #	13	Trade Date		Swaps							
56	Hedge #	14	Trade Date		Swaps							
57	Hedge #	15	Trade Date		Swaps							
58	Hedge #	16	Trade Date		Swaps							
59	Hedge #	17	Trade Date		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					2,068	32,879	43,465	33,270	22,170	362	134,214
81	Remaining					-	-	-	-	-	-	-
82	Total Volumes					2 068	32 879	43 465	33 270	22 170	362	134 214
83												
84												

THIS PAGE HAS BEEN REDACTED

REDACTED

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line							Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Peak Strip Average
5													
6	For Month of:					Reference							
7			(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
85	Strike Price												Weighted Average
86	Hedge #	1	Trade Date	18-Jun-14	Swaps		[redacted]						
87	Hedge #	2	Trade Date	18-Jul-14	Swaps								
88	Hedge #	3	Trade Date	3-Jul-14	Swaps								
89	Hedge #	4	Trade Date		Swaps								
90	Hedge #	5	Trade Date		Swaps								
91	Hedge #	6	Trade Date		Swaps								
92	Hedge #	7	Trade Date		Swaps								
93	Hedge #	8	Trade Date		Swaps								
94	Hedge #	9	Trade Date		Swaps								
95	Hedge #	10	Trade Date		Swaps								
96	Hedge #	11	Trade Date		Swaps								
97	Hedge #	12	Trade Date		Swaps								
98	Hedge #	13	Trade Date		Swaps								
99	Hedge #	14	Trade Date		Swaps								
100	Hedge #	15	Trade Date		Swaps								
101	Hedge #	16	Trade Date		Swaps								
102	Hedge #	17	Trade Date		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						$4.2374	$4.3800	$4 5050	$4.4833	$4.4267	$4.1752	4.4511
124	NYMEX						$2.9163	$3.0743	$3.1769	$3.1714	$3.1281	$2 9695	#DIV/0!
125													
126									**THIS PAGE HAS BEEN REDACTED**				

REDACTED

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line													
5													Peak
6	For Month of:					Reference	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Strip Average
7			(a)			(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
127	Hedge Dollars												
128	Hedge #	1	Trade Date	18-Jun-14	Swaps		[redacted]						
129	Hedge #	2	Trade Date	18-Jul-14	Swaps								
130	Hedge #	3	Trade Date	3-Jul-14	Swaps								
131	Hedge #	4	Trade Date	0-Jan-00	Swaps								
132	Hedge #	5	Trade Date	0-Jan-00	Swaps								
133	Hedge #	6	Trade Date	0-Jan-00	Swaps								
134	Hedge #	7	Trade Date	0-Jan-00	Swaps								
135	Hedge #	8	Trade Date	0-Jan-00	Swaps								
136	Hedge #	9	Trade Date	0-Jan-00	Swaps								
137	Hedge #	10	Trade Date	0-Jan-00	Swaps								
138	Hedge #	11	Trade Date	0-Jan-00	Swaps								
139	Hedge #	12	Trade Date	0-Jan-00	Swaps								
140	Hedge #	13	Trade Date	0-Jan-00	Swaps								
141	Hedge #	14	Trade Date	0-Jan-00	Swaps								
142	Hedge #	15	Trade Date	0-Jan-00	Swaps								
143	Hedge #	16	Trade Date	0-Jan-00	Swaps								
144	Hedge #	17	Trade Date	0-Jan-00	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						$8,763	$144,010	$195,810	$149,161	$98,139	$1,511	$597,394
166	Remaining						-	-	-	-	-	-	-
167													
168			Target Hedged Dollars				$8 763	$144 010	$195 810	$149 161	$98 139	$1 511	$597 394
169													
170			Weighted Average Hedged Cost per Unit				$4 2374	$4.3800	$4 5050	$4.4833	$4.4267	$4.1752	$4.4511
171													
172									THIS PAGE HAS BEEN REDACTED				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**
5

Line	For Month of:	Reference		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Peak Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
173	NYMEX Settlement - 15 Day Average									
174		Days	Date							
175		1	20-Aug	2 8740	3.0260	3.1260	3.1240	3.0830	2 9320	
176		2	19-Aug	2 8360	2.9890	3.0880	3.0880	3.0490	2 9060	
177		3	18-Aug	2 8390	3.0000	3.1020	3.1000	3.0600	2 9150	
178		4	17-Aug	2 8720	3.0380	3.1400	3.1360	3.0940	2 9470	
179		5	14-Aug	2 9390	3.0980	3.1980	3.1920	3.1480	2 9910	
180										
181										
182		6	13-Aug	2 9240	3.0850	3.1850	3.1790	3.1360	2 9790	
183		7	12-Aug	3.0490	3.1930	3 2880	3.2790	3.2310	3.0470	
184		8	11-Aug	2 9730	3.1280	3 2290	3.2220	3.1750	3.0000	
185		9	10-Aug	2 9720	3.1310	3 2330	3.2260	3.1780	3.0030	
186		10	7-Aug	2 9250	3.0820	3.1860	3.1790	3.1340	2 9740	
187										
188										
189		11	6-Aug	2 9300	3.0810	3.1840	3.1780	3.1330	2 9730	
190		12	5-Aug	2 9140	3.0690	3.1750	3.1680	3.1230	2 9610	
191		13	4-Aug	2 9410	3.0980	3 2040	3.1960	3.1520	2 9820	
192		14	3-Aug	2 8880	3.0540	3.1640	3.1580	3.1170	2 9660	
193		15	31-Jul	2 8680	3.0420	3.1520	3.1460	3.1080	2 9660	
194			1-Aug							
195			2-Aug							
196			3-Aug							
197			4-Aug							
198			5-Aug							
199			6-Aug							
200										
201			15 Day Average	2 9163	3.0743	3.1769	3.1714	3.1281	2 9695	

Schedule 8

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2015 - 2016 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 14 - Apr 15 vs Nov 15 - Apr 16 - Residential Heating Rate R-3

November 1, 2015 - April 30, 2016
Residential Heating (R3)

PROPOSED			Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Winter Nov-Apr
average Usage (Therms)			46	96	121	138	129	93	623
	7/1/2015	12/1/2014							
Winter:									
Cust. Chg	$22.04	$19.85	$22.04	$22.04	$22.04	$22.04	$22.04	$22.04	$132.24
Headblock	$0.3486	$0.3140	$15.89	$33.34	$34.86	$34.86	$34.86	$32.51	$186.32
Tailblock	$0.2885	$0.2594	$0.00	$0.00	$6.11	$10.96	$8.40	$0.00	$25.47
HB Threshold	100	100							
Summer:									
Cust. Chg	$22.04	$19.85							
Headblock	$0.3486	$0.3140							
Tailblock	$0.2885	$0.2594							
HB Threshold	20	20							
Total Base Rate Amount			$37.93	$55.38	$63.01	$67.86	$65.30	$54.55	$344.03
COG Rate - (Seasonal)			$0.7516	$0.7516	$0.7516	$0.7516	$0.7516	$0.7516	$0.7516
COG amount			$34.25	$71.89	$91.07	$103.72	$97.04	$70.10	$468.07
LDAC			$0.1014	$0.1014	$0.1014	$0.1014	$0.1014	$0.1014	0.1014
LDAC amount			$4.62	$9.70	$12.29	$13.99	$13.09	$9.46	$63.15
Total Bill			**$76.80**	**$136.97**	**$166.37**	**$185.58**	**$175.42**	**$134.11**	**$875.25**

May 1, 2015 - October 31, 2015

PROPOSED	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Summer May-Oct	Total Nov-Oct
average Usage (Therms)	57	27	17	15	14	22	154	776
Summer: Cust. Chg	$19.85	$19.85	$22.04	$22.04	$22.04	$22.04	$127.86	$260.10
Headblock	$6.28	$6.28	$5.88	$5.37	$5.05	$6.97	$35.83	$222.15
Tailblock	$9.58	$1.94	$0.00	$0.00	$0.00	$0.70	$12.22	$37.69
Total Base Rate Amount	$35.71	$28.07	$27.92	$27.41	$27.09	$29.71	$175.91	$519.94
COG Rate - (Seasonal)	$0.3073	$0.3246	$0.3421	$0.3421	$0.3421	$0.3421	$0.3261	$0.6674
COG amount	$17.49	$8.92	$5.77	$5.27	$4.96	$7.67	$50.08	$518.16
LDAC	$0.0772	$0.0772	$0.0937	$0.0937	$0.0937	$0.0937	$0.0846	$0.0981
LDAC amount	$4.39	$2.12	$1.58	$1.44	$1.36	$2.10	$13.00	$76.15
Total Bill	**$57.59**	**$39.12**	**$35.27**	**$34.11**	**$33.41**	**$39.49**	**$239.00**	**$1,114.25**

November 1, 2014 - April 30, 2015
Residential Heating (R3)

CURRENT				Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	Winter Nov-Apr
average Usage (Therms)				46	96	121	138	129	93	623
Winter:	7/1/2013	7/1/2014	7/1/2015							
Cust. Chg	$17.40	$17.51	$22.04	$17.51	$19.85	$19.85	$19.85	$19.85	$19.85	$116.76
Headblock	$0.2752	$0.2769	$0.3486	$12.62	$30.03	$31.40	$31.40	$31.40	$29.29	$166.14
Tailblock	$0.2274	$0.2288	$0.2885	$0.00	$0.00	$5.49	$9.86	$7.55	$0.00	$22.90
HB Thresh	100	100	100							
Summer:										
Cust. Chg	$17.40	$17.51	$22.04							
Headblock	$0.2752	$0.2769	$0.3486							
Tailblock	$0.2274	$0.2268	$0.2885							
HB Thresh	20	20	20							
Total Base Rate Amount				$30.13	$49.88	$56.74	$61.11	$58.80	$49.14	$305.80
COG Rate - (Seasonal)				$1.1630	$1.1630	$1.0699	$0.9239	$0.8722	$0.6455	$0.9541
COG amount				$53.00	$111.24	$129.64	$127.50	$112.61	$60.20	$594.19
LDAC				$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772
LDAC amount				$3.52	$7.38	$9.35	$10.65	$9.97	$7.20	$48.08
Total Bill				**$86.65**	**$168.51**	**$195.74**	**$199.26**	**$181.37**	**$116.54**	**$948.07**
DIFFERENCE:										
Total Bill				**($9.85)**	**($31.54)**	**($29.37)**	**($13.68)**	**($5.95)**	**$17.57**	**($72.82)**
% Change				**-11.37%**	**-18.71%**	**-15.01%**	**-6.87%**	**-3.28%**	**15.08%**	**-7.68%**
Base Rate				$7.80	$5.50	$6.27	$6.76	$6.50	$5.42	$38.23
% Change				25.88%	11.02%	11.04%	11.06%	11.05%	11.02%	12.50%
COG & LDAC				($17.65)	($37.04)	($35.64)	($20.44)	($12.45)	$12.15	($111.05)
% Change				-33.29%	-33.29%	-27.49%	-16.03%	-11.05%	20.19%	-18.69%
check				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

May 1, 2014 - October 31, 2014

CURRENT	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Summer May-Oct	Total Nov-Oct
average Usage (Therms)	57	27	17	15	14	22	154	776
Summer: Cust. Chg	$17.40	$17.40	$17.51	$17.51	$17.51	$17.51	$104.84	$221.60
Headblock	$5.50	$5.50	$4.67	$4.26	$4.01	$5.54	$29.49	$195.63
Tailblock	$8.40	$1.70	$0.00	$0.00	$0.00	$0.55	$10.65	$33.55
Total Base Rate Amount	$31.30	$24.61	$22.18	$21.77	$21.52	$23.60	$144.98	$450.78
COG Rate - (Seasonal)	$0.5436	$0.5436	$0.5436	$0.5436	$0.3936	$0.3936	$0.5075	$0.8658
COG amount	$30.94	$14.94	$9.17	$8.37	$5.71	$8.83	$77.96	$672.15
LDAC	$0.0290	$0.0290	$0.0290	$0.0290	$0.0290	$0.0290	$0.0290	$0.0677
LDAC amount	$1.65	$0.80	$0.49	$0.45	$0.42	$0.65	$4.45	$52.53
Total Bill	**$63.89**	**$40.35**	**$31.83**	**$30.58**	**$27.65**	**$33.08**	**$227.39**	**$1,175.46**
DIFFERENCE:								
Total Bill	**($6.30)**	**($1.23)**	**$3.43**	**$3.53**	**$5.76**	**$6.41**	**$11.60**	**($61.21)**
% Change	**-9.86%**	**-3.05%**	**10.78%**	**11.54%**	**20.83%**	**19.38%**	**5.10%**	**-5.21%**
Base Rate	$4.41	$3.47	$5.74	$5.63	$5.57	$6.11	$30.93	$69.16
% Change	14.08%	14.08%	25.88%	25.88%	25.88%	25.91%	21.33%	15.34%
COG & LDAC	($10.71)	($4.70)	($2.31)	($2.11)	$0.19	$0.30	($19.33)	($130.38)
% Change	-34.60%	-31.42%	-25.17%	-25.17%	3.35%	3.35%	-24.79%	-19.40%
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 2015 - 2016 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 14 - Apr 15 vs Nov 15 - Apr 16 - Commercial Rate G-41

November 1, 2015 - April 30, 2016 | **May 1, 2015 - October 31, 2015**
Commercial Rate (G-41)

PROPOSED			**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**Winter Nov-Apr**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			99	261	353	424	401	273	1,812	167	63	35	33	18	42	358	2,170
Winter:	7/1/2015	12/1/2014															
Cust. Chg	$48.24	$46.71	$48.24	$48.24	$48.24	$48.24	$48.24	$48.24	$289.44								
Headblock	$0.3956	$0.3727	$39.27	$39.56	$39.56	$39.56	$39.56	$39.56	$237.07								
Tailblock	$0.2657	$0.2424	$0.00	$42.88	$67.26	$86.18	$79.95	$46.01	$322.28								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$48.24	$46.71								$46.71	$46.71	$48.24	$48.24	$48.24	$48.24	$286.38	$575.82
Headblock	$0.3956	$0.3727								$7.45	$7.45	$7.91	$7.91	$7.11	$7.91	$45.76	$282.83
Tailblock	$0.2657	$0.2424								$35.67	$10.34	$3.92	$3.37	$0.00	$5.97	$59.27	$381.56
HB Threshold	20	20															
Total Base Rate Amount			$87.51	$130.68	$155.06	$173.98	$167.75	$133.81	$848.80	$89.84	$64.51	$60.07	$59.52	$55.35	$62.12	$391.41	$1,240.21
COG Rate - (Seasonal)			$0.7454	$0.7454	$0.7454	$0.7454	$0.7454	$0.7454	$0.7454	$0.3210	$0.3383	$0.3558	$0.3558	$0.3558	$0.3558	$0.3365	$0.6780
COG amount			$74.00	$194.83	$263.24	$316.31	$298.84	$203.61	$1,350.85	$53.66	$21.20	$12.37	$11.62	$6.40	$15.11	$120.36	$1,471.20
LDAC			$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	0.0685	$0.0628	$0.0628	$0.0793	$0.0793	$0.0793	$0.0793	$0.0687	$0.0685
LDAC amount			$6.80	$17.90	$24.19	$29.07	$27.46	$18.71	$124.14	$10.50	$3.94	$2.76	$2.59	$1.43	$3.37	$24.57	$148.71
Total Bill			**$168.32**	**$343.42**	**$442.49**	**$519.36**	**$494.06**	**$356.13**	**$2,323.78**	**$154.00**	**$89.64**	**$75.20**	**$73.73**	**$63.17**	**$80.60**	**$536.34**	**$2,860.13**

November 1, 2014 - April 30, 2015 | **May 1, 2014 - October 31, 2014**
Commercial Rate (G-41)

CURRENT				**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)				99	261	353	424	401	273	1,812	167	63	35	33	18	42	358	2,170
Winter:	7/1/2013	7/1/2014	7/1/2015															
Cust. Chg	$40.94	$41.19	$48.24	$41.19	$46.71	$46.71	$46.71	$46.71	$46.71	$274.74								
Headblock	$0.3267	$0.3287	$0.3956	$32.63	$37.27	$37.27	$37.27	$37.27	$37.27	$218.98								
Tailblock	$0.2125	$0.2138	$0.2657	$0.00	$39.12	$61.36	$78.62	$72.94	$41.97	$294.02								
HB Thresh	100	100	100															
Summer:																		
Cust. Chg	$40.94	$41.19	$48.24								$40.94	$40.94	$41.19	$41.19	$41.19	$41.19	$246.64	$521.38
Headblock	$0.3267	$0.3287	$0.3956								$6.53	$6.53	$6.57	$6.57	$5.91	$6.57	$38.70	$257.68
Tailblock	$0.2125	$0.2138	$0.2657								$31.27	$9.07	$3.16	$2.71	$0.00	$4.80	$51.01	$345.03
HB Thresh	20	20	20															
Total Base Rate Amount				$73.82	$123.10	$145.34	$162.60	$156.92	$125.95	$787.75	$78.75	$56.54	$50.92	$50.47	$47.10	$52.57	$336.35	$1,124.09
COG Rate - (Seasonal)				$1.1666	$1.1666	$1.0735	$0.9275	$0.8758	$0.6491	$0.9501	$0.5456	$0.5456	$0.5456	$0.5456	$0.3956	$0.3956	$0.5203	$0.8793
COG amount				$115.82	$304.93	$379.11	$393.59	$351.12	$177.31	$1,721.87	$91.21	$34.19	$18.97	$17.82	$7.11	$16.80	$186.10	$1,907.97
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	$0.0583
LDAC amount				$6.23	$16.41	$22.18	$26.65	$25.18	$17.15	$113.81	$5.97	$2.24	$1.24	$1.17	$0.64	$1.52	$12.77	$126.58
Total Bill				**$195.87**	**$444.44**	**$546.63**	**$582.84**	**$533.22**	**$320.42**	**$2,623.43**	**$175.92**	**$92.97**	**$71.13**	**$69.46**	**$54.85**	**$70.88**	**$535.22**	**$3,158.64**

DIFFERENCE:

Total Bill	**($27.56)**	**($101.02)**	**($104.14)**	**($63.48)**	**($39.16)**	**$35.72**	**($299.64)**	**($21.93)**	**($3.33)**	**$4.07**	**$4.27**	**$8.32**	**$9.72**	**$1.13**	**($298.52)**
% Change	**-14.07%**	**-22.73%**	**-19.05%**	**-10.89%**	**-7.34%**	**11.15%**	**-11.42%**	**-12.46%**	**-3.58%**	**5.72%**	**6.15%**	**15.17%**	**13.71%**	**0.21%**	**-9.45%**
Base Rate	$13.69	$7.58	$9.72	$11.38	$10.83	$7.85	$61.05	$11.09	$7.97	$9.15	$9.05	$8.25	$9.55	$55.06	$116.12
% Change	18.55%	6.16%	6.69%	7.00%	6.90%	6.24%	7.75%	14.08%	14.09%	17.98%	17.92%	17.52%	18.17%	16.37%	10.33%
COG & LDAC	($41.25)	($108.60)	($113.86)	($74.86)	($49.99)	$27.86	($360.70)	($33.02)	($11.29)	($5.08)	($4.78)	$0.07	$0.16	($53.94)	($414.64)
% Change	-35.62%	-35.62%	-30.03%	-19.02%	-14.24%	15.71%	-20.95%	-36.20%	-33.03%	-26.80%	-26.80%	0.96%	0.96%	-28.98%	-21.73%
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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty Utilities**
2 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **Annual Bill Comparisons, Nov 14 - Apr 15 vs Nov 15 - Apr 16 - Commercial Rate G-42**
5
6
7 **November 1, 2015 - April 30, 2016** | **May 1, 2015 - October 31, 2015**
8 **C&I High Winter Use Medium G-42**

Line										Winter							Summer	Total
9	**PROPOSED**									**Winter**							**Summer**	**Total**
10				**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**Nov-Apr**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**May-Oct**	**Nov-Oct**
11	**average Usage (Therms)**			829	1,717	2,288	2,634	2,644	1,812	11,923	1,239	541	286	535	254	400	3,254	15,176
12		7/1/2015	12/1/2014															
13	**Winter:**																	
14	Cust. Chg	$144.73	$140.13	$144.73	$144.73	$144.73	$144.73	$144.73	$144.73	$868.38								
15	Headblock	$0.3598	$0.3483	$298.16	$359.80	$359.80	$359.80	$359.80	$359.80	$2,097.16								
16	Tailblock	$0.2396	$0.2302	$0.00	$171.74	$308.58	$391.53	$393.88	$194.44	$1,460.17								
17	HB Threshold	1,000	1,000															
18																		
19	**Summer:**																	
20	Cust. Chg	$144.73	$140.13								$140.13	$140.13	$144.73	$144.73	$144.73	$144.73	$859.18	$1,727.56
21	Headblock	$0.3598	$0.3483								$139.32	$139.32	$102.75	$143.92	$91.27	$143.76	$760.33	$2,857.49
22	Tailblock	$0.2396	$0.2302								$193.10	$32.41	$0.00	$32.40	$0.00	$0.00	$257.91	$1,718.08
23	HB Threshold	400	400															
24																		
25	Total Base Rate Amount			$442.89	$676.27	$813.11	$896.06	$898.41	$698.97	$4,425.71	$472.55	$311.86	$247.48	$321.05	$236.00	$288.49	$1,877.42	$6,303.13
26																		
27	COG Rate - (Seasonal)			$0.7454	$0.7454	$0.7454	$0.7454	$0.7454	$0.7454	$0.7454	$0.3210	$0.3383	$0.3558	$0.3558	$0.3558	$0.3558	$0.3396	$0.6584
28	COG amount			$617.70	$1,279.68	$1,705.40	$1,963.46	$1,970.76	$1,350.32	$8,887.31	$397.67	$182.95	$101.60	$190.43	$90.25	$142.16	$1,105.07	$9,992.37
29																		
30	LDAC			$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	0.0685	$0.0628	$0.0628	$0.0793	$0.0793	$0.0793	$0.0793	$0.0703	$0.0689
31	LDAC amount			$56.76	$117.60	$156.72	$180.44	$181.11	$124.09	$816.72	$77.80	$33.96	$22.65	$42.44	$20.12	$31.68	$228.65	$1,045.37
32																		
33	**Total Bill**			**$1,117.36**	**$2,073.54**	**$2,675.23**	**$3,039.95**	**$3,050.27**	**$2,173.38**	**$14,129.73**	**$948.02**	**$528.77**	**$371.73**	**$553.93**	**$346.37**	**$462.33**	**$3,211.14**	**$17,340.86**

34
35 **November 1, 2014 - April 30, 2015** | **May 1, 2014 - October 31, 2014**
36 **C&I High Winter Use Medium G-42**

