Ln				
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**			
2	**d/b/a Liberty Utilities**			
3	**Peak 2017 - 2018 Winter Cost of Gas Filing**			
4	**Summary**			
5				PK 17-18
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	$	9,099,131
12	Supply Costs	Sch. 6, col (i), ln 44		40,677,774
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (k), ln 58	$	876,359
16	Commodity Costs:	Sch. 6, col (i), ln 47		4,238,570
17				
18	Produced Gas:	Sch. 6, col (i), ln 53	$	4,764,207
19				
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	-
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 172	$	-
22				
23	**Total Unadjusted Cost of Gas**		$	59,656,041
24				
25	**Adjustments:**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$	1,714,057
28	Interest 05/01/17 - 4/30/18	Sch. 3, col (q) ln 193		(90,332)
29	Prior Period Adjustments	Sch. 4, ln 26 col (b)		-
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		-
31	Broker Revenues	Sch. 4, ln 26 col (d)		(4,580,575)
32	Fuel Financing	Sch. 4, ln 26 col (e)		-
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		(207,219)
34	Interruptible Sales Margin	Sch. 4, ln 26 col (g)		-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)		(2,099,545)
36	Hedging Costs	Sch. 4, ln 26 col (j)		-
38	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		45,000
39				
40	**Total Adjustments**		$	(5,218,614)
41				
42	**Total Anticipated Direct Costs**	lns 23 + 40	$	54,437,427
43				
44	**Anticipated Indirect Cost of Gas**			
45	**Working Capital**			
46	Total Unadjusted Anticipated Cost of Gas	Ln 23	$	59,656,041
47	Lead Lag Days / 365	DG 10-017, 14.27 / 365		0.0391
48	Prime Rate			4.25%
49	Working Capital Percentage	per GTC 16(f), ln 47 * ln 48		0.166%
50	Working Capital	ln 46 * ln 49		99,144
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 100		(24,267)
52				
53	**Total Working Capital Allowance**	lns 50 + 51	$	74,877
54				
55	**Bad Debt**			
56	Total Unadjusted Anticipated Cost of Gas	ln 23	$	59,656,041
57	Less Refunds	ln 30		-
58	Plus Working Capital	ln 53		74,877
59	Plus Prior Period (Over) Under Recovery	ln 27		1,714,057
60	Subtotal		$	61,444,974
61	Bad Debt Percentage	per GTC 16(f)		1.11%
62				
63	Bad Debt Allowance	ln 60 * ln 61	$	682,039
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 181		(652,777)
65				
66	**Total Bad Debt Allowance**	lns 63 + 64	$	29,262
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		85,411
72	Divided by Total Sales	Sch. 10B, ln 23/1000		104,762
73	Ratio			81.53%
74				
75	**Miscellaneous Overhead**	lns 70 * 73	$	10,737
76				
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$	2,095,304
78				
79	**Total Cost of Gas**	lns 42 + 77	$	56,532,731
80				
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		84,893,215

Ln											
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2017 - 2018 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10										1,813,782	2.0%
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	1,618,173	12,837,767	17,996,016	19,423,880	16,492,140	11,368,843	5,156,394	84,893,215
13	Lost Gas (Unaccounted for)		-	187,422	324,709	396,262	352,630	283,191	153,646		1,697,860
14	Company Use		-	12,796	22,170	27,055	24,076	19,335	10,490		115,922
15	Unbilled Therms		-	8,059,868	3,929,499	2,466,055	(1,214,858)	(1,868,806)	(3,434,915)	(5,156,394)	2,780,449
16											
17	**Total Firm Volumes**	Sch. 6, ln 92	-	9,878,258	17,114,145	20,885,388	18,585,729	14,925,860	8,098,065		89,487,445
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 63	-	787,330	850,682	874,909	797,329	841,223	597,333		4,748,807
22	Niagara Supply	Sch. 6, ln 64	-	618,381	685,075	697,621	626,115	686,018	577,956		3,891,167
23	TGP Supply (Direct)	Sch. 6, ln 65	-	4,156,418	2,932,802	2,986,510	2,681,405	2,924,082	-		15,681,218
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	2,627,066	4,458,865	3,002,343	-	-		10,088,274
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	3,142,062	1,669,517	1,395,242	3,233,733	6,398,113	2,669,288		18,507,956
26	ENGIE COMBO	Sch. 6, ln 68	-	-	1,296,548	1,184,082	1,268,707	29,057	-		3,778,393
27	LNG Truck	Sch. 6, ln 69	-	19,139	220,809	248,636	131,814	90,004	-		710,402
28	Propane Truck	Sch. 6, ln 70	-	-	-	763,924	-	-	-		763,924
29	PNGTS	Sch. 6, ln 71	-	54,117	77,142	87,203	73,787	68,035	45,435		405,718
30	TGP Supply (Z4)	Sch. 6, ln 72	-	1,623,498	1,805,400	1,838,462	1,650,536	1,807,885	4,908,951		13,634,732
31	Subtotal Pipeline Volumes		-	10,400,946	12,165,042	14,535,452	13,465,770	12,844,418	8,798,962		72,210,589
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 77	-	1,005,117	4,949,103	5,774,831	5,116,377	2,150,894	-		18,996,322
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 80	-	19,139	220,809	325,749	135,396	20,552	18,708		740,353
38	Propane	Sch. 6, ln 81	-	-	-	1,261,916	-	-	-		1,261,916
39	Subtotal Produced Gas		-	19,139	220,809	1,587,664	135,396	20,552	18,708		2,002,269
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 86	-	(19,139)	(220,809)	(248,636)	(131,814)	(90,004)	-		(710,402)
43	Propane	Sch. 6, ln 87	-	-	-	(763,924)	-	-	-		(763,924)
44	TGP Storage Refill	Sch. 6, ln 88	-	(1,527,804)	-	-	-	-	(719,605)		(2,247,409)
45	Subtotal Refills		-	(1,546,943)	(220,809)	(1,012,559)	(131,814)	(90,004)	(719,605)		(3,721,735)
46											
47	Total Firm Sendout Volumes	lns 31 + 34 + 39 + 45	-	9,878,258	17,114,145	20,885,388	18,585,729	14,925,860	8,098,065		89,487,445
48											

REDACTED

Schedule 1
Page 2 of 4

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Line			Peak Costs May 16 - Oct 16	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Peak Period Nov - Apr
7	For Month of:										
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		$ 1,309,251	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469		$ 9,334,063
74	Less Capacity Credit		(568,608)	(405,387)	(405,387)	(405,387)	(405,387)	(405,387)	(405,387)		(3,000,928)
75	Net Pipeline Demand Costs		$ 740,643	$ 932,082	$ 932,082	$ 932,082	$ 932,082	$ 932,082	$ 932,082		$ 6,333,135
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	ENGIE Demand	Sch.5A, ln 36									
81	Subtotal Peaking Demand		$ -	$ 793,800	$ 793,800	$ 793,800	$ 793,800	$ 793,800	$ -		$ 3,969,000
82	Less Capacity Credit		-	(240,601)	(240,601)	(240,601)	(240,601)	(240,601)	-		(1,203,004)
83	Net Peaking Supply Demand Costs		$ -	$ 553,199	$ 553,199	$ 553,199	$ 553,199	$ 553,199	$ -		$ 2,765,996
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		$ 694,091	$ 115,682	$ 115,682	$ 115,682	$ 115,682	$ 115,682	$ 115,682		$ 1,388,181
94	Less Capacity Credit		(301,444)	(35,063)	(35,063)	(35,063)	(35,063)	(35,063)	(35,063)		(511,822)
95	Net Storage Demand Costs		$ 392,647	$ 80,619	$ 80,619	$ 80,619	$ 80,619	$ 80,619	$ 80,619		$ 876,359
96											
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 2,003,342	$ 2,246,950	$ 2,246,950	$ 2,246,950	$ 2,246,950	$ 2,246,950	$ 1,453,150		$ 14,691,244
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(870,051)	(681,051)	(681,051)	(681,051)	(681,051)	(681,051)	(440,450)		(4,715,755)
99	Net Demand Charges		$ 1,133,290	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,012,701		$ 9,975,490
100											
101											

Ln	Description	Reference	Peak Costs May 16 - Oct 16	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Peak Period Nov - Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2017 - 2018 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Nov - Apr
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	ENGIE COMBO	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		$ -	$ 3,136,238	$ 6,726,344	$ 10,812,720	$ 12,083,378	$ 6,849,929	$ 2,197,086		$ 41,805,695
115											
116	Storage:										
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ 224,267	$ 1,104,273	$ 1,288,514	$ 1,141,596	$ 479,920	$ -		$ 4,238,570
118											
119	Produced Gas Costs:										
120	LNG Vapor	Sch. 6, ln 50	[redacted]								
121	Propane	Sch. 6, ln 51									
122	Subtotal Produced Gas Costs		$ -	$ 220,757	$ 1,199,725	$ 3,052,979	$ 235,896	$ 28,712	$ 26,136		$ 4,764,207
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		$ -	$ (537,991)	$ (244,150)	$ (964,994)	$ (146,793)	$ (99,529)	$ (232,641)		$ (2,226,098)
130											
131	Total Supply Commodity Costs		$ -	$ 3,043,272	$ 8,786,192	$ 14,189,220	$ 13,314,077	$ 7,259,033	$ 1,990,581		$ 48,582,374
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		$ -	$ 191,761	$ 150,706	$ 162,468	$ 147,280	$ 158,492	$ 21,117		$ 831,823
140											
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ 14,093	$ 69,393	$ 80,971	$ 71,738	$ 30,158	$ -		$ 266,354
142											
143	Total Supply Volumetric Trans. Costs	lns 139 + 141	$ -	$ 205,854	$ 220,099	$ 243,438	$ 219,019	$ 188,650	$ 21,117		$ 1,098,177
144											
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 3,249,126	$ 9,006,291	$ 14,432,658	$ 13,533,095	$ 7,447,683	$ 2,011,698		$ 49,680,551
146											
147											

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Line			Peak Costs May 16 - Oct 16	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Peak Period Nov - Apr
5											
6											
7	For Month of:										
148	**D. Supply and Demand Costs by Source**										
149											
150	Purchased Gas Demand Costs										
151	Pipeline Gas Demand Costs	Ins 54 + 73	$ 1,309,251	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469		$ 9,334,063
152	Peaking Gas Demand Costs	In 81	-	793,800	793,800	793,800	793,800	793,800	-		3,969,000
153	Subtotal Purchased Gas Demand Costs		$ 1,309,251	$ 2,131,269	$ 2,131,269	$ 2,131,269	$ 2,131,269	$ 2,131,269	$ 1,337,469		$ 13,303,063
154	Less Capacity Credit	Ins 55 + 74 + 82	(568,608)	(645,988)	(645,988)	(645,988)	(645,988)	(645,988)	(405,387)		(4,203,932)
155	Net Purchased Gas Demand Costs		$ 740,643	$ 1,485,281	$ 1,485,281	$ 1,485,281	$ 1,485,281	$ 1,485,281	$ 932,082		$ 9,099,131
156											
157	Storage Gas Demand Costs										
158	Storage Demand	In 93	$ 694,091	$ 115,682	$ 115,682	$ 115,682	$ 115,682	$ 115,682	$ 115,682		$ 1,388,181
159	Less Capacity Credit	In 94	(301,444)	(35,063)	(35,063)	(35,063)	(35,063)	(35,063)	(35,063)		(511,822)
160	Net Storage Demand Costs		$ 392,647	$ 80,619	$ 80,619	$ 80,619	$ 80,619	$ 80,619	$ 80,619		$ 876,359
161											
162	**Total Demand Costs**	Ins 155 + 160	$ 1,133,290	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,012,701		$ 9,975,490
163											
164	Purchased Gas Supply										
165	Commodity Costs	In 114	$ -	$ 3,136,238	$ 6,726,344	$ 10,812,720	$ 12,083,378	$ 6,849,929	$ 2,197,086		$ 41,805,695
166	Less Storage Inj.(TGP Storage)	In 127	[redacted]								
167	Less Storage Transportation	In 128									
168	Less LNG Truck	In 125									
169	Less Propane Truck	In 126									
170	Plus Transportation Costs	In 139									
171	Subtotal Purchased Gas Supply		$ -	$ 2,790,008	$ 6,632,900	$ 10,010,194	$ 12,083,865	$ 6,908,892	$ 1,985,562		$ 40,411,421
172											
173	Storage Commodity Costs										
174	Commodity Costs	In 117	$ -	$ 224,267	$ 1,104,273	$ 1,288,514	$ 1,141,596	$ 479,920	$ -		$ 4,238,570
175	Transportation Costs	In 141	-	14,093	69,393	80,971	71,738	30,158	-		266,354
176	Subtotal Storage Commodity Costs		$ -	$ 238,361	$ 1,173,666	$ 1,369,485	$ 1,213,334	$ 510,078	$ -		$ 4,504,923
177											
178	Produced Gas Commodity Costs	In 122	$ -	$ 220,757	$ 1,199,725	$ 3,052,979	$ 235,896	$ 28,712	$ 26,136		$ 4,764,207
179											
180	**Subtotal Commodity Costs**	Ins 171 + 176 + 178	$ -	$ 3,249,126	$ 9,006,291	$ 14,432,658	$ 13,533,095	$ 7,447,683	$ 2,011,698		$ 49,680,551
181											
182	Hedge Contract (Savings)/Loss	Sch 7, In 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
183											
184	**Total Commodity Costs**	Ins 180 + 182	$ -	$ 3,249,126	$ 9,006,291	$ 14,432,658	$ 13,533,095	$ 7,447,683	$ 2,011,698		$ 49,680,551
185											
186	**Total Demand Costs**	In 99	$ 1,133,290	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,012,701		$ 9,975,490
187	**Total Supply Costs**	In 184	-	3,249,126	9,006,291	14,432,658	13,533,095	7,447,683	2,011,698		49,680,551
188											
189	**Total Direct Gas Costs**	Ins 186 + 187	$ 1,133,290	$ 4,815,026	$ 10,572,190	$ 15,998,558	$ 15,098,995	$ 9,013,582	$ 3,024,399		$ 59,656,041
190											
191											

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

Peak 2017 - 2018 Winter Cost of Gas Filing
Contracts Ranked on a per Unit Cost Basis

Supplier (a)	Contract (b)	Contract Type (c)	Contract Unit (d)	Unit Dth (MDQ/ACQ) (e)	Peak Period Cost per Unit Dth (f)
Demand Costs					
Granite Ridge Demand		Peaking	MDQ	-	[redacted]
Niagara Supply		Supply	MDQ	3,199	
Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	
Dominion - Demand	GSS 300076	Storage	MDQ	934	
National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
National Fuel	FST N02358	Transportation	MDQ	6,098	
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	
Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
ENGIE Demand	NSB041	Peaking	MDQ	7,000	
Supply Costs - Commodity					
TGP Supply (Z4)		Pipeline	Dkt	1,363,473	[redacted]
Niagara Supply		Pipeline	Dkt	389,117	
ENGIE COMBO		Pipeline	Dkt	377,839	
TGP Supply (Direct)		Pipeline	Dkt	1,568,122	
Dawn Supply		Pipeline	Dkt	474,881	
Dracut Supply 1 - Baseload		Pipeline	Dkt	1,008,827	
TGP Storage		Storage	Dkt	1,899,632	
PNGTS		Pipeline	Dkt	40,572	
Propane Truck		Pipeline	Dkt	76,392	
LNG Truck		Pipeline	Dkt	71,040	
Dracut Supply 2 - Swing		Pipeline	Dkt	1,850,796	
Propane		Produced	Dkt	126,192	
LNG Vapor (Storage)		Produced	Dkt	74,035	
Supply Costs - Volumetric Transportation					
Dracut Supply 1 - Baseload		Pipeline	Dkt	1,008,827	[redacted]
Dracut Supply 2 - Swing		Pipeline	Dkt	1,850,796	
Niagara Supply		Pipeline	Dkt	389,117	
Dawn Supply		Pipeline	Dkt	474,881	
TGP Storage - Withdrawals		Pipeline	Dkt	1,899,632	
TGP Supply (Direct)		Pipeline	Dkt	1,568,122	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln																		
5			Prior Period Bal															
6			Apr-17															
7			Ending Bal	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18		Peak Period
8		Days in Month	Plus May Billings	31	30	31	31	30	31	30	31	31	28	31	30	31		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/	$ 1,714,057	$ 1,714,057	$ 1,320,023	$ 1,056,955	$ 255,085	$ (629,529)	$ (1,271,803)	$ (1,537,696)	$ (3,358,039)	$ (4,491,588)	$ (2,607,474)	$ (145,487)	$ (1,272,120)	$ (3,933,143)		$ 1,714,057
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		188,882	188,882	188,882	188,882	188,882	188,882	4,815,026	10,572,190	15,998,558	15,098,995	9,013,582	3,024,399	-		59,656,041
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	331,861	331,861	331,861	331,861	331,861	331,861			1,991,165
15	Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(1,110,067)	(8,806,708)	(12,345,267)	(13,324,782)	(11,313,608)	(7,799,027)	(3,537,286)		(58,236,745)
16	Projected Unbilled Revenue									(5,529,069)	(8,224,705)	(9,916,419)	(9,083,027)	(7,801,026)	(5,444,674)			(45,998,920)
17	Reverse Prior Month Unbilled										5,529,069	8,224,705	9,916,419	9,083,027	7,801,026	5,444,674		45,998,920
18	Adjustment				-	(263,930)				-								(263,930)
19	Add Net Adjustments	Schedule 4		(588,060)	(455,973)	(729,186)	(1,072,821)	(827,841)	(449,713)	(319,558)	(521,115)	(398,787)	(473,789)	(438,365)	(567,131)	-		(6,842,339)
20	Gas Cost Billed	Account 1920-1740 2/	-		-	-	-	-	-	-	-	-	-	-	-	-		-
21	Monthly (Over)/Under Recovery		$ 1,714,057	$ 1,314,878	$ 1,052,932	$ 252,721	$ (628,854)	$ (1,268,488)	$ (1,532,634)	$ (3,349,503)	$ (4,477,447)	$ (2,596,938)	$ (141,796)	$(1,270,016)	$ (3,925,666)	$ (2,025,755)		$ (1,981,751)
22	Average Monthly Balance	(ln 12 + 21)/2		$ 1,514,468	$ 1,186,478	$ 654,838	$ (186,885)	$ (949,009)	$ (1,402,219)	$ (2,443,599)	$ (3,917,743)	$ (3,544,263)	$ (1,374,635)	$ (707,751)	$ (2,598,893)	$ (2,979,449)		
24	Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%			
26	Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 5,145	$ 4,023	$ 2,364	$ (675)	$ (3,315)	$ (5,061)	$ (8,536)	$ (14,141)	$ (10,536)	$ (3,691)	$ (2,104)	$ (7,476)	$ -		$ (44,004)
28	**(Over)/Under Balance**	ln 21 + ln 26	$ 1,714,057	$ 1,320,023	$ 1,056,955	$ 255,085	$ (629,529)	$ (1,271,803)	$ (1,537,696)	$ (3,358,039)	$ (4,491,588)	$ (2,607,474)	$ (145,487)	$(1,272,120)	$ (3,933,143)	$ (2,025,755)		(2,025,755)
31	**Calculation of COG with Interest**																	
33	**Beginning Balance**	ln 12	$ 1,714,057	$ 1,714,057	$ 1,320,023	$ 1,056,955	$ 255,085	$ (629,529)	$ (1,271,803)	$ (1,537,696)	$ (3,359,993)	$ (4,496,934)	$ (2,616,950)	$ (158,640)	$ (1,288,244)	$ (3,950,913)		$ 1,714,057
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		188,882	188,882	188,882	188,882	188,882	188,882	4,815,026	10,572,190	15,998,558	15,098,995	9,013,582	3,024,399	-		59,656,041
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	331,861	331,861	331,861	331,861	331,861	331,861	-		1,991,165
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(1,110,390)	(8,809,276)	(12,348,866)	(13,328,667)	(11,316,907)	(7,801,300)	(3,538,318)		(58,253,724)
37	Projected Unbilled Revenue									(5,530,681)	(8,227,103)	(9,919,310)	(9,085,675)	(7,803,300)	(5,446,262)			(46,012,331)
38	Reverse Prior Month Unbilled										5,530,681	8,227,103	9,919,310	9,085,675	7,803,300	5,446,262		46,012,331
39	Add Net Adjustments	ln 19		(588,060)	(455,973)	(993,116)	(1,072,821)	(827,841)	(449,713)	(319,558)	(521,115)	(398,787)	(473,789)	(438,365)	(567,131)	-		(7,106,269)
40	Gas Cost Billed	ln 20	-		-	-	-	-	-	-	-	-	-	-	-	-		-
41	Add Interest	ln 26		-	-	-	-	-	-	(8,536)	(14,141)	(10,536)	(3,691)	(2,104)	(7,476)	-		(46,484)
42	**(Over)/Under Balance**		$ 1,714,057	$ 1,314,878	$ 1,052,932	$ 252,721	$ (628,854)	$ (1,268,488)	$ (1,532,634)	$ (3,359,974)	$ (4,496,896)	$ (2,616,912)	$ (158,605)	$(1,288,197)	$ (3,950,854)	$ (2,042,969)		$ (2,045,214)
44	Average Monthly Balance			$ 1,514,468	$ 1,186,478	$ 654,838	$ (186,885)	$ (949,009)	$ (1,402,219)	$ (2,448,835)	$ (3,928,444)	$ (3,556,923)	$ (1,387,777)	$ (723,419)	$ (2,619,549)	$ (2,996,941)		
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		5,145	4,023	2,364	(675)	(3,315)	(5,061)	(8,554)	(14,180)	(10,573)	(3,726)	(2,150)	(7,536)	-		(44,239)
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ 1,714,057	$ 1,320,023	$ 1,056,955	$ 255,085	$ (629,529)	$ (1,271,803)	$ (1,537,696)	$ (3,359,993)	$ (4,496,934)	$ (2,616,950)	$ (158,640)	$(1,288,244)	$ (3,950,913)	$ (2,042,969)		(2,042,969)
51	Forecast Sendout Therms	Sch 1								9,878,258	17,114,145	20,885,388	18,585,729	14,925,860	8,098,065			89,487,445
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								1,618,173	12,837,767	17,996,016	19,423,880	16,492,140	11,368,843	5,156,394		84,893,215
53	Less Forecast Unaccounted For	Sch 1								187,422	324,709	396,262	352,630	283,191	153,646			1,697,860
54	Less Forecast Company Use	Sch 1								12,796	22,170	27,055	24,076	19,335	10,490			115,922
55	Unbilled Volumes									8,059,868	3,929,499	2,466,055	-1,214,858	-1,868,806	-3,434,915	-5,156,394		2,780,449
56	Gross Unbilled									8,059,868	11,989,366	14,455,421	13,240,564	11,371,757	7,936,843	2,780,449		
59	COB w/o Interest	Sch. 3, pg. 4, ln 209 col. (c)								$0.6860	$0.6860	$0.6860	$0.6860	$0.6860	$0.6860	$0.6860		
61	COG With Interest	Sch. 3, pg. 4, ln 209 col. (d)								$0.6862	$0.6862	$0.6862	$0.6862	$0.6862	$0.6862	$0.6862		

63 1/ Beginning Balance for Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
64 2/ Gas Cost Billed Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

Ln																	
69			Prior Period Bal														
70			Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Peak Period
71		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
72	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
74	**Account 1163-1422 Working Capital (Over)/Under Balance - Interest Calculation**																
76	**Beginning Balance**	Account 1163-1422 1/	$ (24,267)	$ (24,267)	$ (24,053)	$ (23,830)	$ (27,372)	$ (27,157)	$ (26,937)	$ (26,720)	$ (24,614)	$ (17,179)	$ (7,597)	$ 2,135	$ 5,709	$ 5,104	$ (24,267)
78	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		
79	Prime Rate			4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
80	Forecast Working Capital	ln 34 * 0.091%		295	305	314	314	314	314	8,002	17,570	21,896	20,665	12,336	4,139	-	86,465
82	Projected Revenues w/o Int.	ln 119 * ln 123		-	-	-	-	-	-	(971)	(7,703)	(10,798)	(11,654)	(9,895)	(6,821)	(3,094)	(50,936)
83	Projected Unbilled Revenue									(4,836)	(7,194)	(8,673)	(7,944)	(6,823)	(4,762)		(40,232)
84	Reverse Prior Month Unbilled										4,836	7,194	8,673	7,944	6,823	4,762	40,232
86	Add Net Adjustments			-	-	(3,764)	-	-	-	-	-	-	-	-	-	-	(3,764)
88	Working Capital Billed	Account 1163-1422 2/	-														-
90	Monthly (Over)/Under Recovery		$ (24,267)	$ (23,972)	$ (23,749)	$ (27,280)	$ (27,058)	$ (26,843)	$ (26,623)	$ (24,524)	$ (17,104)	$ (7,560)	$ 2,143	$ 5,698	$ 5,088	$ 6,772	$ 7,498
92	Average Monthly Balance	(ln 76 + ln 90)/2		$ (24,119)	$ (23,901)	$ (25,555)	$ (27,215)	$ (27,000)	$ (26,780)	$ (25,622)	$ (20,859)	$ (12,370)	$ (2,727)	$ 3,917	$ 5,399	$ 5,938	
94	Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
96	Interest Applied	ln 92 * ln 94 / 365 * Days of Month		$ (82)	$ (81)	$ (92)	$ (98)	$ (94)	$ (97)	$ (90)	$ (75)	$ (37)	$ (7)	$ 12	$ 16	$ -	$ (726)
98	**(Over)/Under Balance**	ln 90 + ln 96	$ (24,267)	$ (24,053)	$ (23,830)	$ (27,372)	$ (27,157)	$ (26,937)	$ (26,720)	$ (24,614)	$ (17,179)	$ (7,597)	$ 2,135	$ 5,709	$ 5,104	$ 6,772	6,772

006

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**
99
100
101 **Calculation of Working Capital with Interest** Schedule 3
102 Page 2 of 2

103	**Beginning Balance**	ln 76	$ (24,267)	$ (24,267)	$ (24,053)	$ (23,830)	$ (27,372)	$ (27,157)	$ (26,937)	$ (26,720)	$ (24,614)	$ (17,180)	$ (7,597)	$ 2,135	$ 5,709	$ 5,104	$ (24,267)
104	Forecast Working Capital	ln 80		295	305	314	314	314	314	8,002	17,570	21,896	20,665	12,336	4,139	-	86,465
105	Projected Rev. with interest	ln 119 * ln 125		-	-	-	-	-	-	(971)	(7,703)	(10,798)	(11,654)	(9,895)	(6,821)	(3,094)	(50,936)
106	Projected Unbilled Revenue									(4,836)	(7,194)	(8,673)	(7,944)	(6,823)	(4,762)		(40,232)
107	Reverse Prior Month Unbilled										4,836	7,194	8,673	7,944	6,823	4,762	40,232
108	Add Net Adjustments	ln 86	-	-	-	(3,764)	-	-	-	-	-	-	-	-	-	-	(3,764)
109	Working Capital Billed	ln 88	-	-	-	-	-	-	-								-
110	Add Interest	ln 96		-	-	-	-	-	-	(90)	(75)	(37)	(7)	12	16	-	(182)
111	Monthly (Over)/Under Recovery		$ (24,267)	$ (23,972)	$ (23,749)	$ (27,280)	$ (27,058)	$ (26,843)	$ (26,623)	$ (24,614)	$ (17,179)	$ (7,597)	$ 2,135	$ 5,709	$ 5,104	$ 6,772	$ 7,317
112																	
113	Average Monthly Balance			$ (24,119)	$ (23,901)	$ (25,555)	$ (27,215)	$ (27,000)	$ (26,780)	$ (25,667)	$ (20,897)	$ (12,388)	$ (2,731)	$ 3,922	$ 5,406	$ 5,938	
114																	
115	Interest Applied	ln 94 * ln 113 / 365 * Days of Month		(82)	(81)	(92)	(98)	(94)	(97)	(90)	(75)	(37)	(7)	12	16	-	$ (726)
116																	
117	**(Over)/Under Balance**	-ln 110 +ln 111 + ln 115	$ (24,267)	$ (24,053)	$ (23,830)	$ (27,372)	$ (27,157)	$ (26,937)	$ (26,720)	$ (24,614)	$ (17,180)	$ (7,597)	$ 2,135	$ 5,709	$ 5,104	$ 6,772	$ 6,772
118																	
119	Forecast Therm Sales	ln 52								1,618,173	12,837,767	17,996,016	19,423,880	16,492,140	11,368,843	5,156,394	84,893,215
120	Unbilled Therm	ln 55								8,059,868	3,929,499	2,466,055	(1,214,858)	(1,868,806)	(3,434,915)		
121	Gross Unbilled									8,059,868	11,989,366	14,455,421	13,240,564	11,371,757	7,936,843		
122																	
123	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 226 col. (c)								$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
124																	
125	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 226 col. (d)								$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	

126 1/ Beginning Balance for Acct 1163-1422. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.
127 2/ Working Capital Billed Acct 1163-1422. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.

128			Prior Period Bal														
129			Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	DemandPeriod
130		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
131	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
132																	
133	**Account 1920-1743 Bad Debt (Over)/Under Balance - Interest Calculation**																
134																	
135	Forecast Direct Gas Costs	ln 34		$ 188,882	$ 188,882	$ 188,882	$ 188,882	$ 188,882	$ 188,882	$ 4,815,026	$10,572,190	$15,998,558	$15,098,995	$ 9,013,582	$ 3,024,399	$ -	59,656,041
136	Forecast Working Capital	ln 104		295	305	314	314	314	314	(16,265)	17,570	21,896	20,665	12,336	4,139		62,198
137	Prior Period Balance	ln 42								285,676	285,676	285,676	285,676	285,676	285,676		1,714,057
138	Total Forecast Direct Gas Costs & Working Capital			189,177	189,186	189,196	189,196	189,196	189,196	5,084,437	10,875,437	16,306,130	15,405,336	9,311,595	3,314,214	-	59,718,239
139																	
140	**Beginning Balance**	Account 1920-1743 1/	**$ (652,777)**	$ (652,777)	$ (652,891)	$ (653,001)	$ (808,100)	$ (808,913)	$ (809,635)	$ (810,454)	$ (1,042,750)	$ (1,421,106)	$ (1,848,591)	$(2,220,213)	$ (2,555,330)	$ (2,760,228)	$ (652,777)
141																	
142	Forecast Bad Debt	ln 138 * 0.0111		2,100	2,100	2,100	2,100	2,100	2,100	56,437	120,717	180,998	170,999	103,359	36,788		681,898
143																	
144	Projected Revenues w/o int	ln 181 * ln 185		-	-	-	-	-	-	(47,736)	(378,714)	(530,882)	(573,004)	(486,518)	(335,381)	(152,114)	(2,504,350)
145	Projected Unbilled Revenue									(237,766)	(353,686)	(426,435)	(390,597)	(335,467)	(234,137)		(1,978,088)
146	Reverse Prior Month Unbilled										237,766	353,686	426,435	390,597	335,467	234,137	1,978,088
147																	
148	Bad Debt Billed	Account 1920-1743 2/	-		-	-	-	-	-		-	-	-	-	-	-	-
149																	
150	Add Net Adjustments		-	-	-	(154,567)	-	-	-		-	-	-	-	-	-	(154,567)
151																	
152	Monthly (Over)/Under Recovery		$ (652,777)	$ (650,677)	$ (650,791)	$ (805,468)	$ (806,000)	$ (806,813)	$ (807,535)	$ (1,039,519)	$ (1,416,667)	$ (1,843,739)	$ (2,214,758)	$(2,548,243)	$ (2,752,593)	$ (2,678,205)	$ (2,629,795)
153																	
154	Average Monthly Balance	(ln 140 + ln 152)/2		$ (651,727)	$ (651,841)	$ (729,235)	$ (807,050)	$ (807,863)	$ (808,585)	$ (924,986)	$ (1,229,709)	$ (1,632,422)	$ (2,031,675)	$(2,384,228)	$ (2,653,962)	$ (2,719,216)	
155																	
156	Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
157																	
158	Interest Applied	ln 154 * ln 156 / 365 * Days of Month		$ (2,214)	$ (2,210)	$ (2,632)	$ (2,913)	$ (2,822)	$ (2,919)	$ (3,231)	$ (4,439)	$ (4,853)	$ (5,455)	$ (7,087)	$ (7,635)		$ (48,409)
159																	
160	**(Over)/Under Balance**	ln 152 + ln 158	$ (652,777)	$ (652,891)	$ (653,001)	$ (808,100)	$ (808,913)	$ (809,635)	$ (810,454)	$ (1,042,750)	$ (1,421,106)	$ (1,848,591)	$ (2,220,213)	$(2,555,330)	$ (2,760,228)	$ (2,678,205)	(2,678,205)
161																	
162																	
163	**Calculation of Bad Debt with Interest**																
164																	
165	**Beginning Balance**	ln 140	$ (652,777)	$ (652,777)	$ (652,891)	$ (653,001)	$ (653,254)	$ (653,509)	$ (653,688)	$ (653,943)	$ (885,698)	$ (1,263,495)	$ (1,690,981)	$(2,062,603)	$ (2,397,720)	$ (2,602,617)	$ (652,777)
166	Forecast Bad Debt	ln 142		2,100	2,100	2,100	2,100	2,100	2,100	56,437	120,717	180,998	170,999	103,359	36,788	-	681,898
167	Projected Revenues with int.	ln 181 * ln 187		-	-	-	-	-	-	(47,736)	(378,714)	(530,882)	(573,004)	(486,518)	(335,381)	(152,114)	(2,504,350)
168	Projected Unbilled Revenue									(237,766)	(353,686)	(426,435)	(390,597)	(335,467)	(234,137)		(1,978,088)
169	Reverse Prior Month Unbilled										237,766	353,686	426,435	390,597	335,467	234,137	1,978,088
170	Bad Debt Billed	ln 148	-		-	-	-	-	-	-	-	-	-	-	-	-	0
171	Add Interest	ln 158		-	-	-	-	-	-	(3,231)	(4,439)	(4,853)	(5,455)	(7,087)	(7,635)	-	(32,699)
172	Add Net Adjustments	ln 150	-							-	-	-	-	-	-	-	0
173	Monthly (Over)/Under Recovery		$ (652,777)	$ (650,677)	$ (650,791)	$ (650,901)	$ (651,154)	$ (651,409)	$ (651,588)	$ (886,239)	$ (1,264,054)	$ (1,690,981)	$ (2,062,603)	$(2,397,720)	$ (2,602,617)	$ (2,520,594)	$ (2,507,928)
174																	
175	Average Monthly Balance			$ (651,727)	$ (651,841)	$ (651,951)	$ (652,204)	$ (652,459)	$ (652,638)	$ (770,091)	$ (1,074,876)	$ (1,477,238)	$ (1,876,792)	$(2,230,161)	$ (2,500,169)	$ (2,561,606)	
176																	
177	Interest Applied	ln 156 * ln 175 / 365 * Days of Month		(2,214)	(2,210)	(2,353)	(2,354)	(2,279)	(2,356)	(2,690)	(3,880)	(4,853)	(5,455)	(7,087)	(7,635)	-	$ (45,366)
178																	
179	**(Over)/Under Balance**	-ln 171 +ln 173 + ln 177	$ (652,777)	$ (652,891)	$ (653,001)	$ (653,254)	$ (653,509)	$ (653,688)	$ (653,943)	$ (885,698)	$ (1,263,495)	$ (1,690,981)	$ (2,062,603)	$(2,397,720)	$ (2,602,617)	$ (2,520,594)	$ (2,520,594)
180																	
181	Forecast Term Sales	ln 52								1,618,173	12,837,767	17,996,016	19,423,880	16,492,140	11,368,843	5,156,394	84,893,215
182	Unbilled Therm	ln 55								8,059,868	3,929,499	2,466,055	(1,214,858)	(1,868,806)	(3,434,915)		
183	Gross Unbilled									8,059,868	11,989,366	14,455,421	13,240,564	11,371,757	7,936,843		
184																	
185	COG Rate Without Interest	Sch. 3, pg. 4, ln 243 col. (c)								$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	
186																	
187	COG With Interest	Sch. 3, pg. 4, ln 243 col. (d)								$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	

188 1/ Beginning Balance for Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.
189 2/ Bad Debt Billed Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.
190

191	**Total Interest**	lns 46 + 115 + 177	$ -	$ 2,849	$ 1,732	$ (82)	$ (3,127)	$ (5,688)	$ (7,514)	$ (11,334)	$ (18,135)	$ (15,463)	$ (9,188)	$ (9,226)	$ (15,155)	$ -	$ (90,332)

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **Adjustments to Gas Costs**
5

Line	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-17		$ -	$ -	(588,060)	$ -	$ -	$ -	[redacted]		$ -	$ -	$ (588,060)
10	Jun-17		-	-	(455,973)	-	-	-	[redacted]		-	-	(455,973)
11	Jul-17	1/	-	-	(729,186)	-	-	-	[redacted]		-	-	(729,186)
12	Aug-17	1/	-	-	(1,072,821)	-	-	-	[redacted]		-	-	(1,072,821)
13	Sep-17	1/	-	-	(827,841)	-	-	-	[redacted]		-	-	(827,841)
14	Oct-17	1/	-	-	(449,713)	-	-	-	[redacted]		-	-	(449,713)
15	Nov-17	1/	-	-	(29,507)	-	(25,481)	-	[redacted]		-	45,000	(319,558)
16	Dec-17	1/	-	-	(161,963)	-	(32,152)	-	[redacted]		-	-	(521,115)
17	Jan-18	1/	-	-	(18,636)	-	(39,857)	-	[redacted]		-	-	(398,787)
18	Feb-18	1/	-	-	(94,708)	-	(41,353)	-	[redacted]		-	-	(473,789)
19	Mar-18	1/	-	-	3,254	-	(37,116)	-	[redacted]		-	-	(438,365)
20	Apr-18	1/	-	-	(155,421)	-	(31,260)	-	[redacted]		-	-	(567,131)
21													
22	Subtotal May 17 - Oct 17		$ -	$ -	$ (4,123,594)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,123,594)
23													
24	Subtotal Nov 17 - Apr 18		$ -	$ -	$ (456,982)	$ -	$ (207,219)	$ -	$ -	$ (2,099,545)	$ -	$ 45,000	$ (2,718,745)
25													
26	Total Peak Period		$ -	$ -	$ (4,580,575)	$ -	$ (207,219)	$ -	$ -	$ (2,099,545)	$ -	$ 45,000	$ (6,842,339)
27													

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

Ln											
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2017 - 2018 Winter Cost of Gas Filing**										
4	**Demand Costs**										
5											
6				Deferred							Peak
7				to Peak							Nov-Apr
8		Peak	Reference	May 17 -Oct 17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	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			$ 1,309,251	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 1,337,469	$ 9,334,063
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	ENGIE Demand	peak	Per Contract								
37	Subtotal Peaking Demand Charges			$ -	$ 793,800	$ 793,800	$ 793,800	$ 793,800	$ 793,800	$ -	$ 3,969,000
38											
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 1,309,251	$ 2,131,269	$ 2,131,269	$ 2,131,269	$ 2,131,269	$ 2,131,269	$ 1,337,469	$ 13,303,063
40											
41	Less Transportation Capacity Credit			$ (568,608)	$ (645,988)	$ (645,988)	$ (645,988)	$ (645,988)	$ (645,988)	$ (405,387)	$ (4,203,932)
42											
43	**Total Supply, Pipeline & Peaking Demand**			$ 740,643	$ 1,485,281	$ 1,485,281	$ 1,485,281	$ 1,485,281	$ 1,485,281	$ 932,082	$ 9,099,131
44											
45											
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 51 x days	$ 10,470	$ 1,745	$ 1,745	$ 1,745	$ 1,745	$ 1,745	$ 1,745	$ 20,940
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	87,200	14,533	14,533	14,533	14,533	14,533	14,533	174,400
50	National Fuel - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 58 x days	147,308	24,551	24,551	24,551	24,551	24,551	24,551	294,615
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 61 x days	195,783	32,631	32,631	32,631	32,631	32,631	32,631	391,567
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 62 x days	191,928	31,988	31,988	31,988	31,988	31,988	31,988	383,856
53											
54	**Subtotal Storage Demand Costs**			$ 694,091	$ 115,682	$ 115,682	$ 115,682	$ 115,682	$ 115,682	$ 115,682	$ 1,388,181
55											
56	Less Transportation Capacity Credit			$ (301,444)	$ (35,063)	$ (35,063)	$ (35,063)	$ (35,063)	$ (35,063)	$ (35,063)	$ (511,822)
57											
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 392,647	$ 80,619	$ 80,619	$ 80,619	$ 80,619	$ 80,619	$ 80,619	$ 876,359
59											
60	**Total Demand Charges**		ln 39 + ln 54	$ 2,003,342	$ 2,246,950	$ 2,246,950	$ 2,246,950	$ 2,246,950	$ 2,246,950	$ 1,453,150	$ 14,691,244
61											
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (870,051)	$ (681,051)	$ (681,051)	$ (681,051)	$ (681,051)	$ (681,051)	$ (440,450)	$ (4,715,755)
63											
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 1,133,290	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,565,900	$ 1,012,701	$ 9,975,490
65											
66											

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2017 - 2018 Winter Cost of Gas Filing
<u>Demand Volumes</u>

		Peak	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18
	(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
	ENGIE Demand	peak	NSB041	7,000	7,000	7,000	7,000	7,000	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

Liberty Utilities (EnergyNorth Natural Gas) Corp. **REDACTED**
d/b/a Liberty Utilities
Peak 2017 - 2018 Winter Cost of Gas Filing
Demand Rates

				Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Nov - Apr
Tariff Rates				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagara Supply		[redacted]	Per Contract	[redacted]						
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$5.9982	First Revised Sheet No. 4	$0.1999	$0.1935	$0.1935	$0.2142	$0.1935	$0.1999	$0.1991
Tenn Gas Pipeline	95346 Z5-Z6	$7.1563	10th Rev Sheet No. 14	$0.2385	$0.2308	$0.2308	$0.2556	$0.2308	$0.2385	$0.2375
Tenn Gas Pipeline	2302 Z5-Z6	$7.1563	10th Rev Sheet No. 14	$0.2385	$0.2308	$0.2308	$0.2556	$0.2308	$0.2385	$0.2375
Tenn Gas Pipeline	8587 Z0-Z6	$23.2169	FT-A (Z0 - Z6)	$0.7739	$0.7489	$0.7489	$0.8292	$0.7489	$0.7739	$0.7706
Tenn Gas Pipeline	8587 Z1-Z6	$20.6088	FT-A (Z1 - Z6)	$0.6870	$0.6648	$0.6648	$0.7360	$0.6648	$0.6870	$0.6841
Tenn Gas Pipeline	8587 Z4-Z6	$8.1475	FT-A (Z4 - Z6)	$0.2716	$0.2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2704
TGP Dracut	42076 FTA Z6-Z6	$4.7447	10th Rev Sheet No. 14	$0.1582	$0.1531	$0.1531	$0.1695	$0.1531	$0.1582	$0.1575
TGP Concord Lateral	Firm Transportatio	$12.1910	Per contract	$0.4064	$0.3933	$0.3933	$0.4354	$0.3933	$0.4064	$0.4047
Portland Natural Gas	FT-1999-001	$25.9843	Part 4.1 v.5.0.0	$0.8661	$0.8382	$0.8382	$0.9280	$0.8382	$0.8661	$0.8625
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.1475	10th Rev Sheet No. 14	$0.2716	$0.2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2704
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.1475	10th Rev Sheet No. 14	$0.2716	$0.2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2704
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.1563	10th Rev Sheet No. 14	$0.2385	$0.2308	$0.2308	$0.2556	$0.2308	$0.2385	$0.2375
National Fuel	FST N02358	$3.6293	4.010 Version 17.0.0 Pg 1	$0.1210	$0.1171	$0.1171	$0.1296	$0.1171	$0.1210	$0.1205
ANE Union Gas		$3.4020								
TransCanada Pipelines Limited		$15.26585	Union Parkway to Iroquois							
Delivery Pressure Demand Charge		1.0123	Union Parkway to Iroquois							
Sub Total Demand Charges		19.6801								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		1.3351	updated 7/28/16							
Demand Rate/US$		$15.5526		$0.5184	$0.5017	$0.5017	$0.5555	$0.5017	$0.5184	$0.5162
Peaking										
Granite Ridge Demand		[redacted]	Per Contract	[redacted]						
ENGIE Demand			Per Contract							
Storage										
Dominion - Demand	GSS 300076	$1.8683	GSS Settled,Tariff Rec #10.30 \	$0.0623	$0.0603	$0.0603	$0.0667	$0.0603	$0.0623	$0.0620
Dominion - Capacity	GSS 300076	$0.0145	GSS Settled,Tariff Rec #10.30 \	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.8828		$0.0628	$0.0607	$0.0607	$0.0672	$0.0607	$0.0628	$0.0624
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0.2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129
National Fuel - Demand	FSS-1 2357	$2.3833	4.020 Version 13.0.0 Pg 1	$0.0794	$0.0769	$0.0769	$0.0851	$0.0769	$0.0794	$0.0790
National Fuel - Capacity	FSS-1 2357	$0.0366	4.020 Version 13.0.0 Pg 1	$0.0012	$0.0012	$0.0012	$0.0013	$0.0012	$0.0012	$0.0012
		$2.4199		$0.0807	$0.0781	$0.0781	$0.0864	$0.0781	$0.0807	$0.0803
Tenn Gas Pipeline	FS-MA 523	$1.4938	13th Rev Sheet No.61	$0.0498	$0.0482	$0.0482	$0.0534	$0.0482	$0.0498	$0.0495
Tenn Gas Pipeline - Space	FS-MA 523	$0.0205	13th Rev Sheet No.61	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007
		$1.5143		$0.0505	$0.0488	$0.0488	$0.0541	$0.0488	$0.0505	$0.0502

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	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	Current Rate [7]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0666	$0.0040	($0.0033)	$0.0026	$1.8683	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0126	$0.0001	($0.0007)	$0.0274	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0007)	$0.0148	[8]
	GSS-TE Surcharge [3]	-	$0.0046	-	$0.0003	-	$0.0049	-
	From Customers Balance	$0.6163	$0.0144	$0.0009	($0.0006)	($0.0001)	$0.6309	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0666	$0.0040	($0.0033)	$0.0026	$2.2812	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0126	$0.0001	($0.0007)	$0.0274	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0007)	$0.0148	[8]
	Authorized Overruns	$1.0657	$0.0144	$0.0009	($0.0006)	($0.0001)	$1.0803	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0001	($0.0001)	$0.0001	$0.0759	-
	Injection Charge	$0.0154	-	$0.0126	$0.0001	($0.0007)	$0.0274	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0007)	$0.0148	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0144	$0.0009	($0.0006)	($0.0001)	$0.6309	[8]
	Excess Injection Charge	$0.2245	-	$0.0126	$0.0001	($0.0007)	$0.2365	-

[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 $0.6161. Daily Capacity Release Rate for GSS-E per Dt is $1.0655.
[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).

General Information

Customer Energy North Natural Gas Inc.	Contract Category Storage	Contract Number EN-11234	Service Type FT	Status Active
Deal Maker Richard Norman	Deal Date 01/17/1986	Deal Time (hh:mm) 08:00	Master Agreement -- None --	
Contact Name John Metress	Contact Number 1 516-545-5425	Contact Number 2 516-458-1165	Contact Email john.metress@us.ngrid.com	

Contract Dates

Effective Date (First Gas Day)
05/01/2010

Termination Date (Last Gas Day)
01/01/2050

Nomination Deadlines

Day Before Flow Deadline
(hh:mm 24-hr CCT)

Day of Flow Deadline
(hh:mm 24-hr CCT)

Transaction Types and Rates

Transaction Type	Allow Transaction			Use Hourly Profiles	Volumetric Charge ($/Dth)	Other Rate ($/Dth)	Fuel Percentage	Invoice Qty Type
	Yes	No	D.E.R Only					
Storage Injection	•				0	0	0	Sch Qty
Storage Withdrawal	•				0	0	0	Sch Qty
Authorized Injection Overrun	•				0	0	0	Sch Qty
Authorized Withdrawal Overrun	•				0	0	0	Sch Qty

Storage and Other Rates

✓ Use Monthly Flat Storage Fee ($/Month)

Monthly Flat Storage Fee Table

From	To	Rate
05/01/10	01/01/50	8,744.39000

FERC Information

Capacity Release Contract: Yes • No

Shipper Affiliation: NONE

Maximum Tariff Rate: 0 OR Market Based Rates

Award:

Negotiated Rate Indicator: Yes • No

Rate Schedule: 157

Contract Quantity Limits

Max Storage Qty: 245280

Min Storage Qty: 0

Seasonal Ratchets

Seasonal Ratchet "Annual" (Jan 01 to Dec 31)

Total Contract MDIQ Ratchets

Total Contract		
Inventory Level		
From	To	MDQ
0	245280	1168

Interconnect MDIQ Ratchets

HSC Tennessee Gas INJ					
Inventory Level			Point Priority		
From	To	MDQ	Pri Qty	Sec Qty	IT Qty
0	245280	1168	0	0	0

Total Contract MDWQ Ratchets

Total Contract		
Inventory Level		
From	To	MDQ
0	15453	699
15454	57150	1765
57151	81678	1765
81679	245380	2044

Interconnect MDWQ Ratchets

HSC Tennessee Gas WDL					
Inventory Level			Point Priority		
From	To	MDQ	Pri Qty	Sec Qty	IT Qty
0	15453	699	0	0	0
15454	57150	1765	0	0	0
57151	81678	1765	0	0	0
81679	245380	2044	0	0	0

Posted Special Terms and Conditions

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

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

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

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

3. RATE

ADWQ = Avg Daily W/d Quantity

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

$6.4187
x 1362.33
$8744.39

4. MINIMUM BILL

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

5. COMPRESSOR FUEL ALLOWANCE

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

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

---------- NON-EASTCHESTER RATES (All in $ Per Dth) 1/ ----------

	Minimum	Maximum		
		Effective 9/1/2016	Effective 9/1/2017	Effective 9/1/2018
RTS DEMAND (Monthly):				
Zone 1	$0.0000	$ 6.1928	$ 5.9982	$ 5.5997
Zone 2	$0.0000	$ 5.3381	$ 5.1678	$ 4.7998
Inter-Zone	$0.0000	$10.4755	$ 9.8672	$ 8.8026
RTS COMMODITY (Daily):				
Zone 1	$0.0034	$ 0.0034	$ 0.0034	$ 0.0034
Zone 2	$0.0022	$ 0.0022	$ 0.0022	$ 0.0022
Inter-Zone	$0.0056	$ 0.0056	$ 0.0056	$ 0.0056
ITS COMMODITY (Daily):				
Zone 1	$0.0034	$ 0.2070	$ 0.2006	$ 0.1875
Zone 2	$0.0022	$ 0.1777	$ 0.1721	$ 0.1600
Inter-Zone	$0.0056	$ 0.3500	$ 0.3300	$ 0.2950
VOLUMETRIC CAPACITY RELEASE (Daily) 2/:				
Zone 1	$0.0000	$ 0.2036	$ 0.1972	$ 0.1841
Zone 2	$0.0000	$ 0.1755	$ 0.1699	$ 0.1578
Inter-Zone	$0.0000	$ 0.3444	$ 0.3244	$ 0.2894

**SEE SHEET NOS. 4A, 4B, AND 4C FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

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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)	$3.6293	-	-	$3.6293	
		(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)	3.8067	0.0000	0.0000	$3.8067	
		(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)	3.6293	-	-	$3.6293	
		(Min)	0.0000	-	-	$0.0000	
	Commodity	(Max)	0.0135	-	-	$0.0135	plus ACA[3/]
		(Min)	0.0135	-	-	$0.0135	plus ACA[3/]
	Overrun	(Max)	0.1378	-	-	$0.1378	plus ACA[3/]
		(Min)	0.0135	-	-	$0.0135	plus ACA[3/]
	Maximum Volumetric Rate		0.1378	-	-	$0.1378	plus ACA[3/]
IT	Commodity	(Max)	$0.1378	-	-	$0.1378	plus ACA[3/]
		(Min)	0.0000	-	-	$0.0000	plus ACA[3/]
	Overrun	(Max)	0.1378	-		$0.1378	plus ACA[3/]
		(Min)	0.0000	-	-	$0.0000	plus ACA[3/]

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

2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.93% and the Transportation LAUF Retention for all applicable rate schedules is 0.39%. The retention rate for Northern Access 2015 is 1.38%. Transporter may from time to time identify point pair transactions where the Transportation Fuel and Company Use Retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF Retention.

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

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component 1/ (2)			Rate 2/ (3)	
ESS	Demand	(Max)		$2.4921	
		(Min)		0.0000	
	Capacity	(Max)		0.0388	
		(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)		2.3833	
		(Min)		0.0000	
	Capacity	(Max)		0.0366	
		(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	

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 0.82%.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
5/ Assessed per dekatherm per day on storage balance.
6/ Rate per nomination.

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 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.

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

Tenth Revised Sheet No. 14
Superseding
Ninth 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	$5.5411		$11.5794	$15.5758	$15.8514	$17.4175	$18.4879	$23.1959
L		$4.9193						
1	$8.3417		$7.9962	$10.6413	$15.0745	$14.8460	$16.7429	$20.5878
2	$15.5759		$10.5774	$5.5014	$5.1427	$6.5803	$9.0504	$11.6830
3	$15.8514		$8.3784	$5.5458	$4.0009	$6.1457	$11.1149	$12.8437
4	$20.1259		$18.5544	$7.0708	$10.7456	$5.2598	$5.6884	$8.1265
5	$23.9973		$16.8625	$7.4172	$8.9748	$5.8432	$5.4810	$7.1353
6	$27.7603		$19.3678	$13.3296	$14.6845	$10.3726	$5.4568	$4.7237

Daily Base
Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1822		$0.3807	$0.5121	$0.5211	$0.5726	$0.6078	$0.7626
L		$0.1617						
1	$0.2742		$0.2629	$0.3499	$0.4956	$0.4881	$0.5505	$0.6769
2	$0.5121		$0.3478	$0.1809	$0.1691	$0.2163	$0.2975	$0.3841
3	$0.5211		$0.2755	$0.1823	$0.1315	$0.2021	$0.3654	$0.4223
4	$0.6617		$0.6100	$0.2325	$0.3533	$0.1729	$0.1870	$0.2672
5	$0.7890		$0.5544	$0.2439	$0.2951	$0.1921	$0.1802	$0.2346
6	$0.9127		$0.6367	$0.4382	$0.4828	$0.3410	$0.1794	$0.1553

Maximum Reservation
Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.5621		$11.6004	$15.5968	$15.8724	$17.4385	$18.5089	$23.2169
L		$4.9403						
1	$8.3627		$8.0172	$10.6623	$15.0955	$14.8670	$16.7639	$20.6088
2	$15.5969		$10.5984	$5.5224	$5.1637	$6.6013	$9.0714	$11.7040
3	$15.8724		$8.3994	$5.5668	$4.0219	$6.1667	$11.1359	$12.8647
4	$20.1469		$18.5754	$7.0918	$10.7666	$5.2808	$5.7094	$8.1475
5	$24.0183		$16.8835	$7.4382	$8.9958	$5.8642	$5.5020	$7.1563
6	$27.7813		$19.3888	$13.3506	$14.7055	$10.3936	$5.4778	$4.7447

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 $0.0210.

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

Thirteenth Revised Sheet No. 15
Superseding
Twelveth Revised Sheet No. 15

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base
Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2668	$0.2546	$0.3030
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2269	$0.2313	$0.2641
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0734	$0.1178	$0.1305
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0982	$0.1358	$0.1482
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0454	$0.0642	$0.1041
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0639	$0.0633	$0.0787
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0984	$0.0533	$0.0324

Minimum
Commodity Rates 1/, 2/

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

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0041		$0.0124	$0.0186	$0.0228	$0.2677	$0.2555	$0.3039
L		$0.0021						
1	$0.0051		$0.0090	$0.0156	$0.0188	$0.2278	$0.2322	$0.2650
2	$0.0176		$0.0096	$0.0021	$0.0037	$0.0743	$0.1187	$0.1314
3	$0.0216		$0.0178	$0.0035	$0.0011	$0.0991	$0.1367	$0.1491
4	$0.0259		$0.0214	$0.0096	$0.0114	$0.0463	$0.0651	$0.1050
5	$0.0293		$0.0265	$0.0109	$0.0127	$0.0648	$0.0642	$0.0796
6	$0.0355		$0.0309	$0.0152	$0.0172	$0.0993	$0.0542	$0.0333

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 $0.0009.

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FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Twelfth Revised Sheet No. 32
Superseding
Eleventh Revised Sheet No. 32

FUEL AND EPCR

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.42%		1.42%	2.15%	2.64%	3.16%	3.57%	4.25%
L		0.18%						
1	0.54%		1.02%	1.80%	2.18%	2.67%	3.24%	3.70%
2	2.19%		1.09%	0.17%	0.37%	0.75%	1.31%	1.80%
3	2.64%		2.18%	0.37%	0.06%	1.06%	1.54%	2.07%
4	3.16%		2.48%	1.08%	1.30%	0.39%	0.63%	1.13%
5	3.70%		3.24%	1.31%	1.56%	0.63%	0.62%	0.81%
6	4.43%		3.84%	1.80%	2.07%	1.06%	0.48%	0.21%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0034		$0.0130	$0.0201	$0.0250	$0.0302	$0.0344	$0.0412
L		$0.0011						
1	$0.0046		$0.0091	$0.0167	$0.0204	$0.0253	$0.0310	$0.0356
2	$0.0201		$0.0098	$0.0010	$0.0030	$0.0065	$0.0120	$0.0164
3	$0.0250		$0.0204	$0.0030	$0.0000	$0.0096	$0.0142	$0.0189
4	$0.0302		$0.0234	$0.0097	$0.0118	$0.0031	$0.0054	$0.0102
5	$0.0344		$0.0310	$0.0120	$0.0142	$0.0054	$0.0053	$0.0071
6	$0.0412		$0.0356	$0.0164	$0.0189	$0.0095	$0.0040	$0.0014

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.01%.
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 0.01%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

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FERC NGA Gas Tariff
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Superseding
Twelveth Revised Sheet No. 61

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	$2.0334	$2.0334 1/		
Space Rate	$0.0207	$0.0207 1/		
Injection Rate	$0.0073	$0.0073	2.18%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.2441	$0.2441 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.4938	$1.4938 1/		
Space Rate	$0.0205	$0.0205 1/		
Injection Rate	$0.0087	$0.0087	2.18%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1793	$0.1793 1/		

Notes:

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 0.33%.

Issued: March 1, 2017
Effective: April 1, 2017

Docket No. RP17-501-000
Accepted: March 27, 2017

TransCanada PipeLines Limited
Final Mainline Transportation Tolls Effective July 1, 2015 (Amended July 1, 2017) and
Final Abandonment Surcharges Effective January 1, 2017
Toll Orders TG-011-2015 and TG-011-2016

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	0.32346	0.0106
2	Union WDA	39.71839	1.30581	3.03602	0.0998
3	Union NDA	16.92748	0.55652	1.11736	0.0367
4	Union EDA	11.84212	0.38933	0.68926	0.0227
5	KPUC EDA	11.39043	0.37448	0.65122	0.0214
6	GMIT EDA	19.47488	0.64027	1.33184	0.0438
7	Enbridge CDA	6.05839	0.19918	0.20233	0.0067
8	Enbridge EDA	15.16514	0.49858	0.96900	0.0319
9	Cornwall	15.38840	0.50592	0.98781	0.0325
10	Iroquois	14.45978	0.47539	0.90962	0.0299
11	Philipsburg	19.52568	0.64194	1.33608	0.0439

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)
11	Kirkwall to Thorold CDA	6.98093	0.22951	0.22659	0.0075
12	Union Parkway Belt to Goreway CDA	5.19730	0.17087	0.09011	0.0030
13	Union Parkway Belt to Victoria Square #2 CDA	6.13839	0.20181	0.16211	0.0053
14	Union Parkway Belt to Schomberg #2 CDA	6.07695	0.19979	0.15741	0.0052

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)
15	Union Parkway Belt to Union EDA	13.02633	0.42826	0.68926	0.0227

Delivery Pressure

Line No	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
16	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 applies to applicable STS Injections/Withdrawals, IT, Diversions, STFT and SSS.