Line											Winter							Summer	Total
37	**CURRENT**										**Winter**							**Summer**	**Total**
38					**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**Nov-Apr**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**May-Oct**	**Nov-Oct**
39	**average Usage (Therms)**				829	1,717	2,288	2,634	2,644	1,812	11,923	1,239	541	286	535	254	400	3,254	15,176
40		7/1/2013	7/1/2014	7/1/2015															
41	**Winter:**																		
42	Cust. Chg	$122.81	$123.58	$144.73	$123.58	$140.13	$140.13	$140.13	$140.13	$140.13	$824.23								
43	Headblock	$0.3053	$0.3072	$0.3598	$254.57	$348.30	$348.30	$348.30	$348.30	$348.30	$1,996.07								
44	Tailblock	$0.2017	$0.2030	$0.2396	$0.00	$165.00	$296.47	$376.17	$378.42	$186.82	$1,402.88								
45	HB Thresh	1,000	1,000	1,000															
46																			
47	**Summer:**																		
48	Cust. Chg	$122.81	$123.58	$144.73								$122.81	$122.81	$123.58	$123.58	$123.58	$123.58	$739.94	$1,564.17
49	Headblock	$0.3053	$0.3072	$0.3598								$122.88	$122.88	$87.73	$122.88	$77.93	$122.74	$657.03	$2,653.10
50	Tailblock	$0.2017	$0.2030	$0.2396								$169.19	$28.58	$0.00	$27.45	$0.00	$0.00	$225.22	$1,628.11
51	HB Thresh	400	400	400															
52																			
53	Total Base Rate Amount				$378.15	$653.43	$784.90	$864.60	$866.85	$675.25	$4,223.18	$414.88	$274.27	$211.31	$273.91	$201.51	$246.32	$1,622.20	$5,845.38
54																			
55	COG Rate - (Seasonal)				$1.1666	$1.1666	$1.0735	$0.9275	$0.8758	$0.6491	$0.9528	$0.5456	$0.5456	$0.5456	$0.5456	$0.3956	$0.3956	$0.5155	$0.8590
56	COG amount				$966.74	$2,002.78	$2,456.05	$2,443.13	$2,315.52	$1,175.87	$11,360.09	$675.91	$295.06	$155.81	$292.02	$100.35	$158.06	$1,677.20	$13,037.29
57																			
58	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	$0.0570
59	LDAC amount				$52.04	$107.81	$143.68	$165.42	$166.04	$113.76	$748.76	$44.23	$19.31	$10.19	$19.11	$9.06	$14.26	$116.15	$864.91
60																			
61	**Total Bill**				**$1,396.94**	**$2,764.02**	**$3,384.64**	**$3,473.15**	**$3,348.41**	**$1,964.88**	**$16,332.03**	**$1,135.02**	**$588.63**	**$377.31**	**$585.04**	**$310.91**	**$418.64**	**$3,415.55**	**$19,747.58**
62																			
63	**DIFFERENCE:**																		
64	**Total Bill**				**($279.58)**	**($690.48)**	**($709.41)**	**($433.19)**	**($298.14)**	**$208.50**	**($2,202.30)**	**($187.00)**	**($59.86)**	**($5.58)**	**($31.11)**	**$35.46**	**$43.68**	**($204.41)**	**($2,406.71)**
65	% Change				**-20.01%**	**-24.98%**	**-20.96%**	**-12.47%**	**-8.90%**	**10.61%**	**-13.48%**	**-16.48%**	**-10.17%**	**-1.48%**	**-5.32%**	**11.40%**	**10.43%**	**-5.98%**	**-12.19%**
66																			
67	**Base Rate**				$64.74	$22.84	$28.21	$31.46	$31.55	$23.73	$202.52	$57.67	$37.59	$36.17	$47.14	$34.49	$42.17	$255.23	$457.75
68	% Change				17.12%	3.50%	3.59%	3.64%	3.64%	3.51%	4.80%	13.90%	13.71%	17.12%	17.21%	17.12%	17.12%	15.73%	7.83%
69																			
70	**COG & LDAC**				($344.32)	($713.32)	($737.62)	($464.65)	($329.69)	$184.78	($2,404.82)	($244.67)	($97.45)	($41.75)	($78.25)	$0.96	$1.52	($459.64)	($2,864.46)
71	% Change				-35.62%	-35.62%	-30.03%	-19.02%	-14.24%	15.71%	-21.17%	-36.20%	-33.03%	-26.80%	-26.80%	0.96%	0.96%	-27.41%	-21.97%
	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 2015 - 2016 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 14 - Apr 15 vs Nov 15 - Apr 16 - Commercial Rate G-52

November 1, 2015 - April 30, 2016 / **May 1, 2015 - October 31, 2015**
Commercial Rate (G-52)

PROPOSED			**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**Winter Nov-Apr**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			1,123	1,655	1,861	1,748	2,049	1,652	10,088	1,142	963	842	832	770	964	5,513	15,601
Winter:	7/1/2015	12/1/2014															
Cust. Chg	$144.73	$140.13	$144.73	$144.73	$144.73	$144.73	$144.73	$144.73	$868.38								
Headblock	$0.2047	$0.1929	$204.70	$204.70	$204.70	$204.70	$204.70	$204.70	$1,228.20								
Tailblock	$0.1364	$0.1309	$16.76	$89.30	$117.45	$101.97	$143.11	$88.95	$557.54								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$144.73	$140.13								$140.13	$140.13	$144.73	$144.73	$144.73	$144.73	$859.18	$1,727.56
Headblock	$0.1484	$0.1417								$141.70	$136.53	$124.89	$123.49	$114.21	$143.10	$783.92	$2,012.12
Tailblock	$0.0843	$0.0816								$12.00	$0.00	$0.00	$0.00	$0.00	$0.00	$12.00	$569.54
HB Threshold	1,000	1,000															
Total Base Rate Amount			$366.19	$438.73	$466.88	$451.40	$492.54	$438.38	$2,654.12	$293.83	$276.66	$269.62	$268.22	$258.94	$287.83	$1,655.09	$4,309.21
COG Rate - (Seasonal)			$0.7647	$0.7647	$0.7647	$0.7647	$0.7647	$0.7647	$0.7647	$0.2728	$0.2901	$0.3076	$0.3076	$0.3076	$0.3076	$0.2973	$0.5995
COG amount			$858.66	$1,265.36	$1,423.14	$1,336.36	$1,567.04	$1,263.39	$7,713.94	$311.62	$279.51	$258.87	$255.97	$236.73	$296.61	$1,639.31	$9,353.25
LDAC			$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	0.0685	$0.0628	$0.0628	$0.0793	$0.0793	$0.0793	$0.0793	$0.0730	$0.0701
LDAC amount			$76.92	$113.35	$127.48	$119.71	$140.37	$113.17	$691.00	$71.74	$60.51	$66.74	$65.99	$61.03	$76.47	$402.47	$1,093.46
Total Bill			**$1,301.76**	**$1,817.43**	**$2,017.50**	**$1,907.47**	**$2,199.95**	**$1,814.95**	**$11,059.06**	**$677.18**	**$616.67**	**$595.23**	**$590.18**	**$556.70**	**$660.91**	**$3,696.87**	**$14,755.93**

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

CURRENT				**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)				1,123	1,655	1,861	1,748	2,049	1,652	10,088	1,142	963	842	832	770	964	5,513	15,601
Winter:	7/1/2013	7/1/2014	7/1/2015															
Cust. Chg	$122.81	$123.58	$144.73	$123.58	$140.13	$140.13	$140.13	$140.13	$140.13	$824.23								
Headblock	$0.1691	$0.1701	$0.2047	$170.10	$192.90	$192.90	$192.90	$192.90	$192.90	$1,134.60								
Tailblock	$0.1147	$0.1154	$0.1364	$14.18	$85.70	$112.71	$97.86	$137.34	$85.37	$533.15								
HB Thresho	1,000	1,000	1,000															
Summer:																		
Cust. Chg	$122.81	$123.58	$144.73								$122.81	$122.81	$123.58	$123.58	$123.58	$123.58	$739.94	$1,564.17
Headblock	$0.1242	$0.1250	$0.1484								$124.20	$119.66	$105.20	$104.02	$96.20	$120.54	$669.82	$1,804.42
Tailblock	$0.0715	$0.0720	$0.0843								$10.17	$0.00	$0.00	$0.00	$0.00	$0.00	$10.17	$543.33
HB Thresho	1,000	1,000	1,000															
Total Base Rate Amount				$307.86	$418.73	$445.74	$430.89	$470.37	$418.40	$2,491.98	$257.18	$242.47	$228.78	$227.60	$219.78	$244.12	$1,419.93	$3,911.92
COG Rate - (Seasonal)				$1.1384	$1.1384	$1.0453	$0.8993	$0.8476	$0.6209	$0.9360	$0.5377	$0.5377	$0.5377	$0.5377	$0.3877	$0.3877	$0.4905	$0.7786
COG amount				$1,278.27	$1,883.72	$1,945.35	$1,571.58	$1,736.92	$1,025.82	$9,441.66	$614.21	$518.06	$452.52	$447.45	$298.38	$373.85	$2,704.47	$12,146.13
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	$0.0532
LDAC amount				$70.52	$103.92	$116.87	$109.75	$128.69	$103.75	$633.50	$40.78	$34.40	$30.04	$29.71	$27.48	$34.42	$196.83	$830.33
Total Bill				**$1,656.65**	**$2,406.37**	**$2,507.96**	**$2,112.22**	**$2,335.98**	**$1,547.97**	**$12,567.14**	**$912.17**	**$794.93**	**$711.34**	**$704.76**	**$545.64**	**$652.39**	**$4,321.23**	**$16,888.37**

DIFFERENCE:

Total Bill	**($354.89)**	**($588.93)**	**($490.46)**	**($204.75)**	**($136.03)**	**$266.98**	**($1,508.08)**	**($235.00)**	**($178.27)**	**($116.11)**	**($114.57)**	**$11.07**	**$8.52**	**($624.36)**	**($2,132.44)**
% Change	**-21.42%**	**-24.47%**	**-19.56%**	**-9.69%**	**-5.82%**	**17.25%**	**-12.00%**	**-25.76%**	**-22.43%**	**-16.32%**	**-16.26%**	**2.03%**	**1.31%**	**-14.45%**	**-12.63%**
Base Rate	$58.33	$20.00	$21.14	$20.51	$22.17	$19.99	$162.14	$36.64	$34.18	$40.84	$40.62	$39.16	$43.71	$235.16	$397.30
% Change	18.95%	4.78%	4.74%	4.76%	4.71%	4.78%	6.51%	14.25%	14.10%	17.85%	17.85%	17.82%	17.91%	16.56%	10.16%
COG & LDAC	($413.22)	($608.93)	($511.60)	($225.26)	($158.20)	$247.00	($1,670.21)	($271.64)	($212.45)	($156.95)	($155.20)	($28.09)	($35.20)	($859.52)	($2,529.74)
% Change	-32.33%	-32.33%	-26.30%	-14.33%	-9.11%	24.08%	-17.69%	-44.23%	-41.01%	-34.68%	-34.68%	-9.41%	-9.41%	-31.78%	-20.83%
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 2015 - 2016 Winter Cost of Gas Filing
Residential Heating

	Winter 2014-15 (Beginning December 2014)	Winter 2015-16
Customer Charge	$19.85	$22.04
First 100 Therms	$0.3140	$0.3486
Excess 100 Therms	$0.2594	$0.2885
LDAC	$0.0772	$0.1014
COG	$0.9541	$0.7516
Total Adjust	$1.0313	$0.8530

	Therms	Winter 2014-15 COG @	Winter 2015-16 COG @	Total $ Impact	Total % Impact	Base Rate $ Impact	Base Rate % Impact	COG $ Impact	COG % Impact	LDAC $ Impact	LDAC % Impact
		$1.0313	$0.8530	($0.18)	-17%						
Cooking alone	5	$24.05	$28.05	$4.00	17%	$4.89	20%	-$1.01	-4%	$0.12	1%
	10	$30.59	$34.06	$3.46	11%	$5.25	17%	-$2.03	-6%	$0.24	1%
	20	$43.67	$46.07	$2.40	5%	$5.96	14%	-$4.05	-9%	$0.48	1%
Water Heating alone	30	$56.76	$58.09	$1.33	2%	$6.68	12%	-$6.08	-10%	$0.73	1%
	45	$76.38	$76.11	($0.27)	0%	$7.76	10%	-$9.11	-12%	$1.09	1%
	50	$82.92	$82.12	($0.80)	-1%	$8.12	10%	-$10.13	-12%	$1.21	1%
Heating Alone	80	$115.63	$112.16	($3.47)	-3%	$9.91	9%	-$15.19	-14%	$1.82	2%
	125	$189.92	$179.87	($10.05)	-5%	$13.67	7%	-$26.93	-15%	$3.22	2%
	150	$211.34	$199.28	($12.06)	-6%	$14.69	7%	-$30.38	-15%	$3.63	2%
	200	$274.34	$256.35	($17.99)	-7%	$17.67	6%	-$40.50	-16%	$4.84	2%

Schedule 9

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2015 - 2016 Winter Cost of Gas Filing
Variance Analysis of the Components of the Winter 2014-15 Actual Results vs Proposed Winter 2014-15 Cost of Gas Rate

	WINTER 2014-15 ACTUAL RESULTS (6 months actual)			WINTER 2015-16 (6 months Proposed)		
Therm Sales	87,985,011			85,749,300		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 8,173,399	$ 0.0929		$ 8,946,041	$ 0.1043
Purchased Gas	73,366,900	$ 57,004,602	0.6479	60,123,217	51,450,609	0.6000
Storage/Produced Gas	23,885,700	6,067,744	0.0690	31,979,180	9,037,455	0.1054
Hedging (Gain)/Loss		1,001,307	0.0114		176,262	0.0021
Total Volumes and Cost	97,252,600	$ 72,247,051	$ 0.8211	92,102,397	$ 69,610,368	$ 0.8118
Direct Costs						
Prior Period Balance		$ 9,837,568	$ 0.1118		(4,339,198)	$ (0.0506)
Interest		603,240	0.0069		(140,799)	(0.0016)
Prior Period Adjustment		2,332,062	0.0265		-	-
Broker Revenues		(1,690,955)	(0.0192)		(1,917,919)	(0.0224)
Refunds from Suppliers		-	-		(358,691)	(0.0042)
Fuel Financing		-	-		-	-
Transportation CGA Revenues		(162,345)	(0.0018)		35,761	0.0004
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		(3,512,740)	(0.0399)		(3,512,739)	(0.0410)
Hedging Costs		-	-		-	-
FPO Admin Costs		-	-		49,565	0.0006
Indirect Costs						
Misc Overhead		12,714	0.0001		10,272	0.0001
Occupant Disallowance/Credits		-	-		-	-
Production & Storage		1,980,428	0.0225		1,980,428	0.0231
Other Indirect Gas Costs		1,341,865	0.0153		3,035,552	0.0354
Cashout, Broker penalty, Canadian Managed,…		(244,989)	(0.0028)		0	0
Total Adjusted Cost		$ 82,743,899	**$ 0.9404**		$ 64,452,600	**$ 0.7516**

Schedule 10

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2015 - 2016 Winter Cost of Gas Filing
Capacity Assignment Calculations 2015-2016
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			445	499	0.3%		124	374
2	RATE R-3-Resi Htg			55,069	63,703	42.0%		3,749	59,953
3	RATE G-41 (T)			22,007	25,529	16.8%		1,078	24,450
4	RATE G-51 (S)			2,853	3,224	2.1%		644	2,581
5	RATE G-42 (V)			29,613	34,264	22.6%		1,969	32,295
6	RATE G-52			4,073	4,512	3.0%		1,461	3,051
7	RATE G-43			5,864	6,532	4.3%		1,891	4,641
8	RATE G-53			5,600	6,047	4.0%		2,940	3,107
9	RATE G-54			7,519	7,519	5.0%		7,519	-
10									
11	Total			133,041	151,828	100.0%		21,375	130,453
12									-
13	Residential Total			55,514	64,201	**42.286%**		3,874	60,328
14	LLF Total			57,484	66,324	**43.684%**		4,938	61,387
15	HLF Total			20,044	21,302	**14.030%**		12,563	8,739
16	Total			133,041	151,828	100.0%		21,375	130,453
17									
18	C&I Breakdown								
19	LLF Total							4,938	61,387
20	HLF Total							12,563	8,739
21	Total							17,501	70,125
22									
23	C&I Breakdown Percentage								
24	LLF Total							28.214%	87.538%
25	HLF Total							71.786%	12.462%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$13,932,735	78,718	$14.7496			
30	Storage			$4,138,570	28,115	$12.2668			
31									
32	Peaking			$1,500,000					
33	Peaking Additional Costs			$0					
34	Subtotal Peaking Costs			$1,500,000	44,995	$2.7781			
35	Total			$19,571,305	151,828	$10.7420			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			3,783,247	21,375	$14.7496			
39	Pipeline - Remaining			10,149,488	57,343	$14.7496			
40	Storage			4,138,570	28,115	$12.2668			
41	Peaking			1,500,000	44,995	$2.7781			
42	Total			19,571,305	151,828	$10.7420			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**42.286%**	1,599,784	9,039	$14.7496			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**42.286%**	4,291,801	24,248	$14.7496			
48	Storage	Line 40 * Line 13 Col C	**42.286%**	1,750,037	11,889	$12.2668			
49	Peaking	Line 41 * Line 13 Col C	**42.286%**	634,307	19,027	$2.7781			
50	Total		**42.286%**	8,275,946	64,202	$10.7420			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2015 - 2016 Winter Cost of Gas Filing
Capacity Assignment Calculations 2015-2016
Derivation of Class Assignments and Weightings

51							
52							**Ratios for COG**
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		2,183,464	12,336	$14.7496	
55	Pipeline - Remaining	Line 39 - Line 47		5,857,687	33,095	$14.7497	
56	Storage	Line 40 - Line 48		2,388,533	16,226	$12.2668	
57	Peaking	Line 41 - Line 49		865,693	25,968	$2.7781	
58	Total		**57.714%**	11,295,376	87,626	$10.7421	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		616,051	3,481	$14.7479	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		5,127,725	28,971	$14.7496	
64	Storage	Line 56 * Line 24 Col F		2,090,883	14,204	$12.2670	
65	Peaking	Line 57 * Line 24 Col F		757,814	22,732	$2.7781	
66	Total		**43.9034%**	8,592,473	69,388	$10.3194	**0.9607**
67			28.214%	76%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		1,567,413	8,855	$14.7507	
71	Pipeline - Remaining	Line 55 - Line 63		729,962	4,124	$14.7503	
72	Storage	Line 56 - Line 64		297,650	2,022	$12.2671	
73	Peaking	Line 57 - Line 65		107,879	3,236	$2.7781	
74	Total		**13.8105%**	2,702,904	18,237	$12.3508	**1.1498**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 14.7496	$ 14.7496	$ 14.7496	
80	Storage			$ 12.2668	$ 12 2668	$ 12 2668	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 10.7420	$ 10 3194	$ 12 3508	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			51.85%	**46.77%**	**71.17%**	
88	Storage			18.52%	**20.47%**	**11.09%**	
89	Peaking			29.64%	**32.76%**	**17.74%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			42.29%	41.23%	16.49%	100.00%
96	Storage			42.29%	50.52%	7.19%	100.00%
97	Peaking			42.29%	50.52%	7.19%	100.00%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **2015-2016 Winter Calculation**
4 **Correction Factor Calculation**

Ln		d	e	f	g	h	i	
8	Data Source: Schedule 10B							Total
9		Nov	Dec	Jan	Feb	Mar	Apr	Sales
10								
11	G-41	942,674	1,825,246	2,573,546	2,731,489	2,139,483	1,627,582	11,840,021
12	G-42	935,865	1,739,756	2,247,525	2,644,346	1,890,855	1,500,449	10,958,795
13	G-43	217,427	290,591	360,107	383,731	281,033	258,516	1,791,406
14	High Winter Use	2,095,967	3,855,593	5,181,178	5,759,566	4,311,371	3,386,547	24,590,222
15								
16	G-51	351,620	668,742	957,756	892,195	834,252	716,590	4,421,156
17	G-52	343,664	648,103	858,214	837,905	808,348	715,523	4,211,756
18	G-53	102,591	179,349	259,491	254,959	236,295	222,023	1,254,708
19	G-54	174,665	257,681	315,486	293,509	299,920	306,103	1,647,363
21	Low Winter Use	972,540	1,753,875	2,390,948	2,278,567	2,178,815	1,960,239	11,534,983
22								
23	Gross Total	3,068,506	5,609,468	7,572,126	8,038,133	6,490,186	5,346,786	36,125,205

Ln			
26	Total Sales	36,125,205	
27	Low Winter Use	11,534,983	
28	Winter Ratio for Low Winter Use	**1.1498**	Schedule 10A p 2, ln 74
29	High Winter Use	24,590,222	
30	Winter Ratio for High Winter Use	**0.9607**	Schedule 10A p 2, ln 66

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 = $\boxed{\textbf{97.9355\%}}$

36 **Allocation Calculation for Miscellaneous Overhead**

38	Projected Winter Sales Volume	(11/1/15 - 4/30/16)	85,913,727	Sch.10B, ln 23
39	Projected Annual Sales Volume	(11/1/15 - 10/31/16)	110,149,849	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales		78.00%	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
4 **2015 - 2016 Winter Cost of Gas Filing**
5
6 **Dry Therms**

								Subtotal							Subtotal	
7	**Firm Sales**															
8		**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**PK 15-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**OP 16**	**Total**
9	R-1	55,270	73,809	91,550	99,032	86,390	77,129	483,180	62,750	51,962	44,865	41,862	42,207	47,726	291,372	774,552
10	R-3	3,874,644	7,306,248	9,947,611	9,927,210	8,230,076	6,682,212	45,968,001	3,836,662	2,148,309	1,339,841	1,148,534	1,348,387	2,559,355	12,381,088	58,349,089
11	R-4	204,363	407,781	651,605	766,666	675,530	631,396	3,337,341	378,893	209,211	109,909	80,531	76,059	123,571	978,174	4,315,515
12	Total Residential.	4,134,277	7,787,838	10,690,766	10,792,908	8,991,996	7,390,737	49,788,522	4,278,304	2,409,481	1,494,615	1,270,928	1,466,653	2,730,652	13,650,633	63,439,156
13																
14	G-41	942,674	1,825,246	2,573,546	2,731,489	2,139,483	1,627,582	11,840,021	833,444	257,783	126,168	101,317	104,053	375,840	1,798,606	13,638,627
15	G-42	935,865	1,739,756	2,247,525	2,644,346	1,890,855	1,500,449	10,958,795	1,010,135	467,652	209,345	104,379	74,088	289,739	2,155,338	13,114,133
16	G-43	217,427	290,591	360,107	383,731	281,033	258,516	1,791,406	175,060	79,805	44,366	39,521	53,806	116,147	508,705	2,300,111
17	G-51	351,620	668,742	957,756	892,195	834,252	716,590	4,421,156	503,742	334,274	275,287	254,080	274,897	325,128	1,967,408	6,388,564
18	G-52	343,664	648,103	858,214	837,905	808,348	715,523	4,211,756	523,236	362,632	306,393	285,890	298,719	333,503	2,110,373	6,322,129
19	G-53	102,591	179,349	259,491	254,959	236,295	222,023	1,254,708	162,884	111,447	92,433	87,998	94,006	101,735	650,503	1,905,211
20	G-54	174,665	257,681	315,486	293,509	299,920	306,103	1,647,363	280,082	235,393	226,191	219,921	224,538	208,430	1,394,555	3,041,918
21	Total C/I	3,068,506	5,609,468	7,572,126	8,038,133	6,490,186	5,346,786	36,125,205	3,488,583	1,848,985	1,280,183	1,093,107	1,124,108	1,750,523	10,585,488	46,710,693
22																
23	**Sales Volume**	**7,202,784**	**13,397,306**	**18,262,892**	**18,831,041**	**15,482,182**	**12,737,522**	**85,913,727**	**7,766,887**	**4,258,466**	**2,774,798**	**2,364,035**	**2,590,761**	**4,481,175**	**24,236,121**	**110,149,849**
24																
25	Transportation Sales															
26																
27	G-41	446,515	726,048	952,621	1,102,493	967,149	784,358	4,979,184	451,940	261,918	171,595	161,338	174,781	263,601	1,485,173	6,464,358
28	G-42	1,494,069	2,384,245	3,174,888	3,675,371	3,244,363	2,607,818	16,580,755	1,479,111	849,098	486,705	405,492	460,710	787,174	4,468,291	21,049,046
29	G-43	609,103	925,371	1,189,479	1,357,509	1,512,464	1,254,974	6,848,900	854,880	531,784	307,527	224,045	240,117	387,829	2,546,182	9,395,082
30	G-51	140,158	146,562	161,472	168,678	151,396	158,084	926,350	160,366	175,117	190,985	184,719	171,943	147,347	1,030,477	1,956,827
31	G-52	498,547	510,497	514,495	520,287	484,063	482,857	3,010,745	508,459	583,159	667,577	647,605	624,275	550,937	3,582,013	6,592,757
32	G-53	575,051	741,704	887,918	976,502	935,228	875,744	4,992,146	793,633	641,266	470,008	342,783	327,443	403,190	2,978,323	7,970,469
33	G-54	1,834,681	1,928,010	1,943,108	1,857,698	1,808,290	1,707,182	11,078,970	1,635,748	1,567,920	1,539,607	1,547,497	1,638,537	1,806,597	9,735,906	20,814,877
34																
35	Total Trans. Sales	**5,598,123**	**7,362,439**	**8,823,981**	**9,658,539**	**9,102,950**	**7,871,017**	**48,417,049**	**5,884,138**	**4,610,262**	**3,834,005**	**3,513,479**	**3,637,806**	**4,346,675**	**25,826,365**	**74,243,414**
36																
37	Total All Sales	**12,800,906**	**20,759,744**	**27,086,873**	**28,489,580**	**24,585,132**	**20,608,540**	**134,330,777**	**13,651,025**	**8,868,729**	**6,608,803**	**5,877,513**	**6,228,566**	**8,827,850**	**50,062,487**	**184,393,263**

THIS PAGE LEFT INTENTIONALLY BLANK

Schedule 11

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2015 - 2016 Winter Cost of Gas Filing
Normal and Design Year Volumes

Volumes (Therms) **Normal Year**

For the Months of November 15 - April 15

	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	836,662	921,223	935,514	851,729	878,077	844,268	5,267,474
Niagara Supply	653,294	719,148	730,305	664,495	685,467	659,233	4,111,942
TGP Supply (Gulf)	4,768,976	3,122,500	3,170,940	2,887,067	2,976,256	4,151,689	21,077,429
Dracut Supply 1 - Baseload	-	2,751,782	4,657,201	3,180,032	-	-	10,589,015
Dracut Supply 2 - Swing	1,584,778	3,727,982	3,922,369	3,133,775	536,760	91,462	12,997,126
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	2,789	2,972	1,083,386	691,663	81,435	-	1,862,243
Propane Truck	-	-	691,828	-	-	-	691,828
PNGTS	57,172	80,978	91,288	78,565	67,980	47,842	423,825
TGP Supply (Z4)	1,680,994	1,851,361	1,880,082	1,711,534	1,764,652	2,074,789	10,963,412
Subtotal Pipeline Volumes	9,584,666	13,177,947	17,162,912	13,198,860	6,990,626	7,869,283	67,984,295
Storage Gas:							
TGP Storage	4,585,608	4,690,065	5,075,164	5,110,373	6,589,118	3,345,413	29,395,741
Produced Gas:							
LNG Vapor	2,789	2,972	1,171,656	691,663	2,833	19,700	1,891,611
Propane	-	-	691,828	-	-	-	691,828
Subtotal Produced Gas	2,789	2,972	1,863,484	691,663	2,833	19,700	2,583,439
Less - Gas Refills:							
LNG Truck	(2,789)	(2,972)	(1,083,386)	(691,663)	(81,435)	-	(1,862,243)
Propane	-	-	(691,828)	-	-	-	(691,828)
TGP Storage Refill	(3,551,632)	-	-	-	-	(1,755,374)	(5,307,007)
Subtotal Refills	(3,554,421)	(2,972)	(1,775,213)	(691,663)	(81,435)	(1,755,374)	(7,861,078)
Total Sendout Volumes	10,618,641	17,868,013	22,326,346	18,309,233	13,501,142	9,479,022	92,102,397

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2015 - 2016 Winter Cost of Gas Filing**
42 **Normal and Design Year Volumes** — **Schedule 11B**
43 **Page 1 of 1**
44
45 **Volumes (Therms)** **Design Year**
46
47 **For the Months of November 15 - April 15**
48

Line		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Peak Nov - Apr
51	Pipeline Gas:							
52	Dawn Supply	836,662	921,223	935,514	851,729	878,077	844,268	5,267,474
53	Niagara Supply	653,294	719,148	730,305	664,495	685,467	659,233	4,111,942
54	TGP Supply (Gulf)	4,768,279	3,122,500	3,170,940	2,887,067	2,976,256	4,199,531	21,124,574
55	Dracut Supply 1 - Baseload	-	2,751,782	4,657,201	3,180,032	-	-	10,589,015
56	Dracut Supply 2 - Swing	4,864,495	5,213,082	3,412,363	4,553,812	6,687,548	4,454,922	29,186,223
57	City Gate Delivered Supply	-	-	-	-	-	-	0
58	LNG Truck	2,789	78,007	1,145,250	489,744	145,874	-	1,861,664
59	Propane Truck	-	-	480,583	205,590	-	-	686,172
60	PNTGS	57,172	80,978	91,288	78,565	67,980	47,842	423,825
61	TGP Supply (Z4)	1,680,994	1,851,361	1,880,082	1,711,534	1,764,652	1,730,046	10,618,669
62	Subtotal Pipeline Volumes	12,863,686	14,738,083	16,503,525	14,622,569	13,205,854	11,935,842	83,869,559
63								
64	Storage Gas:							
65	TGP Storage	2,979,216	4,833,449	6,262,663	5,245,475	1,982,046	166,743	21,469,593
66								
67	Produced Gas:							
68	LNG Vapor	2,789	78,007	1,233,521	483,136	74,353	19,700	1,891,505
69	Propane	-	-	848,753	311,322	-	-	1,160,074
70	Subtotal Produced Gas	2,789	78,007	2,082,273	794,457	74,353	19,700	3,051,579
71								
72	Less - Gas Refills:							
73	LNG Truck	(2,789)	(78,007)	(1,145,250)	(489,744)	(145,874)	-	(1,861,664)
74	Propane	-	-	(480,583)	(205,590)	-	-	(686,172)
75	TGP Storage Refill	(3,521,652)	-	-	-	-	(1,410,631)	(4,932,283)
76	Subtotal Refills	(3,524,441)	(78,007)	(1,625,833)	(695,334)	(145,874)	(1,410,631)	(7,480,120)
77								
78	Total Sendout Volumes	12,321,250	19,571,532	23,222,629	19,967,167	15,116,379	10,711,653	100,910,611

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2015 - 2016 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	5,267,474	4,000	7,240,000	73%	5,267,474	4,000	7,240,000	73%
Niagara Supply	4,111,942	3,122	5,650,820	73%	4,111,942	3,122	5,650,820	73%
TGP Supply (Gulf + Z4)	32,040,841	21,596	39,088,760	82%	31,743,243	21,596	39,088,760	81%
Dracut Supply 1 & 2	23,586,142	50,000	90,500,000	26%	39,775,238	50,000	90,500,000	44%
LNG Truck	1,862,243	-	-	-	1,861,664	-	-	-
Propane Truck	691,828	-	-	-	686,172	-	-	-
PNGTS	423,825	1,000	1,810,000	23%	423,825	1,000	1,810,000	23%
Granite Ridge	-	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	67,984,295				83,869,559			
Storage Gas:								
TGP Storage	29,395,741		25,791,710	114%	21,469,593		25,791,710	83%
Produced Gas:								
LNG Vapor	1,891,611				1,891,505			
Propane	691,827.8				1,160,074			
Subtotal Produced Gas	2,583,439				3,051,579			
Less - Gas Refills:								
LNG Truck	(1,862,243)				(1,861,664)			
Propane	(691,828)				(686,172)			
TGP Storage Refill	(5,307,007)				(4,932,283)			
Subtotal Refills	(7,861,078)				(7,480,120)			
Total Sendout Volumes	92,102,397				100,910,611			

Liberty Utilities (EnergyNorth Natural Gas) Corp. **Schedule 11D**
d/b/a Liberty Utilities
Peak 2015 - 2016 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2015 / 16 Heating Season
(Therms)

EnergyNorth Natural Gas, Inc.
d/b/a Liberty Utilities

Requirements		
	Firm Sales	1,134,863
	Interruptible Sales	0
	Firm Transportation	383,417
	Interruptible Transportation	0
	Total Requirements	1,518,280
Resources		
	Purchased Pipeline Gas	787,180
	Underground Storage Gas	281,150
	Propane Air Production	323,950
	LNG Produced Gas	126,000
	Third-Party Supply	0
	Total Resources	1,518,280

Please refer to the ENGI 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

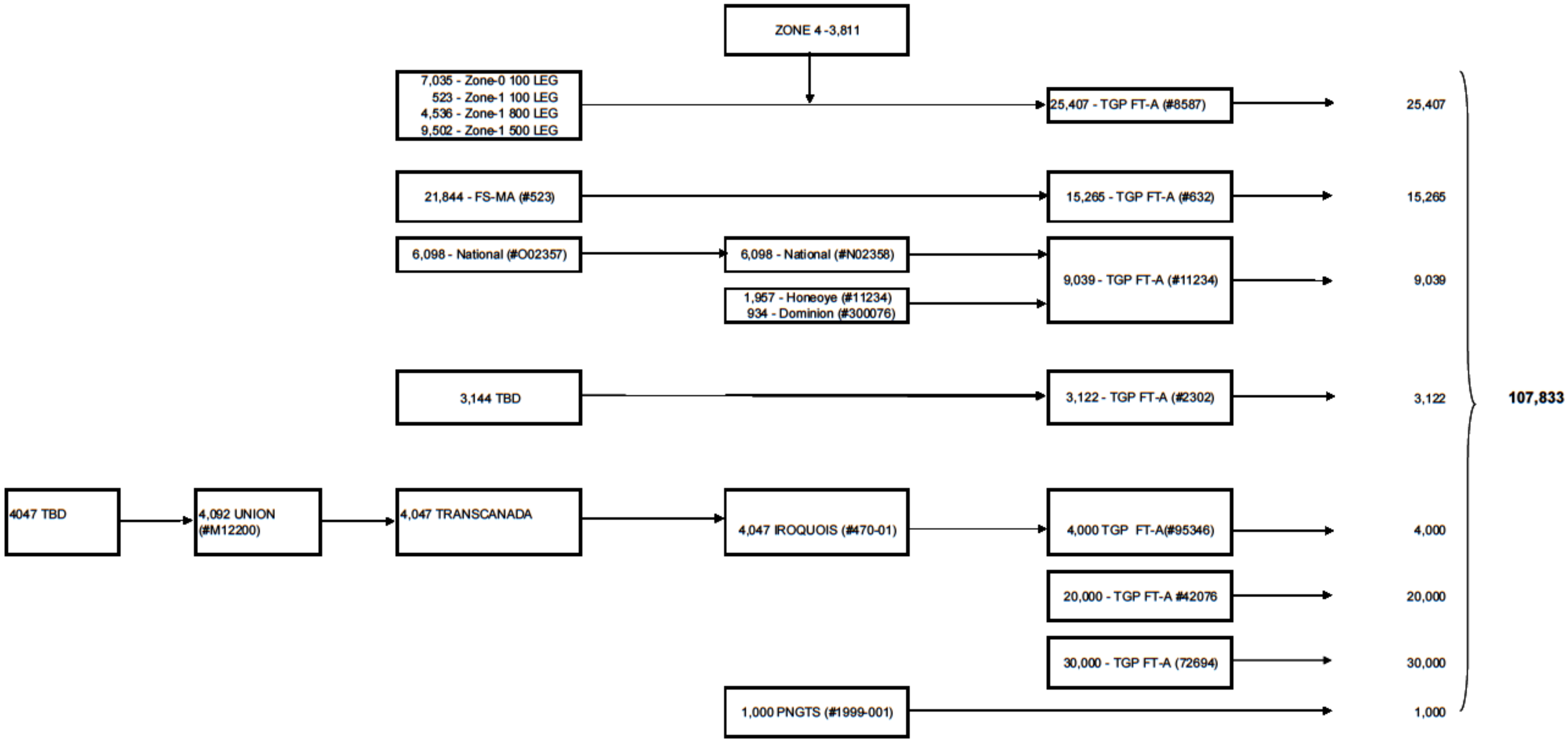
F. Chico DaFonte
Vice President, Energy Procurement

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

THIS PAGE LEFT INTENTIONALLY BLANK

Schedule 12

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2015-2016 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2015-2016 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Niagara	NA	NA	Supply	3,144	1,147,560	3/31/2016	N/a	Terminates
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/a	Terminates
GDF Suez	FLS		Liquid Refill	Up to 5 trucks	250,000	3/31/2016 Peak Only	-	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,427,000	2/29/2016	-	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2015	N/a	Terminates
Northern Transport	NA	NA	Trucking	28,500 Gallons	900,000 Gallons		N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2021	3/31/2019	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/1/2020	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2017	3/31/2016	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2017	3/31/2016	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	11/1/2017	10/31/2016	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	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2020	10/31/2019	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	11/30/2016	10/31/2015	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2020	10/31/2019	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2022	4/30/2021	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.

THIS PAGE LEFT INTENTIONALLY BLANK

Schedule 13

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2015-2016 Winter Cost of Gas Filing

Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2014 - Apr 2015 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	15,715,808	38.26%	75.22%
G-42	14,617,493	35.59%	45.41%
G-43	2,582,838	6.29%	22.45%
G-51	2,717,783	6.62%	66.57%
G-52	2,493,304	6.07%	31.95%
G-53	2,054,744	5.00%	19.91%
G-54	893,924	2.18%	5.08%
Total C/I	41,075,893	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	5,177,626	8.18%	24.78%
G-42	17,575,734	27.75%	54.59%
G-43	8,924,088	14.09%	77.55%
G-51	1,364,913	2.16%	33.43%
G-52	5,310,609	8.39%	68.05%
G-53	8,267,983	13.06%	80.09%
G-54	16,705,479	26.38%	94.92%
Total C/I	63,326,431	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	20,893,433	20.01%	100.00%
G-42	32,193,227	30.84%	100.00%
G-43	11,506,926	11.02%	100.00%
G-51	4,082,696	3.91%	100.00%
G-52	7,803,913	7.47%	100.00%
G-53	10,322,727	9.89%	100.00%
G-54	17,599,402	16.86%	100.00%
Total C/I	104,402,324	100.00%	

Schedule 14

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2015-2016 Winter Cost of Gas Filing

Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak May 14 - Oct 14 (Therms)	Peak Nov 14-Apr 15 (Therms)	Total May 13 - Apr 14 (Therms)	
Pipeline Deliveries	26,228,650	71,208,480	97,437,130	
All Others	-	26,144,120	26,144,120	
	26,228,650	97,352,600	123,581,250	
				Ratio
Total Winter Supplies				97,352,600
Total Pipeline Deliveries				97,437,130
Ratio Winter Supplies to Pipeline Supplies				0.999

Schedule 15

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2015-2016 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-14	Aug-14	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	229,458	220,497	449,956	15,715,808	2.86%
G-42	262,322	502,949	765,272	14,617,493	5.24%
G-43	76,720	275,044	351,764	2,582,838	13.62%
G-51	123,487	143,054	266,540	2,717,783	9.81%
G-52	128,845	125,267	254,112	2,493,304	10.19%
G-53	49,278	45,322	94,600	2,054,744	4.60%
G-54	34,551	33,382	67,933	893,924	7.60%
Total C/I	904,662	1,345,516	2,250,178	41,075,893	5.48%

Schedule 16

Ln	Description	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**														
2	**Peak 2015-2016 Winter Cost of Gas Filing**														
3															
4	**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**														
5															
6	**Underground Storage Gas**														
7			May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		388,143	690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	388,143
10															
11	Injections (MMBtu)	Sch 11A ln 37 /10	307,571	256,483	284,673	273,029	273,029	273,029	-	-	-	-	-	175,537	1,843,351
12															
13	Subtotal		695,714	946,518	1,216,762	1,483,328	1,756,357	2,029,386	2,029,386	1,570,825	1,101,819	594,302	83,265	(400,109)	
14															
15	Storage Sale		-					-							
16															
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(5,679)	(14,429)	(6,463)	-	-	-	(458,561)	(469,007)	(507,516)	(511,037)	(658,912)	(334,541)	(2,966,145)
18															
19	Ending Balance (MMBtu)		690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	(734,651)	(734,651)
20															
21															
22	Beginning Balance		$ 1,192,503	$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	1,192,503
23															
24	Injections	ln 11 * ln 36	482,360	430,490	401,566	436,846	436,846	436,846	-	-	-	-	-	351,075	2,976,030
25															
26	Subtotal		$ 1,674,863	$ 2,101,689	$ 2,498,715	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (727,633)	
27															
28	Storage Sale		$ -					$ -							
29															
30	Withdrawals	ln 17 * ln 34	$ (3,664)	$ (4,540)	$ (6,375)	$ -	$ -	$ -	$ (859,300)	$ (878,874)	$ (951,038)	$ (957,636)	$ (1,234,739)	$ (608,392)	(5,504,558)
31															
32	Ending Balance		$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	$ (1,336,025)	$ (1,336,025)
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.4074	$2.2204	$2.0536	$1.9747	$1.9165	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8186	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$1.5683	$1.6784	$1.4106	$1.6000	$1.6000	$1.6000	$1.6000	$3.4383	$3.5435	$3.5378	$3.4934	$2.0000	
37															
38	For Informational Purposes								Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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								$2.9163	$3.0743	$3.1769	$3.1714	$3.1281	$2.9695	
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				$ 2,710,762	$ 3,147,609	$ 3,584,455	$ 3,373,229	$ 2,504,142	$ 1,589,186	$ 634,849	$ (461,339)	$ (1,207,367)	
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															

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2015-2016 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-14	Aug-14	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	229,458	220,497	449,956	15,715,808	2.86%
G-42	262,322	502,949	765,272	14,617,493	5.24%
G-43	76,720	275,044	351,764	2,582,838	13.62%
G-51	123,487	143,054	266,540	2,717,783	9.81%
G-52	128,845	125,267	254,112	2,493,304	10.19%
G-53	49,278	45,322	94,600	2,054,744	4.60%
G-54	34,551	33,382	67,933	893,924	7.60%
Total C/I	904,662	1,345,516	2,250,178	41,075,893	5.48%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **Peak 2015-2016 Winter Cost of Gas Filing**
3
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-15 (Actual)	Jun-15 (Actual)	Jul-15 (Actual)	Aug-15 (Estimate)	Sep-15 (Estimate)	Oct-15 (Estimate)	Nov-15 (Estimate)	Dec-15 (Estimate)	Jan-16 (Estimate)	Feb-16 (Estimate)	Mar-16 (Estimate)	Apr-16 (Estimate)	Total
9	Beginning Balance (MMBtu)		388,143	690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	388,143
10															
11	Injections (MMBtu)	Sch 11A ln 37 /10	307,571	256,483	284,673	273,029	273,029	273,029	-	-	-	-	-	175,537	1,843,351
12															
13	Subtotal		695,714	946,518	1,216,762	1,483,328	1,756,357	2,029,386	2,029,386	1,570,825	1,101,819	594,302	83,265	(400,109)	
14															
15	Storage Sale		-					-							
16															
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(5,679)	(14,429)	(6,463)	-	-	-	(458,561)	(469,007)	(507,516)	(511,037)	(658,912)	(334,541)	(2,966,145)
18															
19	Ending Balance (MMBtu)		690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	(734,651)	(734,651)
20															
21															
22	Beginning Balance		$ 1,192,503	$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	1,192,503
23															
24	Injections	ln 11 * ln 36	482,360	430,490	401,566	436,846	436,846	436,846	-	-	-	-	-	351,075	2,976,030
25															
26	Subtotal		$ 1,674,863	$ 2,101,689	$ 2,498,715	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (727,633)	
27															
28	Storage Sale		$ -					$ -							
29															
30	Withdrawals	ln 17 * ln 34	$ (3,664)	$ (4,540)	$ (6,375)	$ -	$ -	$ -	$ (859,300)	$ (878,874)	$ (951,038)	$ (957,636)	$ (1,234,739)	$ (608,392)	(5,504,558)
31															
32	Ending Balance		$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	$ (1,336,025)	$ (1,336,025)
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.4074	$2.2204	$2.0536	$1.9747	$1.9165	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8186	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$1.5683	$1.6784	$1.4106	$1.6000	$1.6000	$1.6000	$1.6000	$3.4383	$3.5435	$3.5378	$3.4934	$2.0000	
37															
38	For Informational Purposes								Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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								$2.9163	$3.0743	$3.1769	$3.1714	$3.1281	$2.9695	
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				$ 2,710,762	$ 3,147,609	$ 3,584,455	$ 3,373,229	$ 2,504,142	$ 1,589,186	$ 634,849	$ (461,339)	$ (1,207,367)	
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	Description	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
39															
40	**Liquid Propane Gas (LPG)**														
41			May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
42			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
43	Beginning Balance		56,324	66,458	97,541	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	56,324
44															
45	Injections	Sch 11A ln 36 /10	10,134	46,917	-	-	-	-	-	-	69,183	-	-	-	126,234
46															
47	Subtotal		66,458	113,375	97,541	97,283	97,283	97,283	97,283	97,283	166,466	97,283	97,283	97,283	
48															
49	Withdrawals	Sch 11A ln 31 /10	-	(15,834)	(258)	-	-	-	-	-	(69,183)	-	-	-	(85,275)
50															
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		66,458	97,541	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283
54															
55															
56	Beginning Balance		$ 914,904	$ 1,066,509	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	$ 914,904
57															
58	Injections	ln 45 * ln 68	151,605	392,109	-	-	-	-	-	-	-	-	-	-	543,714
59															
60	Subtotal		$ 1,066,509	$ 1,458,618	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	
61															
62	Withdrawals	ln 51 * ln 66	-	(254,101)	(3,186)	-	-	-	-	-	(499,271)	-	-	-	(756,557)
63															
64	Ending Balance		$ 1,066,509	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	$ 702,061	$ 702,061
65															
66	Average Rate For Withdrawals		$16.0479	$12.8654	$12.3488	$12.3488	$12.3488	$12.3488	$12.3488	$12.3488	$7.2167	$7.2167	$7.2167	$7.2167	
67															
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	
69															
70															
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 951,696	$ 702,061	$ 702,061	$ 702,061	
72															
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%	
74															
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
76															
77															
78															
70															

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **Peak 2015-2016 Winter Cost of Gas Filing**

4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**

6 **Underground Storage Gas**

Line	Description	Reference	May-15 (Actual)	Jun-15 (Actual)	Jul-15 (Actual)	Aug-15 (Estimate)	Sep-15 (Estimate)	Oct-15 (Estimate)	Nov-15 (Estimate)	Dec-15 (Estimate)	Jan-16 (Estimate)	Feb-16 (Estimate)	Mar-16 (Estimate)	Apr-16 (Estimate)	Total
9	Beginning Balance (MMBtu)		388,143	690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	388,143
11	Injections (MMBtu)	Sch 11A ln 37 /10	307,571	256,483	284,673	273,029	273,029	273,029	-	-	-	-	-	175,537	1,843,351
13	Subtotal		695,714	946,518	1,216,762	1,483,328	1,756,357	2,029,386	2,029,386	1,570,825	1,101,819	594,302	83,265	(400,109)	
15	Storage Sale		-					-							
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(5,679)	(14,429)	(6,463)	-	-	-	(458,561)	(469,007)	(507,516)	(511,037)	(658,912)	(334,541)	(2,966,145)
19	Ending Balance (MMBtu)		690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	(734,651)	(734,651)
22	Beginning Balance		$ 1,192,503	$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	1,192,503
24	Injections	ln 11 * ln 36	482,360	430,490	401,566	436,846	436,846	436,846	-	-	-	-	-	351,075	2,976,030
26	Subtotal		$ 1,674,863	$ 2,101,689	$ 2,498,715	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (727,633)	
28	Storage Sale		$ -					$ -							
30	Withdrawals	ln 17 * ln 34	$ (3,664)	$ (4,540)	$ (6,375)	$ -	$ -	$ -	$ (859,300)	$ (878,874)	$ (951,038)	$ (957,636)	$ (1,234,739)	$ (608,392)	(5,504,558)
32	Ending Balance		$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	$ (1,336,025)	$ (1,336,025)
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.4074	$2.2204	$2.0536	$1.9747	$1.9165	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8186	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$1.5683	$1.6784	$1.4106	$1.6000	$1.6000	$1.6000	$1.6000	$3.4383	$3.5435	$3.5378	$3.4934	$2.0000	
38	For Informational Purposes								Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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								$2.9163	$3.0743	$3.1769	$3.1714	$3.1281	$2.9695	
43	Hedged Volumes at Hedged Price								$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX								-	-	-	-	-	-	-
45	Hedge (Savings)/Loss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	Month Dollar Average	ln (22 + ln 32) /2				$ 2,710,762	$ 3,147,609	$ 3,584,455	$ 3,373,229	$ 2,504,142	$ 1,589,186	$ 634,849	$ (461,339)	$ (1,207,367)	
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%	
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					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2015-2016 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-14	Aug-14	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	229,458	220,497	449,956	15,715,808	2.86%
G-42	262,322	502,949	765,272	14,617,493	5.24%
G-43	76,720	275,044	351,764	2,582,838	13.62%
G-51	123,487	143,054	266,540	2,717,783	9.81%
G-52	128,845	125,267	254,112	2,493,304	10.19%
G-53	49,278	45,322	94,600	2,054,744	4.60%
G-54	34,551	33,382	67,933	893,924	7.60%
Total C/I	904,662	1,345,516	2,250,178	41,075,893	5.48%