Union Dawn Receipt Point Surcharge

Line No	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
17	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)
18	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)
19	Western Section	1.52481
20	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	Dawn Export	-	0.4596	-	0.0286
2	Union NDA	Empress	-	1.4286	-	0.1622
3	Union NDA	TransGas SSDA	-	1.1879	-	0.1332
4	Union NDA	Centram SSDA	-	1.0893	-	0.1213
5	Union NDA	Centram MDA	-	0.9409	-	0.1034
6	Union NDA	Centrat MDA	-	0.8727	-	0.0952
7	Union NDA	Union WDA	-	0.6155	-	0.0641
8	Union NDA	Nipigon WDA	-	0.5101	-	0.0514
9	Union NDA	Union NDA	-	0.0927	-	0.0011
10	Union NDA	Calstock NDA	-	0.3266	-	0.0293
11	Union NDA	Tunis NDA	-	0.1989	-	0.0139
12	Union NDA	GMIT NDA	-	0.1848	-	0.0122
13	Union NDA	Union SSMDA	-	0.8518	-	0.0926
14	Union NDA	Union NCDA	-	0.3072	-	0.0244
15	Union NDA	Union CDA	-	0.4534	-	0.0408
16	Union NDA	Union ECDA	-	0.4238	-	0.0375
17	Union NDA	Union EDA	-	0.4902	-	0.0450
18	Union NDA	Union Parkway Belt	-	0.4170	-	0.0367
19	Union NDA	Enbridge CDA	-	0.4128	-	0.0363
20	Union NDA	Enbridge Parkway CDA	-	0.4170	-	0.0367
21	Union NDA	Enbridge EDA	-	0.4480	-	0.0402
22	Union NDA	KPUC EDA	-	0.5277	-	0.0492
23	Union NDA	GMIT EDA	-	0.5801	-	0.0551
24	Union NDA	Enbridge SWDA	-	0.5522	-	0.0519
25	Union NDA	Union SWDA	-	0.5543	-	0.0522
26	Union NDA	Chippawa	-	0.4975	-	0.0458
27	Union NDA	Cornwall	-	0.4798	-	0.0438
28	Union NDA	East Hereford	-	0.6919	-	0.0676
29	Union NDA	Emerson 1	-	0.9514	-	0.1047
30	Union NDA	Emerson 2	-	0.9514	-	0.1047
31	Union NDA	Iroquois	-	0.4600	-	0.0416
32	Union NDA	Kirkwall	-	0.4398	-	0.0393
33	Union NDA	Napierville	-	0.5713	-	0.0541
34	Union NDA	Niagara Falls	-	0.4961	-	0.0456
35	Union NDA	North Bay Junction	-	0.1893	-	0.0127
36	Union NDA	Philipsburg	-	0.5817	-	0.0552
37	Union NDA	Spruce	-	0.8727	-	0.0952
38	Union NDA	St. Clair	-	0.5274	-	0.0535
39	Union NDA	Welwyn	-	1.0893	-	0.1213
40	Union NDA	Dawn Export	-	0.5522	-	0.0519
41	Union Parkway Belt	Empress	72.71500	2.3906	5.81387	0.1911
42	Union Parkway Belt	TransGas SSDA	62.22550	2.0458	4.93081	0.1621
43	Union Parkway Belt	Centram SSDA	57.92793	1.9045	4.56902	0.1502
44	Union Parkway Belt	Centram MDA	51.42698	1.6908	4.02174	0.1322
45	Union Parkway Belt	Centrat MDA	50.92176	1.6741	3.97920	0.1308
46	Union Parkway Belt	Union WDA	39.71839	1.3058	3.03602	0.0998
47	Union Parkway Belt	Nipigon WDA	35.11878	1.1546	2.64878	0.0871
48	Union Parkway Belt	Union NDA	16.92748	0.5565	1.11736	0.0367
49	Union Parkway Belt	Calstock NDA	27.12102	0.8917	1.97555	0.0650
50	Union Parkway Belt	Tunis NDA	20.82538	0.6847	1.44551	0.0475
51	Union Parkway Belt	GMIT NDA	16.14638	0.5308	1.05162	0.0346
52	Union Parkway Belt	Union SSMDA	24.24117	0.7970	1.73306	0.0570
53	Union Parkway Belt	Union NCDA	8.49264	0.2792	0.40726	0.0134
54	Union Parkway Belt	Union CDA	5.51758	0.1814	0.15682	0.0052
55	Union Parkway Belt	Union ECDA	4.32069	0.1421	0.05606	0.0018
56	Union Parkway Belt	Union EDA	11.84212	0.3893	0.68926	0.0227
57	Union Parkway Belt	Union Parkway Belt	4.04238	0.1329	0.03261	0.0011
58	Union Parkway Belt	Enbridge CDA	6.05839	0.1992	0.20233	0.0067
59	Union Parkway Belt	Enbridge Parkway CDA	4.04238	0.1329	0.03261	0.0011
60	Union Parkway Belt	Enbridge EDA	15.16514	0.4986	0.96900	0.0319
61	Union Parkway Belt	KPUC EDA	11.39043	0.3745	0.65122	0.0214
62	Union Parkway Belt	GMIT EDA	19.47488	0.6403	1.33184	0.0438
63	Union Parkway Belt	Enbridge SWDA	9.52802	0.3133	0.49442	0.0163
64	Union Parkway Belt	Union SWDA	9.61501	0.3161	0.50175	0.0165
65	Union Parkway Belt	Chippawa	7.30852	0.2403	0.30761	0.0101
66	Union Parkway Belt	Cornwall	15.38840	0.5059	0.98781	0.0325
67	Union Parkway Belt	East Hereford	24.00088	0.7891	1.71287	0.0563
68	Union Parkway Belt	Emerson 1	47.97256	1.5772	3.73091	0.1227
69	Union Parkway Belt	Emerson 2	47.97256	1.5772	3.73091	0.1227
70	Union Parkway Belt	Iroquois	14.36427	0.4723	0.90158	0.0296
71	Union Parkway Belt	Kirkwall	4.96613	0.1633	0.11039	0.0036
72	Union Parkway Belt	Napierville	19.10349	0.6281	1.30054	0.0428
73	Union Parkway Belt	Niagara Falls	7.25103	0.2384	0.30274	0.0100
74	Union Parkway Belt	North Bay Junction	12.73394	0.4187	0.76433	0.0251
75	Union Parkway Belt	Philipsburg	19.52568	0.6419	1.33608	0.0439
76	Union Parkway Belt	Spruce	50.92176	1.6741	3.97920	0.1308
77	Union Parkway Belt	St. Clair	10.10381	0.3322	0.54293	0.0179

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Effective
2017-07-01
Rate M12
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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 - Parkway 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 Charges (applied to daily contract demand) Rate/GJ	Fuel and Commodity Charges: Union Supplied Fuel — Fuel and Commodity Charge Rate/GJ	Shipper Supplied Fuel: Fuel Ratio %	AND	Shipper Supplied Fuel: Commodity Charge Rate/GJ (2)
Firm Transportation (1)					
Dawn to Parkway (Cons) / Lisgar	$3.402	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		$0.006
Dawn to Parkway (TCPL / EGT)	$3.402				$0.009
Dawn to Kirkwall	$2.865				$0.006
Kirkwall to Parkway (Cons) / Lisgar	$0.537				$0.002
Kirkwall to Parkway (TCPL / EGT)	$0.537				$0.005
M12-X Firm Transportation					
Between Dawn, Kirkwall and Parkway	$4.239	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		Note (2)
Limited Firm/Interruptible Transportation (1)					
Dawn to Parkway (Cons) / Lisgar – Maximum	$8.165	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		$0.006
Dawn to Parkway (TCPL / EGT) – Maximum	$8.165				$0.009
Dawn to Kirkwall – Maximum	$8.165				$0.006
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (3)	n/a	n/a	0.157%		$0.002

Authorized Overrun (4)

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.

	Fuel and Commodity Charges: Union Supplied Fuel — Fuel and Commodity Charge Rate/GJ	Shipper Supplied Fuel: Fuel Ratio %	AND	Shipper Supplied Fuel: Commodity Charge Rate/GJ (2)
Transportation Overrun				
Dawn to Parkway (Cons) / Lisgar	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		$0.118
Dawn to Parkway (TCPL / EGT)				$0.121
Dawn to Kirkwall				$0.100
Kirkwall to Parkway (Cons) / Lisgar				$0.020
Kirkwall to Parkway (TCPL / EGT)				$0.023
Parkway (TCPL) Overrun (5)	n/a	0.704%		n/a
M12-X Firm Transportation				
Dawn to Kirkwall / Parkway (Cons) / Lisgar	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		$0.145
Dawn to Parkway (TCPL / EGT)				$0.148
Kirkwall to Parkway (Cons) / Lisgar				$0.141
Kirkwall to Parkway (TCPL / EGT)				$0.144
Parkway to Dawn / Kirkwall				$0.142
Kirkwall to Dawn				$0.141

Ln										Schedule 6
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**	Schedule 6
2	**d/b/a Liberty Utilities**									Page 1 of 5
3	**Peak 2017 - 2018 Winter Cost of Gas Filing**									
4	**Supply and Commodity Costs, Volumes and Rates**									
5									Peak	
6	For Month of:	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	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	ENGIE COMBO	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		$ 3,136,238	$ 6,726,344	$ 10,812,720	$ 12,083,378	$ 6,849,929	$ 2,197,086	$ 41,805,695	
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	ENGIE COMBO	ln 68 * ln 235								
32	TGP Storage - Withdrawals	ln 77 * ln 165								
33										
34	**Total Volumetric Transportation Costs**		$ 205,854	$ 220,099	$ 243,438	$ 219,019	$ 188,650	$ 21,117	$ 1,098,177	
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		$ (537,991)	$ (244,150)	$ (964,994)	$ (146,793)	$ (99,529)	$ (232,641)	$ (2,226,098)	
43										
44	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 34 + ln 42	$ 2,804,101	$ 6,702,293	$ 10,091,165	$ 12,155,603	$ 6,939,050	$ 1,985,562	$ 40,677,774	
45										
46	**Storage Gas:**									
47	TGP Storage - Withdrawals	ln 77 * ln 157	$ 224,267	$ 1,104,273	$ 1,288,514	$ 1,141,596	$ 479,920	$ -	$ 4,238,570	
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	$ 220,757	$ 1,199,725	$ 3,052,979	$ 235,896	$ 28,712	$ 26,136	$ 4,764,207	
54										
55										
56	**Total Commodity Gas & Trans. Costs**	ln 44 + ln 47 + ln 53	$ 3,249,126	$ 9,006,291	$ 14,432,658	$ 13,533,095	$ 7,447,683	$ 2,011,698	$ 49,680,551	
57									$ 89,487,445	
58										

Line	For Month of:	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Peak Nov- Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2017 - 2018 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									
6	For Month of:	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	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		787,330	850,682	874,909	797,329	841,223	597,333	4,748,807
64	Niagara Supply		618,381	685,075	697,621	626,115	686,018	577,956	3,891,167
65	TGP Supply (Direct)		4,156,418	2,932,802	2,986,510	2,681,405	2,924,082	-	15,681,218
66	Dracut Supply 1 - Baseload		-	2,627,066	4,458,865	3,002,343	-	-	10,088,274
67	Dracut Supply 2 - Swing		3,142,062	1,669,517	1,395,242	3,233,733	6,398,113	2,669,288	18,507,956
68	ENGIE COMBO		-	1,296,548	1,184,082	1,268,707	29,057	-	3,778,393
69	LNG Truck		19,139	220,809	248,636	131,814	90,004	-	710,402
70	Propane Truck		-	-	763,924	-	-	-	763,924
71	PNGTS		54,117	77,142	87,203	73,787	68,035	45,435	405,718
72	TGP Supply (Z4)		1,623,498	1,805,400	1,838,462	1,650,536	1,807,885	4,908,951	13,634,732
73									
74	Subtotal Pipeline Volumes		10,400,946	12,165,042	14,535,452	13,465,770	12,844,418	8,798,962	72,210,589
75									
76	**Storage Gas:**								
77	TGP Storage		1,005,117	4,949,103	5,774,831	5,116,377	2,150,894	-	18,996,322
78									
79	**Produced Gas:**								
80	LNG Vapor		19,139	220,809	325,749	135,396	20,552	18,708	740,353
81	Propane		-	-	1,261,916	-	-	-	1,261,916
82									
83	Subtotal Produced Gas		19,139	220,809	1,587,664	135,396	20,552	18,708	2,002,269
84									
85	**Less - Gas Refill:**								
86	LNG Truck		(19,139)	(220,809)	(248,636)	(131,814)	(90,004)	-	(710,402)
87	Propane		-	-	(763,924)	-	-	-	(763,924)
88	TGP Storage Refill		(1,527,804)	-	-	-	-	(719,605)	(2,247,409)
89									
90	Subtotal Refills		(1,546,943)	(220,809)	(1,012,559)	(131,814)	(90,004)	(719,605)	(3,721,735)
91									
92	**Total Sendout Volumes**		9,878,258	17,114,145	20,885,388	18,585,729	14,925,860	8,098,065	89,487,445
93									
94									
95									

REDACTED

Line	Description	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Peak Nov- Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2017 - 2018 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	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	**ENGIE COMBO**								
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	**$1.0886**	**$1.1057**	**$1.1159**	**$1.1136**	**$1.1058**	**$0.0000**	**$0.9216**
132									
133	**Propane Truck**	Propane WACOG	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**
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	**$11.5345**	**$5.4333**	**$2.7845**	**$1.7423**	**$1.3970**	**$1.3970**	**$4.0481**
146									
147	**Propane**	Sch 16, ln 66 /10	**$1.0189**	**$1.0189**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.4733**
148									
149	**Storage Refill:**								
150	**LNG Truck**	ln 131	**$1.0886**	**$1.1057**	**$1.1159**	**$1.1136**	**$1.1058**	**$0.0000**	**$4.0481**
151	**Propane**	ln 133	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$1.4733**
152									
153									

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln	For Month of:	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	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	$0.2231	$0.2231	$0.2231	$0.2231	$0.2231	$0.2304	$0.2243
158									
159	TGP - Max Commodity - Z 4-6	13th Rev Sheet No. 15	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050
160	TGP - Max Comm. ACA Rate - Z 4-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
161	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.01063	$0.01063	$0.01063	$0.01063	$0.01063	$0.01063	$0.01063
162	TGP - Fuel Charge % - Z 4-6	12th Rev Sheet No. 32	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%
163	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00252	$0.00252	$0.00252	$0.00252	$0.00252	$0.00260	$0.00253
164	TGP - Withdrawal Charge	13th 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)**		$0.01402	$0.01402	$0.01402	$0.01402	$0.01402	$0.01410	$0.01403
166									
167	**Total TGP - Comm. & Vol. Trans. Rate**	ln 157 + ln 165	**$0.23715**	**$0.23715**	**$0.23715**	**$0.23715**	**$0.23715**	**$0.24447**	**$0.23837**
168									
169									
156	**Per Unit Volumetric Transportation Rates**								
157	**Dawn Supply Volumetric Transportation Charge**								
158	**Commodity Costs**	ln 102	**$0.3123**	**$0.3292**	**$0.3384**	**$0.3375**	**$0.3334**	**$0.2828**	**$0.3223**
159									
160	TransCanada - Commodity Rate/GJ	Union Parkway to Iroquois	$0.00090	$0.00090	$0.00090	$0.00090	$0.00090	$0.00090	$0.00090
161	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
162	Conversion Rate to US$	updated 7/28/16	1.3351	1.3351	1.3351	1.3351	1.3351	1.3351	1.3351
163	Commodity Rate/US$	ln 160 x ln 161 x ln 162	$0.00127	$0.00127	$0.00127	$0.00127	$0.00127	$0.00127	$0.00127
164	TransCanada Fuel %	Union Parkway to Iroquois	1.81%	1.54%	2.26%	1.48%	1.73%	1.12%	1.66%
165	TransCanada Fuel * Percentage	ln 158 x ln 164	$0.00564	$0.00507	$0.00764	$0.00499	$0.00576	$0.00317	$0.00538
166	Subtotal TransCanada		**$0.00691**	**$0.00633**	**$0.00891**	**$0.00626**	**$0.00703**	**$0.00444**	**$0.00665**
167	IGTS - Z1 RTS Commodity	First Revised Sheet No. 4	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034
168	IGTS - Z1 RTS ACA Rate Commodity	Fifth Revised Sheet 4A	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
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		**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**
171	TGP NET-NE - Comm. Segments 3 & 4	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
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	**$0.00312**	**$0.00329**	**$0.00338**	**$0.00338**	**$0.00333**	**$0.00283**	**$0.00322**
174	TGP FTA Fuel Charge % Z 5-6	12th Rev Sheet No. 32	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
175	TGP FTA Fuel * Percentage	ln 158 x ln 174	**$0.00253**	**$0.00267**	**$0.00274**	**$0.00273**	**$0.00270**	**$0.00229**	**$0.00261**
176	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01317**	**$0.01289**	**$0.01564**	**$0.01297**	**$0.01366**	**$0.01016**	**$0.01308**
177									
178									
179	**Niagara Supply Volumetric Transportation Charge**								
180	**Commodity Costs**	Ln 107	[redacted]						
181									
182	TGP FTA - FTA Z 5-6 Comm. Rate	13th Rev Sheet No. 15	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796
183	TGP FTA - FTA Z 5-6 - ACA Rate	13th Rev Sheet No. 15	$0.00013	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
184	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00809**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**
185	TGP FTA Fuel Charge % Z 5-6	12th Rev Sheet No. 32	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
186	TGP FTA Fuel * Percentage	ln 180 x ln 185	[redacted]						
187	**Total Volumetric Transportation Rate - Niagara Supply**								
188									
189									
190									

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Ln	For Month of:	Reference	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Peak 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	13th Rev Sheet No. 15	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039
197	TGP - Max Commodity ACA Rate - Z 0-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
198	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052
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		**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**
201	TGP - Max Comm. Base Rate - Z 1-6	13th Rev Sheet No. 15	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650
202	TGP - Max Commodity ACA Rate - Z 1-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
203	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663
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		**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**
206	TGP - Fuel Charge % - Z 0 -6	12th Rev Sheet No. 32	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
207	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
208	Prorated TGP Fuel Charge % - Z 0-6		1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%
209	TGP - Fuel Charge % - Z 1 -6	12th Rev Sheet No. 32	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
210	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
211	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.49%	2.49%	2.49%	2.49%	2.49%	2.49%	2.49%
212	TGP - Fuel Charge % - Z 0-6	ln 194 x ln 208	**$0.00414**	**$0.00435**	**$0.00448**	**$0.00447**	**$0.00440**	**$0.00394**	**$0.00430**
213	TGP - Fuel Charge % - Z 1-6	ln 194 x ln 211	**$0.00746**	**$0.00783**	**$0.00807**	**$0.00804**	**$0.00792**	**$0.00709**	**$0.00773**
214	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.03950**	**$0.04008**	**$0.04045**	**$0.04040**	**$0.04022**	**$0.03893**	**$0.03993**
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	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
220	TGP - Max Commodity ACA Rate - Z 6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
221	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
222	TGP - Fuel Charge % - Z 6-6	12th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
223	TGP - Fuel Charge	ln 217 x ln 222	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**
224	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**
225									
226									
227	**TGP Dracut**								
228	**Commodity Costs - NYMEX Price**	Ln 112	[redacted]						
229									
230	TGP - Trans Charge - Comm. - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
231	TGP - Trans Charge - ACA Rate - Z6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
232	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
233	TGP - Fuel Charge % - Z 6-6	12th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
234	TGP - Fuel Charge	ln 228 x ln 233	[redacted]						
235	**Total Volumetric Transportation Rate - TGP Dracut**								
236									
237									

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2017 - 2018 Winter Cost of Gas Filing
NYMEX Futures @ Henry Hub

									Peak
For Month of:	Reference		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Strip Average
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
I. NYMEX Opening Prices as of:									
Opening Prices (15 day average)			2.9900	3.1408	3.2346	3.2231	3.1751	2.8436	$ 3.1012
NYMEX	ln 45	**Filed COG**	2.9900	3.1408	3.2346	3.2231	3.1751	2.8436	$ 3.1012

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub**

Line										Peak
6	For Month of:	Reference		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
17	NYMEX Settlement - 15 Day Average									
18		Days	Date							
19		1	11-Aug	3.0680	3.2050	3.3070	3.2970	3.2460	2.9030	
20		2	10-Aug	3.0760	3.2090	3.3060	3.2940	3.2440	2.8980	
21		3	9-Aug	2.9930	3.1370	3.2370	3.2280	3.1840	2.8690	
22		4	8-Aug	2.9410	3.0890	3.1880	3.1810	3.1400	2.8500	
23		5	7-Aug	2.9260	3.0790	3.1750	3.1650	3.1250	2.8340	
24										
25										
26		6	31-Jul	2.9200	3.0790	3.1730	3.1640	3.1190	2.7950	
27		7	1-Aug	2.9360	3.0930	3.1820	3.1710	3.1270	2.8060	
28		8	2-Aug	2.9360	3.0940	3.1840	3.1750	3.1320	2.8260	
29		9	3-Aug	2.9330	3.0920	3.1830	3.1720	3.1300	2.8350	
30		10	4-Aug	2.9060	3.0650	3.1580	3.1490	3.1090	2.8220	
31										
32										
33		11	24-Jul	2.9980	3.1530	3.2460	3.2300	3.1780	2.8230	
34		12	25-Jul	3.0400	3.1900	3.2820	3.2660	3.2100	2.8420	
35		13	26-Jul	3.0320	3.1830	3.2750	3.2620	3.2050	2.8380	
36		14	27-Jul	3.0820	3.2310	3.3200	3.3050	3.2460	2.8570	
37		15	28-Jul	3.0630	3.2130	3.3030	3.2880	3.2320	2.8560	
38										
39										
40										
41										
42										
43										
44										
45			15 Day Average	2.9900	3.1408	3.2346	3.2231	3.1751	2.8436	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2017 - 2018 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Residential Heating Rate R-3

November 1, 2017 - April 30, 2018
Residential Heating (R3)

PROPOSED			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter Nov-Apr**
average Usage (Therms)			51	90	136	144	116	100	638
	5/1/2017	7/1/2017							
Winter:									
Cust. Chg	$22.10	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58
Headblock	$0.3495	$0.3863	$19.61	$34.76	$38.63	$38.63	$38.63	$38.63	$208.89
Tailblock	$0.2892	$0.3197	$0.00	$0.00	$11.66	$14.13	$5.15	$0.12	$31.06
HB Threshold	100	100							
Summer:									
Cust. Chg	$22.10	$24.43							
Headblock	$0.3495	$0.3863							
Tailblock	$0.2892	$0.3197							
HB Threshold	20	20							
Total Base Rate Amount			$44.04	$59.19	$74.72	$77.19	$68.21	$63.18	$386.53
COG Rate - (Seasonal)			$0.6659	$0.6659	$0.6659	$0.6659	$0.6659	$0.6659	$0.6659
COG amount			$33.81	$59.92	$90.88	$96.03	$77.32	$66.83	$424.79
LDAC			$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856
LDAC amount			$4.35	$7.70	$11.69	$12.35	$9.94	$8.59	$54.62
Total Bill			**$82.19**	**$126.81**	**$177.29**	**$185.57**	**$155.47**	**$138.60**	**$865.94**

May 1, 2017 - October 31, 2017

	May-17	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)	48	27	16	14	14	22	141	779
Summer: Cust. Chg	$22.10	$22.10	$24.43	$24.43	$24.43	$24.43	$141.92	$288.50
Headblock	$6.99	$6.99	$6.26	$5.45	$5.43	$7.73	$38.84	$247.73
Tailblock	$8.14	$2.02	$0.00	$0.00	$0.00	$0.52	$10.67	$41.73
Total Base Rate Amount	$37.23	$31.11	$30.69	$29.88	$29.86	$32.67	$191.43	$577.96
COG Rate - (Seasonal)	$0.4368	$0.4368	$0.4368	$0.4002	$0.4002	$0.4002	$0.4239	$0.6221
COG amount	$21.02	$11.78	$7.08	$5.64	$5.63	$8.65	$59.79	$484.58
LDAC	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0817
LDAC amount	$3.08	$1.73	$1.04	$0.90	$0.90	$1.38	$9.03	$63.65
Total Bill	**$61.33**	**$44.61**	**$38.80**	**$36.42**	**$36.38**	**$42.71**	**$260.25**	**$1,126.19**

November 1, 2016 - April 30, 2017
Residential Heating (R3)

CURRENT			**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**Winter Nov-Apr**
average Usage (Therms)			51	90	136	144	116	100	638
Winter:	5/1/2016	7/1/2016							
Cust. Chg	$22.04	$22.10	$22.10	$22.10	$22.10	$22.10	$22.10	$22.10	$132.60
Headblock	$0.3486	$0.3495	$17.74	$31.45	$34.95	$34.95	$34.95	$34.95	$188.99
Tailblock	$0.2885	$0.2892	$0.00	$0.00	$10.55	$12.79	$4.66	$0.11	$28.10
HB Threshold	100	100							
Summer:									
Cust. Chg	$22.04	$22.10							
Headblock	$0.3486	$0.3495							
Tailblock	$0.2885	$0.2892							
HB Threshold	20	20							
Total Base Rate Amount			$39.84	$53.55	$67.60	$69.84	$61.71	$57.16	$349.69
COG Rate - (Seasonal)			$0.7162	$0.6439	$0.7276	$0.6012	$0.4841	$0.4002	$0.5905
COG amount			$36.36	$57.94	$99.30	$86.70	$56.21	$40.17	$376.68
LDAC			$0.0553	$0.0553	$0.0640	$0.0640	$0.0640	$0.0640	0.0621
LDAC amount			$2.81	$4.98	$8.73	$9.23	$7.43	$6.42	$39.60
Total Bill			**$79.01**	**$116.46**	**$175.64**	**$165.76**	**$125.35**	**$103.74**	**$765.97**

May 1, 2016 - October 31, 2016

	May-16	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)	48	27	16	14	14	22	141	779
Summer: Cust. Chg	$22.04	$22.04	$22.10	$22.10	$22.10	$22.10	$132.48	$265.08
Headblock	$6.97	$6.97	$5.66	$4.93	$4.91	$6.99	$36.43	$225.43
Tailblock	$8.12	$2.01	$0.00	$0.00	$0.00	$0.47	$10.59	$38.69
Total Base Rate Amount	$37.13	$31.02	$27.76	$27.03	$27.01	$29.56	$179.51	$529.20
COG Rate - (Seasonal)	$0.4117	$0.4400	$0.4400	$0.4200	$0.4200	$0.4890	$0.4339	$0.5621
COG amount	$19.81	$11.87	$7.13	$5.92	$5.90	$10.57	$61.20	$437.88
LDAC	$0.1014	$0.1014	$0.0937	$0.0937	$0.0937	$0.0937	$0.0978	$0.0685
LDAC amount	$4.88	$2.73	$1.52	$1.32	$1.32	$2.03	$13.80	$53.40
Total Bill	**$61.82**	**$45.62**	**$36.41**	**$34.27**	**$34.23**	**$42.15**	**$254.50**	**$1,020.47**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr
Total Bill	**$3.18**	**$10.35**	**$1.65**	**$19.81**	**$30.12**	**$34.86**	**$99.97**
% Change	**4.03%**	**8.89%**	**0.94%**	**11.95%**	**24.03%**	**33.60%**	**13.05%**
Base Rate	$4.20	$5.64	$7.12	$7.36	$6.50	$6.02	$36.84
% Change	10.54%	10.53%	10.54%	10.54%	10.54%	10.53%	10.54%
COG & LDAC	($1.01)	$4.71	($5.47)	$12.45	$23.62	$28.84	$63.13
% Change	-2.79%	8.13%	-5.51%	14.36%	42.02%	71.79%	16.76%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($0.49)**	**($1.01)**	**$2.39**	**$2.15**	**$2.15**	**$0.55**	**$5.74**	**$105.71**
% Change	**-0.80%**	**-2.22%**	**6.57%**	**6.28%**	**6.28%**	**1.31%**	**2.26%**	**10.36%**
Base Rate	$0.10	$0.08	$2.93	$2.85	$2.85	$3.12	$11.92	$48.76
% Change	0.26%	0.27%	10.54%	10.54%	10.54%	10.54%	6.64%	9.21%
COG & LDAC	($0.59)	($1.09)	($0.53)	($0.70)	($0.70)	($2.56)	($6.17)	$56.95
% Change	-2.99%	-9.23%	-7.48%	-11.79%	-11.79%	-24.23%	-10.09%	13.01%
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 2017 - 2018 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-41

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
Commercial Rate (G-41)

PROPOSED			**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Winter Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			119	248	418	448	356	304	1,892	122	49	27	24	23	43	288	2,180
Winter:	7/1/2017	5/1/2017															
Cust. Chg	$53.45	$48.36	$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$320.70								
Headblock	$0.4383	$0.3965	$43.83	$43.83	$43.83	$43.83	$43.83	$43.83	$262.98								
Tailblock	$0.2944	$0.2663	$5.45	$43.57	$93.56	$102.35	$75.36	$60.02	$380.30								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$53.45	$48.36								$48.36	$48.36	$53.45	$53.45	$53.45	$53.45	$310.52	$631.22
Headblock	$0.4383	$0.3965								$7.93	$7.93	$8.77	$8.77	$8.77	$8.77	$50.92	$313.90
Tailblock	$0.2944	$0.2663								$27.20	$7.84	$2.20	$1.08	$0.86	$6.66	$45.85	$426.15
HB Threshold	20	20															
Total Base Rate Amount			$102.73	$140.85	$190.84	$199.63	$172.64	$157.30	$963.98	$83.49	$64.13	$64.42	$63.29	$63.08	$68.88	$407.29	$1,371.27
COG Rate - (Seasonal)			$0.6647	$0.6647	$0.6647	$0.6647	$0.6647	$0.6647	$0.6647	$0.4206	$0.4206	$0.4206	$0.4563	$0.4563	$0.4563	$0.4316	$0.6339
COG amount			$78.77	$164.84	$277.70	$297.55	$236.61	$201.99	$1,257.47	$51.38	$20.79	$11.55	$10.80	$10.46	$19.45	$124.44	$1,381.91
LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0645
LDAC amount			$7.99	$16.72	$28.17	$30.18	$24.00	$20.49	$127.56	$5.50	$2.22	$1.24	$1.06	$1.03	$1.92	$12.97	$140.53
Total Bill			**$189.49**	**$322.42**	**$496.71**	**$527.36**	**$433.25**	**$379.79**	**$2,349.01**	**$140.37**	**$87.15**	**$77.21**	**$75.16**	**$74.57**	**$90.25**	**$544.70**	**$2,893.71**

November 1, 2016 - April 30, 2017 / **May 1, 2016 - October 31, 2016**
Commercial Rate (G-41)

CURRENT			**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**Winter Nov-Apr**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Summer May-Oct**	**Total Nov-Oct**
average Usage (Therms)			119	248	418	448	356	304	1,892	122	49	27	24	23	43	288	2,180
Winter:	5/1/2016	7/1/2016															
Cust. Chg	$48.24	$48.36	$48.36	$48.36	$48.36	$48.36	$48.36	$48.36	$290.16								
Headblock	$0.3956	$0.3965	$39.65	$39.65	$39.65	$39.65	$39.65	$39.65	$237.90								
Tailblock	$0.2657	$0.2663	$4.93	$39.41	$84.63	$92.58	$68.16	$54.29	$344.00								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$48.24	$48.36								$48.24	$48.24	$48.36	$48.36	$48.36	$48.36	$289.92	$580.08
Headblock	$0.3956	$0.3965								$7.91	$7.91	$7.93	$7.93	$7.93	$7.93	$47.54	$285.44
Tailblock	$0.2657	$0.2663								$27.14	$7.82	$1.99	$0.98	$0.78	$6.03	$44.74	$388.74
HB Threshold	20	20															
Total Base Rate Amount			$92.94	$127.42	$172.64	$180.59	$156.17	$142.30	$872.06	$83.29	$63.97	$58.28	$57.27	$57.07	$62.32	$382.20	$1,254.26
COG Rate - (Seasonal)			$0.7121	$0.6398	$0.7235	$0.5971	$0.4800	$0.3961	$0.5835	$0.3210	$0.3383	$0.3558	$0.3558	$0.3558	$0.3933	$0.3436	$0.5518
COG amount			$84.38	$158.67	$302.27	$267.29	$170.86	$120.37	$1,103.84	$39.21	$16.73	$9.77	$8.42	$8.16	$16.77	$99.06	$1,202.90
LDAC			$0.0370	$0.0370	$0.0450	$0.0450	$0.0450	$0.0450	0.0435	$0.0628	$0.0628	$0.0793	$0.0793	$0.0793	$0.0793	$0.0695	$0.0469
LDAC amount			$4.38	$9.18	$18.80	$20.14	$16.02	$13.67	$82.20	$7.67	$3.10	$2.18	$1.88	$1.82	$3.38	$20.03	$102.23
Total Bill			**$181.71**	**$295.27**	**$493.71**	**$468.02**	**$343.05**	**$276.35**	**$2,058.10**	**$130.18**	**$83.80**	**$70.23**	**$67.56**	**$67.05**	**$82.46**	**$501.29**	**$2,559.39**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$7.78**	**$27.15**	**$3.00**	**$59.34**	**$90.19**	**$103.44**	**$290.90**	**$10.19**	**$3.34**	**$6.97**	**$7.60**	**$7.53**	**$7.79**	**$43.42**	**$334.32**
% Change	**4.28%**	**9.20%**	**0.61%**	**12.68%**	**26.29%**	**37.43%**	**14.13%**	**7.83%**	**3.99%**	**9.93%**	**11.24%**	**11.23%**	**9.44%**	**8.66%**	**13.06%**
Base Rate	$9.79	$13.43	$18.20	$19.04	$16.46	$15.00	$91.92	$0.20	$0.16	$6.14	$6.03	$6.01	$6.56	$25.09	$117.01
% Change	10.53%	10.54%	10.54%	10.54%	10.54%	10.54%	10.54%	0.24%	0.24%	10.53%	10.53%	10.53%	10.53%	6.56%	9.33%
COG & LDAC	($2.01)	$13.72	($15.20)	$40.30	$73.73	$88.44	$198.99	$9.99	$3.19	$0.84	$1.57	$1.52	$1.22	$18.33	$217.31
% Change	-2.38%	8.65%	-5.03%	15.08%	43.15%	73.47%	18.03%	25.48%	19.07%	8.57%	18.61%	18.61%	7.30%	18.50%	18.07%
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 2017 - 2018 Winter Cost of Gas Filing**
4 **Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-42**

7 **November 1, 2017 - April 30, 2018** — **May 1, 2017 - October 31, 2017**
8 **C&I High Winter Use Medium G-42**