Ln	Description	Reference	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**														
2	**Peak 2015-2016 Winter Cost of Gas Filing**														
3															
4	**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**														
5															
6	**Underground Storage Gas**														
7			May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		388,143	690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	388,143
10															
11	Injections (MMBtu)	Sch 11A ln 37 /10	307,571	256,483	284,673	273,029	273,029	273,029	-	-	-	-	-	175,537	1,843,351
12															
13	Subtotal		695,714	946,518	1,216,762	1,483,328	1,756,357	2,029,386	2,029,386	1,570,825	1,101,819	594,302	83,265	(400,109)	
14															
15	Storage Sale		-					-							
16															
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(5,679)	(14,429)	(6,463)	-	-	-	(458,561)	(469,007)	(507,516)	(511,037)	(658,912)	(334,541)	(2,966,145)
18															
19	Ending Balance (MMBtu)		690,035	932,089	1,210,299	1,483,328	1,756,357	2,029,386	1,570,825	1,101,819	594,302	83,265	(575,647)	(734,651)	(734,651)
20															
21															
22	Beginning Balance		$ 1,192,503	$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	1,192,503
23															
24	Injections	ln 11 * ln 36	482,360	430,490	401,566	436,846	436,846	436,846	-	-	-	-	-	351,075	2,976,030
25															
26	Subtotal		$ 1,674,863	$ 2,101,689	$ 2,498,715	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (727,633)	
27															
28	Storage Sale		$ -					$ -							
29															
30	Withdrawals	ln 17 * ln 34	$ (3,664)	$ (4,540)	$ (6,375)	$ -	$ -	$ -	$ (859,300)	$ (878,874)	$ (951,038)	$ (957,636)	$ (1,234,739)	$ (608,392)	(5,504,558)
31															
32	Ending Balance		$ 1,671,199	$ 2,097,148	$ 2,492,339	$ 2,929,186	$ 3,366,032	$ 3,802,878	$ 2,943,579	$ 2,064,705	$ 1,113,667	$ 156,031	$ (1,078,708)	$ (1,336,025)	$ (1,336,025)
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.4074	$2.2204	$2.0536	$1.9747	$1.9165	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8739	$1.8186	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$1.5683	$1.6784	$1.4106	$1.6000	$1.6000	$1.6000	$1.6000	$3.4383	$3.5435	$3.5378	$3.4934	$2.0000	
37															
38	For Informational Purposes								Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	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								$2.9163	$3.0743	$3.1769	$3.1714	$3.1281	$2.9695	
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				$ 2,710,762	$ 3,147,609	$ 3,584,455	$ 3,373,229	$ 2,504,142	$ 1,589,186	$ 634,849	$ (461,339)	$ (1,207,367)	
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															

Liquid Propane Gas (LPG)

Line			May-15 (Actual)	Jun-15 (Actual)	Jul-15 (Actual)	Aug-15 (Estimate)	Sep-15 (Estimate)	Oct-15 (Estimate)	Nov-15 (Estimate)	Dec-15 (Estimate)	Jan-16 (Estimate)	Feb-16 (Estimate)	Mar-16 (Estimate)	Apr-16 (Estimate)	Total
40	**Liquid Propane Gas (LPG)**														
43	Beginning Balance		56,324	66,458	97,541	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	56,324
45	Injections	Sch 11A ln 36 /10	10,134	46,917	-	-	-	-	-	-	69,183	-	-	-	126,234
47	Subtotal		66,458	113,375	97,541	97,283	97,283	97,283	97,283	97,283	166,466	97,283	97,283	97,283	
49	Withdrawals	Sch 11A ln 31 /10	-	(15,834)	(258)	-	-	-	-	-	(69,183)	-	-	-	(85,275)
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		66,458	97,541	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283
56	Beginning Balance		$ 914,904	$ 1,066,509	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	$ 914,904
58	Injections	ln 45 * ln 68	151,605	392,109	-	-	-	-	-	-	-	-	-	-	543,714
60	Subtotal		$ 1,066,509	$ 1,458,618	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	
62	Withdrawals	ln 51 * ln 66	-	(254,101)	(3,186)	-	-	-	-	-	(499,271)	-	-	-	(756,557)
64	Ending Balance		$ 1,066,509	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	$ 702,061	$ 702,061
66	Average Rate For Withdrawals		$16.0479	$12.8654	$12.3488	$12.3488	$12.3488	$12.3488	$12.3488	$12.3488	$7.2167	$7.2167	$7.2167	$7.2167	
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				$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 951,696	$ 702,061	$ 702,061	$ 702,061	
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				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Ln			May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
39															
40	**Liquid Propane Gas (LPG)**														
41			May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Total
42			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
43	Beginning Balance		56,324	66,458	97,541	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	56,324
44															
45	Injections	Sch 11A ln 36 /10	10,134	46,917	-	-	-	-	-	-	69,183	-	-	-	126,234
46															
47	Subtotal		66,458	113,375	97,541	97,283	97,283	97,283	97,283	97,283	166,466	97,283	97,283	97,283	
48															
49	Withdrawals	Sch 11A ln 31 /10	-	(15,834)	(258)	-	-	-	-	-	(69,183)	-	-	-	(85,275)
50															
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		66,458	97,541	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283	97,283
54															
55															
56	Beginning Balance		$ 914,904	$ 1,066,509	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	$ 914,904
57															
58	Injections	ln 45 * ln 68	151,605	392,109	-	-	-	-	-	-	-	-	-	-	543,714
59															
60	Subtotal		$ 1,066,509	$ 1,458,618	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	
61															
62	Withdrawals	ln 51 * ln 66	-	(254,101)	(3,186)	-	-	-	-	-	(499,271)	-	-	-	(756,557)
63															
64	Ending Balance		$ 1,066,509	$ 1,204,518	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 702,061	$ 702,061	$ 702,061	$ 702,061	$ 702,061
65															
66	Average Rate For Withdrawals		$16.0479	$12.8654	$12.3488	$12.3488	$12.3488	$12.3488	$12.3488	$12.3488	$7.2167	$7.2167	$7.2167	$7.2167	
67															
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	
69															
70															
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 1,201,332	$ 951,696	$ 702,061	$ 702,061	$ 702,061	
72															
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%	
74															
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
76															
77															
78															
70															

Line	Description	Reference	May-15 (Actual)	Jun-15 (Actual)	Jul-15 (Actual)	Aug-15 (Estimate)	Sep-15 (Estimate)	Oct-15 (Estimate)	Nov-15 (Estimate)	Dec-15 (Estimate)	Jan-16 (Estimate)	Feb-16 (Estimate)	Mar-16 (Estimate)	Apr-16 (Estimate)	Total
72	**Liquid Natural Gas (LNG)**														
74	Beginning Balance		10,798	8,312	6,674	10,259	10,259	10,259	10,259	10,259	10,259	1,432	1,432	9,292	10,798
76	Injections	Sch 11A ln 35 /10	-	-	4,566	-	-	-	279	297	108,339	69,166	8,143	-	190,790
78	Subtotal		10,798	8,312	11,240	10,259	10,259	10,259	10,538	10,556	118,598	70,598	9,575	9,292	
80	Withdrawals	Sch 11A ln 30 /10	(2,486)	(1,638)	(981)	-	-	-	(279)	(297)	(117,166)	(69,166)	(283)	(1,970)	(194,266)
82	Ending Balance		8,312	6,674	10,259	10,259	10,259	10,259	10,259	10,259	1,432	1,432	9,292	7,322	7,322
85	Beginning Balance		$ 144,434	$ 110,775	$ 88,937	$ 125,197	$ 125,197	$ 125,197	$ 125,197	$ 126,761	$ 125,971	$ 17,934	$ 17,753	$ 161,015	$ 144,434
87	Injections	ln 76 * ln 97	-	-	48,363	-	-	-	5,009	2,859	1,359,324	857,316	148,170	-	2,421,042
89	Subtotal		$ 144,434	$ 110,775	$ 137,300	$ 125,197	$ 125,197	$ 125,197	$ 130,206	$ 129,620	$ 1,485,295	$ 875,249	$ 165,923	$ 161,015	
91	Withdrawals	ln 80 * ln 95	(33,659)	(21,838)	(12,103)	-	-	-	(3,446)	(3,649)	(1,467,361)	(857,496)	(4,908)	(34,135)	(2,438,596)
93	Ending Balance		$ 110,775	$ 88,937	$ 125,197	$ 125,197	$ 125,197	$ 125,197	$ 126,761	$ 125,971	$ 17,934	$ 17,753	$ 161,015	$ 126,880	$ 126,880
95	Average Rate For Withdrawals		$13.3759	$13.3271	$12.2153	$12.2036	$12.2036	$12.2036	$12.3560	$12.2790	$12.5238	$12.3976	$17.3280	$17.3280	
97	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	#DIV/0!	#DIV/0!	$10.5920	$10.5920	$10.5920	$10.5920	$17.9620	$9.6210	$12.5470	$12.3950	$18.1950	$18.0450	
100	Month Dollar Average	ln (85 + ln 93) /2				$ 125,197	$ 125,197	$ 125,197	$ 125,979	$ 126,366	$ 71,952	$ 17,843	$ 89,384	$ 143,947	
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				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Schedule 17

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2015-2016 Winter Cost of Gas Filing
Peak 2015 - 2016 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-15	5,598,123	-$0.0007	$ (4,135)
Dec-15	7,362,439	-0.0007	(5,438)
Jan-16	8,823,981	-0.0007	(6,517)
Feb-16	9,658,539	-0.0007	(7,134)
Mar-16	9,102,950	-0.0007	(6,724)
Apr-16	7,871,017	-0.0007	(5,814)
Total	**48,417,049**		**$ (35,761)**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed First Revised Page 79 for calculation of rate.

Schedule 18

NO LONGER INCLUDED IN COG FILING

THIS PAGE LEFT INTENTIONALLY BLANK

Schedule 19

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Local Distribution Adjustment Charge (LDAC) increase due to Rate Case Expense and Recoupment
For LDAC effec ive November 1, 2015 - December 31, 2016
Docket No. DG 14-180

1	Rate Case Expense in Docket No. DG 14-180	$411,782
2	Recoupment in Docket No. DG 14-180	$2,990,348
3		$3,402,130
4		
5	Rate Case Expense Overcollection in Docket No. DG 10-017	($129,262)
6		
7	Es imated July 2015 - October 2015 Recoveries	($281,992)
8		
9	Es imated November 2015 - December 2016 Remaining Recovery	$2,990,876
10	Es imated November 2015 - December 2016 Interest	$50 283
11		
12	Total Remaining Recovery	$3,041,159
13		
14	Es imated November 2015 - December 2016 Sales (therms)	217,953,914
15		
16	RCE rate per therm November 2015 - December 2016	$0.0140

Liberty Utilities (EnergyNorth Natural Gas) Corp.

JULY 2015 THROUGH DECEMBER 2016
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

		(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Total**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	**30**	**31**	
3	Beginning Balance	$ 3,272,868	$ 3,268,697	$ 3,192,378	$ 3,110,471	$ 2,990,876	$ 2,820,054	$ 2,537,840	$ 2,166,462	$ 1,773,938	$ 1,435,399	$ 1,151,360	$ 963,843	$ 842,534	$ 752,540	$ 672,512	$ 587,304	$ 465,607	$ 963,843	$ 3,272,868
4																				
5	Add Actual Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6																				
7	Less Collected Revenue	(13,186)	(85,224)	(90,314)	(128,004)	(178,573)	(289,598)	(377,862)	(397,430)	(342,963)	(287,489)	(190,432)	(123,719)	(92,193)	(81,991)	(86,889)	(123,149)	(178,573)	(289,598)	(3,357,186)
8																				
9	Add Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																				
11	Ending Balance Pre-Interest	$ 3,259,681	$ 3,183,473	$ 3,102,064	$ 2,982,467	$ 2,812,303	$ 2,530,456	$ 2,159,978	$ 1,769,032	$ 1,430,975	$ 1,147,910	$ 960,928	$ 840,125	$ 750,341	$ 670,548	$ 585,624	$ 464,156	$ 287,034	$ 674,245	**$ (84,318)**
12																				
13	Month's Average Balance	$ 3 266 274	$ 3 226 085	$ 3 147 221	$ 3 046 469	$ 2 901 590	$ 2 675 255	$ 2 348 909	$ 1 967 747	$ 1 602 457	$ 1 291 654	$ 1 056 144	$ 901 984	$ 796 438	$ 711 544	$ 629 068	$ 525 730	$ 376 321	$ 819 044	
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%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16																				
17	Interest Applied	$ 9,016	$ 8,905	$ 8,407	$ 8,409	$ 7,751	$ 7,384	$ 6,484	$ 4,906	$ 4,423	$ 3,450	$ 2,915	$ 2,409	$ 2,198	$ 1,964	$ 1,680	$ 1,451	$ 1,005	$ 2,261	**85,020**
18																				
19	Ending Balance	**$ 3,268,697**	**$ 3,192,378**	**$ 3,110,471**	**$ 2,990,876**	**$ 2,820,054**	**$ 2,537,840**	**$ 2,166,462**	**$ 1,773,938**	**$ 1,435,399**	**$ 1,151,360**	**$ 963,843**	**$ 842,534**	**$ 752,540**	**$ 672,512**	**$ 587,304**	**$ 465,607**	**$ 288,039**	**$ 676,506**	**$ 702**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 22.0400	$ 0.3486	$ 0.2885		
3	R-4 Rate at 40% of R-3	$ 8.8200	$ 0.1394	$ 0.1153		
4	Program Subsidy	$ 13.2200	$ 0.2092	$ 0.1732		
5	Average Annual Therms		519	45	564	
6						
7	Peak Period RLIAP Subsidy	$ 79.32	$ 108.51	$ 7.83	$ 195.66	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 22.0400	$ 0.3486	$ 0.2885		
11	R-4 Rate at 40% of R-3	$ 8.8200	$ 0.1394	$ 0.1153		
12	Program Subsidy	$ 13.2200	$ 0.2092	$ 0.1732		
13	Average Annual Therms		108	69	176	
14						
15	Off Peak Period RLIAP Subsidy	$ 79.32	$ 22.49	$ 11.88	$ 113.69	
16						
17	Estimated Annual Subsidy	$ 158.64	$ 131.00	$ 19.71	$ 309.35	
18						
19	Number of Estimated 2015/16 Participants				8,142	1/
20						
21	Annual Subsidy times Number of Participants (Ln 17 * Ln 19)				$ 2,518,737	
22	Prior Year Ending Balance - RLIAP Page 2				155,815	
23	Estimated Annual Administrative Costs				-	
24	Total Program Costs				$ 2,674,553	
25						
26	Estimated weather normalized firm therms billed for the					
27	twelve months ended 10/31/16 sales and transportation				184,393,263	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0145**	

1/
Estimated number of participants for 2015-16 is based on the actual number participants as of June 2015.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2014 THROUGH OCTOBER 2015
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (389,301)	$ (385,902)	$ (385,855)	$ (561,561)	$ (321,138)	$ (285,593)	$ (192,274)	$ (114,714)	$ (34,079)	$ 27,710	$ 72,219	$ 114,380	$ (389,301)
4														
5	Add: Actual Costs	82,641	126,208	-	439,519	252,744	237,268	148,479	137,757	108,805	79,220	79,538	88,501	1,780,681
6														
7	Less: Collected Revenue	(78,208)	(125,097)	(174,400)	(197,997)	(216,444)	(143,311)	(70,496)	(56,924)	(47,008)	(34,849)	(37,627)	(47,438)	(1,229,798)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ (384,868)	$ (384,791)	$ (560,255)	$ (320,039)	$ (284,838)	$ (191,637)	$ (114,290)	$ (33,881)	$ 27,719	$ 72,081	$ 114,131	$ 155,443	**$ 161,581**
12														
13	Month's Average Balance	$ (387,085)	$ (385,347)	$ (473,055)	$ (440,800)	$ (302,988)	$ (238,615)	$ (153,282)	$ (74,297)	$ (3,180)	$ 49,896	$ 93,175	$ 134,911	
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	$ (1,034)	$ (1,064)	$ (1,306)	$ (1,099)	$ (755)	$ (637)	$ (423)	$ (198)	$ (9)	$ 138	$ 249	$ 372	**(5,766)**
18														
19	Ending Balance	**$ (385,902)**	**$ (385,855)**	**$ (561,561)**	**$ (321,138)**	**$ (285,593)**	**$ (192,274)**	**$ (114,714)**	**$ (34,079)**	**$ 27,710**	**$ 72,219**	**$ 114,380**	**$ 155,815**	**$ 155,815**

Schedule 19
Energy Efficiency
Page 1 of 3

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential Non-Heating and Heating Classes
November 1, 2015 - October 31, 2016
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 15	Actual	590,504	($0.0646)	(215,490)	192,391	140,585	36,274	14,209	566,082	578,293	3.25%	1,641	567,723	3,349,634	3,349,991	31
June 15	Actual	567,723	($0.0646)	(140,646)	192,391	153,076	48,277	14,209	642,641	605,182	3.25%	1,660	644,301	1,984,898	2,175,297	30
July 15	Forecast	644,301	($0.0646)	(80,922)	192,391	0	0		755,770	700,035	3.25%	1,932	757,702	1,252,661	0	31
August 15	Forecast	757,702	($0.0646)	(68,261)	192,391	0	0		881,832	819,767	3.25%	2,263	884,094	1,056,675	0	31
September 15	Forecast	884,094	($0.0646)	(73,845)	192,391	0	0		1,002,640	943,367	3.25%	2,520	1,005,160	1,143,113	0	30
October 15	Forecast	1,005,160	($0.0646)	(109,402)	192,391	0	0		1,088,148	1,046,654	3.25%	2,889	1,091,037	1,693,533	0	31
November 15	Forecast	1,091,037	$0.0585	241,649	192,391	0	0		1,525,077	1,308,057	3.25%	3,494	1,528,571	4,134,277	0	30
December 15	Forecast	1,528,571	$0.0585	455,199	192,391	0	0		2,176,160	1,852,366	3.25%	5,113	2,181,274	7,787,838	0	31
January 16	Forecast	2,181,274	$0.0585	624,875	207,932	0	0		3,014,081	2,597,677	3.25%	7,170	3,021,251	10,690,766	0	31
February 16	Forecast	3,021,251	$0.0585	630,845	207,932	0	0		3,860,029	3,440,640	3.25%	8,578	3,868,607	10,792,908	0	28
March 16	Forecast	3,868,607	$0.0585	525,582	207,932	0	0		4,602,121	4,235,364	3.25%	11,691	4,613,812	8,991,996	0	31
April 16	Forecast	4,613,812	$0.0585	431,989	207,932	0	0		5,253,733	4,933,773	3.25%	13,179	5,266,912	7,390,737	0	30
May 16	Forecast	5,266,912	$0.0585	250,067	207,932	0	0		5,724,911	5,495,912	3.25%	15,170	5,740,082	4,278,304	0	31
June 16	Forecast	5,740,082	$0.0585	140,834	207,932	0	0		6,088,848	5,914,465	3.25%	15,799	6,104,647	2,409,481	0	30
July 16	Forecast	6,104,647	$0.0585	87,360	207,932	0	0		6,399,939	6,252,293	3.25%	17,258	6,417,197	1,494,615	0	31
August 16	Forecast	6,417,197	$0.0585	74,286	207,932	0	0		6,699,415	6,558,306	3.25%	18,103	6,717,518	1,270,928	0	31
September 16	Forecast	6,717,518	$0.0585	85,726	207,932	0	0		7,011,176	6,864,347	3.25%	18,336	7,029,512	1,466,653	0	30
October 16	Forecast	7,029,512	$0.0585	159,607	207,932	0	0		7,397,051	7,213,282	3.25%	19,911	7,416,962	2,730,652	0	31
November 16	Forecast	7,416,962	$0.0585	241,649	207,932	0	0		7,866,543	7,641,752	3.25%	20,413	7,886,956	4,134,277	0	30
December 16	Forecast	7,886,956	$0.0585	455,199	207,932	0	0		8,550,087	8,218,521	3.25%	22,685	8,572,772	7,787,838	0	31

Estimated Residential Conservation Charge Effective November 1, 2015 - October 31, 2016		
Beginning Balance	$	1,091,037
Program Budget Nov 15-Oct 16		**2,464,104**
Projected Interest		153,802
Projected Budget with Interest	$	3 708 943
Total Charges	**$**	**3,708,943**
Projected Therm Sales		**63,439,156**
Residential Rate		**$0.0585**
Total Charges with Interest	**$**	**3,711,191**
Projected Therm Sales		**63,439,156**
Residential Rate		**$0.0585**

Residential Non Heating Therm Sales	0%	**829,589**	**774,552**	0%
Residential Heating Therm Sales	37%	**61,254,757**	**62,664,604**	34%
C&I Therm Sales	63%	**104,438,722**	**120,954,108**	66%
Total Therms	100%	**166,523,068**	**184,393,263**	100%
		Budget	Budget	
		2015	**2016**	
Low-Income Program Budget		**$ 921,250**	**$ 895,000**	
Other Refund		-	-	
Total Shared Budget		**$ 921,250**	**$ 895,000**	
Residential Program Budget		**$ 2,206,100**	**$ 2,023,815**	
Residential Program Incentive @ 70%		**$158,693**	**$163,454**	
Total Residential Program Budget		**$ 2,364,793**	**$ 2,187,269**	
Commercial/Industrial Program Budget		**$ 2,493,010**	**$ 2,703,000**	
Commercial/Industrial Program Incentive at 70%		**$139,609**	**$143,772**	
Total Commercial/Industrial Program Budget		**$ 2,632,619**	**$ 2,846,772**	
Total Program Budget		**$ 5,918,662**	**$ 5,929,040**	
Shared Expenses Allocation to Residential		$ 343,467	$ 307,918	
Shared Expenses Allocation to C&I		577,783	587,082	
Total Allocated Shared Expenses		**$ 921,250**	**$ 895,000**	
Total Residential (including allocation of Shared Budget)		$ 2,708,260	$ 2,495,187	
Total C&I (including allocation of Shared Budget)		3,210,402	3,433,853	
Total Budget		**$ 5,918,662**	**$ 5,929,040**	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2015 - October 31, 2016
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 15	Actual	(492,279)	($0.0502)	(330,091)	251,510	167,137	48,084	12,425	(594,725)	(543,502)	3 25%	(1,461)	(596,185)	6,537,363	6,591,542	31
June 15	Actual	(596,185)	($0.0502)	(293,062)	251,510	298,880	63,996	12,425	(513,946)	(555,066)	3 25%	(1,444)	(515,391)	5,092,563	5,835,765	30
July 15	Forecast	(515,391)	($0.0502)	(201,239)	251,510	0	0		(465,120)	(490,255)	3 25%	(1,353)	(466,473)	4,008,754	0	31
August 15	Forecast	(466,473)	($0.0502)	(193,349)	251,510	0	0		(408,312)	(437,392)	3 25%	(1,207)	(409,519)	3,851,567	0	31
September 15	Forecast	(409,519)	($0.0502)	(208,652)	251,510	0	0		(366,661)	(388,090)	3 25%	(1,037)	(367,697)	4,156,413	0	30
October 15	Forecast	(367,697)	($0.0502)	(250,391)	251,510	0	0		(366,578)	(367,138)	3 25%	(1,013)	(367,591)	4,987,864	0	31
November 15	Forecast	(367,591)	$0.0256	221,866	251,510	0	0		105,785	(130,903)	3 25%	(350)	105,435	8,666,629	0	30
December 15	Forecast	105,435	$0.0256	332,081	251,510	0	0		689,026	397,230	3 25%	1,096	690,122	12,971,907	0	31
January 16	Forecast	690,122	$0.0256	419,740	286,154	0	0		1,396,017	1,043,070	3 25%	2,879	1,398,896	16,396,107	0	31
February 16	Forecast	1,398,896	$0.0256	453,035	286,154	0	0		2,138,086	1,768,491	3 25%	4,409	2,142,495	17,696,673	0	28
March 16	Forecast	2,142,495	$0.0256	399,184	286,154	0	0		2,827,834	2,485,164	3 25%	6,860	2,834,693	15,593,136	0	31
April 16	Forecast	2,834,693	$0.0256	338,376	286,154	0	0		3,459,223	3,146,958	3 25%	8,406	3,467,630	13,217,803	0	30
May 16	Forecast	3,467,630	$0.0256	239,942	286,154	0	0		3,993,726	3,730,678	3 25%	10,298	4,004,024	9,372,720	0	31
June 16	Forecast	4,004,024	$0.0256	165,357	286,154	0	0		4,455,535	4,229,779	3 25%	11,299	4,466,833	6,459,248	0	30
July 16	Forecast	4,466,833	$0.0256	130,923	286,154	0	0		4,883,911	4,675,372	3 25%	12,905	4,896,816	5,114,188	0	31
August 16	Forecast	4,896,816	$0.0256	117,929	286,154	0	0		5,300,899	5,098,858	3 25%	14,074	5,314,974	4,606,586	0	31
September 16	Forecast	5,314,974	$0.0256	121,905	286,154	0	0		5,723,033	5,519,003	3 25%	14,743	5,737,776	4,761,914	0	30
October 16	Forecast	5,737,776	$0.0256	156,088	286,154	0	0		6,180,018	5,958,897	3 25%	16,448	6,196,467	6,097,198	0	31
November 16	Forecast	6,196,467	$0.0256	221,866	286,154	0	0		6,704,487	6,450,477	3 25%	17,231	6,721,718	8,666,629	0	30
December 16	Forecast	6,721,718	$0.0256	332,081	286,154	0	0		7,339,953	7,030,835	3 25%	19,407	7,359,360	12,971,907	0	31

0

Estimated C&I Conservation Charge November 1, 2015 - October 31, 2016	
Beginning Balance	(367,591)
Program Budget Nov 15-Oct 16	**3,364,565**
Projected Interest	103,068
Program Budget with Interest	3,100,041
Total Charges	**$3,100,041**
Projected Therm Sales	**120,954,108**
C&I Rate	$0.0256
Total Charges with Interest	**$3,096,425**
Projected Therm Sales	**120,954,108**
C&I Rate	**$0.0256**
C&I Rate from Prior Programs (1)	**$0.0000**
Combined C&I Rate	**$0.0256**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2015 - October 31, 2016
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 15	Actual	98,225	n/a	(545,581)	443,901	140,585	167,137	84,358	392,079	26,634	(28,643)	34,791	**3.25%**	96	(28,547)	9,886,997	9,941,533	31
June 15	Actual	(28,462)	n/a	(433,708)	443,901	153,076	298,880	112,273	564,230	26,634	128,694	50,116	3.25%	134	128,828	7,077,460	8,011,062	30
July 15	Forecast	128,910	n/a	(282,161)	443,901	0	0	0	0		290,650	209,780	3.25%	579	291,229	5,261,414	0	31
August 15	Forecast	291,229	n/a	(261,610)	443,901	0	0	0	0		473,520	382,374	3.25%	1,055	474,575	4,908,241	0	31
September 15	Forecast	474,575	n/a	(282,497)	443,901	0	0	0	0		635,979	555,277	3.25%	1,483	637,463	5,299,526	0	30
October 15	Forecast	637,463	n/a	(359,793)	443,901	0	0	0	0		721,570	679,516	3.25%	1,876	723,446	6,681,398	0	31
November 15	Forecast	723,446	n/a	463,514	443,901	0	0	0	0		1,630,861	1,177,154	3.25%	3,144	1,634,006	12,800,906	0	30
December 15	Forecast	1,634,006	n/a	787,280	443,901	0	0	0	0		2,865,187	2,249,596	3.25%	6,210	2,871,396	20,759,744	0	31
January 16	Forecast	2,871,396	n/a	1,044,616	494,087	0	0	0	0		4,410,098	3,640,747	3.25%	10,049	4,420,148	27,086,873	0	31
February 16	Forecast	4,420,148	n/a	1,083,880	494,087	0	0	0	0		5,998,115	5,209,131	3.25%	12,987	6,011,102	28,489,580	0	28
March 16	Forecast	6,011,102	n/a	924,766	494,087	0	0	0	0		7,429,955	6,720,528	3.25%	18,550	7,448,506	24,585,132	0	31
April 16	Forecast	7,448,506	n/a	770,364	494,087	0	0	0	0		8,712,957	8,080,731	3.25%	21,586	8,734,542	20,608,540	0	30
May 16	Forecast	8,734,542	n/a	490,009	494,087	0	0	0	0		9,718,637	9,226,590	3.25%	25,468	9,744,105	13,651,025	0	31
June 16	Forecast	9,744,105	n/a	306,191	494,087	0	0	0	0		10,544,383	10,144,244	3.25%	27,098	10,571,480	8,868,729	0	30
July 16	Forecast	10,571,480	n/a	218,283	494,087	0	0	0	0		11,283,851	10,927,665	3.25%	30,163	11,314,014	6,608,803	0	31
August 16	Forecast	11,314,014	n/a	192,214	494,087	0	0	0	0		12,000,315	11,657,164	3.25%	32,177	12,032,492	5,877,513	0	31
September 16	Forecast	12,032,492	n/a	207,631	494,087	0	0	0	0		12,734,209	12,383,351	3.25%	33,079	12,767,288	6,228,566	0	30
October 16	Forecast	12,767,288	n/a	315,695	494,087	0	0	0	0		13,577,070	13,172,179	3.25%	36,359	13,613,429	8,827,850	0	31
November 16	Forecast	13,613,429	n/a	463,515	494,087	0	0	0	0		14,571,030	14,092,229	3.25%	37,644	14,608,673	12,800,906	0	30
December 16	Forecast	14,608,673	n/a	787,280	494,087	0	0	0	0		15,890,040	15,249,357	3.25%	42,092	15,932,133	20,759,744	0	31

0

Residential (R-1 & R-3) and C & I Conservation Charge November 1, 2015 - October 31, 2016		
Beginning Balance	$	723,446
Program Budget Nov 15-Oct 16	$	5,828,669
Projected Interest	$	256,870
Program Budget with Interest	$	6,808,985
Total Charges		**$6,808,985**

Schedule 20

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual Environmental increase	$2,651,933	
DG 10-17 Base Rate Revision Collections	$0	
Environmental Subtotal	$2,651,933	
Overall Annual Net Increase to Rates	$2,651,933	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/16 - sales and transportation	184,393,263	therms
Surcharge per therm	$0.0144	per therm
Total Environmental Surcharge	$0.0144	

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:

Concord MGP: 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. 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. The investigation work was completed in July 2012, and summarized in a Supplement Data Collection Report that was submitted 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 (GMP) application. **The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014. On March 31, 2015, ENGI submitted a proposed Remedial Action Plan involving removal of shallow soils displaying MGP-related residual impacts, investigation and**

remediation of remaining known subsurface structures, capping of components of the local storm water drainage system, site capping design, and continued monitoring of groundwater on the site. NHDES approved the RAP on May 29, 2015, with the condition that roof of the brick gas holder either be restored, or the holder be razed and the soils beneath it remediated. Both options are being weighed presently. A Remedial Design Report is to be provided to NHDES by December 31, 2015 summarizing pre-design investigations to be completed in 2015.

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 has evaluated damage to the roof and structure of the holder, and will be using this information to determine whether the holder will be restored or razed.**

Concord Pond: 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, 2007 and 2012, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit.

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 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. Contact was reconvened with the City in 2013, and adjustments to the original design are being made presently to address outfall maintenance and access concerns of the City and NHDOT, respectively.

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:

Concord MGP: 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 Supplemental Data Collection report summarizing the investigation activities was accepted in October 2013, authorizing ENGI to prepare a RAP and GMP Application.

The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014. On March 31, 2015, ENGI submitted a proposed RAP, and NHDES approved the RAP with conditions. A Remedial Design Report, summarizing pre-design investigations, is to be provided to NHDES by the end of 2015.

Concord Pond: 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 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 2010 and 2011. The Company reinitiated discussion with the City in July 2014 regarding access to the site to implement the approved design of the wetland cap. **The design is currently being adjusted for final approval.**

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.

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

LINE
NO.

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.

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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.

LINE
NO.

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

LINE
NO.

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 began to remove tar-impacted soil on the south side of the site in the first season, with little to no impact to the surrounding community. In 2014, approximately 65% of the impacted soil was removed for treatment. On April 8, 2015, ENGI presented the results of the first season of construction at a Gilford Town Select Board meeting, and presented expectations for the second season to the community. Starting on April 13, 2015, the north side of the site is being remediated this year, with the removal of all tar-impacted soil expected by July 31, 2015. The entire project is expected to be complete in the last half of September 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.

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.

MANCHESTER FORMER MGP

LINE
NO.

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.

LINE
NO.

- 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

LINE
NO.

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. In addition to routine Groundwater Management Permit (GMP) sampling and reporting, an application for GMP renewal was also submitted to NHDES during June 2014. **The Remedial Design Report was submitted to NHDES on December 19, 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**

LINE
NO.

summarizing the activities for addressing on-site and off-site impacts was submitted on December 19, 2014.

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.

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.

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.

LINE
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.

LINE
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.

LINE
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

LINE
NO.

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.

- 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.

LINE
NO.

- 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.

LINE
NO.

- 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.

- The first groundwater monitoring annual summary report was submitted to NHDES in February 2015, and included the groundwater data from the first GMP round of sampling on October 27, 2014

LINE
NO.

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. **A RAP Summary involving the asphalt capping of the area over Holder #2 and continued groundwater monitoring was submitted on April 2, 2015. A Monitoring Summary and Progress Report was submitted by ENGI on February 7, 2015. NHDES accepted the RAP Summary on April 10, 2015, with the provisions that ENGI submit the draft Activity and Use Restriction (AUR) and final engineering design plan for the cap by September 15, 2015. ENGI is preparing these submittals.**

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.

NASHUA FORMER MGP

LINE
NO.

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 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.

DOVER FORMER MGP

LINE
NO.

- 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

LINE
NO.

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.

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

LINE
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.

LINE
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 mediated cost allocation settlement that resolved the matter. Under that agreement, ENGI will pay some of the remediation expense incurred by PSNH.

KEENE FORMER MGP

LINE
NO.

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.

ENERGYNORTH NATURAL GAS, INC. **REDACTED**

MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS

2015 SUMMARY BY SITE

LINE NO.	SITE	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
	Concord Pond	DEF056	-	79,719.57	-	-	9,906.55	89,626.12	[redacted]		78,234.56
	Concord MGP	DEF077	-	187,305.04	-	-	5,219.96	192,525.00			163,783.28
	Laconia/Liberty Hill	DEF086	135.00	735,587.10	6,797,613.29	-	232,921.36	7,766,256.75			7,766,256.75
	Manchester MGP	DEF057	-	71,286.12	-	-	45,210.24	116,496.36			75,439.59
	Nashua MGP	DEF054	-	93,004.37	-	-	12,912.45	105,916.82			65,217.46
	Dover MGP	DEF059	-	-	-	-	-	-			-
	Keene MGP	DEF055	462.50	-	-	-	57.44	519.94			2,500,519.94
	General Expenses	DEF064	1,184.50	-	-	-	15,427.77	16,612.27			(7,637.72)
	Total Pool Activity		**1,782.00**	**1,166,902.20**	**1,168,684.20**	**-**	**321,655.77**	**8,287,953.26**	**2,500,000.00**	**(146,139.40)**	**10,641,813.86**

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

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	HILLSBOROUGH COUNTY REGISTRY OF DEEDS	Recording Fee					98.94	98.94			98.94
2	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 8323					986.59	986.59			986.59
3	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11593		4,754.40				4,754.40			4,754.40
4	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11556		3,379.20				3,379.20			3,379.20
5	ESMI OF NH	1011601					2,480.00	2,480.00			2,480.00
6	ESMI OF NH	1011478					2,063.75	2,063.75			2,063.75
[redacted]											
8	ESMI OF NH	1011674					4,368.88	4,368.88			4,368.88
9	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11616		3,130.50				3,130.50			3,130.50
10	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11640		3,287.04				3,287.04			3,287.04
11	NH DEPT OF ENVIRONMENTAL SERVICES	199810022A					276.92	276.92			276.92
[redacted]											
13	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11672		15,066.39				15,066.39			15,066.39
14	O'HARA INDUSTRIAL SERVICES LLC	31321					2,074.00	2,074.00			2,074.00
15	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11712		16,074.37				16,074.37			16,074.37
16	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11786		14,394.17				14,394.17			14,394.17
17	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11758		5,272.12				5,272.12			5,272.12
18	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11797		2,949.35				2,949.35			2,949.35
[redacted]											
20	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11831		4,572.57				4,572.57			4,572.57
21	NH DEPT OF ENVIRONMENTAL SERVICES	1998810022 8323					388.19	388.19			388.19
22	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11856		11,785.46				11,785.46			11,785.46
[redacted]											
24	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11886		8,338.80				8,338.80			8,338.80
25								0.00			0.00
26	Environmental Staff Time						175.18	175.18			175.18
	Total Pool Activity		**-**	**93,004.37**	**-**	**-**	**12,912.45**	**105,916.82**	**-**	**(40,699.36)**	**65,217.46**

REDACTED

185

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

REDACTED

			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
[redacted]											
	Total Pool Activity		462.50	0.00	0.00	0.00	57.44	519.94	2,500,000.00	0.00	2,500,519.94

REDACTED

186

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

REDACTED

			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	CITY OF CONCORD	2014-50460156					1,020.00	1,020.00			1,020.00
2	CLEAN HARBORS	1000527632					1,782.66	1,782.66			1,782.66
3	GEI CONSULTANTS, INC.	59795		4,224.69				4,224.69			4,224.69
4	CASEY MARY	07/01 THRU 07/31/14					55.60	55.60			55.60
5	GEI CONSULTANTS, INC.	59886		2,587.36				2,587.36			2,587.36
[redacted]											
7	GEI CONSULTANTS, INC.	60174		2,156.64				2,156.64			2,156.64
8	GEI CONSULTANTS, INC.	60305		4,652.42				4,652.42			4,652.42
9	CASEY MARY	09/01 THRU 09/30/14					55.10	55.10			55.10
10	CLEAN HARBORS	1000685958					814.00	814.00			814.00
11	NH DEPT OF ENVIRONMENTAL SERVICES	199212014A					54.65	54.65			54.65
[redacted]											
13	ANCHOR QEA LLC	40034		5,341.80				5,341.80			5,341.80
14	GEI CONSULTANTS, INC.	60508		2,942.42				2,942.42			2,942.42
15	ANCHOR QEA LLC	40427		10,011.34				10,011.34			10,011.34
16	GEI CONSULTANTS, INC.	60761		4,239.85				4,239.85			4,239.85
17	CASEY MARY	10/01 THRU 10/31/14					31.13	31.13			31.13
18	GEI CONSULTANTS, INC.	60897		3,998.75				3,998.75			3,998.75
19	ANCHOR QEA LLC	40758		10,988.75				10,988.75			10,988.75
20	GEI CONSULTANTS, INC.	61088		2,576.86				2,576.86			2,576.86
21	ANCHOR QEA LLC	41163		9,436.00				9,436.00			9,436.00
22	GEI CONSULTANTS, INC.	61321		922.54				922.54			922.54
23	ANCHOR QEA LLC	41579		5,145.25				5,145.25			5,145.25
[redacted]											
25	GEI CONSULTANTS, INC.	61505		768.99				768.99			768.99
26	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 4042					2,419.15	2,419.15			2,419.15
27	CITY OF CONCORD	2015-50460152					1,440.00	1,440.00			1,440.00
28	GEI CONSULTANTS, INC.	61669		1,751.33				1,751.33			1,751.33
[redacted]											
30	CLEAN HARBORS	1000941568					1,516.26	1,516.26			1,516.26
31	ANCHOR QEA LLC	42177		3,151.90				3,151.90			3,151.90
32	ANCHOR QEA LLC	42581		264.00				264.00			264.00
33	GEI CONSULTANTS, INC.	61946		4,558.68				4,558.68			4,558.68
34								0.00			0.00
35	Environmental Staff Time						718.00	718.00			718.00
	Total Pool Activity		**0.00**	**79,719.57**	**0.00**	**0.00**	**9,906.55**	**89,626.12**	**0.00**	**(11,391.56)**	**78,234.56**

REDACTED

187

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

REDACTED

			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	CLEAN HARBORS	1000527599					837.10	837.10			837.10
2	GZA GEOENVIRONMENTAL INC	690121		9,707.03				9,707.03			9,707.03
3	NH DEPT OF ENVIRONMENTAL SERVICES	200003011-9890					45.59	45.59			45.59
[redacted]											
5	CASEY MARY	08/01 THRU 08/31/14					138.97	138.97			138.97
[redacted]											
7	CASEY MARY	09/01 THRU 09/30/14					35.22	35.22			35.22
8	ESMI OF NH	1011877					6,863.13	6,863.13			6,863.13
9	ESMI OF NH	1011876					2,173.98	2,173.98			2,173.98
[redacted]											
11	NORTHPOINT CONSTRUCTION MGMT, LLC	1554					3,644.49	3,644.49			3,644.49
12	NORTHPOINT CONSTRUCTION MGMT, LLC	1550					28,034.30	28,034.30			28,034.30
13	GZA GEOENVIRONMENTAL INC	695410		22,485.37				22,485.37			22,485.37
14	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 9890A					382.18	382.18			382.18
15	ESMI OF NH	1012023					1,601.40	1,601.40			1,601.40
[redacted]											
19	NH DEPT OF ENVIRONMENTAL SERVICES	2000030110 9890					46.60	46.60			46.60
20	GZA GEOENVIRONMENTAL INC	702511		30,074.62				30,074.62			30,074.62
[redacted]											
22	GZA GEOENVIRONMENTAL INC	703054		9,019.10				9,019.10			9,019.10
[redacted]											
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						1,407.28	1,407.28			1,407.28
	Total Pool Activity		**0.00**	**71,286.12**	**0.00**	**0.00**	**45,210.24**	**116,496.36**	**0.00**	**(41,056.77)**	**75,439.59**

REDACTED

188

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	E&A Insurance Proceeds	Insurance check						-		(20,185.83)	(20,185.83)
2	World Marine & Gen'l Insurance payment	Check No. 0000950364						-		(2,902.97)	(2,902.97)
3	Allegra Marketing Print Mail	27582					$122.00	122.00			122.00
4	CASEY MARY	8/1 THRU 8/31/2014					$53.60	53.60			53.60
5	World Marine & Gen'l Insurance payment	Check No. 0000850304						-		(1,161.19)	(1,161.19)
6	CASEY MARY	10/1 THRU 10/31/2014					89.38	89.38			89.38
7	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2015051290	$ 1,184.50					1,184.50			1,184.50
8	Removal of Winter 2014/2015 MGP Consortium related costs						(3,431.24)	(3,431.24)			(3,431.24)
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						18,594.03	18,594.03			18,594.03
	Total Pool Activity		**1,184.50**	**-**	**-**	**-**	**15,427.77**	**16,612.27**	**-**	**(24,249.99)**	**(7,637.72)**

189

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

REDACTED

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	CITY OF CONCORD	2014-50460156					1,020.00	1,020.00			1,020.00
3	CLEAN HARBORS	1000527626					1,246.74	1,246.74			1,246.74
4	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 1479					735.26	735.26			735.26
[redacted]											
6	GZA GEOENVIRONMENTAL INC	690126		28,696.49				28,696.49			28,696.49
7	GZA GEOENVIRONMENTAL INC	690122		18,812.52				18,812.52			18,812.52
8	GZA GEOENVIRONMENTAL INC	684968		2,660.92				2,660.92			2,660.92
9	GZA GEOENVIRONMENTAL INC	694181		72,684.79				72,684.79			72,684.79
[redacted]											
11	GZA GEOENVIRONMENTAL INC	694846		7,700.48				7,700.48			7,700.48
12	MERRIMACK COUNTY REGISTRY OF DEEDS	Document Fee-GMP					144.90	144.90			144.90
13	COULOMBE JUDITH A	2/1 THRU 2/28/15					52.88	52.88			52.88
[redacted]											
15	CITY OF CONCORD	2015-50460152					600.00	600.00			600.00
16	GZA GEOENVIRONMENTAL INC	702508		35,768.85				35,768.85			35,768.85
[redacted]											
18	GZA GEOENVIRONMENTAL INC	703050		10,425.54				10,425.54			10,425.54
19	GZA GEOENVIRONMENTAL INC	703097		10,555.45				10,555.45			10,555.45
20								0.00			0.00
21	Environmental Staff Time						1,420.18	1,420.18			1,420.18
	Total Pool Activity		**0.00**	**187,305.04**	**0.00**	**0.00**	**5,219.96**	**192,525.00**	**0.00**	**(28,741.72)**	**163,783.28**

REDACTED

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	SUB-TOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	ESMI OF NH	1011348			114,871.68			114,871.68			114,871.68
2	BLUE CHIP FILMS LLC	1194					725.00	725.00			725.00
3	CASEY MARY	06/01 THRU 06/30/14					166.40	166.40			166.40
4	CASEY MARY	07/01 THRU 07/01/14					70.85	70.85			70.85
5	ESMI OF NH	1011411			59,778.04			59,778.04			59,778.04
6	GEI CONSULTANTS, INC.	59627		66,395.07				66,395.07			66,395.07
7	OSTROW & PARTNERS INC	07 14 01					1,027.25	1,027.25			1,027.25
8	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 07 14					50.41	50.41			50.41
9	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 07 14					285.92	285.92			285.92
10	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 07 14					105.36	105.36			105.36
11	CHARTER ENVIRONMENTAL INC	APP3 2-1055			742,430.38			742,430.38			742,430.38
12	ESMI OF NH	1011446			104,229.86			104,229.86			104,229.86
13	ESMI OF NH	1011406			132,760.11			132,760.11			132,760.11
14	DRAGONFLY AERIALS LLC	71					460.00	460.00			460.00
15	DE MAXIMIS, INC.	141654					34,850.70	34,850.70			34,850.70
16	ESMI OF NH	1011473			111,132.00			111,132.00			111,132.00
17	GEI CONSULTANTS, INC.	59793		52,751.61				52,751.61			52,751.61
18	ESMI OF NH	1011480			114,285.64			114,285.64			114,285.64
19	NH DEPT OF ENVIRONMENTAL SERVICES	200411113 14262					3,091.93	3,091.93			3,091.93
20	ESMI OF NH	1011505			88,205.88			88,205.88			88,205.88
21	CHARTER ENVIRONMENTAL INC	APP 4 2-1055			528,547.10			528,547.10			528,547.10
22	ESMI OF NH	1011530			19,681.83			19,681.83			19,681.83
23	ESMI OF NH	1011537			104,035.33			104,035.33			104,035.33
24	CASEY MARY	07/01 THRU 07/31/14					771.28	771.28			771.28
25	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 0814					266.87	266.87			266.87
26	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 0814					72.51	72.51			72.51
27	OSTROW & PARTNERS INC	08 14 01					1,496.75	1,496.75			1,496.75
28	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 0814					195.12	195.12			195.12
29	ESMI OF NH	1011556			108,299.80			108,299.80			108,299.80
30	GEI CONSULTANTS, INC.	59884		50,938.33				50,938.33			50,938.33
31	ESMI OF NH	1011577			129,678.50			129,678.50			129,678.50
32	DE MAXIMIS, INC.	141918		37,916.50				37,916.50			37,916.50
33	AIRLOGICS LLC	691464			8,100.00			8,100.00			8,100.00
34	BLUE CHIP FILMS LLC	1204					1,937.50	1,937.50			1,937.50
35	ESMI OF NH	1011596			108,326.26			108,326.26			108,326.26
36	CASEY MARY	08/01 THRU 08/31/14					213.92	213.92			213.92
37	ESMI OF NH	1011621			97,708.94			97,708.94			97,708.94
38	OSTROW & PARTNERS INC	09 14 01					1,183.75	1,183.75			1,183.75
39	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 0914					171.85	171.85			171.85
40	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 0914					56.96	56.96			56.96
41	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 0914					266.41	266.41			266.41
42	CHARTER ENVIRONMENTAL INC	APP 5 2-1055			251,983.94			251,983.94			251,983.94
43	ESMI OF NH	1011651			139,481.93			139,481.93			139,481.93
44	DE MAXIMIS, INC.	142166		31,471.13				31,471.13			31,471.13
45	AIRLOGICS LLC	692789			8,100.00			8,100.00			8,100.00
46	ESMI OF NH	1011692			160,429.43			160,429.43			160,429.43
47	ESMI OF NH	1011700			34,599.41			34,599.41			34,599.41
48	GEI CONSULTANTS, INC.	60172		76,234.44				76,234.44			76,234.44
49	BLUE CHIP FILMS LLC	1208					1,050.00	1,050.00			1,050.00
50	DRAGONFLY AERIALS LLC	83					460.00	460.00			460.00
51	CASEY MARY	09/16 THRU 09/16/14					22.05	22.05			22.05
52	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 1014					299.14	299.14			299.14
53	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 1014					104.99	104.99			104.99
54	ESMI OF NH	1011724			207,321.64			207,321.64			207,321.64
55	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 1014					38.24	38.24			38.24
56	CHARTER ENVIRONMENTAL INC	APP 6 2-1055			312,593.57			312,593.57			312,593.57