										Winter							Summer	Total
9	**PROPOSED**																	
10				**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**May-Oct**	**Nov-Oct**
11	**average Usage (Therms)**			938	1,648	2,668	2,696	2,751	2,348	13,049	1,081	517	269	267	264	435	2,834	15,883
12		7/1/2017	5/1/2017															
13	**Winter:**																	
14	Cust. Chg	$160.36	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
15	Headblock	$0.3986	$0.3606	$373.70	$398.60	$398.60	$398.60	$398.60	$398.60	$2,366.70								
16	Tailblock	$0.2655	$0.2402	$0.00	$172.09	$442.83	$450.39	$464.79	$358.00	$1,888.11								
17	HB Threshold	1,000	1,000															
18																		
19	**Summer:**																	
20	Cust. Chg	$160.36	$145.08								$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
21	Headblock	$0.3986	$0.3606								$144.24	$144.24	$107.22	$106.46	$105.25	$159.44	$766.85	$3,133.55
22	Tailblock	$0.2655	$0.2402								$163.65	$28.09	$0.00	$0.00	$0.00	$9.42	$201.15	$2,089.26
23	HB Threshold	400	400															
24																		
25	Total Base Rate Amount			$534.06	$731.05	$1,001.79	$1,009.35	$1,023.75	$916.96	$5,216.96	$452.97	$317.41	$267.58	$266.82	$265.61	$329.22	$1,899.60	$7,116.57
26																		
27	COG Rate - (Seasonal)			$0.6647	$0.6647	$0.6647	$0.6647	$0.6647	$0.6647	$0.6647	$0.4206	$0.4206	$0.4206	$0.4563	$0.4563	$0.4563	$0.4328	$0.6233
28	COG amount			$623.18	$1,095.55	$1,773.35	$1,792.29	$1,828.34	$1,560.99	$8,673.69	$454.79	$217.43	$113.14	$121.87	$120.49	$198.71	$1,226.42	$9,900.11
29																		
30	LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0634
31	LDAC amount			$63.22	$111.13	$179.89	$181.81	$185.47	$158.35	$879.88	$48.66	$23.26	$12.10	$12.02	$11.88	$19.60	$127.52	$1,007.40
32																		
33	**Total Bill**			**$1,220.45**	**$1,937.73**	**$2,955.03**	**$2,983.46**	**$3,037.56**	**$2,636.30**	**$14,770.54**	**$956.42**	**$558.10**	**$392.82**	**$400.71**	**$397.98**	**$547.52**	**$3,253.55**	**$18,024.08**

34
35 **November 1, 2016 - April 30, 2017** — **May 1, 2016 - October 31, 2016**
36 **C&I High Winter Use Medium G-42**

										Winter							Summer	Total
37	**CURRENT**																	
38				**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**Nov-Apr**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**May-Oct**	**Nov-Oct**
39	**average Usage (Therms)**			938	1,648	2,668	2,696	2,751	2,348	13,049	1,081	517	269	267	264	435	2,834	15,883
40		5/1/2016	7/1/2016															
41	**Winter:**																	
42	Cust. Chg	$144.73	$145.08	$145.08	$145.08	$145.08	$145.08	$145.08	$145.08	$870.48								
43	Headblock	$0.3598	$0.3606	$338.07	$360.60	$360.60	$360.60	$360.60	$360.60	$2,141.07								
44	Tailblock	$0.2396	$0.2402	$0.00	$155.69	$400.63	$407.47	$420.50	$323.89	$1,708.18								
45	HB Threshold	1,000	1,000															
46																		
47	**Summer:**																	
48	Cust. Chg	$144.73	$145.08								$144.73	$144.73	$145.08	$145.08	$145.08	$145.08	$869.78	$1,740.26
49	Headblock	$0.3598	$0.3606								$143.92	$143.92	$97.00	$96.31	$95.22	$144.24	$720.61	$2,861.68
50	Tailblock	$0.2396	$0.2402								$163.24	$28.09	$0.00	$0.00	$0.00	$8.52	$199.85	$1,908.03
51	HB Threshold	400	400															
52																		
53	Total Base Rate Amount			$483.15	$661.37	$906.31	$913.15	$926.18	$829.57	$4,719.74	$451.89	$316.74	$242.08	$241.39	$240.30	$297.84	$1,790.23	$6,509.97
54																		
55	COG Rate - (Seasonal)			$0.7121	$0.6398	$0.7235	$0.5971	$0.4800	$0.3961	$0.5757	$0.3976	$0.4259	$0.4259	$0.4059	$0.4059	$0.4749	$0.4189	$0.5478
56	COG amount			$667.61	$1,054.51	$1,930.22	$1,610.02	$1,320.30	$930.21	$7,512.87	$429.92	$220.17	$114.56	$108.41	$107.18	$206.80	$1,187.04	$8,699.91
57																		
58	LDAC			$0.0370	$0.0370	$0.0450	$0.0450	$0.0450	$0.0450	0.0434	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0479
59	LDAC amount			$34.69	$60.98	$120.06	$121.34	$123.78	$105.68	$566.52	$74.07	$35.41	$18.43	$18.30	$18.09	$29.83	$194.12	$760.64
60																		
61	**Total Bill**			**$1,185.46**	**$1,776.86**	**$2,956.59**	**$2,644.51**	**$2,370.26**	**$1,865.45**	**$12,799.12**	**$955.88**	**$572.32**	**$375.07**	**$368.10**	**$365.56**	**$534.47**	**$3,171.40**	**$15,970.52**

62

63	**DIFFERENCE:**															
64	**Total Bill**	**$35.00**	**$160.87**	**($1.56)**	**$338.95**	**$667.30**	**$770.85**	**$1,971.41**	**$0.54**	**($14.22)**	**$17.75**	**$32.61**	**$32.42**	**$13.04**	**$82.15**	**$2,053.56**
65	% Change	**2.95%**	**9.05%**	**-0.05%**	**12.82%**	**28.15%**	**41.32%**	**15.40%**	**0.06%**	**-2.48%**	**4.73%**	**8.86%**	**8.87%**	**2.44%**	**2.59%**	**12.86%**
66																
67	**Base Rate**	$50.91	$69.68	$95.48	$96.20	$97.57	$87.39	$497.23	$1.08	$0.67	$25.50	$25.43	$25.31	$31.38	$109.37	$606.60
68	% Change	10.54%	10.54%	10.53%	10.53%	10.53%	10.53%	10.54%	0.24%	0.21%	10.53%	10.53%	10.53%	10.53%	6.11%	9.32%
69																
70	**COG & LDAC**	($15.91)	$91.19	($97.03)	$242.75	$569.73	$683.46	$1,474.19	($0.54)	($14.89)	($7.75)	$7.18	$7.10	($18.33)	($27.22)	$1,446.97
71	% Change	-2.38%	8.65%	-5.03%	15.08%	43.15%	73.47%	19.62%	-0.13%	-6.76%	-6.76%	6.63%	6.63%	-8.87%	-2.29%	16.63%
	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 2017 - 2018 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-52

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
Commercial Rate (G-52)

PROPOSED			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			1,156	1,463	2,024	1,273	2,179	1,858	9,953	1,353	1,084	818	759	782	897	5,693	15,645
Winter:	7/1/2017	5/1/2017															
Cust. Chg	$160.36	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
Headblock	$0.2268	$0.2052	$226.80	$226.80	$226.80	$226.80	$226.80	$226.80	$1,360.80								
Tailblock	$0.1511	$0.1367	$23.60	$69.93	$154.66	$41.25	$178.16	$129.66	$597.25								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$160.36	$145.08								$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
Headblock	$0.1644	$0.1487								$148.70	$148.70	$134.43	$124.85	$128.59	$147.43	$832.70	$2,193.50
Tailblock	$0.0934	$0.0845								$32.97	$7.82	$0.00	$0.00	$0.00	$0.00	$40.79	$638.04
HB Threshold	1,000	1,000															
Total Base Rate Amount			$410.76	$457.09	$541.82	$428.41	$565.32	$516.82	$2,920.21	$326.75	$301.60	$294.79	$285.21	$288.95	$307.79	$1,805.09	$4,725.30
COG Rate - (Seasonal)			$0.6774	$0.6774	$0.6774	$0.6774	$0.6774	$0.6774	$0.6774	$0.4574	$0.4574	$0.4574	$0.4931	$0.4931	$0.4931	$0.4727	$0.6029
COG amount			$783.19	$990.89	$1,370.78	$862.31	$1,476.10	$1,258.69	$6,741.95	$618.84	$495.70	$374.01	$374.49	$385.69	$442.21	$2,690.94	$9,432.89
LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0593
LDAC amount			$77.96	$98.63	$136.45	$85.84	$146.93	$125.29	$671.10	$60.88	$48.77	$36.80	$34.18	$35.20	$40.36	$256.18	$927.27
Total Bill			**$1,271.90**	**$1,546.61**	**$2,049.05**	**$1,376.56**	**$2,188.34**	**$1,900.80**	**$10,333.26**	**$1,006.47**	**$846.07**	**$705.59**	**$693.88**	**$709.84**	**$790.35**	**$4,752.20**	**$15,085.46**

November 1, 2016 - April 30, 2017 / **May 1, 2016 - October 31, 2016**
Commercial Rate (G-52)

CURRENT			Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Winter Nov-Apr	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			1,156	1,463	2,024	1,273	2,179	1,858	9,953	1,353	1,084	818	759	782	897	5,693	15,645
Winter:	5/1/2016	7/1/2016															
Cust. Chg	$144.73	$145.08	$145.08	$145.08	$145.08	$145.08	$145.08	$145.08	$870.48								
Headblock	$0.2047	$0.2052	$205.20	$205.20	$205.20	$205.20	$205.20	$205.20	$1,231.20								
Tailblock	$0.1364	$0.1367	$21.35	$63.26	$139.92	$37.32	$161.18	$117.30	$540.33								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$144.73	$145.08								$144.73	$144.73	$145.08	$145.08	$145.08	$145.08	$869.78	$1,740.26
Headblock	$0.1484	$0.1487								$148.40	$148.40	$121.59	$112.93	$116.31	$133.35	$780.98	$2,012.18
Tailblock	$0.0843	$0.0845								$29.75	$7.06	$0.00	$0.00	$0.00	$0.00	$36.81	$577.15
HB Threshold	1,000	1,000															
Total Base Rate Amount			$371.63	$413.54	$490.20	$387.60	$511.46	$467.58	$2,642.01	$322.88	$300.19	$266.67	$258.01	$261.39	$278.43	$1,687.58	$4,329.59
COG Rate - (Seasonal)			$0.7305	$0.6582	$0.7419	$0.6155	$0.4984	$0.4145	$0.5977	$0.4415	$0.4698	$0.4698	$0.4498	$0.4498	$0.5188	$0.4654	$0.5495
COG amount			$844.58	$962.81	$1,501.30	$783.52	$1,086.04	$770.19	$5,948.43	$597.33	$509.14	$384.14	$341.60	$351.83	$465.25	$2,649.30	$8,597.73
LDAC			$0.0370	$0.0370	$0.0450	$0.0450	$0.0450	$0.0450	0.0429	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0522
LDAC amount			$42.78	$54.12	$91.06	$57.28	$98.06	$83.62	$426.92	$92.68	$74.24	$56.01	$52.02	$53.58	$61.43	$389.96	$816.88
Total Bill			**$1,258.98**	**$1,430.47**	**$2,082.57**	**$1,228.40**	**$1,695.56**	**$1,321.39**	**$9,017.36**	**$1,012.89**	**$883.57**	**$706.82**	**$651.64**	**$666.80**	**$805.11**	**$4,726.83**	**$13,744.19**

DIFFERENCE:

Total Bill	**$12.92**	**$116.14**	**($33.52)**	**$148.16**	**$492.78**	**$579.41**	**$1,315.89**	**($6.42)**	**($37.49)**	**($1.24)**	**$42.24**	**$43.05**	**($14.76)**	**$25.37**	**$1,341.27**
% Change	**1.03%**	**8.12%**	**-1.61%**	**12.06%**	**29.06%**	**43.85%**	**14.59%**	**-0.63%**	**-4.24%**	**-0.18%**	**6.48%**	**6.46%**	**-1.83%**	**0.54%**	**9.76%**
Base Rate	$39.13	$43.54	$51.62	$40.81	$53.86	$49.24	$278.20	$3.86	$1.41	$28.12	$27.20	$27.56	$29.36	$117.51	$395.71
% Change	10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	1.20%	0.47%	10.54%	10.54%	10.54%	10.54%	6.96%	9.14%
COG & LDAC	($26.21)	$72.60	($85.13)	$107.35	$438.93	$530.17	$1,037.70	($10.28)	($38.91)	($29.35)	$15.04	$15.49	($44.12)	($92.14)	$945.56
% Change	-3.10%	7.54%	-5.67%	13.70%	40.42%	68.84%	17.44%	-1.72%	-7.64%	-7.64%	4.40%	4.40%	-9.48%	-3.48%	11.00%
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 2017 - 2018 Winter Cost of Gas Filing
Residential Heating

	Winter 2016-17	Winter 2017-18
Customer Charge	$22.10	$24.43
First 100 Therms	$0.3495	$0.3863
Excess 100 Therms	$0.2892	$0.3197
LDAC	$0.0621	$0.0856
COG	$0.5905	$0.6659
Total Adjust	$0.6526	$0.7515

		Winter 2016-17 COG @	Winter 2017-18 COG @	Total		Base Rate		COG		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$0.6526	$0.7515	$0.10	15%						
Cooking alone	5	$27.11	$27.61	$0.49	2%	$0.00	0%	$0.38	1%	$0.12	0%
	10	$32.12	$33.11	$0.99	3%	$0.00	0%	$0.75	2%	$0.24	1%
	20	$42.14	$44.12	$1.98	5%	$0.00	0%	$1.51	3%	$0.47	1%
Water Heating alone	30	$52.16	$55.13	$2.97	6%	$0.00	0%	$2.26	4%	$0.71	1%
	45	$67.19	$71.65	$4.45	7%	$0.00	0%	$3.39	5%	$1.06	2%
	50	$72.20	$77.15	$4.95	7%	$0.00	0%	$3.77	5%	$1.18	2%
Heating Alone	80	$97.25	$104.68	$7.42	8%	$0.00	0%	$5.66	5%	$1.77	2%
	125	$153.38	$166.55	$13.16	9%	$0.00	0%	$10.03	6%	$3.13	2%
	150	$169.39	$184.24	$14.84	9%	$0.00	0%	$11.31	6%	$3.53	2%
	200	$216.48	$236.27	$19.79	9%	$0.00	0%	$15.08	6%	$4.71	2%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **Variance Analysis of the Components of the Winter 2016-17 Actual Results vs Proposed Winter 2017-18 Cost of Gas Rate**

Line		**WINTER 2016-17 ACTUAL RESULTS (6 months actual)**			**WINTER 2017-18 (6 months Proposed)**		
11	Therm Sales	75,280,949			84,893,215		
12–14		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
16	Demand Charges		$ 9,945,212	$ 0.1321		$ 9,975,490	$ 0.1175
18	Purchased Gas		$ 22,216,320	0.2951	68,488,854	$ 40,677,774	0.4792
20	Storage/Produced Gas		$ 3,835,498	0.0509	20,998,591	$ 9,002,777	0.1060
22	Hedging (Gain)/Loss		0	0.0000		0	0.0000
25	Total Volumes and Cost	67,985,084	$ 35,997,030	$ 0.4782	89,487,445	$ 59,656,041	$ 0.7027
27	Direct Costs						
28	Prior Period Balance		$ 4,964,031	$ 0.0659		1,714,057	$ 0.0202
29	Interest		36,067	0.0005		(90,332)	(0.0011)
30	Prior Period Adjustment		-	-		-	-
31	Broker Revenues		(456,982)	(0.0061)		(4,580,575)	(0.0540)
32	Refunds from Suppliers		-	-		-	-
33	Fuel Financing		-	-		-	-
34	Transportation CGA Revenues		28,808	0.0004		(207,219)	(0.0024)
35	280 Day Margin		-	-		-	-
36	Interruptible Sales Margin		-	-		-	-
37	Capacity Release and Off System Sales Margins		(2,099,545)	(0.0279)		(2,099,545)	(0.0247)
38	Hedging Costs		-	-		-	-
39	FPO Admin Costs		45,000	0.0006		45,000	0.0005
40	Indirect Costs		-	-			
41	Misc Overhead		7,926	0.0001		10,737	0.0001
42	Occupant Disallowance/Credits		-	-		-	-
43	Production & Storage		1,980,428	0.0263		1,980,428	0.0233
44	Bad Debt Adjustment %		(911,388)	(0.0121)		104,139	0.0012
45	Cashout, Broker penalty, Canadian Managed,…		-	-		0	0
46	Total Adjusted Cost		$ 39,591,376	**$ 0.5259**		$ 56,532,731	**$ 0.6659**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2017 - 2018 Winter Cost of Gas Filing
Capacity Assignment Calculations 2016-2017
<u>Derivation of Class Assignments and Weightings</u>

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			554	548	0.3%		99	450
2	RATE R-3-Resi Htg			67,351	66,495	42.3%		3,710	62,785
3	RATE G-41 (T)			27,438	27,082	17.2%		973	26,109
4	RATE G-51 (S)			2,631	2,604	1.7%		624	1,980
5	RATE G-42 (V)			36,637	36,174	23.0%		2,164	34,009
6	RATE G-52			4,655	4,610	2.9%		1,365	3,246
7	RATE G-43			9,973	9,851	6.3%		886	8,965
8	RATE G-53			4,956	4,916	3.1%		1,995	2,921
9	RATE G-54			4,979	4,978	3.2%		4,895	83
10									
11	Total			159,173	157,258	100.0%		16,711	140,548
12									-
13	Residential Total			67,905	67,044	**42.633%**		3,809	63,235
14	LLF Total			74,048	73,107	**46.488%**		4,024	69,083
15	HLF Total			17,220	17,108	**10.879%**		8,878	8,230
16	Total			159,173	157,258	100.0%		16,711	140,548
17									
18	C&I Breakdown								
19	LLF Total							4,024	69,083
20	HLF Total							8,878	8,230
21	Total							12,902	77,313
22									
23	C&I Breakdown Percentage								
24	LLF Total							31.186%	89.355%
25	HLF Total							68.814%	10.645%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$13,574,999	79,718	$14.1906			
30	Storage			$4,006,683	28,115	$11.8759			
31									
32	Peaking			$3,969,000					
33	Peaking Additional Costs			$0					
34	Subtotal Peaking Costs			$3,969,000	49,425	$6.6919			
35	Total			$21,550,682	157,258	$11.4200			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			2,845,602	16,711	$14.1906			
39	Pipeline - Remaining			10,729,397	63,007	$14.1907			
40	Storage			4,006,683	28,115	$11.8759			
41	Peaking			3,969,000	49,425	$6.6919			
42	Total			21,550,682	157,258	$11.4200			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**42.633%**	1,213,165	7,124	$14.1906			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**42.633%**	4,574,277	26,862	$14.1907			
48	Storage	Line 40 * Line 13 Col C	**42.633%**	1,708,173	11,986	$11.8759			
49	Peaking	Line 41 * Line 13 Col C	**42.633%**	1,692,141	21,072	$6.6919			
50	Total		**42.633%**	9,187,770	67,044	$11.4200			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2017 - 2018 Winter Cost of Gas Filing
Capacity Assignment Calculations 2016-2017
<u>Derivation of Class Assignments and Weightings</u>

51								
52								**Ratios for COG**
53	C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46			1,632,437	9,586	$14.1906	
55	Pipeline - Remaining	Line 39 - Line 47			6,155,120	36,145	$14.1906	
56	Storage	Line 40 - Line 48			2,298,511	16,129	$11.8759	
57	Peaking	Line 41 - Line 49			2,276,859	28,353	$6.6920	
58	Total			**57.367%**	12,362,926	90,214	$11.4201	**1.0000**
59								
60								
61	LLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E			509,094	2,990	$14.1888	
63	Pipeline - Remaining	Line 55 * Line 24 Col F			5,499,921	32,298	$14.1906	
64	Storage	Line 56 * Line 24 Col F			2,053,839	14,412	$11.8757	
65	Peaking	Line 57 * Line 24 Col F			2,034,493	25,335	$6.6920	
66	Total			**46.8540%**	10,097,347	75,035	$11.2140	**0.9820**
67				31.186%	82%			(Line 66 / Line 58)
68								
69	HLF - C&I Allocation				Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62			1,123,343	6,596	$14.1922	
71	Pipeline - Remaining	Line 55 - Line 63			655,199	3,847	$14.1929	
72	Storage	Line 56 - Line 64			244,672	1,717	$11.8750	
73	Peaking	Line 57 - Line 65			242,366	3,018	$6.6922	
74	Total			**10.5128%**	2,265,580	15,178	$12.4389	**1.0892**
75								(Line 74 / Line 58)
76								
77	Unit Cost				Residential	LLF C&I	HLF C&I	
78								
79	Pipeline				$ 14.1906	$ 14.1906	$ 14.1906	
80	Storage				$ 11.8759	$ 11.8759	$ 11.8759	
81	Peaking				$ -	$ -	$ -	
82	Total				$ 11.4200	$ 11.2140	$ 12.4389	
83								
84								
85	Load Makeup				Residential	**LLF C&I**	**HLF C&I**	
86								
87	Pipeline				50.69%	**47.03%**	**68.80%**	
88	Storage				17.88%	**19.21%**	**11.31%**	
89	Peaking				31.43%	**33.76%**	**19.88%**	
90	Total				100.00%	**100.00%**	**100.00%**	
91								
92								
93	Supply Makeup				Residential	LLF C&I	HLF C&I	Total
94								
95	Pipeline				42.63%	44.27%	13.10%	100.00%
96	Storage				42.63%	51.26%	6.11%	100.00%
97	Peaking				42.63%	51.26%	6.11%	100.00%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **2017-2018 Winter Calculation**
4 **Correction Factor Calculation**
5
6

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	1,321,111	2,319,295	3,165,324	3,498,898	2,926,489	1,918,432	15,149,549
12	G-42	978,411	1,695,282	2,275,930	2,377,110	1,979,683	1,404,182	10,710,597
13	G-43	274,121	383,394	557,113	635,485	555,751	454,729	2,860,593
14	High Winter Use	2,573,642	4,397,970	5,998,368	6,511,493	5,461,922	3,777,343	28,720,738
15								
16	G-51	145,709	190,756	233,577	243,976	225,059	174,292	1,213,369
17	G-52	140,479	175,745	215,637	228,808	215,572	171,476	1,147,717
18	G-53	35,436	56,344	139,247	114,987	104,323	93,403	543,741
19	G-54	26,753	27,864	29,471	31,094	31,443	28,854	175,480
21	Low Winter Use	348,377	450,708	617,932	618,866	576,398	468,025	3,080,306
22								
23	Gross Total	2,922,019	4,848,678	6,616,300	7,130,359	6,038,320	4,245,368	31,801,045

24
25

Ln			
26	Total Sales	31,801,045	
27	Low Winter Use	3,080,306	
28	Winter Ratio for Low Winter Use	**1.0892**	Schedule 10A p 2, ln 74
29	High Winter Use	28,720,738	
30	Winter Ratio for High Winter Use	**0.9820**	Schedule 10A p 2, ln 66

31
32 Correction Factor = Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use
33 Correction Factor = **100.7675%**
34
35
36 **Allocation Calculation for Miscellaneous Overhead**
37

38	Projected Winter Sales Volume	11/1/17 - 4/30/18	85,410,999	Sch.10B, ln 23
39	Projected Annual Sales Volume	11/1/17 - 10/31/18	104,762,210	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales		81.53%	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
4 **2017 - 2018 Winter Cost of Gas Filing**
5

6		**Dry Therms**														
7	**Firm Sales**							**Subtotal**							**Subtotal**	
8		**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**PK 17-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**OP 18**	**Total**
9	R-1	57,623	72,661	84,359	86,699	79,383	60,378	441,104	43,684	29,768	23,029	24,282	31,635	42,827	195,224	636,328
10	R-3	4,079,242	7,475,896	10,601,656	11,353,277	9,618,787	6,468,165	49,597,025	3,724,993	1,790,044	1,015,816	990,808	1,495,623	2,684,292	11,701,577	61,298,601
11	R-4	233,466	440,531	693,701	853,546	755,650	594,932	3,571,826	374,489	184,989	93,885	82,302	101,018	155,695	992,377	4,564,203
12	Total Residential.	4,370,332	7,989,089	11,379,716	12,293,522	10,453,820	7,123,475	53,609,954	4,143,166	2,004,800	1,132,729	1,097,392	1,628,276	2,882,815	12,889,178	66,499,132
13																
14	G-41	1,321,111	2,319,295	3,165,324	3,498,898	2,926,489	1,918,432	15,149,549	800,752	362,799	221,003	168,494	181,681	460,017	2,194,746	17,344,295
15	G-42	978,411	1,695,282	2,275,930	2,377,110	1,979,683	1,404,182	10,710,597	817,806	502,755	252,343	126,836	81,887	248,961	2,030,588	12,741,185
16	G-43	274,121	383,394	557,113	635,485	555,751	454,729	2,860,593	231,121	150,438	102,345	80,518	92,255	145,983	802,660	3,663,253
17	G-51	145,709	190,756	233,577	243,976	225,059	174,292	1,213,369	123,414	79,565	60,119	60,427	76,255	101,798	501,577	1,714,946
18	G-52	140,479	175,745	215,637	228,808	215,572	171,476	1,147,717	125,965	84,837	66,025	66,047	80,932	103,486	527,290	1,675,006
19	G-53	35,436	56,344	139,247	114,987	104,323	93,403	543,741	65,831	46,531	37,351	35,453	38,931	45,666	269,763	813,504
20	G-54	26,753	27,864	29,471	31,094	31,443	28,854	175,480	26,582	21,741	19,064	19,946	23,411	24,666	135,409	310,889
21	Total C/I	2,922,019	4,848,678	6,616,300	7,130,359	6,038,320	4,245,368	31,801,045	2,191,471	1,248,665	758,249	557,720	575,351	1,130,577	6,462,033	38,263,077
22																
23	**Sales Volume**	**7,292,351**	**12,837,767**	**17,996,016**	**19,423,880**	**16,492,140**	**11,368,843**	**85,410,999**	**6,334,637**	**3,253,466**	**1,890,979**	**1,655,112**	**2,203,627**	**4,013,391**	**19,351,211**	**104,762,210**
24																
25	Transportation Sales															
26																
27	G-41	539,128	767,088	1,039,425	1,121,625	930,642	730,368	5,128,276	419,152	223,968	126,739	130,012	177,081	307,285	1,384,236	6,512,512
28	G-42	1,628,897	2,359,192	3,236,038	3,506,931	2,907,187	2,278,846	15,917,091	1,277,699	653,670	331,128	308,102	424,112	829,661	3,824,373	19,741,464
29	G-43	1,114,669	1,636,244	2,104,524	2,324,958	2,147,547	1,701,680	11,029,622	1,166,024	718,428	474,845	407,575	463,279	699,961	3,930,112	14,959,734
30	G-51	66,126	73,032	85,860	99,636	94,845	91,257	510,757	77,824	67,235	64,233	77,040	88,667	80,334	455,334	966,091
31	G-52	282,820	298,833	328,371	353,283	342,688	316,601	1,922,596	283,695	260,424	264,769	323,847	380,983	356,910	1,870,628	3,793,224
32	G-53	515,413	675,134	870,468	981,648	976,626	894,346	4,913,637	739,996	529,662	363,450	297,063	282,627	351,494	2,564,292	7,477,928
33	G-54	2,242,756	2,253,199	2,330,289	1,981,930	1,908,058	1,825,916	12,542,149	1,781,763	1,808,656	1,788,616	1,955,455	2,061,440	2,219,044	11,614,976	24,157,124
34																
35	Total Trans. Sales	**6,389,809**	**8,062,724**	**9,994,975**	**10,370,011**	**9,307,593**	**7,839,016**	**51,964,128**	**5,746,154**	**4,262,044**	**3,413,780**	**3,499,094**	**3,878,188**	**4,844,690**	**25,643,949**	**77,608,077**
36																
37	Total All Sales	**13,682,160**	**20,900,491**	**27,990,992**	**29,793,891**	**25,799,733**	**19,207,859**	**137,375,127**	**12,080,790**	**7,515,509**	**5,304,758**	**5,154,206**	**6,081,815**	**8,858,081**	**44,995,160**	**182,370,287**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2017 - 2018 Winter Cost of Gas Filing
Normal and Design Year Volumes

Volumes (Therms) **Normal Year**

For the Months of November 17 - April 18

	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	787,330	850,682	874,909	797,329	841,223	597,333	4,748,807
Niagara Supply	618,381	685,075	697,621	626,115	686,018	577,956	3,891,167
TGP Supply (Gulf)	4,156,418	2,932,802	2,986,510	2,681,405	2,924,082	-	15,681,218
Dracut Supply 1 - Baseload	-	2,627,066	4,458,865	3,002,343	-	-	10,088,274
Dracut Supply 2 - Swing	3,142,062	1,669,517	1,395,242	3,233,733	6,398,113	2,669,288	18,507,956
ENGIE Combo	-	1,296,548	1,184,082	1,268,707	29,057	-	3,778,393
LNG Truck	19,139	220,809	248,636	131,814	90,004	-	710,402
Propane Truck	-	-	763,924	-	-	-	763,924
PNGTS	54,117	77,142	87,203	73,787	68,035	45,435	405,718
TGP Supply (Z4)	1,623,498	1,805,400	1,838,462	1,650,536	1,807,885	4,908,951	13,634,732
Subtotal Pipeline Volumes	10,400,946	12,165,042	14,535,452	13,465,770	12,844,418	8,798,962	72,210,589
Storage Gas:							
TGP Storage	1,005,117	4,949,103	5,774,831	5,116,377	2,150,894	-	18,996,322
Produced Gas:							
LNG Vapor	19,139	220,809	325,749	135,396	20,552	18,708	740,353
Propane	-	-	1,261,916	-	-	-	1,261,916
Subtotal Produced Gas	19,139	220,809	1,587,664	135,396	20,552	18,708	2,002,269
Less - Gas Refills:							
LNG Truck	(19,139)	(220,809)	(248,636)	(131,814)	(90,004)	-	(710,402)
Propane	-	-	(763,924)	-	-	-	(763,924)
TGP Storage Refill	(1,527,804)	-	-	-	-	(719,605)	(2,247,409)
Subtotal Refills	(1,546,943)	(220,809)	(1,012,559)	(131,814)	(90,004)	(719,605)	(3,721,735)
Total Sendout Volumes	9,878,258	17,114,145	20,885,388	18,585,729	14,925,860	8,098,065	89,487,445

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2017 - 2018 Winter Cost of Gas Filing**
42 **Normal and Design Year Volumes**

43
44
45 **Volumes (Therms)** **Design Year**
46
47 **For the Months of November 17 - April 18**
48