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	SUB-TOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
57	ESMI OF NH	1011749			258,972.08			258,972.08			258,972.08
58	OSTROW & PARTNERS INC	10 14 01					1,262.00	1,262.00			1,262.00
59	CASEY MARY	09/01 THRU 09/30/14					741.60	741.60			741.60
60	GEI CONSULTANTS, INC.	60303		61,593.39				61,593.39			61,593.39
61	ESMI OF NH	1011787			137,054.97			137,054.97			137,054.97
62	DE MAXIMIS, INC.	142409		30,054.65				30,054.65			30,054.65
63	AIRLOGICS LLC	694072					8,100.00	8,100.00			8,100.00
64	Laconia Daily Sun	Public Notice					151.75	151.75			151.75
65	ESMI OF NH	1011809			95,325.09			95,325.09			95,325.09
66	ESMI OF NH	1011813			118,826.96			118,826.96			118,826.96
67	BLUE CHIP FILMS LLC	1218					800.00	800.00			800.00
68	OSTROW & PARTNERS INC	11 14 01					1,340.25	1,340.25			1,340.25
69	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 1114					515.92	515.92			515.92
70	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 1114					88.26	88.26			88.26
71	CHARTER ENVIRONMENTAL INC	APP 7 2-1055			258,314.38			258,314.38			258,314.38
72	NH DEPT OF ENVIRONMENTAL SERVICES	200411113 103114					24,473.88	24,473.88			24,473.88
73	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 1114					441.67	441.67			441.67
74	ESMI OF NH	1011870			143,072.07			143,072.07			143,072.07
75	ESMI OF NH	1011847			83,881.63			83,881.63			83,881.63
76	DE MAXIMIS, INC.	142670		40,225.91				40,225.91			40,225.91
77	AIRLOGICS LLC	695111					8,100.00	8,100.00			8,100.00
78	ESMI OF NH	1011885			145,328.90			145,328.90			145,328.90
79	BLUE CHIP FILMS LLC	1220					887.50	887.50			887.50
80	ESMI OF NH	1011899			80,514.32			80,514.32			80,514.32
81	CASEY MARY	10/01 THRU 10/31/14					(70.85)	(70.85)			(70.85)
82	CASEY MARY	10/01 THRU 10/31/14					447.13	447.13			447.13
83	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 1214					205.91	205.91			205.91
84	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 1214					941.72	941.72			941.72
85	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 1214					1,182.95	1,182.95			1,182.95
86	ESMI OF NH	1011921			10,366.96			10,366.96			10,366.96
87	OSTROW & PARTNERS INC	12 14 01					1,262.00	1,262.00			1,262.00
88	TOWN OF GILFORD NH	637					44,017.00	44,017.00			44,017.00
89	GEI CONSULTANTS, INC.	60506		65,810.37				65,810.37			65,810.37
90	DRAGONFLY AERIALS LLC	88					460.00	460.00			460.00
91	ESMI OF NH	1011928			11,095.80			11,095.80			11,095.80
92	CHARTER ENVIRONMENTAL INC	APP 8 2-1055			314,574.48			314,574.48			314,574.48
93	ESMI OF NH	1011952			10,996.12			10,996.12			10,996.12
94	DE MAXIMIS, INC.	142921		26,159.99				26,159.99			26,159.99
95	AIRLOGICS LLC	696606			4,617.00			4,617.00			4,617.00
96	BLUE CHIP FILMS LLC	1225					1,050.00	1,050.00			1,050.00
97	CASEY MARY	12/01 THRU 12/22/14					177.18	177.18			177.18
98	CASEY MARY	11/01 THRU 11/30/14					265.24	265.24			265.24
99	CHARTER ENVIRONMENTAL INC	APP 9 2-1055			169,287.90			169,287.90			169,287.90
100	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 0115					1,100.29	1,100.29			1,100.29
101	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 0115					609.73	609.73			609.73
102	OSTROW & PARTNERS INC	01 15 01					1,575.00	1,575.00			1,575.00
103	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 0115					623.62	623.62			623.62
104	GEI CONSULTANTS, INC.	60759		39,260.75				39,260.75			39,260.75
105	AIRLOGICS LLC	690293			8,100.00			8,100.00			8,100.00
106	GEI CONSULTANTS, INC.	60896		39,417.64				39,417.64			39,417.64
107	DE MAXIMIS, INC.	150192		24,166.23				24,166.23			24,166.23
108	NH DEPT OF ENVIRONMENTAL SERVICES	200411113 012315					27,594.58	27,594.58			27,594.58
109	BLUE CHIP FILMS LLC	1231					237.50	237.50			237.50
110	OSTROW & PARTNERS INC	02 15 01					323.00	323.00			323.00
111	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 0215					561.36	561.36			561.36
112	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 0215					574.03	574.03			574.03
113	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 0215					1,033.86	1,033.86			1,033.86
114	GEI CONSULTANTS, INC.	61086		6,705.44				6,705.44			6,705.44

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	SUB-TOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
115	DE MAXIMIS, INC.	150478		919.98				919.98			919.98
116	OSTROW & PARTNERS INC	03 15 01					626.00	626.00			626.00
117	PUBLIC SERVICE OF NEW HAMPSHIRE	56549986081 0315					544.25	544.25			544.25
118	PUBLIC SERVICE OF NEW HAMPSHIRE	56382976025 0315					1,008.75	1,008.75			1,008.75
119	PUBLIC SERVICE OF NEW HAMPSHIRE	56272196049 0315					1,169.50	1,169.50			1,169.50
120	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2015031003	135.00					135.00			135.00
121	DE MAXIMIS, INC.	150731		465.06				465.06			465.06
122	GEI CONSULTANTS, INC.	61320		9,293.93				9,293.93			9,293.93
123	BLUE CHIP FILMS LLC	1240					150.00	150.00			150.00
124	CASEY MARY	03/01 THRU 03/31/15					37.08	37.08			37.08
125	EVERSOURCE	56382976025 0415					701.38	701.38			701.38
126	EVERSOURCE	56272196049 0415					905.63	905.63			905.63
127	DE MAXIMIS, INC.	150974		476.68				476.68			476.68
128	AIRLOGICS LLC	701650			4,779.00			4,779.00			4,779.00
129	BLUE CHIP FILMS LLC	1247					1,000.00	1,000.00			1,000.00
130	CHARTER ENVIRONMENTAL INC	2-1055 APP 10			97,691.90			97,691.90			97,691.90
131	ESMI OF NH	1012290			115,090.22			115,090.22			115,090.22
132	CASEY MARY	04/01 THRU 04/30/15					353.71	353.71			353.71
133	CASEY MARY	04/28 THRU 04/29/15					70.85	70.85			70.85
134	OSTROW & PARTNERS INC	04 15 01					244.75	244.75			244.75
135	OSTROW & PARTNERS INC	05 15 01					1,418.50	1,418.50			1,418.50
136	EVERSOURCE	56272196049 0515					490.90	490.90			490.90
137	EVERSOURCE	56382976025 0515					424.46	424.46			424.46
138	GEI CONSULTANTS, INC.	61503		26,053.33				26,053.33			26,053.33
139	DRAGONFLY AERIALS LLC	96					460.00	460.00			460.00
140	DE MAXIMIS, INC.	151240		22,040.57				22,040.57			22,040.57
141	ESMI OF NH	1012327			124,677.56			124,677.56			124,677.56
142	GEI CONSULTANTS, INC.	61668		27,236.10				27,236.10			27,236.10
143	NH DEPT OF ENVIRONMENTAL SERVICES	200411113 14262 0415					22,511.12	22,511.12			22,511.12
144	ESMI OF NH	1012342			128,873.92			128,873.92			128,873.92
145	AIRLOGICS LLC	703053			8,100.00			8,100.00			8,100.00
146	ESMI OF NH	1012369			77,108.85			77,108.85			77,108.85
147	BLUE CHIP FILMS LLC	1254					725.00	725.00			725.00
148	CASEY MARY	05/01 THRU 05/31/15					369.64	369.64			369.64
149	EVERSOURCE	56382976025 0615					260.56	260.56			260.56
150	ESMI OF NH	1012394			161,943.44			161,943.44			161,943.44
151	OSTROW & PARTNERS INC	06 15 01					1,228.75	1,228.75			1,228.75
152	EVERSOURCE	56272196049 0615					96.84	96.84			96.84
153	CHARTER ENVIRONMENTAL INC	APP 11 LIBERTY HILL			287,456.95			287,456.95			287,456.95
154	KNOTT MICHAEL G	03/30 THRU 06/05/15					13.80	13.80			13.80
155	CASEY MARY	05/26 THRU 05/27/15					70.85	70.85			70.85
156	ESMI OF NH	1012415			138,819.30			138,819.30			138,819.30
157	ESMI OF NH	1012435			116,162.22			116,162.22			116,162.22
158	CASEY MARY	06/16 THRU 06/17/15					70.85	70.85			70.85
159								-			-
160								-			-
Environmental Staff Time							17,452.95	17,452.95			17,452.95
	Total Pool Activity		135.00	735,587.10	6,797,613.29	0.00	232,921.36	7,766,256.75			7,766,256.75

193

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
Tariff page 80

Concord Pond

DEF056

internal order no. 500061 (formerly acc no. 1796)

		(thru 3/98)	(4/98 9/98)	10/98 9/15/9!	(9/99 9/00)	(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)	(9/14 - 9/15)	
		pool #1	pool #2	pool #3	pool #4	pool #5	pool #6	pool #7	pool #8	pool #9	pool #10	pool #11	pool #12	pool #13	pool #14	pool #15	pool #16	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	89,626	6,794,309
	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	89,626	6,794,309
																		-
	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)	(11,392)	(2,170,665)
	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)	(11,392)	(1,992,866)
																		-
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	78,235	4,801,443
																		-
																		-
	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												(12,749)	(12,749)				(25,497)
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																	-
Act	Nov 2014-Oct 2015 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)	(13,948)	(14,173)	(176,865)
	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)	(98,295)	(33,631)	(13,725)	(13,948)	(14,173)	(3,951,598)
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	118,448	47,608	45,345	18,376	64,062	849,844
E	Allocation of Litigated Recovery					-		-		(329,540)	(102,675)	(123,791)	(61,965)	-	-	-	-	(617,971)
	Surcharge calculation																	
	Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	-	56,483	47,608	45,345	18,376	64,062	231,873
	remaining life	-	-	-	-	24	36	48	60	72	84	84	36	48	60	72	84	
	one year	-	-	-	-	12	12	12	12	12	12	12	12	12	12	12	12	
F	amortization	-	-	-	-	-	-	-		-	-	-	18,828	11,902	9,069	3,063	9,152	52,013
	Required annual increase in rates:																	
	smaller of D or F	-	-	-	-	-	-	-		-	-	-	18,828	11,902	9,069	3,063	9,152	52,013
	forecasted therm sales	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263
	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	$0.0000	$0.0003

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

REDACTED

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
Tariff page 80

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	(9/14 - 9/15) pool #14	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 Restructuring						-	-	-							
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											(25,497)	(76,491)			(101,988)
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											(28,433)	(28,433)	(28,433)		(85,298)
Act	Nov 2014-Oct 2015 Base Rate Rev											(21,909)	(21,909)	(21,909)	(21,909)	(87,637)
	AES collections															-
	Gas Street overcollection															-
	Prior Period Pool under/overcollection		11,434	(1,477)	99,902	109,604	2,130,162	4,231,004		-	-	(31,789)	-	-	-	
C	Surcharge Subtotal	(1,016,313)	(3,514,762)	(600,098)	99,902	(200,393)	2,130,162	4,231,004	-	-	(63,313)	(141,842)	(126,833)	(50,342)	(21,909)	(5,823,577)
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	127,439	516,153	[redacted]		
E	Allocation of Litigated Recovery							(4,680,958)	(607,876)	(262,678)	(179,008)	-	-			
	Surcharge calculation															
	Unrecovered costs (D+E)	-	-	-	-			-	-	-	-	127,439	516,153			
	remaining life	-	-	-	36	48	60	72	84	84	48	48	60			
	one year	-	-	-	12	12	12	12	12	12	12	12	12			
F	amortization	-	-	-	-	-	-	-	-	-	-	31,860	103,231			
	Required annual increase in rates:															
	smaller of D or F	-	-	-	-	-		-	-	-	-	31,860	103,231	[redacted]		
	forecasted therm sales	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263
	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

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
Tariff page 80

Manchester

DEF057

	(9/00 9/01) pool #1	(9/00 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	(9/13 9/14) pool #14	(9/14 9/15) pool #15	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	116,496	10,002,333
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	116,496	10,827,425
Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(2,577,139)
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)	(31,690)	(41,057)	(1,332,267)
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)	61,210	75,440	9,495,158
																-
																-
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												(50,994)				(50,994)
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											-	(23,337)				(23,337)
Act Nov 2013-Oct 2014 Base Rate Rev																-
Act Nov 2014-Oct 2015 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	-	-	-	(114,343)	-	-	-	(1,954,576)
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	327,955	(188,619)	61,210	75,440	7,540,582
E Allocation of Litigated Recovery			-	-	-			(6,486,145)	(312,185)	(328,678)	(123,580)	-	-	-	-	(7,250,588)
Surcharge calculation																
Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-	14,009	327,955	(188,619)	61,210	75,440	289,993
remaining life	-	-	-	24	36	48	60	70	84	84	36	48	60	72	84	
one year	-	-	-	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	-	4 670	81 989	(37 724)	10 202	10 777	
Required annual increase in rates:																
smaller of D or F	-	-	-	-	-	-		-	-	-	4,670	81,989	(37,724)	10,202	10,777	69,913
forecasted therm sales	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263
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	($0.0002)	$0.0001	$0.0001	$0.0004

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
Tariff page 80

		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	(9/14 9/15) pool #15	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	105,917	1,352,095
	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	105,917	3,123,662
																	-
	Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(461,385)
	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)	(40,699)	(442,998)
																	-
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	65,217	2,680,664
	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												(38,246)				(38,246)
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											-	(20,916)				(20,916)
Act	Nov 2013-Oct 2014 Base Rate Rev																-
Act	Nov 2014-Oct 2015 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	-	-	-	(962)	-	-	-	
C	Surcharge Subtotal	(1,045,263)	(69,925)	179,564	354,741	309,902	516,269	526,492	545,015	-	-	-	(100,136)	-	-	-	(1,571,680)
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	296,275	(80,241)	35,950	65,217	1,108,985
E	Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	(16,289)	(98,975)	(34,313)	-	-	-	-	(791,783)
	Surcharge calculation																
	Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-		296,275	(80,241)	35,950	65,217	317,201
	remaining life	-	-	12	24	36	48	60	72	84	84	72	48	60	72	84	
	one year	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F	amortization	-	-	-	-	-	-	-	-	-	-	-	74 069	(16 048)	5 992	9 317	
	Required annual increase in rates:																
	smaller of D or F	-	-	-	-	-	-		-	-	-	-	74,069	(16,048)	5,992	9,317	73,329
	forecasted therm sales	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263
	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	$0.0001	$0.0004

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
Tariff page 80

		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	(9/14 - 9/15) pool #12	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													-
Act	Nov 2014-Oct 2015 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	84	
	one year	12	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	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263
	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	$0.0000

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: **REDACTED**

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
Tariff page 80

			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	(9/14 - 9/15) pool #12	subtotal
1	1	Remediation costs (i.o. 500061)	-										[redacted]		
2		Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
3	A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
4															
5		Cash recoveries (i.o. 500061)	-												
6		Cash recoveries (i.o. 500004)	-												
7		Recovery costs (i.o. 500004)			18,831	823	-	-	-	-					
8		Transfer Credit from Gas Restructuring				-	-	-							
9	B	Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-			
10															
11	A-B	Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400			
12															-
13															-
14		Surcharge revenue:													-
15	Act	June 1998 - October 1998	-												-
16	Act	November 1998 - October 1999	-												-
17	Act	November 1999 - October 2000	-												-
18	Act	November 2000 - October 2001	-												-
19	Act	November 2001 - October 2002	-												-
20	Act	November 2002 - October 2003	-												-
21	Act	November 2003 - October 2004	-												-
22	Act	November 2004- October 2005	-	-				-	-	-	-	-	-	-	-
23	Act	November 2005- October 2006	-	-				-	-	-	-	-	-	-	-
24	Act	November 2006- October 2007	-	-	(14,091)										(14,091)
25	Act	November 2007- October 2008													-
26	Act	November 2012- October 2013													-
27	Act	November 2013- October 2014													-
28	Act	Nov 2009-Oct 2010 Base Rate Rev													-
29	Act	Nov 2010-Oct 2011 Base Rate Rev													-
30	Act	Nov 2011-Oct 2012 Base Rate Rev													-
31	Act	Nov 2012-Oct 2013 Base Rate Rev													-
32	Act	Nov 2013-Oct 2014 Base Rate Rev													-
33	Act	Nov 2014-Oct 2015 Base Rate Rev													
34		AES collections													-
35		Gas Street overcollection													-
36		Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	-	-	-	-	-	
37															
38															
39	C	Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	-	-	-	-	-	(14,091)
40															
41															
42	D	Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	-	488	1,400	[redacted]		
43															
44	E	Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	-			
45															
46		Surcharge calculation													
47		Unrecovered costs (D+E)	-	-	-			-	-	-	488	1,400			
48		remaining life	24	36	48	60	72	84	84	84	48	60			
49		one year	12	12	12	12	12	12	12	12	12	12			
50	F	amortization	-	-	-	-	-	-	-	-	122	280			
51															
52		Required annual increase in rates:													
53		smaller of D or F	-	-	-			-	-	-	122	280	[redacted]		
54															
55		forecasted therm sales	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263
56															
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
Tariff page 80

	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	(9/14 - 9/15) pool #12	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	192,525	1,412,871
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	192,525	1,412,871
													-
Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(192,308)
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)	(28,742)	(191,882)
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	163,783	1,220,989
													-
													-
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								(12,749)	(25,497)				(38,246)
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													-
Act Nov 2014-Oct 2015 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	-	-	(67,420)	(52,297)	-	-	-	(175,398)
D Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	92,679	46,190	100,919	205,231	45,384	123,355	163,783	1,045,591
													-
E Allocation of Litigated Recovery	-	-	-	-	(268,051)	(92,679)	(46,190)	(13,870)	-	-	-	-	(420,789)
													-
Surcharge calculation													-
Unrecovered costs (D+E)	-	-	-		-	-	-	87,049	205,231	45,384	123,355	163,783	624,802
remaining life	36	48	60		72	84	84	36	48	60	72	84	
one year	12	12	12		12	12	12	12	12	12	12	12	
F amortization	-	-	-		-	-	-	29,016	51,308	9,077	20,559	23,398	
Required annual increase in rates:													
smaller of D or F	-	-	-		-	-	-	29,016	51,308	9,077	20,559	23,398	133,358
forecasted therm sales	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0003	$0.0000	$0.0001	$0.0001	$0.0007

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: **REDACTED**

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
Tariff page 80

	General														
				Corrected per 1/24/07 Audit									DEF064		2015 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	(9/14 - 9/15) pool #13	subtotal	subtotal
1 Remediation costs (i.o. 500061)	-													-	[redacted]
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	16,612	870,202	
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	16,612	870,202	
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)	-	(24,250)	322,270	
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)	-	(24,250)	318,939	
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	(7,638)	1,189,141	
															-
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									(12,749)	(12,749)	(12,749)			(38,246)	(293,217)
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															(85,298)
Act Nov 2014-Oct 2015 Base Rate Rev															(87,637)
AES collections		-												-	(176,865)
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	-	-	(17,750)	(17,750)	(12,749)	-	-	(378,657)	(13,982,750)
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	51,536	61,217	61,098	13,139	(7,638)	810,484	[redacted]
E Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	2,931	(4,199)	(15,701)	-	-	-	-	(646,833)	
Surcharge calculation															
Unrecovered costs (D+E)	-	-	-	-		-	-	-	35,835	61,217	61,098	13,139	(7,638)	163,651	
remaining life		36	48	60	72	84	84	84	36	48	60	72	84		
one year		12	12	12	12	12	12	12	12	12	12	12	12		
F amortization		-	-	-	-	-	-	-	11,945	15,304	12,220	2,190	(1,091)		
Required annual increase in rates:															
smaller of D or F	-	-	-	-		-	-	-	11,945	15,304	12,220	2,190	(1,091)	40,567	
forecasted therm sales	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	184,393,263	**184,393,263**
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	$0.0000	$0.0002	**$0.0144**

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: **REDACTED**
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
Tariff page 80

Expense and Collection Summary per Year

		(thru 9/98)	(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)	(9/14 9/15)	Total
1	Remediation costs (i.o. 500061)	5,420,852	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	312,039	[redacted]
	Remediation costs (i.o. 500005)	1,027,747	3,513,285	2,428,832	362,663	359,451	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	7,975,914	[redacted]
A	Subtotal - remediation costs	6,448,599	3,642,287	2,428,832	362,663	359,451	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	8,287,953	[redacted]
	Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(105,062)	(528,258)	(79,446)	(121,889)	[redacted]
	Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	-	[redacted]
	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	2,475,750	[redacted]
	Transfer Credit from Gas Restructuring	-	-	-	-	(3 331)	-	-	-	-	-	-	-	-	-	-	-	-	[redacted]
B	Subtotal - net recoveries	(1,836,941)	(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)	2,420,554	2,353,861	[redacted]
A-B	Total net expenses to recover	4,611,659	3,609,083	2,428,832	362,663	356,120	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	4,418,569.29	10,641,813.86	[redacted]
	Surcharge revenue:																		
Act	June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
Act	November 1998 - October 1999	(538,143)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
Act	November 1999 - October 2000	(912,804)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
Act	November 2000 - October 2001	(779,786)	(556,990)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,336,776)
Act	November 2001 - October 2002	(759,943)	(551,571)	(367,714)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,679,228)
Act	November 2002 - October 2003	(744,646)	(562,284)	(364,725)	(60,787)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,732,442)
Act	November 2003 - October 2004	(422,442)	(480,710)	(349,608)	(43,701)	(107,858)	-	-	-	-	-	-	-	-	-	-	-	-	(1,404,319)
Act	November 2004- October 2005	(184,336)	(453,749)	(326,132)	(42,539)	(56,719)	(297,773)	-	-	-	-	-	-	-	-	-	-	-	(1,361,248)
Act	November 2005- October 2006	(141,176)	(460,610)	(316,240)	(54,998)	(54,998)	(281,866)	(343,739)	-	-	-	-	-	-	-	-	-	-	(1,653,628)
Act	November 2006- October 2007	-	(549,539)	(338,178)	(56,363)	(56,363)	(288,860)	(366,359)	(429,768)	-	-	-	-	-	-	-	-	-	(2,085,430)
Act	November 2007- October 2008													-	-	-	-	-	-
Act	November 2012- October 2013									-	-	-	-	(30,009)	(130,039)	-	-	-	(160,048)
Act	November 2013- October 2014													(38,246)	(165,731)	(89,240)	-	-	(293,217)
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													-	(28,433)	(28,433)	(28,433)	-	(85,298)
Act	Nov 2014-Oct 2015 Base Rate Rev													-	(21,909)	(21,909)	(21,909)	(21,909)	(87,637)
	AES collections	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,725)	(13,948)	(14,173)	(176,865)
	Gas Street overcollection	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
	Prior Period Pool under/overcollection																		
C	Surcharge Subtotal	(4,561,677)	(3,615,454)	(2,062,596)	(258,389)	(275,938)	(902,092)	(721,725)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(246,777)	(427,248)	(153,306)	(64,290)	(36,082)	(13,818,184)
D	Net balance to be recovered (A-B+C)	49,982	(6,371)	366,236	104,274	80,183	932,934	2,086,746	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	589,062	1,098,962	400,519	4,354,279	10,605,732	[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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2015-16

Rate: $0.24 /MMBtu

	Rate	Volume	Total	
Injection Cost	$0.0087	**321,091**	$2,793	
Fuel (.80%)	$0.0140	**321,091**	$4,495	
Withdrawal Cost	$0.0087	**292,252**	$2,543	
Delivery Rate	$0.0506	292,252	$14,797	
FTA Demand Charge	$0.2768	292,252	$80,883	
FTA Commodity Charge	$0.1250	292,252	$36,531	
Fuel (.88%)	$0.0154	292,252	$4,501	
		Total Cost	$146,544	
	Absolute Value of the	Sendout Error	**613,343**	MMBtu
		Rate	$ 0.24	/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	$8.4181	/ MMBtu per month
	$0.2768	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.1250	/ MMBtu

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2015-16
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	787	775	12	1,383,237	1,365,555	17,682	67,780	42,731	25,049
Dec	963	971	-8	1,781,465	1,795,646	-14,181	116,991	51,405	65,586
Jan	1,343	1,350	-7	2,455,050	2,467,458	-12,408	108,128	47,860	60,268
Feb	1,398	1,387	11	2,545,337	2,525,839	19,499	83,312	51,405	31,907
Mar	1,080	1,043	37	1,948,088	1,883,212	64,876	89,424	77,150	12,274
Apr	523	539	-17	901,123	921,664	-20,541	70,337	24,898	45,439
May	197	214	-17	441,048	450,305	-9,257	24,503	7,623	16,880
Jun	16	25	-9	274,873	276,262	-1,388	1,697	154	1,543
Jul	0	0	0	251,297	251,297	0	0	0	0
Aug	0	4	-4	252,327	254,636	-2,309	2,309	0	2,309
Sep	102	133	-31	303,763	318,727	-14,964	15,929	483	15,446
Oct	346	344	2	590,148	588,319	1,830	32,934	17,382	15,552
Total	**6,755**	**6,785**	**-31**	**13,127,757**	**13,098,918**	**28,839**	**613,343**	**321,091**	**292,252**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2015-16
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, 2014	25	22	3	39,478	35,743	3,735	3,735	3,735	0
Apr 2, 14	21	24	-3	34,498	38,233	-3,735	3,735	0	3,735
Apr 3, 14	25	23	2	39,478	36,988	2,490	2,490	2,490	0
Apr 4, 14	24	25	-1	38,233	39,478	-1,245	1,245	0	1,245
Apr 5, 14	24	24	0	38,233	38,233	0	0	0	0
Apr 6, 14	21	21	0	34,498	34,498	0	0	0	0
Apr 7, 14	13	15	-2	24,539	27,029	-2,490	2,490	0	2,490
Apr 8, 14	14	16	-2	25,784	28,274	-2,490	2,490	0	2,490
Apr 9, 14	22	23	-1	35,743	36,988	-1,245	1,245	0	1,245
Apr 10, 14	12	10	2	23,294	20,804	2,490	2,490	2,490	0
Apr 11, 14	10	10	0	20,804	20,804	0	0	0	0
Apr 12, 14	9	9	-1	18,937	19,560	-622	622	0	622
Apr 13, 14	7	19	-12	17,070	32,009	-14,939	14,939	0	14,939
Apr 14, 14	1	0	1	9,600	8,355	1,245	1,245	1,245	0
Apr 15, 14	15	18	-3	27,029	30,764	-3,735	3,735	0	3,735
Apr 16, 14	31	31	0	46,947	46,947	0	0	0	0
Apr 17, 14	29	30	-1	44,457	45,702	-1,245	1,245	0	1,245
Apr 18, 14	23	25	-2	36,988	39,478	-2,490	2,490	0	2,490
Apr 19, 14	20	19	1	33,253	32,009	1,245	1,245	1,245	0
Apr 20, 14	18	19	-1	30,764	32,009	-1,245	1,245	0	1,245
Apr 21, 14	9	5	4	19,560	14,580	4,980	4,980	4,980	0
Apr 22, 14	6	3	3	15,825	12,090	3,735	3,735	3,735	0
Apr 23, 14	18	18	0	30,764	30,764	0	0	0	0
Apr 24, 14	18	16	2	30,764	28,274	2,490	2,490	2,490	0
Apr 25, 14	13	11	2	24,539	22,049	2,490	2,490	2,490	0
Apr 26, 14	21	23	-2	34,498	36,988	-2,490	2,490	0	2,490
Apr 27, 14	19	19	0	32,009	32,009	0	0	0	0
Apr 28, 14	14	16	-2	25,784	28,274	-2,490	2,490	0	2,490
Apr 29, 14	20	23	-3	33,253	36,988	-3,735	3,735	0	3,735
Apr 30, 14	21	22	-1	34,498	35,743	-1,245	1,245	0	1,245
May 1, 14	7	10	-3	14,579	16,212	-1,634	1,634	0	1,634
May 2, 14	10	9	1	16,212	15,668	545	545	545	0
May 3, 14	8	7	1	15,123	14,579	545	545	545	0
May 4, 14	14	12	2	18,390	17,301	1,089	1,089	1,089	0
May 5, 14	13	12	1	17,846	17,301	545	545	545	0
May 6, 14	13	11	2	17,846	16,757	1,089	1,089	1,089	0
May 7, 14	9	9	0	15,668	15,668	0	0	0	0
May 8, 14	6	5	1	14,034	13,490	545	545	545	0
May 9, 14	8	14	-6	15,123	18,390	-3,267	3,267	0	3,267
May 10, 14	0	0	0	10,767	10,767	0	0	0	0
May 11, 14	1	0	1	11,312	10,767	545	545	545	0
May 12, 14	0	0	0	10,767	10,767	0	0	0	0
May 13, 14	12	15	-3	17,301	18,935	-1,634	1,634	0	1,634
May 14, 14	1	4	-3	11,312	12,945	-1,634	1,634	0	1,634
May 15, 14	0	0	0	10,767	10,767	0	0	0	0
May 16, 14	1	0	1	11,312	10,767	545	545	545	0
May 17, 14	4	4	0	12,945	12,945	0	0	0	0
May 18, 14	7	5	2	14,579	13,490	1,089	1,089	1,089	0
May 19, 14	7	7	0	14,579	14,579	0	0	0	0
May 20, 14	3	2	1	12,401	11,856	545	545	545	0
May 21, 14	3	3	0	12,401	12,401	0	0	0	0
May 22, 14	7	9	-2	14,579	15,668	-1,089	1,089	0	1,089
May 23, 14	9	13	-4	15,668	17,846	-2,178	2,178	0	2,178
May 24, 14	7	8	-1	14,579	15,123	-545	545	0	545
May 25, 14	1	2	-1	11,312	11,856	-545	545	0	545
May 26, 14	0	0	0	10,767	10,767	0	0	0	0
May 27, 14	10	14	-4	16,212	18,390	-2,178	2,178	0	2,178
May 28, 14	16	19	-3	19,479	21,113	-1,634	1,634	0	1,634
May 29, 14	8	8	0	15,123	15,123	0	0	0	0
May 30, 14	4	5	-1	12,945	13,490	-545	545	0	545
May 31, 14	8	7	1	15,123	14,579	545	545	545	0
Jun 1, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 2, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 3, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 4, 14	3	6	-3	9,543	10,006	-463	463	0	463
Jun 5, 14	5	5	0	9,851	9,851	0	0	0	0
Jun 6, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 7, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 8, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 9, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 10, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 11, 14	3	2	1	9,543	9,389	154	154	154	0
Jun 12, 14	2	2	0	9,389	9,389	0	0	0	0
Jun 13, 14	1	6	-5	9,234	10,006	-771	771	0	771
Jun 14, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 15, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 16, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 17, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 18, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 19, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 20, 14	2	2	0	9,389	9,389	0	0	0	0
Jun 21, 14	0	2	-2	9,080	9,389	-309	309	0	309
Jun 22, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 23, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 24, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 25, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 26, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 27, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 28, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 29, 14	0	0	0	9,080	9,080	0	0	0	0
Jun 30, 14	0	0	0	9,080	9,080	0	0	0	0
Jul 1, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 2, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 3, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 4, 14	0	0	0	8,106	8,106	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2015-16
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, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 6, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 7, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 8, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 9, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 10, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 11, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 12, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 13, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 14, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 15, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 16, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 17, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 18, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 19, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 20, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 21, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 22, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 23, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 24, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 25, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 26, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 27, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 28, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 29, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 30, 14	0	0	0	8,106	8,106	0	0	0	0
Jul 31, 14	0	0	0	8,106	8,106	0	0	0	0
Aug 1, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 2, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 3, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 4, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 5, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 6, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 7, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 8, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 9, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 10, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 11, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 12, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 13, 14	0	1	-1	8,140	8,717	-577	577	0	577
Aug 14, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 15, 14	0	1	-1	8,140	8,717	-577	577	0	577
Aug 16, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 17, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 18, 14	0	1	-1	8,140	8,717	-577	577	0	577
Aug 19, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 20, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 21, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 22, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 23, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 24, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 25, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 26, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 27, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 28, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 29, 14	0	1	-1	8,140	8,717	-577	577	0	577
Aug 30, 14	0	0	0	8,140	8,140	0	0	0	0
Aug 31, 14	0	0	0	8,140	8,140	0	0	0	0
Sep 1, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 2, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 3, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 4, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 5, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 6, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 7, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 8, 14	1	3	-2	8,967	9,932	-965	965	0	965
Sep 9, 14	3	3	0	9,932	9,932	0	0	0	0
Sep 10, 14	0	1	-1	8,484	8,967	-483	483	0	483
Sep 11, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 12, 14	5	7	-2	10,898	11,863	-965	965	0	965
Sep 13, 14	7	9	-2	11,863	12,829	-965	965	0	965
Sep 14, 14	10	12	-2	13,311	14,277	-965	965	0	965
Sep 15, 14	8	8	0	12,346	12,346	0	0	0	0
Sep 16, 14	6	10	-4	11,380	13,311	-1,931	1,931	0	1,931
Sep 17, 14	5	8	-3	10,898	12,346	-1,448	1,448	0	1,448
Sep 18, 14	7	9	-2	11,863	12,829	-965	965	0	965
Sep 19, 14	14	17	-3	15,242	16,690	-1,448	1,448	0	1,448
Sep 20, 14	0	2	-2	8,484	9,450	-965	965	0	965
Sep 21, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 22, 14	9	8	1	12,829	12,346	483	483	483	0
Sep 23, 14	6	7	-1	11,380	11,863	-483	483	0	483
Sep 24, 14	7	9	-2	11,863	12,829	-965	965	0	965
Sep 25, 14	7	9	-2	11,863	12,829	-965	965	0	965
Sep 26, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 27, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 28, 14	0	0	0	8,484	8,484	0	0	0	0
Sep 29, 14	1	4	-3	8,967	10,415	-1,448	1,448	0	1,448
Sep 30, 14	6	7	-1	11,380	11,863	-483	483	0	483
Oct 1, 14	8	8	0	16,145	16,145	0	0	0	0
Oct 2, 14	10	12	-2	17,975	19,804	-1,830	1,830	0	1,830
Oct 3, 14	8	8	0	16,145	16,145	0	0	0	0
Oct 4, 14	9	7	2	17,060	15,230	1,830	1,830	1,830	0
Oct 5, 14	14	16	-2	21,634	23,464	-1,830	1,830	0	1,830
Oct 6, 14	8	7	1	16,145	15,230	915	915	915	0
Oct 7, 14	1	0	1	9,741	8,826	915	915	915	0
Oct 8, 14	6	6	0	14,315	14,315	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2015-16
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, 14	12	13	-1	19,804	20,719	-915	915	0	915
Oct 10, 14	14	15	-1	21,634	22,549	-915	915	0	915
Oct 11, 14	17	19	-2	24,378	26,208	-1,830	1,830	0	1,830
Oct 12, 14	15	18	-3	22,549	25,293	-2,744	2,744	0	2,744
Oct 13, 14	8	6	2	16,145	14,315	1,830	1,830	1,830	0
Oct 14, 14	0	0	0	8,826	8,826	0	0	0	0
Oct 15, 14	0	0	0	8,826	8,826	0	0	0	0
Oct 16, 14	1	0	1	9,741	8,826	915	915	915	0
Oct 17, 14	3	2	1	11,571	10,656	915	915	915	0
Oct 18, 14	9	7	2	17,060	15,230	1,830	1,830	1,830	0
Oct 19, 14	22	22	0	28,953	28,953	0	0	0	0
Oct 20, 14	16	14	2	23,464	21,634	1,830	1,830	1,830	0
Oct 21, 14	12	12	0	19,804	19,804	0	0	0	0
Oct 22, 14	16	16	0	23,464	23,464	0	0	0	0
Oct 23, 14	16	14	2	23,464	21,634	1,830	1,830	1,830	0
Oct 24, 14	17	16	1	24,378	23,464	915	915	915	0
Oct 25, 14	10	9	1	17,975	17,060	915	915	915	0
Oct 26, 14	16	16	0	23,464	23,464	0	0	0	0
Oct 27, 14	17	17	0	24,378	24,378	0	0	0	0
Oct 28, 14	9	11	-2	17,060	18,889	-1,830	1,830	0	1,830
Oct 29, 14	13	15	-2	20,719	22,549	-1,830	1,830	0	1,830
Oct 30, 14	20	17	3	27,123	24,378	2,744	2,744	2,744	0
Oct 31, 14	19	21	-2	26,208	28,038	-1,830	1,830	0	1,830
Nov 1, 14	26	25	1	45,764	44,291	1,473	1,473	1,473	0
Nov 2, 14	29	26	3	50,185	45,764	4,420	4,420	4,420	0
Nov 3, 14	23	24	-1	41,344	42,817	-1,473	1,473	0	1,473
Nov 4, 14	14	14	0	28,082	28,082	0	0	0	0
Nov 5, 14	16	16	0	31,029	31,029	0	0	0	0
Nov 6, 14	18	20	-2	33,976	36,923	-2,947	2,947	0	2,947
Nov 7, 14	26	25	1	45,764	44,291	1,473	1,473	1,473	0
Nov 8, 14	24	23	1	42,817	41,344	1,473	1,473	1,473	0
Nov 9, 14	22	25	-3	39,870	44,291	-4,420	4,420	0	4,420
Nov 10, 14	20	23	-3	36,923	41,344	-4,420	4,420	0	4,420
Nov 11, 14	14	11	3	28,082	23,662	4,420	4,420	4,420	0
Nov 12, 14	20	18	2	36,923	33,976	2,947	2,947	2,947	0
Nov 13, 14	25	25	0	44,291	44,291	0	0	0	0
Nov 14, 14	32	32	0	54,605	54,605	0	0	0	0
Nov 15, 14	34	35	-1	57,552	59,025	-1,473	1,473	0	1,473
Nov 16, 14	29	28	1	50,185	48,711	1,473	1,473	1,473	0
Nov 17, 14	27	29	-2	47,238	50,185	-2,947	2,947	0	2,947
Nov 18, 14	38	38	0	63,446	63,446	0	0	0	0
Nov 19, 14	36	35	1	60,499	59,025	1,473	1,473	1,473	0
Nov 20, 14	35	32	3	59,025	54,605	4,420	4,420	4,420	0
Nov 21, 14	38	39	-1	63,446	64,919	-1,473	1,473	0	1,473
Nov 22, 14	28	26	2	48,711	45,764	2,947	2,947	2,947	0
Nov 23, 14	21	15	6	38,397	29,556	8,841	8,841	8,841	0
Nov 24, 14	7	3	4	17,768	11,874	5,894	5,894	5,894	0
Nov 25, 14	18	18	0	33,976	33,976	0	0	0	0
Nov 26, 14	30	33	-3	51,658	56,078	-4,420	4,420	0	4,420
Nov 27, 14	35	36	-1	59,025	60,499	-1,473	1,473	0	1,473
Nov 28, 14	43	42	1	70,813	69,340	1,473	1,473	1,473	0
Nov 29, 14	37	37	0	61,972	61,972	0	0	0	0
Nov 30, 14	22	22	0	39,870	39,870	0	0	0	0
Dec 1, 14	28	25	3	52,034	46,717	5,318	5,318	5,318	0
Dec 2, 14	30	34	-4	55,580	62,670	-7,090	7,090	0	7,090
Dec 3, 14	26	29	-3	48,489	53,807	-5,318	5,318	0	5,318
Dec 4, 14	36	37	-1	66,215	67,988	-1,773	1,773	0	1,773
Dec 5, 14	30	34	-4	55,580	62,670	-7,090	7,090	0	7,090
Dec 6, 14	30	31	-1	55,580	57,352	-1,773	1,773	0	1,773
Dec 7, 14	44	44	0	80,396	80,396	0	0	0	0
Dec 8, 14	37	40	-3	67,988	73,306	-5,318	5,318	0	5,318
Dec 9, 14	28	27	1	52,034	50,262	1,773	1,773	1,773	0
Dec 10, 14	29	28	1	53,807	52,034	1,773	1,773	1,773	0
Dec 11, 14	33	33	0	60,897	60,897	0	0	0	0
Dec 12, 14	34	31	3	62,670	57,352	5,318	5,318	5,318	0
Dec 13, 14	33	30	3	60,897	55,580	5,318	5,318	5,318	0
Dec 14, 14	32	30	2	59,125	55,580	3,545	3,545	3,545	0
Dec 15, 14	33	31	2	60,897	57,352	3,545	3,545	3,545	0
Dec 16, 14	26	29	-3	48,489	53,807	-5,318	5,318	0	5,318
Dec 17, 14	26	24	2	48,489	44,944	3,545	3,545	3,545	0
Dec 18, 14	31	29	2	57,352	53,807	3,545	3,545	3,545	0
Dec 19, 14	36	37	-1	66,215	67,988	-1,773	1,773	0	1,773
Dec 20, 14	35	34	1	64,443	62,670	1,773	1,773	1,773	0
Dec 21, 14	35	33	2	64,443	60,897	3,545	3,545	3,545	0
Dec 22, 14	29	28	1	53,807	52,034	1,773	1,773	1,773	0
Dec 23, 14	23	26	-3	43,172	48,489	-5,318	5,318	0	5,318
Dec 24, 14	16	25	-9	30,763	46,717	-15,953	15,953	0	15,953
Dec 25, 14	23	21	2	43,172	39,626	3,545	3,545	3,545	0
Dec 26, 14	27	27	0	50,262	50,262	0	0	0	0
Dec 27, 14	23	21	2	43,172	39,626	3,545	3,545	3,545	0
Dec 28, 14	27	25	2	50,262	46,717	3,545	3,545	3,545	0
Dec 29, 14	36	37	-1	66,215	67,988	-1,773	1,773	0	1,773
Dec 30, 14	44	46	-2	80,396	83,941	-3,545	3,545	0	3,545
Dec 31, 14	43	45	-2	78,623	82,169	-3,545	3,545	0	3,545
Jan 1, 15	38	37	1	69,760	67,988	1,773	1,773	1,773	0
Jan 2, 15	40	38	2	73,306	69,760	3,545	3,545	3,545	0
Jan 3, 15	35	37	-2	64,443	67,988	-3,545	3,545	0	3,545
Jan 4, 15	26	30	-4	48,489	55,580	-7,090	7,090	0	7,090
Jan 5, 15	47	48	-1	85,714	87,486	-1,773	1,773	0	1,773
Jan 6, 15	49	53	-4	89,259	96,349	-7,090	7,090	0	7,090
Jan 7, 15	58	59	-1	105,212	106,985	-1,773	1,773	0	1,773
Jan 8, 15	49	49	0	89,259	89,259	0	0	0	0
Jan 9, 15	46	45	1	83,941	82,169	1,773	1,773	1,773	0
Jan 10, 15	50	53	-3	91,032	96,349	-5,318	5,318	0	5,318
Jan 11, 15	41	39	2	75,078	71,533	3,545	3,545	3,545	0
Jan 12, 15	38	37	1	69,760	67,988	1,773	1,773	1,773	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2015-16
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, 15	54	55	-1	98,122	99,894	-1,773	1,773	0	1,773
Jan 14, 15	47	45	2	85,714	82,169	3,545	3,545	3,545	0
Jan 15, 15	42	41	1	76,851	75,078	1,773	1,773	1,773	0
Jan 16, 15	50	49	1	91,032	89,259	1,773	1,773	1,773	0
Jan 17, 15	46	45	1	83,941	82,169	1,773	1,773	1,773	0
Jan 18, 15	27	29	-2	50,262	53,807	-3,545	3,545	0	3,545
Jan 19, 15	34	31	3	62,670	57,352	5,318	5,318	5,318	0
Jan 20, 15	42	39	3	76,851	71,533	5,318	5,318	5,318	0
Jan 21, 15	39	39	0	71,533	71,533	0	0	0	0
Jan 22, 15	38	45	-7	69,760	82,169	-12,408	12,408	0	12,408
Jan 23, 15	44	36	8	80,396	66,215	14,181	14,181	14,181	0
Jan 24, 15	35	34	1	64,443	62,670	1,773	1,773	1,773	0
Jan 25, 15	47	47	0	85,714	85,714	0	0	0	0
Jan 26, 15	46	48	-2	83,941	87,486	-3,545	3,545	0	3,545
Jan 27, 15	50	51	-1	91,032	92,804	-1,773	1,773	0	1,773
Jan 28, 15	51	52	-1	92,804	94,577	-1,773	1,773	0	1,773
Jan 29, 15	38	38	0	69,760	69,760	0	0	0	0
Jan 30, 15	43	46	-3	78,623	83,941	-5,318	5,318	0	5,318
Jan 31, 15	53	55	-2	96,349	99,894	-3,545	3,545	0	3,545
Feb 1, 15	51	50	1	92,804	91,032	1,773	1,773	1,773	0
Feb 2, 15	55	57	-2	99,894	103,440	-3,545	3,545	0	3,545
Feb 3, 15	51	54	-3	92,804	98,122	-5,318	5,318	0	5,318
Feb 4, 15	37	34	3	67,988	62,670	5,318	5,318	5,318	0
Feb 5, 15	55	55	0	99,894	99,894	0	0	0	0
Feb 6, 15	50	48	2	91,032	87,486	3,545	3,545	3,545	0
Feb 7, 15	42	41	1	76,851	75,078	1,773	1,773	1,773	0
Feb 8, 15	49	53	-4	89,259	96,349	-7,090	7,090	0	7,090
Feb 9, 15	50	49	1	91,032	89,259	1,773	1,773	1,773	0
Feb 10, 15	45	45	0	82,169	82,169	0	0	0	0
Feb 11, 15	51	50	1	92,804	91,032	1,773	1,773	1,773	0
Feb 12, 15	48	51	-3	87,486	92,804	-5,318	5,318	0	5,318
Feb 13, 15	62	59	3	112,303	106,985	5,318	5,318	5,318	0
Feb 14, 15	46	49	-3	83,941	89,259	-5,318	5,318	0	5,318
Feb 15, 15	61	62	-1	110,530	112,303	-1,773	1,773	0	1,773
Feb 16, 15	57	55	2	103,440	99,894	3,545	3,545	3,545	0
Feb 17, 15	52	49	3	94,577	89,259	5,318	5,318	5,318	0
Feb 18, 15	43	42	1	78,623	76,851	1,773	1,773	1,773	0
Feb 19, 15	53	52	1	96,349	94,577	1,773	1,773	1,773	0
Feb 20, 15	58	57	1	105,212	103,440	1,773	1,773	1,773	0
Feb 21, 15	38	38	0	69,760	69,760	0	0	0	0
Feb 22, 15	38	35	3	69,760	64,443	5,318	5,318	5,318	0
Feb 23, 15	61	60	1	110,530	108,757	1,773	1,773	1,773	0
Feb 24, 15	50	51	-1	91,032	92,804	-1,773	1,773	0	1,773
Feb 25, 15	46	43	3	83,941	78,623	5,318	5,318	5,318	0
Feb 26, 15	50	48	2	91,032	87,486	3,545	3,545	3,545	0
Feb 27, 15	51	51	0	92,804	92,804	0	0	0	0
Feb 28, 15	48	49	-1	87,486	89,259	-1,773	1,773	0	1,773
Mar 1, 15	39	41	-2	70,138	73,645	-3,507	3,507	0	3,507
Mar 2, 15	42	40	2	75,398	71,891	3,507	3,507	3,507	0
Mar 3, 15	34	35	-1	61,371	63,124	-1,753	1,753	0	1,753
Mar 4, 15	33	28	5	59,618	50,851	8,767	8,767	8,767	0
Mar 5, 15	48	50	-2	85,919	89,425	-3,507	3,507	0	3,507
Mar 6, 15	47	45	2	84,165	80,658	3,507	3,507	3,507	0
Mar 7, 15	39	37	2	70,138	66,631	3,507	3,507	3,507	0
Mar 8, 15	36	34	2	64,878	61,371	3,507	3,507	3,507	0
Mar 9, 15	31	28	3	56,111	50,851	5,260	5,260	5,260	0
Mar 10, 15	24	21	3	43,837	38,577	5,260	5,260	5,260	0
Mar 11, 15	26	21	5	47,344	38,577	8,767	8,767	8,767	0
Mar 12, 15	40	39	1	71,891	70,138	1,753	1,753	1,753	0
Mar 13, 15	34	30	4	61,371	54,357	7,014	7,014	7,014	0
Mar 14, 15	30	31	-1	54,357	56,111	-1,753	1,753	0	1,753
Mar 15, 15	34	35	-1	61,371	63,124	-1,753	1,753	0	1,753
Mar 16, 15	29	29	0	52,604	52,604	0	0	0	0
Mar 17, 15	35	35	0	63,124	63,124	0	0	0	0
Mar 18, 15	45	44	1	80,658	78,905	1,753	1,753	1,753	0
Mar 19, 15	42	41	1	75,398	73,645	1,753	1,753	1,753	0
Mar 20, 15	37	37	0	66,631	66,631	0	0	0	0
Mar 21, 15	32	31	1	57,864	56,111	1,753	1,753	1,753	0
Mar 22, 15	46	45	1	82,412	80,658	1,753	1,753	1,753	0
Mar 23, 15	44	42	2	78,905	75,398	3,507	3,507	3,507	0
Mar 24, 15	36	34	2	64,878	61,371	3,507	3,507	3,507	0
Mar 25, 15	24	23	1	43,837	42,084	1,753	1,753	1,753	0
Mar 26, 15	22	22	0	40,330	40,330	0	0	0	0
Mar 27, 15	27	26	1	49,097	47,344	1,753	1,753	1,753	0
Mar 28, 15	37	36	1	66,631	64,878	1,753	1,753	1,753	0
Mar 29, 15	31	30	1	56,111	54,357	1,753	1,753	1,753	0
Mar 30, 15	27	27	0	49,097	49,097	0	0	0	0
Mar 31, 15	29	26	3	52,604	47,344	5,260	5,260	5,260	0
Apr 1, 15	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Apr	523	539	-17	901,123	921,664	-20,541	70,337	24,898	45,439
May	197	214	-17	441,048	450,305	-9,257	24,503	7,623	16,880
Jun	16	25	-9	274,873	276,262	-1,388	1,697	154	1,543
Jul	0	0	0	251,297	251,297	0	0	0	0
Aug	0	4	-4	252,327	254,636	-2,309	2,309	0	2,309
Sep	102	133	-31	303,763	318,727	-14,964	15,929	483	15,446
Oct	346	344	2	590,148	588,319	1,830	32,934	17,382	15,552
Nov	787	775	12	1,383,237	1,365,555	17,682	67,780	42,731	25,049
Dec	963	971	-8	1,781,465	1,795,646	-14,181	116,991	51,405	65,586
Jan	1,343	1,350	-7	2,455,050	2,467,458	-12,408	108,128	47,860	60,268
Feb	1,398	1,387	11	2,545,337	2,525,839	19,499	83,312	51,405	31,907
Mar	1,080	1,043	37	1,948,088	1,883,212	64,876	89,424	77,150	12,274
Total	6,755	6,785	-31	13,127,757	13,098,918	28,839	613,343	321,091	292,252