Line		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Peak Nov - Apr
51	Pipeline Gas:							
52	Dawn Supply	782,760	872,256	888,272	796,908	873,488	702,736	4,916,420
53	Niagara Supply	618,420	685,344	697,928	625,784	686,312	604,540	3,918,328
54	TGP Supply (Gulf)	4,156,680	2,933,952	2,987,824	2,679,988	2,938,096	-	15,696,540
55	Dracut Supply 1 - Baseload	-	2,628,096	4,460,827	3,000,756	-	-	10,089,679
56	Dracut Supply 2 - Swing	3,971,880	3,776,472	3,366,349	4,444,928	8,060,621	3,420,160	27,040,410
57	ENGIE Combo	-	1,299,888	1,421,091	1,112,664	170,869	-	4,004,512
58	LNG Truck	19,140	42,480	7,931	287,116	127,620	-	484,287
59	Propane Truck	-	-	713,790	50,120	-	-	763,910
60	PNGTS	54,120	77,172	87,241	73,748	68,064	45,424	405,769
61	TGP Supply (Z4)	1,623,600	1,806,108	1,839,271	1,649,664	1,808,659	4,760,836	13,488,138
62	Subtotal Pipeline Volumes	11,226,600	14,121,768	16,470,524	14,721,676	14,733,729	9,533,696	80,807,993
63								
64	Storage Gas:							
65	TGP Storage	1,042,800	5,049,456	6,047,748	5,071,428	1,846,236	-	19,057,668
66								0
67	Produced Gas:							0
68	LNG Vapor	19,140	42,480	87,962	287,116	58,847	18,704	514,249
69	Propane	-	-	1,212,001	50,120	-	-	1,262,121
70	Subtotal Produced Gas	19,140	42,480	1,299,963	337,236	58,847	18,704	1,776,370
71								
72	Less - Gas Refills:							
73	LNG Truck	(19,140)	(42,480)	(7,931)	(287,116)	(127,620)	-	-484,287
74	Propane	-	-	(713,790)	(50,120)	-	-	-763,910
75	TGP Storage Refill	(1,566,180)	-	-	-	-	(563,124)	-2,129,304
76	Subtotal Refills	(1,585,320)	(42,480)	(721,721)	(337,236)	(127,620)	(563,124)	(3,377,501)
77								
78	Total Sendout Volumes	10,703,220	19,171,224	23,096,514	19,793,104	16,511,192	8,989,276	98,264,530

Liberty Utilities (EnergyNorth Natural Gas) Corp. — **Schedule 11C**
d/b/a Liberty Utilities — **Page 1 of 1**
Peak 2017 - 2018 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	4,748,807	4,000	7,240,000	66%	4,916,420	4,000	7,240,000	68%
Niagara Supply	3,891,167	3,122	5,650,820	69%	3,918,328	3,122	5,650,820	69%
TGP Supply (Gulf + Z4)	29,315,950	21,596	39,088,760	75%	29,184,678	21,596	39,088,760	75%
Dracut Supply 1 & 2	28,596,229	50,000	90,500,000	32%	37,130,089	50,000	90,500,000	41%
LNG Truck	710,402	-	-	-	484,287	-	-	-
Propane Truck	763,924	-	-	-	763,910	-	-	-
PNGTS	405,718	1,000	1,810,000	22%	405,769	1,000	1,810,000	22%
Engie Vapor	3,778,393	7,000	6,300,000	60%	4,004,512	7,000	6,300,000	64%
Subtotal Pipeline Volumes	72,210,589				80,807,993			
Storage Gas:								
TGP Storage	18,996,322		25,791,710	74%	19,057,668		25,791,710	74%
Produced Gas:								
LNG Vapor	740,353				514,249			
Propane	1,261,915.6				1,262,121			
Subtotal Produced Gas	2,002,269				1,776,370			
Less - Gas Refills:								
LNG Truck	(710,402)				(484,287)			
Propane	(763,924)				(763,910)			
TGP Storage Refill	(2,247,409)				(2,129,304)			
Subtotal Refills	(3,721,735)				(3,377,501)			
Total Sendout Volumes	89,487,445				98,264,530			

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2017 - 2018 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2017 / 18 Heating Season
(Therms)

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

Requirements	
Firm Sales	1,100,809
Interruptible Sales	0
Firm Transportation	471,775
Interruptible Transportation	0
Total Requirements	1,572,585
Resources	
Purchased Pipeline Gas	797,180
Underground Storage Gas	281,150
Propane Air Production	298,255
LNG Produced Gas	126,000
Third-Party Supply	70,000
Total Resources	1,572,585

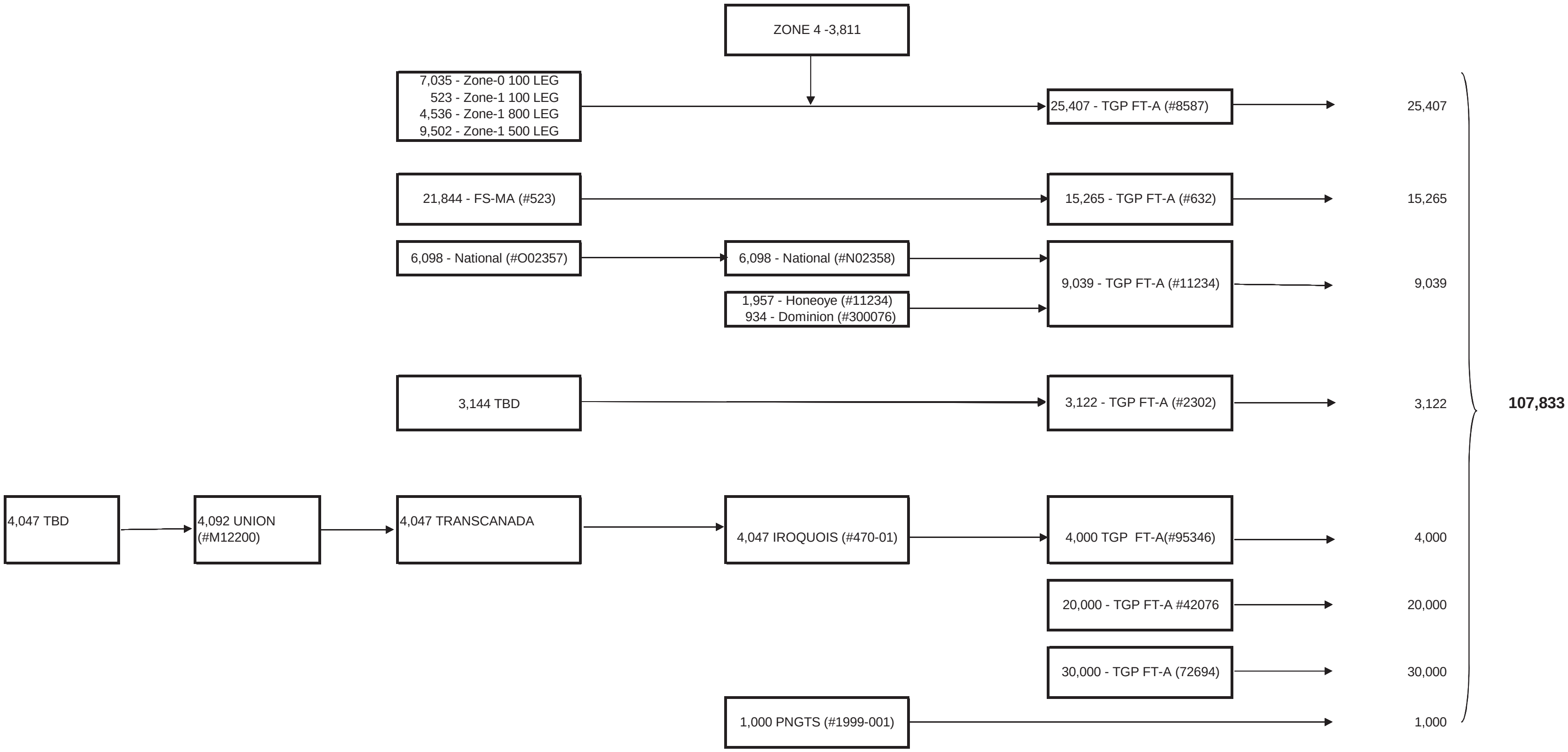
Please refer to the ENGI 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

Deborah Gilbertson
Sr. Manager, Energy Procurement

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

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2017 - 2018 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2017 - 2018 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	3,147	1,148,655	3/31/2018	N/a	Terminates
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/a	Terminates
ENGIE	FCS		Firm Combination Liquid and Vapor Svc	Up to 7 trucks	630,000	3/31/2018 Peak Only	-	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2018	-	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2018	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	3/31/2020	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2019	3/31/2018	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2019	3/31/2018	Evergreen Provision
Iroquois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11/1/2018	11/1/2017	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	11/30/2021	11/30/2020	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	41232	Transportation	4,047	1,477,155	10/31/2022	10/31/2020	Evergreen Provision
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2022	10/31/2020	Evergreen Provision

* MAQ is calculated on a 365 day calendar year.

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2017 - 2018 Winter Cost of Gas Filing

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

May 2015 - Apr 2016 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	16,184,505	44.55%	72.29%
G-42	13,003,688	35.79%	38.78%
G-43	1,585,779	4.36%	14.51%
G-51	2,305,581	6.35%	63.31%
G-52	2,195,274	6.04%	28.66%
G-53	517,621	1.42%	5.22%
G-54	538,468	1.48%	3.19%
Total C/I	36,330,917	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	6,202,935	9.04%	27.71%
G-42	20,524,759	29.91%	61.22%
G-43	9,345,069	13.62%	85.49%
G-51	1,336,159	1.95%	36.69%
G-52	5,465,341	7.97%	71.34%
G-53	9,396,822	13.69%	94.78%
G-54	16,345,493	23.82%	96.81%
Total C/I	68,616,578	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	22,387,440	21.33%	100.00%
G-42	33,528,446	31.95%	100.00%
G-43	10,930,848	10.42%	100.00%
G-51	3,641,741	3.47%	100.00%
G-52	7,660,614	7.30%	100.00%
G-53	9,914,443	9.45%	100.00%
G-54	16,883,961	16.09%	100.00%
Total C/I	104,947,494	100.00%	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2017 - 2018 Winter Cost of Gas Filing

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

	Off-Peak May 16 - Oct 16 (Therms)	Peak Nov 16-Apr 17 (Therms)	Total May 16 - Apr 17 (Therms)	Ratio
Pipeline Deliveries	16,593,820	61,069,600	77,663,420	
All Others	11,705,960	6,915,480	18,621,440	
	28,299,780	67,985,080	96,284,860	
Total Winter Supplies				67,985,080
Total Pipeline Deliveries				77,663,420
Ratio Winter Supplies to Pipeline Supplies				0.875

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2017 - 2018 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-16**	**Aug-16**	**Jul - Aug Total**	**Total Annual**	**% of Jul-Aug to Total**
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	187,156	166,953	354,109	16,184,505	2.19%
G-42	230,590	242,068	472,659	13,003,688	3.63%
G-43	18,327	36,883	55,210	1,585,779	3.48%
G-51	119,037	116,282	235,320	2,305,581	10.21%
G-52	117,664	103,210	220,875	2,195,274	10.06%
G-53	19,777	14,475	34,251	517,621	6.62%
G-54	37,899	29,892	67,791	538,468	12.59%
Total C/I	730,451	709,763	1,440,214	36,330,917	3.96%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **Peak 2017 - 2018 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-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Total
8			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		683,080	849,079	1,076,180	1,305,521	1,529,383	1,753,246	1,977,108	2,029,377	1,534,466	956,983	445,346	230,256	683,080
10															
11	Injections (MMBtu)	Sch 11A ln 37 /10	200,399	236,879	235,603	223,862	223,862	223,862	152,780	-	-	-	-	71,961	1,569,209
12															
13	Subtotal		883,479	1,085,958	1,311,783	1,529,383	1,753,246	1,977,108	2,129,888	2,029,377	1,534,466	956,983	445,346	302,217	
14															
15	Storage Sale/Adjustments		(3,426)	(2,722)	(1,716)			-							
16															
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(30,974)	(7,056)	(4,546)	-	-	-	(100,512)	(494,910)	(577,483)	(511,638)	(215,089)	-	(1,942,208)
18															
19	Ending Balance (MMBtu)		849,079	1,076,180	1,305,521	1,529,383	1,753,246	1,977,108	2,029,377	1,534,466	956,983	445,346	230,256	302,217	310,081
20															
21															
22	Beginning Balance		$ 1,462,637	$ 1,955,655	$ 2,624,008	$ 3,099,651	$ 3,547,375	$ 3,972,714	$ 4,375,666	$ 4,528,063	$ 3,423,791	$ 2,135,277	$ 993,681	$ 513,761	1,462,637
23															
24	Injections	ln 11 * ln 36	$ 558,764	$ 675,871	$ 475,112	$ 447,725	$ 425,338	$ 402,952	$ 376,665	$ -	$ -	$ -	$ -	$ 182,442	$ 3,544,869
25															
26	Subtotal		$ 2,021,401	$ 2,631,526	$ 3,099,120	$ 3,547,375	$ 3,972,714	$ 4,375,666	$ 4,752,331	$ 4,528,063	$ 3,423,791	$ 2,135,277	$ 993,681	$ 696,202	
27															
28	Storage Sale/Adjustments		$ 5,596	$ (1,601)	$ 531			$ -							
29															
30	Withdrawals	ln 17 * ln 34	$ (71,341)	$ (5,918)	$ -	$ -	$ -	$ -	$ (224,267)	$ (1,104,273)	$ (1,288,514)	$ (1,141,596)	$ (479,920)	$ -	(4,315,829)
31															
32	Ending Balance		$ 1,955,655	$ 2,624,008	$ 3,099,651	$ 3,547,375	$ 3,972,714	$ 4,375,666	$ 4,528,063	$ 3,423,791	$ 2,135,277	$ 993,681	$ 513,761	$ 696,202	$ 691,676
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.2880	$2.4232	$2.3625	$2.3195	$2.2659	$2.2132	$2.2313	$2.2313	$2.2313	$2.2313	$2.2313	$2.3037	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$1.3812	$1.5040	$2.1500	$2.0000	$1.9000	$1.8000	$2.4654	$2.7095	$2.8883	$2.9063	$2.8054	$2.5353	
37															
38	For Informational Purposes								Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	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								$2.9900	$3.1408	$3.2346	$3.2231	$3.1751	$2.8436	
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				$ 3,323,513	$ 3,760,045	$ 4,174,190	$ 4,451,865	$ 3,975,927	$ 2,779,534	$ 1,564,479	$ 753,721	$ 604,982	
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-17 (Actual)	Jun-17 (Actual)	Jul-17 (Actual)	Aug-17 (Estimate)	Sep-17 (Estimate)	Oct-17 (Estimate)	Nov-17 (Estimate)	Dec-17 (Estimate)	Jan-18 (Estimate)	Feb-18 (Estimate)	Mar-18 (Estimate)	Apr-18 (Estimate)	Total
39															
40	**Liquid Propane Gas (LPG)**														
43	Beginning Balance		85,361	85,689	85,611	86,178	86,178	86,178	86,178	86,178	86,178	36,379	36,379	36,379	85,361
44															
45	Injections	Sch 11A ln 36 /10	328	(78)	567	-	-	-	-	-	76,392	-	-	-	77,209
46															
47	Subtotal		85,689	85,611	86,178	86,178	86,178	86,178	86,178	86,178	162,570	36,379	36,379	36,379	
48															
49	Withdrawals	Sch 11A ln 31 /10	-	-	-	-	-	-	-	-	(126,192)	-	-	-	(126,192)
50															
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		85,689	85,611	86,178	86,178	86,178	86,178	86,178	86,178	36,379	36,379	36,379	36,379	36,379
54															
55															
56	Beginning Balance		$ 869,765	$ 873,107	$ 872,312	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 196,492	$ 196,492	$ 196,492	$ 869,765
57															
58	Injections	ln 45 * ln 68	3,342	(795)	5,777	-	-	-	-	-	-	-	-	-	8,325
59															
60	Subtotal		$ 873,107	$ 872,312	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 196,492	$ 196,492	$ 196,492	
61															
62	Withdrawals	ln 51 * ln 66	-	-	-	-	-	-	-	-	(681,597)	-	-	-	(681,597)
63															
64	Ending Balance		$ 873,107	$ 872,312	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 196,492	$ 196,492	$ 196,492	$ 196,492	$ 196,492
65															
66	Average Rate For Withdrawals		$10.1893	$10.1893	$10.1893	$10.1893	$10.1893	$10.1893	$10.1893	$10.1893	$5.4013	$5.4013	$5.4013	$5.4013	
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				$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 878,090	$ 537,291	$ 196,492	$ 196,492	$ 196,492	
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															

Ln			May-17 (Actual)	Jun-17 (Actual)	Jul-17 (Actual)	Aug-17 (Estimate)	Sep-17 (Estimate)	Oct-17 (Estimate)	Nov-17 (Estimate)	Dec-17 (Estimate)	Jan-18 (Estimate)	Feb-18 (Estimate)	Mar-18 (Estimate)	Apr-18 (Estimate)	Total
72	**Liquid Natural Gas (LNG)**														
74	Beginning Balance		10,638	8,696	10,846	9,212	11,362	13,512	15,662	15,662	15,662	7,951	7,593	14,538	10,638
76	Injections	Sch 11A ln 35 /10	16	3,447	42	3,447	3,447	3,447	1,914	22,081	24,864	13,181	9,000	-	84,886
78	Subtotal		10,654	12,143	10,888	12,659	14,809	16,959	17,576	37,743	40,526	21,132	16,593	14,538	
80	Withdrawals	Sch 11A ln 30 /10	(1,958)	(1,297)	(1,676)	(1,297)	(1,297)	(1,297)	(1,914)	(22,081)	(32,575)	(13,540)	(2,055)	(1,871)	(82,857)
82	Ending Balance		8,696	10,846	9,212	11,362	13,512	15,662	15,662	15,662	7,951	7,593	14,538	12,667	12,667
85	Beginning Balance		$ 69,371	$ 64,139	$ 79,815	$ 75,495	$ 761,384	$ 1,399,819	$ 2,006,463	$ 1,806,540	$ 850,964	$ 221,386	$ 132,282	$ 203,099	$ 69,371
87	Injections	ln 76 * ln 97	9,211	21,935	9,416	772,803	772,803	772,803	20,834	244,150	277,462	146,793	99,529	-	3,147,739
89	Subtotal		$ 78,582	$ 86,074	$ 89,231	$ 848,297	$ 1,534,186	$ 2,172,622	$ 2,027,297	$ 2,050,690	$ 1,128,427	$ 368,179	$ 231,811	$ 203,099	
91	Withdrawals	ln 80 * ln 95	(14,443)	(6,259)	(13,736)	(86,914)	(134,367)	(166,159)	(220,757)	(1,199,725)	(907,041)	(235,896)	(28,712)	(26,136)	(3,040,147)
93	Ending Balance		$ 64,139	$ 79,815	$ 75,495	$ 761,384	$ 1,399,819	$ 2,006,463	$ 1,806,540	$ 850,964	$ 221,386	$ 132,282	$ 203,099	$ 176,962	$ 176,962
95	Average Rate For Withdrawals		$7.3758	$7.0883	$8.1954	$67.0114	$103.5982	$128.1103	$115.3454	$54.3331	$27.8448	$17.4228	$13.9705	$13.9705	
97	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	$575.7181	$6.3635	$224.1957	$224.1957	$224.1957	$224.1957	$10.8857	$11.0571	$11.1594	$11.1364	$11.0582	$0.0000	
100	Month Dollar Average	ln (85 + ln 93) /2				$ 418,439	$ 1,080,601	$ 1,703,141	$ 1,906,501	$ 1,328,752	$ 536,175	$ 176,834	$ 167,691	$ 190,030	
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				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2017 - 2018 Winter Cost of Gas Filing
Peak 2017 - 2018 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-17	6,389,809	$0.0040	$ 25,481
Dec-17	8,062,724	0.0040	32,152
Jan-18	9,994,975	0.0040	39,857
Feb-18	10,370,011	0.0040	41,353
Mar-18	9,307,593	0.0040	37,116
Apr-18	7,839,016	0.0040	31,260
Total	**51,964,128**		**$ 207,219**

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

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 effective November 1, 2017 - October 31, 2018
Docket No. DG 14-180

1	Rate Case Expense in Docket No. DG 14-180	$39,486
2	Recoupment in Docket No. DG 14-180	$1,167,759
3		$1,207,245
4		
5	Estimated November 2017 - October 2018 Interest	$21,681
6		
7	Total Remaining Recovery	$1,228,926
8		
9	Estimated November 2017 - October 2018 Sales (therms)	196,892,274
10		
11	RCE rate per therm November 2017 - October 2018	$0.0062

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2017 THROUGH OCTOBER 2018
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-17**	**Dec-17**	**Jan-18**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**28**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	**30**	
3	Beginning Balance	$ 1,207,245	$ 1,125,914	$ 999,290	$ 827,873	$ 644,306	$ 485,112	$ 366,709	$ 292,493	$ 246,524	$ 214,244	$ 178,266	$ 139,944	$ 85,250	$ 6,813,171
4															
5	Add: Actual Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6															
7	Less: Collected Revenue	(85,399)	(130,453)	(174,709)	(185,962)	(161,032)	(119,888)	(75,404)	(46,909)	(33,110)	(36,685)	(38,876)	(55,100)	(85,399)	(1,228,927)
8															
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10															
11	Ending Balance Pre-Interest	$ 1,121,846	$ 995,461	$ 824,581	$ 641,910	$ 483,274	$ 365,224	$ 291,306	$ 245,584	$ 213,414	$ 177,559	$ 139,389	$ 84,844	$ (149)	**$ 5,584,244**
12															
13	Month's Average Balance	$ 1,164,546	$ 1,060,688	$ 911,935	$ 734,891	$ 563,790	$ 425,168	$ 329,007	$ 269,039	$ 229,969	$ 195,901	$ 158,828	$ 112,394	$ 42,550	
14															
15	Interest Rate	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
16															
17	Interest Applied	$ 4,068	$ 3,829	$ 3,292	$ 2,396	$ 1,838	$ 1,485	$ 1,188	$ 940	$ 830	$ 707	$ 555	$ 406	$ 149	**21,681**
18															
19	Ending Balance	**$ 1,125,914**	**$ 999,290**	**$ 827,873**	**$ 644,306**	**$ 485,112**	**$ 366,709**	**$ 292,493**	**$ 246,524**	**$ 214,244**	**$ 178,266**	**$ 139,944**	**$ 85,250**	**$ (0)**	

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Local Distribution Adjustment Charge (LDAC) increase due to Lost Revenue Adjustment Mechanism
For LDAC effective November 1, 2017 - October 31, 2018

	Residential	
1	October 31, 2017 Projected Balance	($39,021)
2	Calculated Lost Distribution Revenue - November 2017 through October 2018	$165,852
3	Calculated Interest - January 2017 through October 2017	($1,958)
4		
5	Total to be recovered	$124,873
6		
7	Estimated January 2017 - October 2017 Sales (therms)	66,499,132
8		
9	LRAM residential rate per therm January 2017 - October 2017	$0.0019
	Commercial & Industrial	
10	October 31, 2016 Balance	($18,597)
11	Calculated Lost Distribution Revenue - January 2017 through October 2017	$262,648
12	Calculated Interest - January 2017 through October 2017	($2,215)
13		
14	Total to be recovered	$241,836
15		
16	Estimated January 2017 - October 2017 Sales (therms)	115,871,154
17		
18	LRAM C&I rate per therm January 2017 - October 2017	$0.0021

Schedule 19
LRAM
Page 2 of 2

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2017 THROUGH OCTOBER 2018
LOST REVENUE ADJUSTMENT MECHANISM

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
	RESIDENTIAL													
3	Beginning Balance	$ (39,021)	$ (38,374)	$ (43,080)	$ (53,628)	$ (65,347)	$ (73,099)	$ (73,650)	$ (67,653)	$ (56,654)	$ (43,035)	$ (28,357)	$ (13,682)	**$ (595,579)**
4														
5	Add: Lost Distribution Revenues	8,987	10,450	11,014	11,578	12,142	13,081	14,021	14,961	15,901	16,840	17,780	19,096	**165,852**
6														
7	Less: Lost Distribution Revenue Collections	(8,207)	(15,002)	(21,369)	(23,085)	(19,630)	(13,377)	(7,780)	(3,765)	(2,127)	(2,061)	(3,058)	(5,413)	**(101,664)**
8														
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-	-	**-**
10														
11	Ending Balance Pre-Interest	$ (38,240)	$ (42,925)	$ (53,435)	$ (65,135)	$ (72,836)	$ (73,394)	$ (67,409)	$ (56,456)	$ (42,880)	$ (28,255)	$ (13,635)	$ 0	**$ (554,601)**
12														
13	Month's Average Balance	$ (38,630)	$ (40,649)	$ (48,258)	$ (59,382)	$ (69,092)	$ (73,246)	$ (70,530)	$ (62,054)	$ (49,767)	$ (35,645)	$ (20,996)	$ (6,841)	
14														
15	Interest Rate	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
16														
17	Interest Applied	$ (134)	$ (155)	$ (193)	$ (212)	$ (263)	$ (256)	$ (243)	$ (197)	$ (155)	$ (102)	$ (48)	$ 0	**(1,958)**
18														
19	Ending Balance	**$ (38,374)**	**$ (43,080)**	**$ (53,628)**	**$ (65,347)**	**$ (73,099)**	**$ (73,650)**	**$ (67,653)**	**$ (56,654)**	**$ (43,035)**	**$ (28,357)**	**$ (13,682)**	**$ 0**	
	COMMERCIAL & INDUSTRIAL													
3	Beginning Balance	$ (18,597)	$ (23,761)	$ (34,140)	$ (51,433)	$ (69,753)	$ (82,778)	$ (87,552)	$ (82,211)	$ (70,304)	$ (54,102)	$ (36,144)	$ (17,564)	**$ (628,339)**
4														
5	Add: Lost Distribution Revenues	14,354	16,691	17,561	18,432	19,302	20,752	22,203	23,653	25,104	26,555	28,005	30,036	**262,648**
6														
7	Less: Lost Distribution Revenue Collections	(19,435)	(26,948)	(34,670)	(36,525)	(32,029)	(25,221)	(16,567)	(11,501)	(8,707)	(8,467)	(9,295)	(12,471)	**(195,454)**
8														
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-	-	**-**
10														
11	Ending Balance Pre-Interest	$ (23,678)	$ (34,017)	$ (51,248)	$ (69,527)	$ (82,480)	$ (87,247)	$ (81,915)	$ (70,059)	$ (53,907)	$ (36,014)	$ (17,434)	$ 0	**$ (607,527)**
12														
13	Month's Average Balance	$ (21,138)	$ (28,889)	$ (42,694)	$ (60,480)	$ (76,117)	$ (85,012)	$ (84,733)	$ (76,135)	$ (62,105)	$ (45,058)	$ (26,789)	$ (8,782)	
14														
15	Interest Rate	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
16														
17	Interest Applied	$ (83)	$ (123)	$ (185)	$ (227)	$ (298)	$ (305)	$ (296)	$ (245)	$ (195)	$ (130)	$ (130)	$ 0	**(2,215)**
18														
19	Ending Balance	**$ (23,761)**	**$ (34,140)**	**$ (51,433)**	**$ (69,753)**	**$ (82,778)**	**$ (87,552)**	**$ (82,211)**	**$ (70,304)**	**$ (54,102)**	**$ (36,144)**	**$ (17,564)**	**$ 0**	

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

Ln		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 24.4300	$ 0.3863	$ 0.3197		
3	R-4 Rate at 40% of R-3	$ 9.7700	$ 0.1545	$ 0.1278		
4	Program Subsidy	$ 14.6600	$ 0.2318	$ 0.1919		
5	Average Annual Therms		466	141	607	
6						
7	Peak Period RLIAP Subsidy	$ 87.96	$ 107.97	$ 27.15	$ 223.07	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 24.4300	$ 0.3863	$ 0.3197		
11	R-4 Rate at 40% of R-3	$ 9.7700	$ 0.1545	$ 0.1278		
12	Program Subsidy	$ 14.6600	$ 0.2318	$ 0.1919		
13	Average Annual Therms		81	47	128	
14						
15	Off Peak Period RLIAP Subsidy	$ 87.96	$ 18.83	$ 8.98	$ 115.77	
16						
17	Estimated Annual Subsidy	$ 175.92	$ 126.79	$ 36.13	$ 338.84	
18						
19	Number of Estimated 2017/18 Participants				4,463	1/
20						
21	Annual Subsidy times Number of Participants (Ln 17 * Ln 19)				$ 1,512,253	
22	Prior Year Ending Balance - RLIAP Page 2				235,606	
23	Estimated Annual Administrative Costs				-	
24	Total Program Costs				$ 1,747,858	
25						
26	Estimated weather normalized firm therms billed for the					
27	twelve months ended 10/31/18 sales and transportation				182,370,287	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0096**	

1/ Estimated number of participants for 2017-18 is based on the actual number participants as of July 2017.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2016 THROUGH OCTOBER 2017
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.6

		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (333,808)	$ (369,996)	$ (332,358)	$ (281,118)	$ (225,919)	$ (158,720)	$ (75,963)	$ 18,833	$ 75,824	$ 123,849	$ 170,103	$ 209,072	$ (333,808)
4														
5	Add: Actual Costs	102,238	163,002	213,021	213,505	216,864	222,530	168,140	113,084	84,159	81,227	80,423	86,333	1,744,525
6														
7	Less: Collected Revenue	(137,384)	(124,324)	(160,277)	(157,575)	(149,049)	(139,647)	(73,245)	(56,249)	(36,494)	(35,502)	(42,114)	(60,600)	(1,172,461)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ (368,954)	$ (331,318)	$ (279,614)	$ (225,188)	$ (158,105)	$ (75,837)	$ 18,931	$ 75,668	$ 123,489	$ 169,573	$ 208,411	$ 234,804	**$ 238,257**
12														
13	Month's Average Balance	$ (351,381)	$ (350,657)	$ (305,986)	$ (253,153)	$ (192,012)	$ (117,279)	$ (28,516)	$ 47,250	$ 99,656	$ 146,711	$ 189,257	$ 221,938	
14														
15	Interest Rate	3.75%	3.75%	3.75%	3.75%	3.88%	4.00%	4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	
16														
17	Interest Applied	$ (1,042)	$ (1,040)	$ (1,504)	$ (732)	$ (615)	$ (127)	$ (99)	$ 155	$ 360	$ 530	$ 661	$ 801	**(2,651)**
18														
19	Ending Balance	**$ (369,996)**	**$ (332,358)**	**$ (281,118)**	**$ (225,919)**	**$ (158,720)**	**$ (75,963)**	**$ 18,833**	**$ 75,824**	**$ 123,849**	**$ 170,103**	**$ 209,072**	**$ 235,606**	**$ 235,606**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential Non-Heating and Heating Classes
November 1, 2017 - October 31, 2018
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 17	Actual	(749,641)	($0.0402)	(143,125)	265,627	331,161	32,602	10,550	(518,452)	(634,046)	4.00%	(2,154)	(520,606)	3,349,634	3,608,154	31
June 17	Actual	(520,606)	($0.0402)	(96,040)	265,627	152,820	10,518	10,550	(442,758)	(481,682)	4.13%	(1,683)	(444,441)	1,984,898	2,388,901	30
July 17	Forecast	(444,441)	($0.0402)	(50,357)	265,627	0	0		(229,171)	(336,806)	4.25%	(1,216)	(230,387)	1,252,661	0	31
August 17	Forecast	(230,387)	($0.0402)	(42,478)	265,627	0	0		(7,238)	(118,813)	4.25%	(429)	(7,667)	1,056,675	0	31
September 17	Forecast	(7,667)	($0.0402)	(45,953)	265,627	0	0		212,007	102,170	4.25%	357	212,364	1,143,113	0	30
October 17	Forecast	212,364	($0.0402)	(68,080)	265,627	0	0		409,911	311,137	4.25%	1,123	411,034	1,693,533	0	31
November 17	Forecast	411,034	($0.0516)	(225,509)	265,627	0	0		451,152	431,093	4.25%	1,506	452,657	4,370,332	0	30
December 17	Forecast	452,657	($0.0516)	(412,237)	265,627	0	0		306,047	379,352	4.25%	1,369	307,417	7,989,089	0	31
January 18	Forecast	307,417	($0.0516)	(587,193)	250,275	0	0		(29,502)	138,958	4.25%	502	(29,000)	11,379,716	0	31
February 18	Forecast	(29,000)	($0.0516)	(634,346)	250,275	0	0		(413,071)	(221,035)	4.25%	(721)	(413,792)	12,293,522	0	28
March 18	Forecast	(413,792)	($0.0516)	(539,417)	250,275	0	0		(702,934)	(558,363)	4.25%	(2,015)	(704,949)	10,453,820	0	31
April 18	Forecast	(704,949)	($0.0516)	(367,571)	250,275	0	0		(822,246)	(763,597)	4.25%	(2,667)	(824,913)	7,123,475	0	30
May 18	Forecast	(824,913)	($0.0516)	(213,787)	250,275	0	0		(788,425)	(806,669)	4.25%	(2,912)	(791,337)	4,143,166	0	31
June 18	Forecast	(791,337)	($0.0516)	(103,448)	250,275	0	0		(644,510)	(717,924)	4.25%	(2,508)	(647,018)	2,004,800	0	30
July 18	Forecast	(647,018)	($0.0516)	(58,449)	250,275	0	0		(455,192)	(551,105)	4.25%	(1,989)	(457,181)	1,132,729	0	31
August 18	Forecast	(457,181)	($0.0516)	(56,625)	250,275	0	0		(263,532)	(360,356)	4.25%	(1,301)	(264,832)	1,097,392	0	31
September 18	Forecast	(264,832)	($0.0516)	(84,019)	250,275	0	0		(98,576)	(181,704)	4.25%	(635)	(99,211)	1,628,276	0	30
October 18	Forecast	(99,211)	($0.0516)	(148,753)	250,275	0	0		2,311	(48,450)	4.25%	(175)	2,136	2,882,815	0	31
November 18	Forecast	2,136	($0.0516)	(225,509)	250,275	0	0		26,901	14,519	4.25%	51	26,952	4,370,332	0	30
December 18	Forecast	26,952	($0.0516)	(412,237)	250,275	0	0		(135,010)	(54,029)	4.25%	(195)	(135,205)	7,989,089	0	31

Estimated Residential Conservation Charge Effective November 1, 2017 - October 31, 2018		
Beginning Balance	$	411,034
Program Budget Nov 17-Oct 18		3,034,003
Projected Interest		(11,361)
Projected Budget with Interest	$	3,433,676
Total Charges	**$**	**3,433,676**
Projected Therm Sales		**66,499,132**
Residential Rate		**$0.0516**
Total Charges with Interest	**$**	**3,431,355**
Projected Therm Sales		**66,499,132**
Residential Rate		**$0.0516**

Residential Non Heating Therm Sales	0%	778,066	636,328	0%
Residential Heating Therm Sales	35%	64,872,183	65,862,804	36%
C&I Therm Sales	65%	121,258,966	115,871,154	64%
Total Therms	100%	**186,909,214**	**182,370,287**	100%
		Budget 2017	Budget 2018	
Low-Income Program Budget		$ 1,005,700	$ 1,217,300	
Other Refund		-	-	
Total Shared Budget		**$ 1,005,700**	**$ 1,217,300**	
Residential Program Budget		$ 1,907,420	$ 2,362,534	
Residential Program Incentive @ 70%		$160,222	$196,891	
Total Residential Program Budget		**$ 2,067,642**	**$ 2,559,425**	
Commercial/Industrial Program Budget		$ 3,000,600	$ 3,580,741	
Commercial/Industrial Program Incentive at 70%		$165,033	$196,941	
Total Commercial/Industrial Program Budget		**$ 3,165,633**	**$ 3,777,682**	
Total Program Budget		**$ 6,238,975**	**$ 7,554,407**	
Shared Expenses Allocation to Residential		$ 353,243	$ 443,874	
Shared Expenses Allocation to C&I		652,457	773,426	
Total Allocated Shared Expenses		**$ 1,005,700**	**$ 1,217,300**	
Total Residential (including allocation of Shared Budget)		$ 2,420,885	$ 3,003,299	
Total C&I (including allocation of Shared Budget)		3,818,090	4,551,108	
Total Budget		**$ 6,238,975**	**$ 7,554,407**	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2017 - October 31, 2018
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures C&I	Actual DSM Expenditures Low-Income	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
May 17	Actual	(1,094,665)	($0.0219)	(158,066)	245,987	106,016	43,216	9,778	(1,093,721)	(1,094,193)	4.00%	(3,717)	(1,097,438)	6,537,363	7,299,008	31
June 17	Actual	(1,097,438)	($0.0219)	(131,661)	245,987	198,094	13,943	9,778	(1,007,284)	(1,052,361)	4.13%	(3,676)	(1,010,960)	5,092,563	6,011,635	30
July 17	Forecast	(1,010,960)	($0.0219)	(87,792)	245,987	0	0		(852,765)	(931,862)	4.25%	(3,364)	(856,128)	4,008,754	0	31
August 17	Forecast	(856,128)	($0.0219)	(84,349)	245,987	0	0		(694,491)	(775,310)	4.25%	(2,799)	(697,289)	3,851,567	0	31
September 17	Forecast	(697,289)	($0.0219)	(91,025)	245,987	0	0		(542,328)	(619,808)	4.25%	(2,165)	(544,493)	4,156,413	0	30
October 17	Forecast	(544,493)	($0.0219)	(109,234)	245,987	0	0		(407,740)	(476,116)	4.25%	(1,719)	(409,459)	4,987,864	0	31
November 17	Forecast	(409,459)	($0.0332)	(309,153)	245,987	0	0		(472,624)	(441,041)	4.25%	(1,541)	(474,165)	9,311,828	0	30
December 17	Forecast	(474,165)	($0.0332)	(428,659)	245,987	0	0		(656,836)	(565,501)	4.25%	(2,041)	(658,878)	12,911,402	0	31
January 18	Forecast	(658,878)	($0.0332)	(551,494)	379,259	0	0		(831,113)	(744,995)	4.25%	(2,689)	(833,802)	16,611,276	0	31
February 18	Forecast	(833,802)	($0.0332)	(581,012)	379,259	0	0		(1,035,555)	(934,679)	4.25%	(3,047)	(1,038,603)	17,500,370	0	28
March 18	Forecast	(1,038,603)	($0.0332)	(509,484)	379,259	0	0		(1,168,828)	(1,103,715)	4.25%	(3,984)	(1,172,812)	15,345,913	0	31
April 18	Forecast	(1,172,812)	($0.0332)	(401,202)	379,259	0	0		(1,194,754)	(1,183,783)	4.25%	(4,135)	(1,198,890)	12,084,384	0	30
May 18	Forecast	(1,198,890)	($0.0332)	(263,529)	379,259	0	0		(1,083,160)	(1,141,025)	4.25%	(4,119)	(1,087,278)	7,937,624	0	31
June 18	Forecast	(1,087,278)	($0.0332)	(182,956)	379,259	0	0		(890,975)	(989,127)	4.25%	(3,455)	(894,430)	5,510,709	0	30
July 18	Forecast	(894,430)	($0.0332)	(138,511)	379,259	0	0		(653,682)	(774,056)	4.25%	(2,794)	(656,476)	4,172,029	0	31
August 18	Forecast	(656,476)	($0.0332)	(134,686)	379,259	0	0		(411,904)	(534,190)	4.25%	(1,928)	(413,832)	4,056,814	0	31
September 18	Forecast	(413,832)	($0.0332)	(147,858)	379,259	0	0		(182,430)	(298,131)	4.25%	(1,041)	(183,472)	4,453,539	0	30
October 18	Forecast	(183,472)	($0.0332)	(198,379)	379,259	0	0		(2,592)	(93,032)	4.25%	(336)	(2,927)	5,975,266	0	31
November 18	Forecast	(2,927)	($0.0332)	(309,153)	379,259	0	0		67,179	32,126	4.25%	112	67,291	9,311,828	0	30
December 18	Forecast	67,291	($0.0332)	(428,659)	379,259	0	0		17,891	42,591	4.25%	154	18,045	12,911,402	0	31

Estimated C&I Conservation Charge November 1, 2017 - October 31, 2018	
Beginning Balance	(409,459)
Program Budget Nov 17-Oct 18	**4,284,564**
Projected Interest	(31,111)
Program Budget with Interest	3,843,995
Total Charges	**$3,843,995**
Projected Therm Sales	**115,871,154**
C&I Rate	$0.0332
Total Charges with Interest	**$3,846,922**
Projected Therm Sales	**115,871,154**
C&I Rate	**$0.0332**
C&I Rate from Prior Programs	**$0.0000**
Combined C&I Rate	**$0.0332**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2017 - October 31, 2018
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures: Residential	Actual DSM Expenditures: C&I	Actual DSM Expenditures: Low-Income	Actual DSM Expenditures: 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 17	Actual	(1,844,306)	n/a	(301,191)	511,614	331,161	106,016	75,818	512,995	20,328	(1,612,173)	(1,728,239)	**4.00%**	(5,871)	(1,618,044)	9,886,997	10,907,162	31
June 17	Actual	(1,618,044)	n/a	(227,701)	511,614	152,820	198,094	24,461	375,375	20,328	(1,450,042)	(1,534,043)	4.13%	(5,201)	(1,455,243)	7,077,460	8,400,536	30
July 17	Forecast	(1,455,401)	n/a	(138,149)	511,614	0	0	0	0		(1,081,936)	(1,268,669)	4.25%	(4,579)	(1,086,515)	5,261,414	0	31
August 17	Forecast	(1,086,515)	n/a	(126,828)	511,614	0	0	0	0		(701,729)	(894,122)	4.25%	(3,227)	(704,956)	4,908,241	0	31
September 17	Forecast	(704,956)	n/a	(136,979)	511,614	0	0	0	0		(330,321)	(517,639)	4.25%	(1,808)	(332,129)	5,299,526	0	30
October 17	Forecast	(332,129)	n/a	(177,314)	511,614	0	0	0	0		2,171	(164,979)	4.25%	(596)	1,575	6,681,398	0	31
November 17	Forecast	1,575	n/a	(534,662)	511,614	0	0	0	0		(21,473)	(9,949)	4.25%	(35)	(21,507)	13,682,160	0	30
December 17	Forecast	(21,507)	n/a	(840,896)	511,614	0	0	0	0		(350,789)	(186,148)	4.25%	(672)	(351,461)	20,900,491	0	31
January 18	Forecast	(351,461)	n/a	(1,138,688)	629,534	0	0	0	0		(860,615)	(606,038)	4.25%	(2,188)	(862,802)	27,990,992	0	31
February 18	Forecast	(862,802)	n/a	(1,215,358)	629,534	0	0	0	0		(1,448,626)	(1,155,714)	4.25%	(3,768)	(1,452,394)	29,793,891	0	28
March 18	Forecast	(1,452,394)	n/a	(1,048,901)	629,534	0	0	0	0		(1,871,762)	(1,662,078)	4.25%	(5,999)	(1,877,761)	25,799,733	0	31
April 18	Forecast	(1,877,761)	n/a	(768,773)	629,534	0	0	0	0		(2,017,000)	(1,947,381)	4.25%	(6,802)	(2,023,803)	19,207,859	0	30
May 18	Forecast	(2,023,803)	n/a	(477,316)	629,534	0	0	0	0		(1,871,585)	(1,947,694)	4.25%	(7,030)	(1,878,616)	12,080,790	0	31
June 18	Forecast	(1,878,616)	n/a	(286,403)	629,534	0	0	0	0		(1,535,485)	(1,707,050)	4.25%	(5,963)	(1,541,448)	7,515,509	0	30
July 18	Forecast	(1,541,448)	n/a	(196,960)	629,534	0	0	0	0		(1,108,874)	(1,325,161)	4.25%	(4,783)	(1,113,657)	5,304,758	0	31
August 18	Forecast	(1,113,657)	n/a	(191,312)	629,534	0	0	0	0		(675,435)	(894,546)	4.25%	(3,229)	(678,664)	5,154,206	0	31
September 18	Forecast	(678,664)	n/a	(231,877)	629,534	0	0	0	0		(281,007)	(479,835)	4.25%	(1,676)	(282,683)	6,081,815	0	30
October 18	Forecast	(282,683)	n/a	(347,132)	629,534	0	0	0	0		(281)	(141,482)	4.25%	(511)	(792)	8,858,081	0	31
November 18	Forecast	(792)	n/a	(534,662)	629,534	0	0	0	0		94,080	46,644	4.25%	163	94,243	13,682,160	0	30
December 18	Forecast	94,243	n/a	(840,896)	629,534	0	0	0	0		(117,119)	(11,438)	4.25%	(41)	(117,160)	20,900,491	0	31

0

Residential (R-1 & R-3) and C & I Conservation Charge November 1, 2017 - October 31, 2018		
Beginning Balance	$	1,575
Program Budget Nov 17-Oct 18	$	7,318,567
Projected Interest	$	(42,472)
Program Budget with Interest	$	7,277,670
Total Charges		**$7,277,670**

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants		
Required annual Environmental increase	$2,970,202	
DG 10-17 Base Rate Revision Collections	$0	
Environmental Subtotal	$2,970,202	
Overall Annual Net Increase to Rates	$2,970,202	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/17 - sales and transportation	182,370,287	therms
Surcharge per therm	$0.0163	per therm
Total Environmental Surcharge	$0.0163	

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

NASHUA FORMER MGP

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.

NASHUA FORMER MGP

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.

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

NASHUA FORMER MGP

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

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

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

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

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

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

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

- 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.

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

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

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

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

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

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- In December 2013 ENGI submitted a request to revise the RAP. The purpose of the request was to summarize activities conducted since submittal of the 2013 Supplemental Investigation Report and to propose a revision to the approved RAP for the area on site known as "Holder # 2."

- The RAP submitted in 2005 selected asphalt capping in the area of Holder #2. The entire area of the Holder was not designated to be capped with asphalt. At the time of the preparation of the RAP, separate phase NAPL was not considered to be present in recoverable quantities in Holder #2. In order to address what appears to be a limited area and quantity of NAPL in a monitoring well in Holder #2, continued manual NAPL recovery from two additional wells in the Holder #2 area was proposed as part of the GMP monitoring program.

- In addition to the NAPL recovery activity, the area of asphalt capping was proposed to be expanded to include all of former Holder #2. This expansion of paving will also address the asbestos contaminated material (ACM) present in this area of the site. The asphalt cap detail presented in the proposed RAP revision will be modified (as necessary) to address the relevant solid waste regulations for ACM in soil.

- On June 4, 2014, the NHDES approved of the requested RAP revision and required that a RAP Summary Report, with the necessary engineering details for the selected remedies, be provided. ENGI plans to submit this RAP Summary Report by December 31, 2014.

- The GMP Application was submitted in March 2014. The GMP proposed a list of monitoring wells and analytical methods in order to monitor the Groundwater Management Zone.

- On June 5, 2014, the NHDES approved the GMP application. This Permit was issued for a period of 5 years requiring the monitoring of groundwater quality, assessing and recovering any free product found, and visually inspecting the Nashua River sediment cap area. During the first year of the Permit, monitoring events will be conducted in October 2014 and April 2015, and each successive April and October. Annual summary reports are 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.

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- ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. **ENGI received comments from NHDES on December 15, 2016. NHDES altered the design to include an impermeable capping layer, and incorporation of standards in the Waste Management Bureau's Asbestos Disposal Site rules. As ENGI is planning to pave the Nashua property in 2018, the cap will be installed in conjunction with this capital project.**

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 submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. **NHDES responded to ENGI with their comments on December 15, 2016. The capping remedy is planned for 2018 in conjunction with an overall paving of the property.**

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-

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called Nashua River Asbestos Site located adjacent to the former MGP. EPA was removing asbestos from the Nashua River, when some was found to be mixed with wastes allegedly from the MGP. Without admitting any facts or liability, by agreement effective December 21, 2000, ENGI resolved EPA's claim in exchange for a payment of $387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

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

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

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

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

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

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

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

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

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

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

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

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- 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

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attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment were being addressed concurrently and that ENGI avoided incurring costs associated with another entity's contamination.

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

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

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

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

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

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

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

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

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

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- 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. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions involving further remediation of historical Holder 3, and further investigation of the storm drain system beneath and downstream of the site. **ENGI responded to NHDES' comments and requests on May 12, 2017, and is planning to do on-site removals, well installations, and drain improvements in 2017, prior to property paving in Fall 2017.**

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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 summarizing the activities for addressing on-site and off-site impacts was submitted on December 19, 2014. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions. **ENGI addressed these concerns and plans to implement the remedial activities on-site and off-site over the next year.**

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

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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.

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.

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LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

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

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

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

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

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

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

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

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LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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.

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

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 was remediated, with the removal of all tar-impacted soil completed on August 3, 2015. The entire project was completed on September 24, 2015 with 2,662 truckloads hauling 93,502 tons of tar-impacted soil removed for thermal treatment. Some additional site restoration work was needed in October 2015 and another seeding in April 2016 to repair damage to the original restoration caused by a heavy rainstorm that occurred on September 30, 2015. Throughout the course of the project there was no disruption to the neighboring community and no safety incidents, logging 26,975 safe working hours. The project was completed within budget parameters.

The only activities on this site during the past year and ongoing are semi-annual mowing and annual groundwater and surface sampling, per the new post-remedial Ground Water Management Permit received on May 10, 2017.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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.

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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

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LINE
NO.

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.

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LINE
NO.

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.

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. Soil vapor monitoring; soil vapor probe installation; and remedial design investigations including subsurface structure location and inspection, shallow tar-saturated soil delineation, and site storm drain system inspections, as approved by the RAP, were performed in December 2015. A Remedial Design Report (RDR)was submitted to NHDES on March 16, 2016 summarizing the above remedial design investigations . The remediation activities, including tar-impacted material removals and plugging of the on-site drain system, will take place in 2017.

In early 2016 ENGI was approached by a commercial developer who is interested in purchasing the property and repurposing the holder house structure. Several site meetings took place with the developer, and ENGI is negotiating the terms of the property's sale. If the property is transferred, the purchaser's future use design will be taken into account when the final design of the engineered cap is being developed.

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

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LINE
NO.

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 were made to address outfall maintenance and access concerns of the City and NHDOT, respectively. The design was presented to the City on January 26, 2016. A rigorous schedule toward construction in late summer 2017 was agreed to by ENGI and the City in February 2016. The City did not meet an early deadline to determine and communicate details regarding access to their storm water system. Communication was again resumed in July 2016 by the City, however the City remains unresponsive to ENGI on implementation of the joint remedial design.

In late summer 2017, the Company plans to complete various final subsurface remedial activities that need to occur prior to capping.

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

CONCORD FORMER MGP

LINE
NO.

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.

In May 2016, ENGI submitted a proposed plan for monitoring the near-bank sediments to the pond area in the Merrimack River. After discussions regarding frequency, duration of the Monitored Natural Recovery (MNR) program, and methodologies to be used in determining the contaminant trending in the river sediment, NHDES approved a revised MNR Plan in a letter dated July 2017. The 5-year sampling plan will commence in 2017 with the first of 5 annual samplings.

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

CONCORD FORMER MGP

LINE
NO.

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 was adjusted to accommodate the City's desire to simplify maintenance of the storm water system, however ENGI has received no response from the City after numerous attempts to begin the implementation

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 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.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS

2017 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
1	Concord Pond	DEF056	-	100,238.64	-	-	2,321.44	102,195.57	[redacted]	[redacted]	88,512.90
2	Concord MGP	DEF077	-	139,194.76	-	-	14,304.62	153,499.38	[redacted]	[redacted]	133,269.47
3	Laconia/Liberty Hill	DEF086	-	40,948.88	54,414.95	-	4,969.80	100,333.63	[redacted]	[redacted]	100,333.63
4	Manchester MGP	DEF057	-	51,698.59	-	-	2,634.09	54,332.68	[redacted]	[redacted]	50,522.79
5	Nashua MGP	DEF054	-	93,742.43	-	-	6,599.85	100,342.28	[redacted]	[redacted]	85,313.64
6	General Expenses	DEF064	-	-	-	-	6,546.57	6,546.57	[redacted]	[redacted]	6,546.57
	Total Pool Activity		**-**	**425,823.30**	**425,823.30**	**-**	**37,376.37**	**517,250.11**	**-**	**(53,115.62)**	**464,499.00**

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

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 EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	GEI CONSULTANTS, INC.	3004821		5,896.99				5,896.99			5,896.99
2	GEI CONSULTANTS, INC.	3006640		2,417.48				2,417.48			2,417.48
3	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 0116-0316					507.80	507.80			507.80
4	GEI CONSULTANTS, INC.	3008413		3,993.33				3,993.33			3,993.33
[redacted]											
6	GEI CONSULTANTS, INC.	3009587		1,058.10				1,058.10			1,058.10
7	GEI CONSULTANTS, INC.	3011271		1,202.50				1,202.50			1,202.50
8	GEI CONSULTANTS, INC.	3012349		2,516.28				2,516.28			2,516.28
9	ANCHOR QEA LLC	49351		22,184.97				22,184.97			22,184.97
[redacted]											
11	GEI CONSULTANTS, INC.	3013812		5,094.44				5,094.44			5,094.44
12	ANCHOR QEA LLC	49765		5,707.44				5,707.44			5,707.44
13	ANCHOR QEA LLC	50207		11,595.70				11,595.70			11,595.70
14	CLEAN HARBORS	1001670402					724.62	724.62			724.62
15	GEI CONSULTANTS, INC.	3014930		5324.48				5324.48			5,324.48
16	ANCHOR QEA LLC	50546		11,666.25				11,666.25			11,666.25
17	GEI CONSULTANTS, INC.	3016233		5,078.31				5,078.31			5,078.31
18	ANCHOR QEA LLC	51034		956.00				956.00			956.00
19	GEI CONSULTANTS, INC.	3017307		1,815.14				1,815.14			1,815.14
20	ANCHOR QEA LLC	51510		1,129.00				1,129.00			1,129.00
21	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 0417					69.21	69.21			69.21
22	GEI CONSULTANTS, INC.	3019092		2,270.22				2,270.22			2,270.22
23	ANCHOR QEA LLC	51800		3,146.00				3,146.00			3,146.00
24	CLEAN HARBORS	1001815179					602.80	602.80			602.80
25	GEI CONSULTANTS, INC.	3019991		1,548.94				1,548.94			1,548.94
26	ANCHOR QEA LLC	52183		2,585.50				2,585.50			2,585.50
27	CASEY MARY	5/1 THRU 5/31/17					52.50	52.50			52.50
[redacted]											
29	GEI CONSULTANTS, INC.	3021713		3,051.57				3,051.57			3,051.57
30								0.00			0.00
31	Environmental Staff Time						364.51	364.51			364.51
	Total Pool Activity		**0.00**	**100,238.64**	**0.00**	**0.00**	**2,321.44**	**102,195.57**	**0.00**	**(14,047.18)**	**88,512.90**

REDACTED

154

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

			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	GZA GEOENVIRONMENTAL INC	721199		37,349.92				37,349.92			37,349.92
3	JOE GAUCI LANDSCAPING LLC	2016-6-3576					620.00	620.00			620.00
4	JOE GAUCI LANDSCAPING LLC	2016-7-3576					252.00	252.00			252.00
5	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 0116-0316					309.10	309.10			309.10
6	GZA GEOENVIRONMENTAL INC	713909		210.80				210.80			210.80
7	GZA GEOENVIRONMENTAL INC	704992		206.10				206.10			206.10
8	GZA GEOENVIRONMENTAL INC	1713665		15,855.67				15,855.67			15,855.67
9	CLEAN HARBORS	1001513394					2,143.25	2,143.25			2,143.25
10	CASEY MARY	8/1 THRU 8/31/16					52.76	52.76			52.76
11	JOE GAUCI LANDSCAPING LLC	2016-8-3576					385.00	385.00			385.00
[redacted]											
13	CASEY MARY	6/1 THRU 6/30/16					56.58	56.58			56.58
14	JOE GAUCI LANDSCAPING LLC	2016-9-3186					908.00	908.00			908.00
15	JOE GAUCI LANDSCAPING LLC	2016-9-3576					2,200.00	2,200.00			2,200.00
16	JOE GAUCI LANDSCAPING LLC	2016-10-3576					165.00	165.00			165.00
[redacted]											
18	CLEAN HARBORS	1001670402					1,051.88	1,051.88			1,051.88
19	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 0716-0916					530.54	530.54			530.54
20	LEIDINGER APPRAISALS	1700					4,000.00	4,000.00			4,000.00
21	GZA GEOENVIRONMENTAL INC	728936		15,560.48				15,560.48			15,560.48
22	GZA GEOENVIRONMENTAL INC	723863		10,663.82				10,663.82			10,663.82
23	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 0417					64.88	64.88			64.88
24	GZA GEOENVIRONMENTAL INC	735153		8,962.00				8,962.00			8,962.00
25	JOE GAUCI LANDSCAPING LLC	3576					228.00	228.00			228.00
26	GZA GEOENVIRONMENTAL INC	734860		44,537.80				44,537.80			44,537.80
27	GZA GEOENVIRONMENTAL INC	736201		2,606.64				2,606.64			2,606.64
28	GZA GEOENVIRONMENTAL INC	738580		2,667.63				2,667.63			2,667.63
29	GZA GEOENVIRONMENTAL INC	738581		573.90				573.90			573.90
30	CLEAN HARBORS	1001863878					195.80	195.80			195.80
[redacted]											
32								0.00			0.00
33								0.00			0.00
34	Environmental Staff Time						1,141.83	1,141.83			1,141.83
	Total Pool Activity		**0.00**	**139,194.76**	**0.00**	**0.00**	**14,304.62**	**153,499.38**	**0.00**	**(20,229.91)**	**133,269.47**

REDACTED

155

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	GEI CONSULTANTS, INC.	3004820		1,153.80				1,153.80			1,153.80
2	CHARTER ENVIRONMENTAL INC	APP 18 RETAINAGE			54,414.95			54,414.95			54,414.95
3	GEI CONSULTANTS, INC.	3006636		409.54				409.54			409.54
4	DE MAXIMIS, INC.	161582		825.11				825.11			825.11
5	NH DEPT OF ENVIRONMENTAL SERVICES	200411113 0116-0316					1,222.01	1,222.01			1,222.01
6	BLUE CHIP FILMS LLC	1337					825.00	825.00			825.00
7	MULLER'S LAWN & LANDSCAPING, LLC	4083					800.00	800.00			800.00
8	GEI CONSULTANTS, INC.	3008410		2,475.30				2,475.30			2,475.30
9	GEI CONSULTANTS, INC.	3009586		849.38				849.38			849.38
10	GEI CONSULTANTS, INC.	3011270		18,933.81				18,933.81			18,933.81
11	BLUE CHIP FILMS LLC	1349					150.00	150.00			150.00
13	NH DEPT OF ENVIRONMENTAL SERVICES	200411113 4/16-6/16					712.83	712.83			712.83
14	GEI CONSULTANTS, INC.	3012348		7,722.44				7,722.44			7,722.44
15	GEI CONSULTANTS, INC.	3013811		1,391.00				1,391.00			1,391.00
16	GEI CONSULTANTS, INC.	3014929		4,729.48				4,729.48			4,729.48
17	GEI CONSULTANTS, INC.	3016232		1,445.78				1,445.78			1,445.78
18	GEI CONSULTANTS, INC.	3017303		1,013.24				1,013.24			1,013.24
19	BLUE CHIP FILMS LLC	1381					600.00	600.00			600.00
20	BLUE CHIP FILMS LLC	1396					300.00	300.00			300.00
21								-			-
22								-			-
23	Environmental Staff Time						359.96	359.96			359.96
	Total Pool Activity		0.00	40,948.88	54,414.95	0.00	4,969.80	100,333.63			100,333.63

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 0116-0316					101.83	101.83			101.83
2	GZA GEOENVIRONMENTAL INC	713664		5,101.13				5,101.13			5,101.13
3	CLEAN HARBORS	1001518924					747.18	747.18			747.18
[redacted]											
8	CLEAN HARBORS	1001670404					650.10	650.10			650.10
9	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 0716-0916					152.76	152.76			152.76
10	CASEY MARY	3/1 THRU 3/31/17					100.94	100.94			100.94
11	GZA GEOENVIRONMENTAL INC	734859		30,291.73				30,291.73			30,291.73
12	GZA GEOENVIRONMENTAL INC	736202		4,539.52				4,539.52			4,539.52
13	CLEAN HARBORS	1001817619					213.40	213.40			213.40
[redacted]											
15	GZA GEOENVIRONMENTAL INC	738392		11,766.21				11,766.21			11,766.21
[redacted]											
17								0.00			0.00
18								0.00			0.00
19	Environmental Staff Time						**667.88**	667.88			667.88
	Total Pool Activity		**0.00**	**51,698.59**	**0.00**	**0.00**	**2,634.09**	**54,332.68**	**0.00**	**(3,809.89)**	**50,522.79**

REDACTED

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12296		1,734.37				1,734.37			1,734.37
2	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12328		1,807.54				1,807.54			1,807.54
3	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12358		2,172.97				2,172.97			2,172.97
4	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12384		2,453.40				2,453.40			2,453.40
[redacted]											
7	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12414		21,305.04				21,305.04			21,305.04
8	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12454		8,317.98				8,317.98			8,317.98
9	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12468		5,696.11				5,696.11			5,696.11
10	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 0716-0916					230.68	230.68			230.68
11	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12491		11,958.95				11,958.95			11,958.95
12	CASEY MARY	02/01/17-02/28/17					53.04	53.04			53.04
13	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12528		3,112.04				3,112.04			3,112.04
14	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 0417					415.21	415.21			415.21
15	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12541		2,848.25				2,848.25			2,848.25
16	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12567		21,265.05				21,265.05			21,265.05
17	CLEAN HARBORS	1001861926					5,029.10	5,029.10			5,029.10
18	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12608		11,070.73				11,070.73			11,070.73
19	CASEY MARY	5/1 THRU 5/31/17					26.22	26.22			26.22
20								0.00			0.00
21								0.00			0.00
22								0.00			0.00
23	Environmental Staff Time						845.60	845.60			845.60
	Total Pool Activity		**-**	**93,742.43**	**-**	**-**	**6,599.85**	**100,342.28**	**-**	**(15,028.64)**	**85,313.64**

REDACTED

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	ALLEGRA MARKETING PRINT MAIL	30167					304.00	304.00			304.00
2	CASEY MARY	8/1 THRU 8/31/16					76.94	76.94			76.94
3	CASEY MARY	10/1 THRU 10/31/16					69.96	69.96			69.96
4								0.00			0.00
5								0.00			0.00
6	Environmental Staff Time						6,095.67	6,095.67			6,095.67
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**6,546.57**	**6,546.57**	**0.00**	**0.00**	**6,546.57**