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		151,828	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			78,718	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		44,995	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$1,500,000		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		$3,480,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$77.35		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$12.89**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	76 6%	47 7%
Storage	9 0%	20 1%
Peaking	14 4%	32 2%
TOTAL:	100 00%	100 00%

Capacity Resources effective November 1, 2015:

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	TCPL + Union	FT to Parkway & IGTS	M12200 & 41232	4,000		$16 3894		10/31/2022	
	Iroquois	RTS to Wright	470-01	4,047		$6 5971		11/1/2017	
	TGP	NET-NE (Z5-Z6)	95346	4,000		$7 3963		11/30/2016	
	TGP	FT-A (Z5-Z6)	2302	3,122		$7 3963		10/31/2020	
	TGP	FT-A (Z0-Z6)	8587	7,035		$23 9536		10/31/2020	
	TGP	FT-A (Z1-Z6)	8587	14,561		$21 2648		10/31/2020	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4 9101		10/31/2020	
	TGP	FT-A (Z6-Z6)	72694	30,000		$12 2103		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523*	21,844	1,560,391	$1 5400	$0.0211	10/31/2020	
	TGP	FT-A (Z4-Z6)	632	15,265		$8.4181		10/31/2020	
	TGP	FT-A (Z4-Z6)	8587	3,811		$8.4181		10/31/2020	
	National Fuel	FSS-1 (Storage)	O02357*	6,098	670,800	$2.4826	$0.0381	3/31/2017	
	National Fuel	FST (Transport)	N02358	6,098		$3.7805		3/31/2017	
	TGP	FT-A (Z4-Z6)	11234	6,150		$8.4181		10/31/2020	
	Honeoye	SS-NY (Storage)	SS-NY**	1,957	245,380	$4.4683	$0.0000	4/1/2020	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$7 3963		10/31/2020	
	Dominion	GSS (Storage)	300076*	934	102,700	$1 8625	$0.0145	3/31/2021	
	TGP	FT-A (Z4-Z6)	11234	932		$8.4181		10/31/2020	
Peaking									
	Energy Nor h	LNG/Propane****		44,995	-	$12.8900	$0 0000		X

* 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 11/01/15. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the EnergyNorth 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 $25.9843/dth.

REDACTED
Schedule 21
2015 - 2016 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 143
Attachment B - Peaking Demand Charge

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					**$1,500,000**	*
8							
9	**Total**					**$1,500,000**	
10							

* Contract currently being negotiated for an effective date of November 1, 2015

THIS PAGE HAS BEEN REDACTED

Schedule 22

ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	47.7%	20.1%	32.2%	100.0%
G-51	Low Annual /Low Winter Use	76.6%	9.0%	14.4%	100.0%
G-42	Medium Annual / High Winter	47.7%	20.1%	32.2%	100.0%
G-52	High Annual / Low Winter Use	76.6%	9.0%	14.4%	100.0%
G-43	High Annual / High Winter	47.7%	20.1%	32.2%	100.0%
G-53	High Annual / Load Factor < 90%	76.6%	9.0%	14.4%	100.0%
G-54	High Annual / Load Factor < 90%	76.6%	9.0%	14.4%	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	47.7%	20.1%	32.2%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	76.6%	9.0%	14.4%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	47.7%	20.1%	32.2%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	76.6%	9.0%	14.4%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	47.7%	20.1%	32.2%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	76.6%	9.0%	14.4%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	76.6%	9.0%	14.4%	100.0%

HLF	High Load Factor	76.57%	9.01%	14.42%	100%
LLF	Low Load Factor	47.70%	20.11%	32.19%	100%
	Total	51.85%	18.52%	29.64%	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	71.5182 Heat load	Total
HLF	R-1 RNSH	124	374	499
LLF	R-3 RSH	3,749	59,953	63,703
LLF	G-41 SL	1,078	24,450	25,529
HLF	G-51 SH	644	2,581	3,224
LLF	G-42 ML	1,969	32,295	34,264
HLF	G-52 MH	1,461	3,051	4,512
LLF	G-43 LL	1,891	4,641	6,532
HLF	G-53 LLL90	2,940	3,107	6,047
HLF	G-54 LLG90	7,519	-	7,519
	TOTAL	21,375	130,453	151,828
	HLF	12,688	9,113	21,801
	LLF	8,687	121,340	130,027
	Total	21,375	130,453	151,828

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	124	165	289	81	129	499
R-3 RSH	3,749	26,354	30,103	12,921	20,679	63,703
G-41 SL	1,078	10,748	11,826	5,269	8,433	25,529
G-51 SH	644	1,134	1,778	556	890	3,224
G-42 ML	1,969	14,196	16,165	6,960	11,139	34,264
G-52 MH	1,461	1,341	2,802	658	1,052	4,512
G-43 LL	1,891	2,040	3,931	1,000	1,601	6,532
G-53 LLL90	2,940	1,366	4,306	670	1,072	6,047
G-54 LLG90	7,519	-	7,519	-	-	7,519
TOTAL	21,375	57,343	78,718	28,115	44,995	151,828
HLF	12,688	4,006	16,693	1,964	3,143	21,801
LLF	8,687	53,337	62,025	26,151	41,852	130,027
Total	21,375	57,343	78,718	28,115	44,995	151,828

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	57 9%	16.2%	25 9%	100.0%
R-3 RSH	47 3%	20.3%	32 5%	100.0%
G-41 SL	46 3%	20.6%	33.0%	100.0%
G-51 SH	55.1%	17.2%	27.6%	100.0%
G-42 ML	47 2%	20.3%	32 5%	100.0%
G-52 MH	62.1%	14.6%	23 3%	100.0%
G-43 LL	60 2%	15.3%	24 5%	100.0%
G-53 LLL90	71 2%	11.1%	17.7%	100.0%
G-54 LLG90	100.0%	0.0%	0.0%	100.0%
TOTAL	51 8%	18.5%	29.6%	100.0%
High Load Factor	76.57%	9.01%	14.42%	100%
Low Load Factor	47.70%	20.11%	32.19%	100%
Total	51.85%	18 52%	29.64%	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 71.5182

	Daily Baseload * 1000	March Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total
R-1 RNSH	124	4.482	321	445
R-3 RSH	3,749	717.573	51,320	55,069
G-41 SL	1,078	292.642	20,929	22,007
G-51 SH	644	30.886	2,209	2,853
G-42 ML	1,969	386.535	27,644	29,613
G-52 MH	1,461	36.515	2,612	4,073
G-43 LL	1,891	55.549	3,973	5,864
G-53 LLL90	2,940	37.191	2,660	5,600
G-54 LLG90	7,519	-	-	7,519
TOTAL	21,375	1,540.913	111,667	133,041

Baseload as % of Total Class Load	Heat Load as % of Total
28%	0.287%
7%	45.958%
5%	18.743%
23%	1.978%
7%	24.756%
36%	2.339%
32%	3.558%
53%	2.382%
100%	0.000%
	100.000%

Allocate Design Day Sendout to Rate Classes

Base Load	Heat Load	Total
124	374	499
3,749	59,953	63,703
1,078	24,450	25,529
644	2,581	3,224
1,969	32,295	34,264
1,461	3,051	4,512
1,891	4,641	6,532
2,940	3,107	6,047
7,519	-	7,519
21,375	130,453	151,828

HLF	12,688	109	7,801	20,488
LLF	8,687	1,432	103,866	112,553
Total	21,375	1,541	111,667	133,041

Design Day from 2015-2016 COG	151,828
Design Day from Billing Calculation	133,041
Variance	18,787

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-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-14	Aug-14	Sep-14	Oct-14	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	5	7	9	10	9	8	7	3	4	4	3	3	71	3 850	0 124
LLF	R-3 RSH	338	692	951	1,087	1,070	716	368	186	121	112	106	152	5,896	116 231	3 749
LLF	G-41 SL	103	240	360	431	434	256	133	65	35	32	19	41	2,149	33 425	1 078
HLF	G-51 SH	28	39	50	60	56	40	28	22	20	20	20	20	403	19 955	0 644
LLF	G-42 ML	191	358	518	584	618	361	210	110	57	65	58	91	3,222	61 035	1 969
HLF	G-52 MH	62	72	92	91	102	76	58	54	45	46	42	45	783	45 295	1 461
LLF	G-43 LL	82	118	143	129	178	128	89	67	50	67	71	32	1,153	58 615	1 891
HLF	G-53 LLL90	72	89	84	133	144	106	87	88	64	118	61	77	1,124	91 137	2 940
HLF	G-54 LLL110	185	179	129	104	103	117	113	166	158	308	171	191	1,923	233 079	7 519
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	0	0 000	0 000
	TOTAL	1,066	1,794	2,335	2,629	2,713	1,808	1,092	761	553	772	550	653	16,725	662 621	21 375
	HLF	352	386	364	398	413	347	292	334	291	496	296	336	4,304	393 316	12 688
	LLF	715	1,408	1,971	2,231	2,300	1,461	800	427	263	276	254	317	12,421	269 305	8 687

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

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-14	Aug-14	Sep-14	Oct-14	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	3	4	4	3	3	45
LLF	R-3 RSH	112	116	116	105	116	112	116	112	121	112	106	116	1,369
LLF	G-41 SL	32	33	33	30	33	32	33	32	35	32	19	33	394
HLF	G-51 SH	19	20	20	18	20	19	20	19	20	20	19	20	235
LLF	G-42 ML	59	61	61	55	61	59	61	59	57	65	58	61	719
HLF	G-52 MH	44	45	45	41	45	44	45	44	45	46	42	45	533
LLF	G-43 LL	57	59	59	53	59	57	59	57	50	67	57	32	690
HLF	G-53 LLL90	72	89	84	82	91	88	87	88	64	118	61	77	1,073
HLF	G-54 LLL110	185	179	129	104	103	117	113	166	158	308	171	191	1,923
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	615	637	582	520	563	562	569	611	584	803	565	610	7,802
	HLF	324	337	282	249	263	272	269	321	291	496	296	336	3,810
	LLF	261	269	269	243	269	261	269	261	263	276	239	243	3,171

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Heating Volumes (= Actual Volumes - Baseload)

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-14	Aug-14	Sep-14	Oct-14	Total
HLF	R-1 RNSH	1	3	5	6	5	4	3	0	0	0	0	0	26
LLF	R-3 RSH	226	575	834	982	953	604	251	73	0	0	0	36	4,528
LLF	G-41 SL	71	206	327	400	400	223	100	33	0	0	0	8	1,756
HLF	G-51 SH	9	19	30	42	36	21	8	3	0	0	0	0	168
LLF	G-42 ML	132	297	457	529	557	302	149	51	0	0	0	30	2,503
HLF	G-52 MH	18	26	47	50	57	32	13	11	0	0	0	0	250
LLF	G-43 LL	25	60	84	76	120	71	30	10	0	0	14	0	463
HLF	G-53 LLL90	0	0	0	51	53	18	0	0	0	0	0	0	51
HLF	G-54 LLL110	0	0	0	0	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	452	1,157	1,752	2,109	2,150	1,245	523	150	(31)	(31)	(15)	43	8,923

	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-14	Aug-14	Sep-14	Oct-14	Total
HLF	27	49	82	149	150	75	23	13	0	0	0	0	495
LLF	454	1,138	1,702	1,987	2,031	1,200	530	166	0	0	14	74	9,250

	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-14	Aug-14	Sep-14	Oct-14	Total
Actual BDD	559.5	873.0	1160.5	1368.5	1231.0	798.5	322.0	97.5	12.5	3.5	70.0	238.5	6735 0

Heat Factors

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-14	Aug-14	Sep-14	Oct-14	Total
HLF	R-1 RNSH	0 0016	0 0038	0 0041	0 0045	0 0042	0 0049	0 0089	0 0000	0 0000	0 0000	0 0000	0 0000	
LLF	R-3 RSH	0 4036	0 6591	0 7189	0 7176	0 7745	0 7559	0 7808	0 7492	0 0000	0 0000	0 0000	0 1493	
LLF	G-41 SL	0 1269	0 2364	0 2817	0 2926	0 3253	0 2795	0 3092	0 3365	0 0000	0 0000	0 0000	0 0336	
HLF	G-51 SH	0 0159	0 0223	0 0261	0 0309	0 0290	0 0262	0 0238	0 0285	0 0000	0 0000	0 0052	0 0005	
LLF	G-42 ML	0 2362	0 3402	0 3934	0 3865	0 4527	0 3786	0 4637	0 5196	0 0000	0 0000	0 0000	0 1269	
HLF	G-52 MH	0 0316	0 0303	0 0402	0 0365	0 0459	0 0400	0 0402	0 1088	0 0000	0 0000	0 0000	0 0000	
LLF	G-43 LL	0 0448	0 0682	0 0723	0 0555	0 0972	0 0894	0 0937	0 1014	0 0000	0 0000	0 2031	0 0000	
HLF	G-53 LLL90	0 0000	0 0000	0 0000	0 0372	0 0427	0 0226	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	
HLF	G-54 LLL110	0 0000	0 0000	0 0000	0 0000	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 8070	1 3248	1 5100	1 5409	1 7465	1 5596	1 6241	1 5364	-2 4800	-8 8571	-0 2203	0 1803	

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	**559.5**	**873.0**	**1,160.5**	**1,368.5**	**1,231.0**	**798.5**	**322.0**	**97.5**	**12.5**	**3.5**	**70.0**	**238.5**	**6735.0**
Norm Billing DD	**566.7**	**891.1**	**1147.6**	**1135.4**	**966.5**	**702.5**	**374.8**	**144.2**	**31.1**	**9.7**	**67.5**	**271.1**	**6308.3**

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

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-14	Aug-14	Sep-14	Oct-14	Total
HLF	**R-1 RNSH**	5	7	9	9	8	7	7	3	4	4	3	3	69
LLF	**R-3 RSH**	341	704	941	920	865	644	409	221	121	112	106	157	5,538
LLF	**G-41 SL**	104	244	357	362	348	229	149	81	35	32	19	43	2,003
HLF	**G-51 SH**	28	40	50	53	48	38	29	23	20	20	20	20	389
LLF	**G-42 ML**	193	364	513	494	499	325	235	134	57	65	58	95	3,031
HLF	**G-52 MH**	62	72	91	82	90	72	60	60	45	46	42	45	766
LLF	**G-43 LL**	82	119	142	116	153	120	94	71	50	67	70	32	1,116
HLF	**G-53 LLL90**	72	89	84	125	132	104	87	88	64	118	61	77	1,102
HLF	**G-54 LLL110**	185	179	129	104	103	117	113	166	158	308	171	191	1,923
HLF	**G-63 LLG110**	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	1,072	1,818	2,315	2,270	2,251	1,658	1,178	833	507	717	550	659	15,828

HLF	352	387	363	373	381	338	296	341	291	496	296	336	4,249
LLF	720	1,431	1,952	1,892	1,864	1,317	887	507	263	276	253	327	11,689

Schedule 23

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2015 - 2016 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
1	Nov 98 - Mar 99	6.0%				$0.3927	$0.3722	$ 943.37	$ 926.93	$ 16.44	1.77%
2	Nov 99 - Mar 00	9.0%				$0.4724	$0.4628	$ 679.85	$ 672.22	$ 7.63	1.13%
3	Nov 00 - Mar 01	20.0%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10.90%
4	Nov 01 - Apr 02	24.0%				$0.5141	$0.4818	$ 790.65	$ 760.55	$ 30.10	3.96%
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%
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%
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%
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%
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%
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%
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%
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%
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%
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%
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%
16	Nov 13 - Apr 14	10 5%	$0.0200	8,930,779	$ 178,616	$0.9095	$1.1078	$857.72	$981.21	$ (123.48)	-12.58%
17	Nov 14 - Apr 15	15.1%	$0.0795	8,779,742	$ 697,989	$1.2425	$0.9541	$1,127.66	$948.07	$ 179.59	18.94%
18	Nov 15 - Apr 16					$0.7716	$0.7516	$950.73	$875.25	$ 75.48	8.62%
19	Total									$ 613.29	

		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	$0.3927	$0.3736	$ 1,570.86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	$0.4724	$0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10 22%
4	Nov 01 - Apr 02	$0.5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3 52%
5	Nov 02 - Apr 03	$0.5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	$0.8759	$0.8352	$ 1,798.38	$ 1,740.30	$ 58.08	3 34%
7	Nov 04 - Apr 05	$0.9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3 51%
8	Nov 05 - Apr 06	$1.3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9.61%
9	Nov 06 - Apr 07	$1.2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	$1.2044	$1.1725	$ 2,232.39	$ 2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	$1.2836	$1.0958	$ 2,467.49	$ 2,199.54	$ 267.95	12.18%
12	Nov 09 - Apr 10	$0.9865	$0.9408	$ 1,984.29	$ 1,919.03	$ 65.26	3.40%
13	Nov 10 - Apr 11	$0.8434	$0.8030	$ 1,880.96	$ 1,823.34	$ 57.63	3.16%
14	Nov 11 - Apr 12	$0.8129	$0.7327	$ 1,845.28	$ 1,730.88	$ 114.40	6.61%
15	Nov 12 - Apr 13	$0.6936	$0.7724	$ 1,989.86	$ 2,132.90	$ (143.03)	-6.71%
16	Nov 13 - Apr 14	$0.9108	$1.1181	$2,418.74	$2,794.40	$ (375.65)	-13.44%
17	Nov 14 - Apr 15						
18	Nov 15 - Apr 16						
19	Total					$ 279.35	

Schedule 24

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2015 - 2016 Winter Cost of Gas Filing
Short-Term Debt Limitations

		For Purposes of Fuel Financing
Total Direct Gas Costs	$	59,426,348
Total Indirect Gas Costs		5,026,252
Total Gas Costs	$	64,452,601
% of Debt to Total Gas Costs		30%
Short Term Debt	$	19,335,780

		For Purposes Other Than Fuel Financing
12/31/2016 Projected Net Plant	**$**	**369,357,526**
% of Debt to Net Plant		20%
Short Term Debt	$	73,871,505

Schedule 25

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
2015 - 2016 Winter Cost of Gas Filing

Company Allowance Calculation

	Jul-2014	Aug-2014	Sep-2014	Oct-2014	Nov-2014	Dec-2014	Jan-2015	Feb-2015	Mar-2015	Apr-2015	May-2015	Jun-2015	Total
Total Sendout- Therms	5,296,900	5,571,400	6,338,580	9,422,180	17,674,080	22,027,850	30,818,380	30,372,710	23,948,970	13,041,730	6,738,680	6,186,320	177,437,780
Total Throughput- Therms	5,533,572	7,718,839	5,499,214	6,157,089	10,577,688	17,654,115	24,633,382	27,927,580	30,558,372	20,217,979	9,941,533	8,011,062	174,430,425
Variance	(236,672)	(2,147,439)	839,366	3,265,091	7,096,392	4,373,735	6,184,998	2,445,130	(6,609,402)	(7,176,249)	(3,202,853)	(1,824,742)	3,007,355
Company Allowance													**1.69%**

Lost and Unaccounted For Gas ("LAUF") Calculation

	Jul-2014	Aug-2014	Sep-2014	Oct-2014	Nov-2014	Dec-2014	Jan-2015	Feb-2015	Mar-2015	Apr-2015	May-2015	Jun-2015	Total
Total Sendout- Therms	5,296,900	5,571,400	6,338,580	9,422,180	17,674,080	22,027,850	30,818,380	30,372,710	23,948,970	13,041,730	6,738,680	6,186,320	177,437,780
Total Throughput- Therms	5,533,572	7,718,839	5,499,214	6,157,089	10,577,688	17,654,115	24,633,382	27,927,580	30,558,372	20,217,979	9,941,533	8,011,062	174,430,425
Company Use	4,218	2,245	3,018	3,471	11,711	21,679	58,413	72,677	38,462	15,411	6,177	3,248	240,730
Variance	(240,890)	(2,149,684)	836,348	3,261,620	7,084,681	4,352,056	6,126,585	2,372,453	(6,647,864)	(7,191,660)	(3,209,030)	(1,827,990)	2,766,625
LAUF													**1.56%**