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

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

																	DEF056	
	(thru - 9/98) pool #1 & #2	10/98 - 9/15/9! pool #3	(9/99 - 9/00) pool #4	(9/03 - 9/04) pool #5	(9/04 - 9/05) pool #6	(9/05 - 9/06) pool #7	(9/06 - 9/07) pool #8	(9/07 - 9/08) pool #9	(9/08 - 9/09) pool #10	(9/09 - 9/10) pool #11	(9/10 - 9/11) pool #12	(9/11 - 9/12) pool #13	(9/12 - 6/13) pool #14	(7/13 - 6/14) pool #15	(7/14 - 6/15) pool #16	(7/15 - 6/16) pool #17	(7/16 - 6/17) pool #18	subtotal
1 Remediation costs (i.o. 500061)	3,266,617	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	43,204	102,196	6,939,708
Remediation costs (i.o. 500005)	-	-	-															-
A Subtotal - remediation costs	3,266,617	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	43,204	102,196	6,939,708
																		-
Cash recoveries (i.o. 500061)	(1,515,056)	(499,684)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(2,193,326)
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	(1,337,257)	(499,684)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(2,015,527)
																		-
A-B Total net expenses to recover	1,929,360	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	34,590	88,148	4,924,181
																		-
																		-
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	(444,531)	(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)	(14,405)	(14,664)	(205,934)
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	(1,908,322)	(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)	(14,405)	(14,664)	(3,980,667)
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	84,595	47,608	45,345	18,376	64,062	20,185	73,484	943,513
E Allocation of Litigated Recovery				-		-		(329,540)	(102,675)	(123,791)	(46,869)	-	-	-	-	-	-	(602,875)
Surcharge calculation																		
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	37,726	13,602	19,433	10,501	45,759	17,301.40	73,484.23	217,806
remaining life	-	-	-	24	36	48	60	72	84	84	12	24	36	48	60	72	84	
one year	-	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-		-	-	-	37,726	6,801	6,478	2,625	9,152	2,884	10,498	76,163
Required annual increase in rates:																		
smaller of D or F	-	-	-	-	-	-		-	-	-	37,726	6,801	6,478	2,625	9,152	2,884	10,498	76,163
forecasted therm sales	368,786,526	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287
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	$0.0000	$0.0000	$0.0000	$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
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Laconia & Liberty Hill

		i.o. no. 500005														DEF086	
		(thru - 9/00) pool #1 & #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 - 6/13) pool #12	(7/13 - 6/14) pool #13	(7/14 - 6/15) pool #14	(7/15 - 6/16) pool #15	(7/16 - 6/17) pool #16	subtotal
1	Remediation costs (i.o. 500061)	-		-									[redacted]				
	Remediation costs (i.o. 500005)	4,541,032	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	4,541,032	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	4,541,032	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	(696,237)	-	-	-		-	-	-	-	-	-	-	-	-	-	(696,237)
Act	November 2001 - October 2002	(686,400)	(110,314)	-	-		-	-	-	-	-	-	-	-	-	-	(796,714)
Act	November 2002 - October 2003	(699,056)	(106,378)	-	-		-	-	-	-	-	-	-	-	-	-	(805,434)
Act	November 2003 - October 2004	(597,246)	(101,969)														(699,215)
Act	November 2004- October 2005	(567,186)	(85,078)														(652,264)
Act	November 2005- October 2006	(594,912)	(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	9,957	111,336	121,038	2,141,596	4,242,438		-	-	(91,120)	-	-	-	-	-	
C	Surcharge Subtotal	(4,531,075)	(588,664)	111,336	(188,958)	2,141,596	4,242,438	-	-	(63,313)	(201,173)	(126,833)	(50,342)	(21,909)	-	-	(5,823,577)
D	Net balance to be recovered (A-B+C)	9,957	111,336	121,038	2,141,596	4,242,438	4,692,393	607,876	262,678	147,219	68,108	516,153	[redacted]				
E	Allocation of Litigated Recovery						(4,692,393)	(607,876)	(262,678)	(238,339)	-	-					
	Surcharge calculation																
	Unrecovered costs (D+E)	-	-	-			-	-	-	-	19,459	73,736					
	remaining life	-	-	36	48	60	72	84	84	48	24	36					
	one year	-	-	12	12	12	12	12	12	12	12	12					
F	amortization	-	-	-	-	-	-	-	-	-	9,730	24,579					
	Required annual increase in rates:																
	smaller of D or F	-	-	-	-		-	-	-	-	9,730	24,579	[redacted]				
	forecasted therm sales	368,786,526	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	[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
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Manchester

DEF057

			(9/00 - 9/03) pool #1 & #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 - 6/13) pool #13	(7/13 - 6/14) pool #14	(7/14 - 6/15) pool #15	(7/15 - 6/16) pool #16	(7/16 - 6/17) pool #17	subtotal
				(withdrawn 2/1/04)					Incl. Audit Corr										
1	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	71,011	54,333	10,127,677
2		Remediation costs (i.o. 500005)	825,092																825,092
3	A	Subtotal - remediation costs	825,092	-	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	71,011	54,333	10,952,769
4																			
5		Cash recoveries (i.o. 500061)	-				(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(2,629,270)
6		Cash recoveries (i.o. 500004)	-																-
7		Recovery costs (i.o. 500004)	-		1,242,326			2,546	-										1,244,872
8		Transfer Credit from Gas Restructuring						-	-										-
9	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)	(48,322)	(3,810)	(1,384,399)
10																			
11	A-B	Total net expenses to recover	825,092	-	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	22,690	50,523	9,568,370
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	(73,543)	-	-														(73,543)
20	Act	November 2002 - October 2003	(75,984)	-	-														(75,984)
21	Act	November 2003 - October 2004	(97,251)	(41,325)	-														(138,576)
22	Act	November 2004- October 2005	(113,437)	-	(212,695)	-			-	-	-	-	-	-	-	-	-	-	(326,132)
23	Act	November 2005- October 2006	(96,247)	-	(206,243)	(261,242)			-	-	-	-	-	-	-	-	-	-	(563,732)
24	Act	November 2006- October 2007	(126,817)	-	(211,361)	(281,815)	(42,272)												(662,265)
25	Act	November 2007- October 2008																	-
26	Act	November 2012- October 2013											(40,012)						(40,012)
27	Act	November 2013- October 2014											(50,994)						(50,994)
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										-	(23,337)						(23,337)
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	76,393	318,206	276,881	1,224,246	2,671,037	2,958,927	3,302,330	-	-	-							
37																			
38																			
39	C	Surcharge Subtotal	(506,886)	276,881	(353,418)	681,189	2,628,765	2,958,927	3,302,330	-	-	-	(114,343)	-	-	-	-	-	(1,954,576)
40																			
41																			
42	D	Net balance to be recovered (A-B+C)	318,206	276,881	1,224,246	2,671,037	2,958,927	3,302,330	6,562,539	312,185	328,678	137,589	327,955	(188,619)	61,210	75,440	22,690	50,523	7,613,794
43																			
44	E	Allocation of Litigated Recovery		-	-	-			(6,562,539)	(312,185)	(328,678)	(92,244)	-	-	-	-	-	-	(7,295,646)
45																			
46		Surcharge calculation																	
47		Unrecovered costs (D+E)	-	-	-	-	-		-	-	-	22,850	93,701	(80,837)	34,977	53,885	19,448	50,523	194,548
48		remaining life	-	-	24	36	48	60	70	84	84	12	24	36	48	60	72	84	
49		one year	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F	amortization	-	-	-	-	-	-	-	-	-	22,850	46,851	(26,946)	8,744	10,777	3,241	7,218	
51																			
52		Required annual increase in rates:																	
53		smaller of D or F	-	-	-	-	-		-	-	-	22,850	46,851	(26,946)	8,744	10,777	3,241	7,218	72,736
54																			
55		forecasted therm sales	368,786,526	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287
56																			
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0003	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0000	$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
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Nashua

		(9/00 - 9/02) pool #1 & #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	Corrected per 2/08 Audit (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 - 6/13) pool #13	(7/13 - 6/14) pool #14	(7/14 - 6/15) pool #15	(7/15 - 6/16) pool #16	DEF054 (7/16 - 6/17) pool #17	subtotal
1	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	106,129	100,342	1,558,566
2	Remediation costs (i.o. 500005)	1,596,389	175,178															1,771,567
3	A Subtotal - remediation costs	1,596,389	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	106,129	100,342	3,330,133
4																		-
5	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)	(43,694)	(15,029)	(520,108)
6	Cash recoveries (i.o. 500004)	-	-															-
7	Recovery costs (i.o. 500004)	-	-			5,449	12,938	-	-									18,388
8	Transfer Credit from Gas Restructuring						-	-	-									-
9	B Subtotal - net recoveries	-	-	-		(13,131)	8,787	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(501,720)
10																		-
11	A-B Total net expenses to recover	1,596,389	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	62,435	85,314	2,828,412
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	(183,857)	-	-														(183,857)
20	Act November 2002 - October 2003	(243,150)	-	-														(243,150)
21	Act November 2003 - October 2004	(218,505)	(29,134)	-														(247,639)
22	Act November 2004- October 2005	(212,695)	(28,359)	-														(241,054)
23	Act November 2005- October 2006	(219,993)	(27,499)	-	(27,499)			-	-	-	-	-	-	-	-	-	-	(274,991)
24	Act November 2006- October 2007	(225,452)	(28,181)	-	(28,181)	-												(281,815)
25	Act November 2007- October 2008																	-
26	Act November 2012- October 2013											(40,012)						(40,012)
27	Act November 2013- October 2014											(38,246)						(38,246)
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										-	(20,916)						(20,916)
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	188,463	481,201	543,205	554,046	704,732	714,955	733,479	-	-	-	6,766	-	-	-	-	-	
37																		
38																		
39	C Surcharge Subtotal	(1,115,188)	368,027	543,205	498,365	704,732	714,955	733,479	-	-	-	(92,408)	-	-	-	-	-	(1,571,680)
40																		
41																		
42	D Net balance to be recovered (A-B+C)	481,201	543,205	554,046	704,732	714,955	733,479	830,669	16,289	98,975	33,351	304,003	(80,241)	35,950	65,217	62,435	85,314	1,256,733
43																		
44	E Allocation of Litigated Recovery	-	-	-	-	-	-	(830,669)	(16,289)	(98,975)	(26,585)	-	-	-	-	-	-	(972,519)
45																		
46	Surcharge calculation																	
47	Unrecovered costs (D+E)	-	-	-	-	-		-	-	-		86,858	(34,389)	20,543	46,584	53,515	85,314	258,425
48	remaining life	-	12	24	36	48	60	72	84	84	72	24	36	48	60	72	84	
49	one year	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	-	-	-	-	-	-	-	-	-	-	43,429	(11,463)	5,136	9,317	8,919	12,188	
51																		
52	Required annual increase in rates:																	
53	smaller of D or F	-	-	-	-	-		-	-	-	-	43,429	(11,463)	5,136	9,317	8,919	12,188	67,525
54																		
55	forecasted therm sales	368,786,526	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287
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	$0.0002	($0.0001)	$0.0000	$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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
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		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 - 6/13) pool #10	(7/13 - 6/14) pool #11	(7/16 - 6/17) 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	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287
	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

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
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		Keene												
													DEF055	
		(9/03 - 9/04) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	(9/08 - 9/09) pool #6	(9/09 - 9/10) pool #7	(9/10 - 9/11) pool #8	(9/11 - 9/12) pool #9	(9/12 - 6/13) pool #10	(7/13 - 6/14) pool #11	(7/14 - 6/15) pool #12	subtotal
1	Remediation costs (i.o. 500061)	-										[redacted]		
	Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400	[redacted]		
A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400	[redacted]		
	Cash recoveries (i.o. 500061)	-										[redacted]		
	Cash recoveries (i.o. 500004)	-										[redacted]		
	Recovery costs (i.o. 500004)			18,831	823	-	-	-	-			[redacted]		
	Transfer Credit from Gas Restructurin				-	-	-					[redacted]		
B	Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-	[redacted]		
A-B	Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400	[redacted]		
														-
														-
	Surcharge revenue:													-
Act	June 1998 - October 1998	-												-
Act	November 1998 - October 1999	-												-
Act	November 1999 - October 2000	-												-
Act	November 2000 - October 2001	-												-
Act	November 2001 - October 2002	-												-
Act	November 2002 - October 2003	-												-
Act	November 2003 - October 2004	-												-
Act	November 2004- October 2005	-	-				-	-	-	-	-	-	-	-
Act	November 2005- October 2006	-	-				-	-	-	-	-	-	-	-
Act	November 2006- October 2007	-	-	(14,091)										(14,091)
Act	November 2007- October 2008													-
Act	November 2012- October 2013													-
Act	November 2013- October 2014													-
Act	Nov 2009-Oct 2010 Base Rate Rev													-
Act	Nov 2010-Oct 2011 Base Rate Rev													-
Act	Nov 2011-Oct 2012 Base Rate Rev													-
Act	Nov 2012-Oct 2013 Base Rate Rev													-
Act	Nov 2013-Oct 2014 Base Rate Rev													-
Act	Nov 2014-Oct 2015 Base Rate Rev													
	AES collections													-
	Gas Street overcollection													-
	Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	-	-	-	-	-	
C	Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	-	-	-	-	-	(14,091)
D	Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	-	488	1,400	[redacted]		
E	Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	-	[redacted]		
	Surcharge calculation											[redacted]		
	Unrecovered costs (D+E)	-	-	-			-	-	-	139	600	[redacted]		
	remaining life	24	36	48	60	72	84	84	84	24	36	[redacted]		
	one year	12	12	12	12	12	12	12	12	12	12	[redacted]		
F	amortization	-	-	-	-	-	-	-	-	70	200	[redacted]		
	Required annual increase in rates:													
	smaller of D or F	-	-	-			-	-	-	70	200	[redacted]		
	forecasted therm sales	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287
	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.
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			Concord														
					Corrected per 1/24/07 Audit	Corrected per 2/08 Audit										DEF077	
			(9/03 - 9/04) pool #1	(9/04 - 9/05) pool #2	(9/05 - 9/06) pool #3	(9/06 - 9/07) pool #4	(9/07 - 9/08) pool #5	(9/08 - 9/09) pool #6	(9/09 - 9/10) pool #7	(9/10 - 9/11) pool #8	(9/11 - 9/12) pool #9	(9/12 - 6/13) pool #10	(7/13 - 6/14) pool #11	(7/14 - 6/15) pool #12	(7/15 - 6/16) pool #13	(7/16 - 6/17) pool #14	subtotal
1	1	Remediation costs (i.o. 500061)	-														-
2		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	114,749	153,499	1,681,119
3	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	114,749	153,499	1,681,119
4																	-
5		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)	(19,197)	(20,230)	(231,734)
6		Cash recoveries (i.o. 500004)	-														-
7		Recovery costs (i.o. 500004)					1,432	(1,007)									425
8		Transfer Credit from Gas Restructuring			-												-
9	B	Subtotal - net recoveries	-	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)	(20,230)	(231,308)
10																	
11	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	95,553	133,269	1,449,811
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	-	(27,499)			-	-	-	-	-	-	-	-	-	-	(27,499)
24	Act	November 2006- October 2007	-	(28,181)	-												(28,181)
25	Act	November 2007- October 2008															-
26	Act	November 2012- October 2013								(20,006)	(20,006)						(40,012)
27	Act	November 2013- October 2014								(12,749)	(25,497)						(38,246)
28	Act	Nov 2009-Oct 2010 Base Rate Rev								($1,891)							(1,891)
29	Act	Nov 2010-Oct 2011 Base Rate Rev								($13,816)							(13,816)
30	Act	Nov 2011-Oct 2012 Base Rate Rev								($12,164)							(12,164)
31	Act	Nov 2012-Oct 2013 Base Rate Rev								($6,794)	($6,794)						(13,588)
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		22,191	187,442	209,549	271,214	-	-	-	-	-	-	-	-	-	
37																	
38																	
39	C	Surcharge Subtotal	-	(33,490)	187,442	209,549	271,214	-	-	(67,420)	(52,297)	-	-	-	-	-	(175,398)
40																	
41																	
42	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	95,553	133,269	1,274,413
43																	-
44	E	Allocation of Litigated Recovery	-	-	-	-	(268,051)	(92,679)	(46,190)	(12,760)	-	-	-	-	-	-	(419,679)
45																	-
46		Surcharge calculation															-
47		Unrecovered costs (D+E)	-	-	-		-	-	-	50,460	58,638	19,450	70,488	116,988	81,902	133,269	531,196
48		remaining life	36	48	60		72	84	84	12	24	36	48	60	72	84	
49		one year	12	12	12		12	12	12	12	12	12	12	12	12	12	
50	F	amortization	-	-	-		-	-	-	50,460	29,319	6,483	17,622	23,398	13,650	19,038	
51																	
52		Required annual increase in rates:															
53		smaller of D or F	-	-	-		-	-	-	50,460	29,319	6,483	17,622	23,398	13,650	19,038	159,970
54																	
55		forecasted therm sales	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287
56																	
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	$0.0002	$0.0000	$0.0001	$0.0001	$0.0001	$0.0001	$0.0009

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
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		General															
				Corrected per 1/24/07 Audit											DEF064		2017 MGP Remediation
		(9/02 - 9/04) pool #1 & #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 - 6/13) pool #11	(7/13 - 6/14) pool #12	(7/14 - 6/15) pool #13	(7/15 - 6/16) pool #14	(7/16 - 6/17) pool #15	subtotal	subtotal
1	Remediation costs (i.o. 500061)	-														-	[redacted]
	Remediation costs (i.o. 500005)	542,111	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	888,628	
A	Subtotal - remediation costs	542,111	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	888,628	
	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	538,780	208,128	324,511	53,844	(164,988)	(2,931)	4,199	69,286	78,967	73,846	13,139	(7,638)	11,879	6,547	1,207,567	
																	-
	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		(28,181)	(49,318)												(77,499)	(2,064,294)
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	-														-	(205,934)
	Gas Street overcollection															-	(23,511)
	Prior Period Pool under/overcollection	(8,388)	304,982	457,429	732,622	786,465	-	-	-	-	-	-	-	-	-		
C	Surcharge Subtotal	(233,798)	249,301	408,111	732,622	786,465	-	-	(17,750)	(17,750)	(12,749)	-	-	-	-	(301,158)	(13,934,320)
D	Net balance to be recovered (A-B+C)	304,982	457,429	732,622	786,465	621,477	(2,931)	4,199	51,536	61,217	61,098	13,139	(7,638)	11,879	6,547	906,409	[redacted]
E	Allocation of Litigated Recovery	-	-	-	-	(621,477)	2,931	(4,199)	(11,640)	-	-	-	-	-	-	(634,384)	
	Surcharge calculation																
	Unrecovered costs (D+E)	-	-	-		-	-	-	19,948	17,490	26,185	7,508	(5,456)	10,182	6,547	82,404	
	remaining life	36	48	60	72	84	84	84	12	24	36	48	60	72	84		
	one year	12	12	12	12	12	12	12	12	12	12	12	12	12	12		
F	amortization	-	-	-	-	-	-	-	19,948	8,745	8,728	1,877	(1,091)	1,697	935		
	Required annual increase in rates:																
	smaller of D or F	-	-	-		-	-	-	19,948	8,745	8,728	1,877	(1,091)	1,697	935	40,840	
	forecasted therm sales	368,786,526	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	182,370,287	**182,370,287**
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	**$0.0163**

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

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)	(7/13 - 6/14)	(7/14 - 6/15)	(7/15 - 6/16)	(7/16 - 6/17)	Total
1	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	196,611	312,039	220,344	256,871	[redacted]
2		Remediation costs (i.o. 500005)	1,027,747	-	700,000	-	356,243	32,356	445,367	2,444,366	2,229,625	255,263	658,324	316,280	459,550	651,906	1,801,404	7,975,914	3,307,910	260,380	
3	A	Subtotal - remediation costs	6,448,599	129,002	700,000	-	356,243	438,828	2,682,050	3,442,003	2,956,367	4,845,887	1,177,231	991,045	1,146,065	1,645,340	1,998,015	8,287,953	3,528,254	517,250	
4																					
5		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)	(79,446)	(121,889)	(119,826)	(53,116)	
6		Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	-	-	
7		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)	2,500,000	2,475,750	-	-	
8		Transfer Credit from Gas Restructuring	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
9	B	Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	-	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(310,226)	(119,129)	2,420,554	2,353,861	(119,826)	(53,116)	
10																					
11	A-B	Total net expenses to recover	4,611,659	95,798	700,000	-	356,243	1,296,123	2,808,471	1,903,772	(8,887,756)	3,340,669	(949,571)	877,655	835,839	1,526,211	4,418,569.29	10,641,813.86	3,408,427.63	464,499.00	
12																					
13																					
14		Surcharge revenue:																			
15	Act	June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
16	Act	November 1998 - October 1999	(538,143)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
17	Act	November 1999 - October 2000	(912,804)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
18	Act	November 2000 - October 2001	(779,786)	(13,925)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(793,711)
19	Act	November 2001 - October 2002	(759,943)	(24,514)	(110,314)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(894,771)
20	Act	November 2002 - October 2003	(744,646)	(15,197)	(106,378)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(866,221)
21	Act	November 2003 - October 2004	(422,442)	(14,567)	(101,969)	-	(99,593)	-	-	-	-	-	-	-	-	-	-	-	-	-	(638,571)
22	Act	November 2004- October 2005	(184,336)	(14,180)	(85,078)	-	(56,719)	(226,875)	-	-	-	-	-	-	-	-	-	-	-	-	(567,186)
23	Act	November 2005- October 2006	(141,176)	(6,875)	(96,247)	-	(54,998)	(213,118)	(343,739)	-	-	-	-	-	-	-	-	-	-	-	(856,153)
24	Act	November 2006- October 2007	-	-	(98,635)	-	(56,363)	(211,361)	(366,359)	(429,768)	-	-	-	-	-	-	-	-	-	-	(1,162,487)
25	Act	November 2007- October 2008													-	-	-	-	-	-	-
26	Act	November 2012- October 2013									-	-	-	-	(30,009)	(130,039)	-	-	-	-	(160,048)
27	Act	November 2013- October 2014													(38,246)	(165,731)	-	-	-	-	(203,977)
28	Act	Nov 2009-Oct 2010 Base Rate Rev													(10,611)	-	-	-	-	-	(10,611)
29	Act	Nov 2010-Oct 2011 Base Rate Rev													(77,509)	-	-	-	-	-	(77,509)
30	Act	Nov 2011-Oct 2012 Base Rate Rev													(68,244)	-	-	-	-	-	(68,244)
31	Act	Nov 2012-Oct 2013 Base Rate Rev													(8,937)	(67,398)	-	-	-	-	(76,335)
32	Act	Nov 2013-Oct 2014 Base Rate Rev													-	(28,433)	(28,433)	-	-	-	(56,865)
33	Act	Nov 2014-Oct 2015 Base Rate Rev													-	(21,909)	(21,909)	(21,909)	-	-	(65,728)
34		AES collections	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,948)	(14,173)	(14,405)	(14,664)	(192,209)
35		Gas Street overcollection	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
36		Prior Period Pool under/overcollection																			
37																					
38																					
39	C	Surcharge Subtotal	(4,561,677)	(89,257)	(598,621)	-	(267,673)	(684,947)	(721,725)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(246,777)	(427,248)	(64,290)	(36,082)	(14,405)	(14,664)	(8,219,976)
40																					
41																					
42	D	Net balance to be recovered (A-B+C)	49,982	6,541	101,379	-	88,571	611,176	2,086,746	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	589,062	1,098,962	4,354,279	10,605,732	3,394,023	449,835	[redacted]
43																					
44	E	Allocation of Litigated Recovery																			
45																					
46		Surcharge calculation																			
47		Unrecovered costs (D+E)																			
48		remaining life																			
49		one year																			
50	F	amortization																			
51																					
52		Required annual increase in rates:																			
53		smaller of D or F																			
54																					
55		forecasted therm sales																			
56																					
57		surcharge per therm																			

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

Schedule 21
2017 - 2018 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed Third Revised Page 143
Attachment - B Supplier Balancing Charge

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2017-2018

Rate: $0.20 /MMBtu

	Rate	Volume	Total	
Injection Cost	$0.0087	**504,271**	$4,387	
Fuel (2.18%)	$0.0523	**504,271**	$26,383	
Withdrawal Cost	$0.0087	**251,713**	$2,190	
Delivery Rate	$0.0491	251,713	$12,362	
FTA Demand Charge	$0.2679	251,713	$67,425	
FTA Commodity Charge	$0.1165	251,713	$29,325	
Fuel (1.13%)	$0.0271	251,713	$6,826	
		Total Cost	$148,898	
	Absolute Value of the	Sendout Error	**755,983**	MMBtu
		Rate	$ 0.20	/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	$1.4938	/ MMBtu per month
	$0.0491	/ MMBtu per day
TGP Z4-6 Demand Charge	$8.1475	/ MMBtu per month
	$0.2679	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.1165	/ MMBtu

Schedule 21
2017 - 2018 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed Third Revised Page 143
Attachment - B Supplier Balancing Charge

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2017-2018
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	680	667	13	1,400,103	1,380,046	20,056	78,683	49,370	29,313
Dec	1,076	1,070	6	2,390,731	2,380,049	10,682	113,941	62,311	51,629
Jan	1,060	1,043	17	2,362,245	2,331,980	30,265	97,918	64,092	33,826
Feb	987	879	108	2,198,902	2,007,213	191,689	234,417	213,053	21,364
Mar	1,047	1,036	11	2,164,976	2,146,681	18,295	104,781	61,538	43,243
Apr	552	549	3	1,194,074	1,189,671	4,403	51,367	27,885	23,482
May	208	216	-8	593,964	600,545	-6,581	27,971	10,695	17,276
Jun	25	32	-7	360,055	362,869	-2,814	3,618	402	3,216
Jul	4	8	-4	317,143	317,143	0	0	0	0
Aug	0	0	0	317,143	317,143	0	0	0	0
Sep	66	73	-7	362,784	365,561	-2,777	2,777	0	2,777
Oct	391	401	-10	830,911	841,572	-10,661	40,512	14,925	25,587
Total	**6,096**	**5,974**	**122**	**14,493,031**	**14,240,473**	**252,558**	**755,983**	**504,271**	**251,713**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2017-2018
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Apr 1, 2016	7	6	1	23,072	21,604	1,468	1,468	1,468	0
Apr 2, 16	21	24	-3	43,618	48,021	-4,403	4,403	0	4,403
Apr 3, 16	35	37	-2	64,165	67,100	-2,935	2,935	0	2,935
Apr 4, 16	38	42	-4	68,568	74,438	-5,870	5,870	0	5,870
Apr 5, 16	37	36	1	67,100	65,633	1,468	1,468	1,468	0
Apr 6, 16	25	23	2	49,489	46,554	2,935	2,935	2,935	0
Apr 7, 16	15	14	1	34,813	33,345	1,468	1,468	1,468	0
Apr 8, 16	26	27	-1	50,956	52,424	-1,468	1,468	0	1,468
Apr 9, 16	28	27	1	53,892	52,424	1,468	1,468	1,468	0
Apr 10, 16	25	23	2	49,489	46,554	2,935	2,935	2,935	0
Apr 11, 16	14	12	2	33,345	30,410	2,935	2,935	2,935	0
Apr 12, 16	20	22	-2	42,151	45,086	-2,935	2,935	0	2,935
Apr 13, 16	21	21	0	43,618	43,618	0	0	0	0
Apr 14, 16	20	20	0	42,151	42,151	0	0	0	0
Apr 15, 16	17	16	1	37,748	36,280	1,468	1,468	1,468	0
Apr 16, 16	17	17	0	37,748	37,748	0	0	0	0
Apr 17, 16	8	8	0	24,539	24,539	0	0	0	0
Apr 18, 16	10	10	0	27,474	27,474	0	0	0	0
Apr 19, 16	16	14	2	36,280	33,345	2,935	2,935	2,935	0
Apr 20, 16	15	15	0	34,813	34,813	0	0	0	0
Apr 21, 16	2	0	2	15,734	12,798	2,935	2,935	2,935	0
Apr 22, 16	0	2	-2	12,798	15,734	-2,935	2,935	0	2,935
Apr 23, 16	14	13	1	33,345	31,877	1,468	1,468	1,468	0
Apr 24, 16	17	18	-1	37,748	39,215	-1,468	1,468	0	1,468
Apr 25, 16	14	13	1	33,345	31,877	1,468	1,468	1,468	0
Apr 26, 16	28	28	0	53,892	53,892	0	0	0	0
Apr 27, 16	18	16	2	39,215	36,280	2,935	2,935	2,935	0
Apr 28, 16	17	17	0	37,748	37,748	0	0	0	0
Apr 29, 16	16	16	0	36,280	36,280	0	0	0	0
Apr 30, 16	11	12	-1	28,942	30,410	-1,468	1,468	0	1,468
May 1, 16	17	19	-2	27,626	29,271	-1,645	1,645	0	1,645
May 2, 16	17	18	-1	27,626	28,448	-823	823	0	823
May 3, 16	15	16	-1	25,980	26,803	-823	823	0	823
May 4, 16	18	19	-1	28,448	29,271	-823	823	0	823
May 5, 16	16	16	0	26,803	26,803	0	0	0	0
May 6, 16	12	12	0	23,512	23,512	0	0	0	0
May 7, 16	13	14	-1	24,335	25,158	-823	823	0	823
May 8, 16	14	14	0	25,158	25,158	0	0	0	0
May 9, 16	16	13	3	26,803	24,335	2,468	2,468	2,468	0
May 10, 16	9	4	5	21,044	16,931	4,113	4,113	4,113	0
May 11, 16	3	1	2	16,108	14,463	1,645	1,645	1,645	0
May 12, 16	0	0	0	13,640	13,640	0	0	0	0
May 13, 16	1	0	1	14,463	13,640	823	823	823	0
May 14, 16	1	1	0	14,463	14,463	0	0	0	0
May 15, 16	15	17	-2	25,980	27,626	-1,645	1,645	0	1,645
May 16, 16	12	14	-2	23,512	25,158	-1,645	1,645	0	1,645
May 17, 16	6	4	2	18,576	16,931	1,645	1,645	1,645	0
May 18, 16	6	7	-1	18,576	19,399	-823	823	0	823
May 19, 16	6	7	-1	18,576	19,399	-823	823	0	823
May 20, 16	0	1	-1	13,640	14,463	-823	823	0	823
May 21, 16	0	0	0	13,640	13,640	0	0	0	0
May 22, 16	4	5	-1	16,931	17,754	-823	823	0	823
May 23, 16	0	0	0	13,640	13,640	0	0	0	0
May 24, 16	5	5	0	17,754	17,754	0	0	0	0
May 25, 16	0	0	0	13,640	13,640	0	0	0	0
May 26, 16	0	0	0	13,640	13,640	0	0	0	0
May 27, 16	0	0	0	13,640	13,640	0	0	0	0
May 28, 16	0	0	0	13,640	13,640	0	0	0	0
May 29, 16	2	9	-7	15,286	21,044	-5,759	5,759	0	5,759
May 30, 16	0	0	0	13,640	13,640	0	0	0	0
May 31, 16	0	0	0	13,640	13,640	0	0	0	0
Jun 1, 16	1	1	0	12,069	12,069	0	0	0	0
Jun 2, 16	2	3	-1	12,471	12,873	-402	402	0	402
Jun 3, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 4, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 5, 16	0	2	-2	11,667	12,471	-804	804	0	804
Jun 6, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 7, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 8, 16	4	5	-1	13,275	13,677	-402	402	0	402
Jun 9, 16	7	7	0	14,481	14,481	0	0	0	0
Jun 10, 16	4	3	1	13,275	12,873	402	402	402	0
Jun 11, 16	0	4	-4	11,667	13,275	-1,608	1,608	0	1,608
Jun 12, 16	5	5	0	13,677	13,677	0	0	0	0
Jun 13, 16	2	2	0	12,471	12,471	0	0	0	0
Jun 14, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 15, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 16, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 17, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 18, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 19, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 20, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 21, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 22, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 23, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 24, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 25, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 26, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 27, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 28, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 29, 16	0	0	0	11,667	11,667	0	0	0	0
Jun 30, 16	0	0	0	11,667	11,667	0	0	0	0
Jul 1, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 2, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 3, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 4, 16	0	0	0	10,230	10,230	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2017-2018
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jul 5, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 6, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 7, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 8, 16	0	1	-1	10,230	10,230	0	0	0	0
Jul 9, 16	3	5	-2	10,230	10,230	0	0	0	0
Jul 10, 16	1	2	-1	10,230	10,230	0	0	0	0
Jul 11, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 12, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 13, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 14, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 15, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 16, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 17, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 18, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 19, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 20, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 21, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 22, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 23, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 24, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 25, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 26, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 27, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 28, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 29, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 30, 16	0	0	0	10,230	10,230	0	0	0	0
Jul 31, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 1, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 2, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 3, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 4, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 5, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 6, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 7, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 8, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 9, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 10, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 11, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 12, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 13, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 14, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 15, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 16, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 17, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 18, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 19, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 20, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 21, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 22, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 23, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 24, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 25, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 26, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 27, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 28, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 29, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 30, 16	0	0	0	10,230	10,230	0	0	0	0
Aug 31, 16	0	0	0	10,230	10,230	0	0	0	0
Sep 1, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 2, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 3, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 4, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 5, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 6, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 7, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 8, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 9, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 10, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 11, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 12, 16	0	1	-1	11,220	11,617	-397	397	0	397
Sep 13, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 14, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 15, 16	4	5	-1	12,807	13,203	-397	397	0	397
Sep 16, 16	1	1	0	11,617	11,617	0	0	0	0
Sep 17, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 18, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 19, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 20, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 21, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 22, 16	0	0	0	11,220	11,220	0	0	0	0
Sep 23, 16	1	4	-3	11,617	12,807	-1,190	1,190	0	1,190
Sep 24, 16	9	9	0	14,790	14,790	0	0	0	0
Sep 25, 16	12	12	0	15,980	15,980	0	0	0	0
Sep 26, 16	5	5	0	13,203	13,203	0	0	0	0
Sep 27, 16	3	3	0	12,410	12,410	0	0	0	0
Sep 28, 16	10	11	-1	15,187	15,583	-397	397	0	397
Sep 29, 16	10	11	-1	15,187	15,583	-397	397	0	397
Sep 30, 16	11	11	0	15,583	15,583	0	0	0	0
Oct 1, 16	12	13	-1	26,150	27,216	-1,066	1,066	0	1,066
Oct 2, 16	10	11	-1	24,018	25,084	-1,066	1,066	0	1,066
Oct 3, 16	6	4	2	19,754	17,621	2,132	2,132	2,132	0
Oct 4, 16	12	13	-1	26,150	27,216	-1,066	1,066	0	1,066
Oct 5, 16	10	12	-2	24,018	26,150	-2,132	2,132	0	2,132
Oct 6, 16	5	6	-1	18,687	19,754	-1,066	1,066	0	1,066
Oct 7, 16	5	5	0	18,687	18,687	0	0	0	0
Oct 8, 16	3	3	0	16,555	16,555	0	0	0	0

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Oct 9, 16	16	16	0	30,415	30,415	0	0	0	0
Oct 10, 16	18	18	0	32,547	32,547	0	0	0	0
Oct 11, 16	13	13	0	27,216	27,216	0	0	0	0
Oct 12, 16	9	9	0	22,952	22,952	0	0	0	0
Oct 13, 16	9	9	0	22,952	22,952	0	0	0	0
Oct 14, 16	19	19	0	33,613	33,613	0	0	0	0
Oct 15, 16	16	19	-3	30,415	33,613	-3,198	3,198	0	3,198
Oct 16, 16	3	3	0	16,555	16,555	0	0	0	0
Oct 17, 16	1	1	0	14,423	14,423	0	0	0	0
Oct 18, 16	0	6	-6	13,357	19,754	-6,397	6,397	0	6,397
Oct 19, 16	4	4	0	17,621	17,621	0	0	0	0
Oct 20, 16	7	8	-1	20,820	21,886	-1,066	1,066	0	1,066
Oct 21, 16	2	1	1	15,489	14,423	1,066	1,066	1,066	0
Oct 22, 16	18	18	0	32,547	32,547	0	0	0	0
Oct 23, 16	17	14	3	31,481	28,282	3,198	3,198	3,198	0
Oct 24, 16	21	17	4	35,745	31,481	4,264	4,264	4,264	0
Oct 25, 16	25	25	0	40,010	40,010	0	0	0	0
Oct 26, 16	28	27	1	43,208	42,142	1,066	1,066	1,066	0
Oct 27, 16	22	20	2	36,811	34,679	2,132	2,132	2,132	0
Oct 28, 16	23	22	1	37,877	36,811	1,066	1,066	1,066	0
Oct 29, 16	14	19	-5	28,282	33,613	-5,331	5,331	0	5,331
Oct 30, 16	18	19	-1	32,547	33,613	-1,066	1,066	0	1,066
Oct 31, 16	25	27	-2	40,010	42,142	-2,132	2,132	0	2,132
Nov 1, 16	21	19	2	44,099	41,013	3,086	3,086	3,086	0
Nov 2, 16	11	13	-2	28,671	31,756	-3,086	3,086	0	3,086
Nov 3, 16	16	15	1	36,385	34,842	1,543	1,543	1,543	0
Nov 4, 16	24	24	0	48,727	48,727	0	0	0	0
Nov 5, 16	20	18	2	42,556	39,470	3,086	3,086	3,086	0
Nov 6, 16	24	23	1	48,727	47,184	1,543	1,543	1,543	0
Nov 7, 16	25	26	-1	50,270	51,813	-1,543	1,543	0	1,543
Nov 8, 16	16	18	-2	36,385	39,470	-3,086	3,086	0	3,086
Nov 9, 16	22	20	2	45,642	42,556	3,086	3,086	3,086	0
Nov 10, 16	19	17	2	41,013	37,928	3,086	3,086	3,086	0
Nov 11, 16	27	25	2	53,356	50,270	3,086	3,086	3,086	0
Nov 12, 16	25	21	4	50,270	44,099	6,171	6,171	6,171	0
Nov 13, 16	19	21	-2	41,013	44,099	-3,086	3,086	0	3,086
Nov 14, 16	19	16	3	41,013	36,385	4,628	4,628	4,628	0
Nov 15, 16	17	16	1	37,928	36,385	1,543	1,543	1,543	0
Nov 16, 16	17	14	3	37,928	33,299	4,628	4,628	4,628	0
Nov 17, 16	18	19	-1	39,470	41,013	-1,543	1,543	0	1,543
Nov 18, 16	18	18	0	39,470	39,470	0	0	0	0
Nov 19, 16	18	15	3	39,470	34,842	4,628	4,628	4,628	0
Nov 20, 16	29	30	-1	56,441	57,984	-1,543	1,543	0	1,543
Nov 21, 16	31	32	-1	59,527	61,070	-1,543	1,543	0	1,543
Nov 22, 16	31	29	2	59,527	56,441	3,086	3,086	3,086	0
Nov 23, 16	31	30	1	59,527	57,984	1,543	1,543	1,543	0
Nov 24, 16	27	28	-1	53,356	54,898	-1,543	1,543	0	1,543
Nov 25, 16	26	28	-2	51,813	54,898	-3,086	3,086	0	3,086
Nov 26, 16	27	26	1	53,356	51,813	1,543	1,543	1,543	0
Nov 27, 16	30	28	2	57,984	54,898	3,086	3,086	3,086	0
Nov 28, 16	30	31	-1	57,984	59,527	-1,543	1,543	0	1,543
Nov 29, 16	22	27	-5	45,642	53,356	-7,714	7,714	0	7,714
Nov 30, 16	20	20	0	42,556	42,556	0	0	0	0
Dec 1, 16	22	21	1	54,493	52,713	1,780	1,780	1,780	0
Dec 2, 16	24	23	1	58,054	56,273	1,780	1,780	1,780	0
Dec 3, 16	30	28	2	68,736	65,175	3,561	3,561	3,561	0
Dec 4, 16	34	34	0	75,857	75,857	0	0	0	0
Dec 5, 16	31	38	-7	70,516	82,978	-12,462	12,462	0	12,462
Dec 6, 16	30	30	0	68,736	68,736	0	0	0	0
Dec 7, 16	31	31	0	70,516	70,516	0	0	0	0
Dec 8, 16	32	30	2	72,296	68,736	3,561	3,561	3,561	0
Dec 9, 16	39	40	-1	84,759	86,539	-1,780	1,780	0	1,780
Dec 10, 16	43	47	-4	91,880	99,001	-7,121	7,121	0	7,121
Dec 11, 16	36	36	0	79,418	79,418	0	0	0	0
Dec 12, 16	31	31	0	70,516	70,516	0	0	0	0
Dec 13, 16	32	30	2	72,296	68,736	3,561	3,561	3,561	0
Dec 14, 16	38	38	0	82,978	82,978	0	0	0	0
Dec 15, 16	52	54	-2	107,903	111,463	-3,561	3,561	0	3,561
Dec 16, 16	49	51	-2	102,562	106,122	-3,561	3,561	0	3,561
Dec 17, 16	33	39	-6	74,077	84,759	-10,682	10,682	0	10,682
Dec 18, 16	37	33	4	81,198	74,077	7,121	7,121	7,121	0
Dec 19, 16	50	52	-2	104,342	107,903	-3,561	3,561	0	3,561
Dec 20, 16	40	39	1	86,539	84,759	1,780	1,780	1,780	0
Dec 21, 16	34	32	2	75,857	72,296	3,561	3,561	3,561	0
Dec 22, 16	34	36	-2	75,857	79,418	-3,561	3,561	0	3,561
Dec 23, 16	32	29	3	72,296	66,955	5,341	5,341	5,341	0
Dec 24, 16	30	26	4	68,736	61,614	7,121	7,121	7,121	0
Dec 25, 16	41	39	2	88,319	84,759	3,561	3,561	3,561	0
Dec 26, 16	26	26	0	61,614	61,614	0	0	0	0
Dec 27, 16	30	23	7	68,736	56,273	12,462	12,462	12,462	0
Dec 28, 16	35	32	3	77,637	72,296	5,341	5,341	5,341	0
Dec 29, 16	31	33	-2	70,516	74,077	-3,561	3,561	0	3,561
Dec 30, 16	38	37	1	82,978	81,198	1,780	1,780	1,780	0
Dec 31, 16	31	32	-1	70,516	72,296	-1,780	1,780	0	1,780
Jan 1, 17	36	37	-1	79,418	81,198	-1,780	1,780	0	1,780
Jan 2, 17	31	32	-1	70,516	72,296	-1,780	1,780	0	1,780
Jan 3, 17	28	28	0	65,175	65,175	0	0	0	0
Jan 4, 17	32	30	2	72,296	68,736	3,561	3,561	3,561	0
Jan 5, 17	38	38	0	82,978	82,978	0	0	0	0
Jan 6, 17	42	42	0	90,099	90,099	0	0	0	0
Jan 7, 17	46	49	-3	97,221	102,562	-5,341	5,341	0	5,341
Jan 8, 17	52	52	0	107,903	107,903	0	0	0	0
Jan 9, 17	49	52	-3	102,562	107,903	-5,341	5,341	0	5,341
Jan 10, 17	29	29	0	66,955	66,955	0	0	0	0
Jan 11, 17	23	19	4	56,273	49,152	7,121	7,121	7,121	0
Jan 12, 17	18	14	4	47,372	40,250	7,121	7,121	7,121	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2017-2018
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jan 13, 17	39	39	0	84,759	84,759	0	0	0	0
Jan 14, 17	39	40	-1	84,759	86,539	-1,780	1,780	0	1,780
Jan 15, 17	39	41	-2	84,759	88,319	-3,561	3,561	0	3,561
Jan 16, 17	33	35	-2	74,077	77,637	-3,561	3,561	0	3,561
Jan 17, 17	31	30	1	70,516	68,736	1,780	1,780	1,780	0
Jan 18, 17	31	34	-3	70,516	75,857	-5,341	5,341	0	5,341
Jan 19, 17	31	31	0	70,516	70,516	0	0	0	0
Jan 20, 17	30	29	1	68,736	66,955	1,780	1,780	1,780	0
Jan 21, 17	24	23	1	58,054	56,273	1,780	1,780	1,780	0
Jan 22, 17	30	30	0	68,736	68,736	0	0	0	0
Jan 23, 17	31	34	-3	70,516	75,857	-5,341	5,341	0	5,341
Jan 24, 17	30	30	0	68,736	68,736	0	0	0	0
Jan 25, 17	32	28	4	72,296	65,175	7,121	7,121	7,121	0
Jan 26, 17	29	23	6	66,955	56,273	10,682	10,682	10,682	0
Jan 27, 17	33	28	5	74,077	65,175	8,902	8,902	8,902	0
Jan 28, 17	35	32	3	77,637	72,296	5,341	5,341	5,341	0
Jan 29, 17	37	34	3	81,198	75,857	5,341	5,341	5,341	0
Jan 30, 17	42	40	2	90,099	86,539	3,561	3,561	3,561	0
Jan 31, 17	40	40	0	86,539	86,539	0	0	0	0
Feb 1, 17	36	34	2	79,418	75,857	3,561	3,561	3,561	0
Feb 2, 17	40	36	4	86,539	79,418	7,121	7,121	7,121	0
Feb 3, 17	43	40	3	91,880	86,539	5,341	5,341	5,341	0
Feb 4, 17	41	38	3	88,319	82,978	5,341	5,341	5,341	0
Feb 5, 17	35	30	5	77,637	68,736	8,902	8,902	8,902	0
Feb 6, 17	40	34	6	86,539	75,857	10,682	10,682	10,682	0
Feb 7, 17	33	42	-9	74,077	90,099	-16,023	16,023	0	16,023
Feb 8, 17	33	28	5	74,077	65,175	8,902	8,902	8,902	0
Feb 9, 17	51	51	0	106,122	106,122	0	0	0	0
Feb 10, 17	53	51	2	109,683	106,122	3,561	3,561	3,561	0
Feb 11, 17	45	47	-2	95,440	99,001	-3,561	3,561	0	3,561
Feb 12, 17	39	40	-1	84,759	86,539	-1,780	1,780	0	1,780
Feb 13, 17	43	40	3	91,880	86,539	5,341	5,341	5,341	0
Feb 14, 17	39	36	3	84,759	79,418	5,341	5,341	5,341	0
Feb 15, 17	35	32	3	77,637	72,296	5,341	5,341	5,341	0
Feb 16, 17	38	37	1	82,978	81,198	1,780	1,780	1,780	0
Feb 17, 17	38	34	4	82,978	75,857	7,121	7,121	7,121	0
Feb 18, 17	29	22	7	66,955	54,493	12,462	12,462	12,462	0
Feb 19, 17	30	19	11	68,736	49,152	19,584	19,584	19,584	0
Feb 20, 17	36	33	3	79,418	74,077	5,341	5,341	5,341	0
Feb 21, 17	32	26	6	72,296	61,614	10,682	10,682	10,682	0
Feb 22, 17	28	22	6	65,175	54,493	10,682	10,682	10,682	0
Feb 23, 17	21	12	9	52,713	36,690	16,023	16,023	16,023	0
Feb 24, 17	14	5	9	40,250	24,228	16,023	16,023	16,023	0
Feb 25, 17	20	13	7	50,932	38,470	12,462	12,462	12,462	0
Feb 26, 17	33	31	2	74,077	70,516	3,561	3,561	3,561	0
Feb 27, 17	28	22	6	65,175	54,493	10,682	10,682	10,682	0
Feb 28, 17	21	16	5	52,713	43,811	8,902	8,902	8,902	0
Mar 1, 17	13	8	5	35,742	27,426	8,316	8,316	8,316	0
Mar 2, 17	37	35	2	75,659	72,332	3,326	3,326	3,326	0
Mar 3, 17	45	43	2	88,964	85,638	3,326	3,326	3,326	0
Mar 4, 17	54	54	0	103,933	103,933	0	0	0	0
Mar 5, 17	49	44	5	95,617	87,301	8,316	8,316	8,316	0
Mar 6, 17	35	30	5	72,332	64,016	8,316	8,316	8,316	0
Mar 7, 17	21	24	-3	49,047	54,037	-4,990	4,990	0	4,990
Mar 8, 17	19	17	2	45,721	42,395	3,326	3,326	3,326	0
Mar 9, 17	30	28	2	64,016	60,690	3,326	3,326	3,326	0
Mar 10, 17	40	44	-4	80,648	87,301	-6,653	6,653	0	6,653
Mar 11, 17	51	54	-3	98,943	103,933	-4,990	4,990	0	4,990
Mar 12, 17	47	48	-1	92,290	93,954	-1,663	1,663	0	1,663
Mar 13, 17	40	37	3	80,648	75,659	4,990	4,990	4,990	0
Mar 14, 17	38	39	-1	77,322	78,985	-1,663	1,663	0	1,663
Mar 15, 17	41	42	-1	82,311	83,975	-1,663	1,663	0	1,663
Mar 16, 17	42	39	3	83,975	78,985	4,990	4,990	4,990	0
Mar 17, 17	41	38	3	82,311	77,322	4,990	4,990	4,990	0
Mar 18, 17	33	34	-1	69,006	70,669	-1,663	1,663	0	1,663
Mar 19, 17	33	32	1	69,006	67,343	1,663	1,663	1,663	0
Mar 20, 17	25	23	2	55,700	52,374	3,326	3,326	3,326	0
Mar 21, 17	25	23	2	55,700	52,374	3,326	3,326	3,326	0
Mar 22, 17	44	45	-1	87,301	88,964	-1,663	1,663	0	1,663
Mar 23, 17	38	35	3	77,322	72,332	4,990	4,990	4,990	0
Mar 24, 17	25	29	-4	55,700	62,353	-6,653	6,653	0	6,653
Mar 25, 17	30	33	-3	64,016	69,006	-4,990	4,990	0	4,990
Mar 26, 17	29	29	0	62,353	62,353	0	0	0	0
Mar 27, 17	27	28	-1	59,027	60,690	-1,663	1,663	0	1,663
Mar 28, 17	25	27	-2	55,700	59,027	-3,326	3,326	0	3,326
Mar 29, 17	26	26	0	57,363	57,363	0	0	0	0
Mar 30, 17	26	24	2	57,363	54,037	3,326	3,326	3,326	0
Mar 31, 17	31	32	-1	65,679	67,343	-1,663	1,663	0	1,663
Apr	552	549	3	1,194,074	1,189,671	4,403	51,367	27,885	23,482
May	208	216	-8	593,964	600,545	-6,581	27,971	10,695	17,276
Jun	25	32	-7	360,055	362,869	-2,814	3,618	402	3,216
Jul	4	8	-4	317,143	317,143	0	0	0	0
Aug	0	0	0	317,143	317,143	0	0	0	0
Sep	66	73	-7	362,784	365,561	-2,777	2,777	0	2,777
Oct	391	401	-10	830,911	841,572	-10,661	40,512	14,925	25,587
Nov	680	667	13	1,400,103	1,380,046	20,056	78,683	49,370	29,313
Dec	1,076	1,070	6	2,390,731	2,380,049	10,682	113,941	62,311	51,629
Jan	1,060	1,043	17	2,362,245	2,331,980	30,265	97,918	64,092	33,826
Feb	987	879	108	2,198,902	2,007,213	191,689	234,417	213,053	21,364
Mar	1,047	1,036	11	2,164,976	2,146,681	18,295	104,781	61,538	43,243
Total	6,096	5,974	122	14,493,031	14,240,473	252,558	755,983	504,271	251,713

Schedule 21
2017 - 2018 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed Third Revised Page 143
Attachment B - Peaking Demand Charge

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		157,258	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 95346	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
		TGP FT-A (Z6-Z6) 72694	30,000		
10			79,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3 of 3: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		49,425	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$3,969,000		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		$5,949,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$120.37		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$20.06**	**/Dekatherm**	Line 29 divided by 6 month

Schedule 21
2017 - 2018 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed Third Revised Page 143
Attachment B - Peaking Demand Charge

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	72.9%	47.9%
Storage	9.8%	18.9%
Peaking	17.3%	33.2%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2017:

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		$15.5526		10/31/2022	
	Iroquois	RTS to Wright	470-01	4,047		$5.9982		11/1/2018	
	TGP	NET-NE (Z5-Z6)	95346	4,000		$7.1563		11/30/2021	
	TGP	FT-A (Z5-Z6)	2302	3,122		$7.1563		10/31/2020	
	TGP	FT-A (Z0-Z6)	8587	7,035		$23.2169		10/31/2020	
	TGP	FT-A (Z1-Z6)	8587	14,561		$20.6088		10/31/2020	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4.7447		10/31/2020	
	TGP	FT-A (Z6-Z6)	72694	30,000		$12.1910		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523*	21,844	1,560,391	$1.4938	$0.0205	10/31/2020	
	TGP	FT-A (Z4-Z6)	632	15,265		$8.1475		10/31/2020	
	TGP	FT-A (Z4-Z6)	8587	3,811		$8.1475		10/31/2020	
	National Fuel	FSS-1 (Storage)	O02357*	6,098	670,800	$2.4329	$0.0373	3/31/2018	
	National Fuel	FST (Transport)	N02358	6,098		$3.7049		3/31/2018	
	TGP	FT-A (Z4-Z6)	11234	6,150		$8.1475		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		$7.1563		10/31/2020	
	Dominion	GSS (Storage)	300076*	934	102,700	$1.8683	$0.0145	3/31/2021	
	TGP	FT-A (Z4-Z6)	11234	932		$8.1475		10/31/2020	
Peaking									
	Energy North	LNG/Propane****		49,425	-	$20.0600	$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 11/01/17. 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.

2017 - 2018 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed Third 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	ENGIE						
6							
7	Subtotal					**$3,969,000**	*
8							
9	**Total**					**$3,969,000**	
10							

* Contract currently being negotiated for an effective date of November 1, 2017

Liberty Utilities (EnergyNorth Natural Gas) Corp

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	47.9%	18.9%	33.2%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	72.9%	9.8%	17.3%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	47.9%	18.9%	33.2%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	72.9%	9.8%	17.3%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	47.9%	18.9%	33.2%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	72.9%	9.8%	17.3%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	72.9%	9.8%	17.3%	100.0%

HLF	High Load Factor	72.88%	9.83%	17.29%	100%
LLF	Low Load Factor	47.89%	18.90%	33.22%	100%
	Total	50.69%	17.88%	31.43%	100%

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD		Base load	71.386 Heat load	Total
HLF	R-1 RNSH	99	450	548
LLF	R-3 RSH	3,710	62,785	66,495
LLF	G-41 SL	973	26,109	27,082
HLF	G-51 SH	624	1,980	2,604
LLF	G-42 ML	2,164	34,009	36,173
HLF	G-52 MH	1,365	3,246	4,610
LLF	G-43 LL	886	8,965	9,851
HLF	G-53 LLL90	1,995	2,921	4,916
HLF	G-54 LLG90	4,895	83	4,978
	TOTAL	16,711	140,547	157,258

HLF	8,977	8,679	17,656
LLF	7,734	131,868	139,602
Total	16,711	140,547	157,258

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	99	202	300	90	158.15	548
R-3 RSH	3,710	28,147	31,857	12,559	22,079	66,495
G-41 SL	973	11,705	12,677	5,223	9,182	27,082
G-51 SH	624	888	1,512	396	696	2,604
G-42 ML	2,164	15,246	17,411	6,803	11,960	36,173
G-52 MH	1,365	1,455	2,820	649	1,141	4,610
G-43 LL	886	4,019	4,905	1,793	3,153	9,851
G-53 LLL90	1,995	1,310	3,304	584	1,027	4,916
G-54 LLG90	4,895	37	4,932	17	29	4,978
TOTAL	16,711	63,007	79,718	28,115	49,425	157,258

HLF	8,977	3,891	12,868	1,736	3,052	17,656
LLF	7,734	59,116	66,850	26,379	46,373	139,602
Total	16,711	63,007	79,718	28,115	49,425	157,258

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	54.7%	16.4%	28.8%	100.0%
R-3 RSH	47.9%	18.9%	33.2%	100.0%
G-41 SL	46.8%	19.3%	33.9%	100.0%
G-51 SH	58.1%	15.2%	26.7%	100.0%
G-42 ML	48.1%	18.8%	33.1%	100.0%
G-52 MH	61.2%	14.1%	24.8%	100.0%
G-43 LL	49.8%	18.2%	32.0%	100.0%
G-53 LLL90	67.2%	11.9%	20.9%	100.0%
G-54 LLG90	99.1%	0.3%	0.6%	100.0%
TOTAL	50.7%	17.9%	31.4%	100.0%

High Load Factor	72.88%	9.83%	17.29%	100%
Low Load Factor	47.89%	18.90%	33.22%	100%
Total	50.69%	17.88%	31.43%	100%

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU) — **Allocate Design Day Sendout to Rate Classes**

Design DD 71.386

	Daily Baseload * 1000	January Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	99	6.386	456	554	18%	0.320%	99	450	548
R-3 RSH	3,710	891.498	63,640	67,351	6%	44.672%	3,710	62,785	66,495
G-41 SL	973	370.728	26,465	27,438	4%	18.577%	973	26,109	27,082
G-51 SH	624	28.115	2,007	2,631	24%	1.409%	624	1,980	2,604
G-42 ML	2,164	482.901	34,472	36,637	6%	24.197%	2,164	34,009	36,173
G-52 MH	1,365	46.085	3,290	4,655	29%	2.309%	1,365	3,246	4,610
G-43 LL	886	127.295	9,087	9,973	9%	6.379%	886	8,965	9,851
G-53 LLL90	1,995	41.481	2,961	4,956	40%	2.079%	1,995	2,921	4,916
G-54 LLG90	4,895	1.175	84	4,979	98%	0.059%	4,895	83	4,978
TOTAL	16,711	2,274.749	142,462	159,173		100.000%	16,711	140,547	157,258

HLF	8,977	123	8,798	17,775
LLF	7,734	2,152	133,665	141,398
Total	16,711	2,275	142,462	159,173

Design Day from 2017-2018 COG	**157,258**
Design Day from Billing Calculation	159,173
Variance	(1,915)

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-16	Aug-16	Sep-16	Oct-16	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	5	8	10	11	8	7	5	4	3	3	3	3	69	3.055	0.099
LLF	R-3 RSH	370	723	1,057	1,082	886	786	369	213	128	102	104	165	5,984	115.013	3.710
LLF	G-41 SL	121	270	422	429	367	306	124	59	33	27	27	49	2,234	30.157	0.973
HLF	G-51 SH	26	39	49	50	37	34	32	25	20	18	18	22	371	19.345	0.624
LLF	G-42 ML	226	406	577	583	492	424	201	107	77	57	59	107	3,317	67.099	2.164
HLF	G-52 MH	56	75	91	81	99	88	70	63	45	40	40	45	794	42.307	1.365
LLF	G-43 LL	90	109	162	174	147	144	107	63	29	26	26	44	1,121	27.476	0.886
HLF	G-53 LLL90	79	83	106	123	101	106	84	82	68	55	71	66	1,024	61.838	1.995
HLF	G-54 LLL110	157	147	153	139	114	122	133	165	166	152	170	164	1,784	151.717	4.894
HLF	G-63 LLG110	-	-	-	0	-	0	0	0	-	-	-	-	0	0.022	0.001
	TOTAL	1,131	1,858	2,626	2,673	2,252	2,018	1,124	783	570	480	517	665	16,698	525.211	16.942

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-16	Aug-16	Sep-16	Oct-16	Total	Monthly Baseload	Daily Baseload
HLF	323	352	408	404	359	358	324	341	303	268	301	301	4,042	278.284	9.209
LLF	808	1,506	2,218	2,269	1,893	1,660	800	442	267	212	216	364	12,656	239.745	7.734

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

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-16	Aug-16	Sep-16	Oct-16	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	3	3	3	3	3	3	3	3	3	3	3	3	36
LLF	R-3 RSH	111	115	115	104	115	111	115	111	128	102	104	115	1,354
LLF	G-41 SL	29	30	30	27	30	29	30	29	33	27	27	30	355
HLF	G-51 SH	19	19	19	17	19	19	19	19	20	18	18	19	228
LLF	G-42 ML	65	67	67	61	67	65	67	65	77	57	59	67	790
HLF	G-52 MH	41	42	42	38	42	41	42	41	45	40	40	42	498
LLF	G-43 LL	27	27	27	25	27	27	27	27	29	26	26	27	324
HLF	G-53 LLL90	60	62	62	56	62	60	62	60	68	55	60	62	728
HLF	G-54 LLL110	147	147	152	137	114	122	133	147	166	152	147	152	1,784
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	531	545	549	496	511	507	530	531	601	511	514	549	6,184

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-16	Aug-16	Sep-16	Oct-16	Total
HLF	269	274	278	251	241	245	259	269	303	268	267	278	3,274
LLF	232	240	240	217	240	232	240	232	267	212	216	240	2,823

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Heating Volumes (= Actual Volumes - Baseload)

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-16	Aug-16	Sep-16	Oct-16	Total
HLF	R-1 RNSH	2	5	7	8	5	4	2	1	0	0	0	0	34
LLF	R-3 RSH	259	608	942	979	771	674	253	101	0	0	0	50	4,630
LLF	G-41 SL	92	240	392	402	337	277	94	30	0	0	0	19	1,879
HLF	G-51 SH	7	20	30	32	17	16	13	7	0	0	0	2	143
LLF	G-42 ML	161	338	510	523	425	359	134	42	0	0	0	39	2,527
HLF	G-52 MH	15	33	49	43	57	47	27	22	0	0	0	3	296
LLF	G-43 LL	64	81	134	149	120	118	79	37	0	0	0	17	798
HLF	G-53 LLL90	19	21	44	67	39	46	22	22	0	0	11	4	296
HLF	G-54 LLL110	11	0	1	2	0	0	0	18	0	0	23	13	0
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	599	1,313	2,077	2,177	1,741	1,512	593	251	(31)	(31)	4	116	10,514

HLF	54	78	130	152	118	114	65	71	0	0	34	23	768
LLF	576	1,267	1,978	2,052	1,654	1,428	560	210	0	0	0	124	9,833

Actual BDD	524.0	858.5	1056.5	957.0	957.5	733.0	356.0	170.0	20.0	4.0	36.5	237.0	5910.0

Heat Factors

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-16	Aug-16	Sep-16	Oct-16	Total	AVG	AVG Peak
HLF	R-1 RNSH	0.0035	0.0053	0.0064	0.0081	0.0050	0.0058	0.0066	0.0078	0.0000	0.0000	0.0000	0.0014		0.0041	0.0057
LLF	R-3 RSH	0.4934	0.7078	0.8915	1.0225	0.8053	0.9202	0.7121	0.5970	0.0000	0.0000	0.0000	0.2093		0.5299	0.8068
LLF	G-41 SL	0.1753	0.2791	0.3707	0.4199	0.3522	0.3776	0.2627	0.1753	0.0000	0.0000	0.0000	0.0795		0.2077	0.3291
HLF	G-51 SH	0.0140	0.0227	0.0281	0.0338	0.0180	0.0215	0.0365	0.0398	0.0000	0.0000	0.0000	0.0092		0.0186	0.0230
LLF	G-42 ML	0.3080	0.3942	0.4829	0.5462	0.4442	0.4899	0.3757	0.2487	0.0000	0.0000	0.0000	0.1663		0.2880	0.4442
HLF	G-52 MH	0.0287	0.0383	0.0461	0.0445	0.0595	0.0646	0.0772	0.1319	0.0000	0.0000	0.0000	0.0133		0.0420	0.0469
LLF	G-43 LL	0.1217	0.0944	0.1273	0.1562	0.1253	0.1606	0.2221	0.2147	0.0000	0.0000	0.0000	0.0701		0.1077	0.1309
HLF	G-53 LLL90	0.0361	0.0241	0.0415	0.0705	0.0412	0.0631	0.0609	0.1315	0.0000	0.0000	0.2931	0.0180		0.0650	0.0461
HLF	G-54 LLL110	0.0203	0.0000	0.0012	0.0024	0.0000	0.0000	0.0000	0.1085	0.0000	0.0000	0.6339	0.0533		0.0683	0.0040
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		0.0000	0.0000
	TOTAL	1.1438	1.5298	1.9663	2.2747	1.8182	2.0624	1.6668	1.4787	-1.5500	-7.7500	0.1052	0.4896		0.4363	1.7992

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	**524.0**	**858.5**	**1,056.5**	**957.0**	**957.5**	**733.0**	**356.0**	**170.0**	**20.0**	**4.0**	**36.5**	**237.0**	**5910.0**
Norm Billing DD	**564.5**	**881.8**	**1137.6**	**1137.0**	**972.3**	**705.0**	**373.9**	**141.4**	**30.8**	**9.4**	**65.0**	**268.3**	**6287.1**

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

		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-16	Aug-16	Sep-16	Oct-16	Total
HLF	**R-1 RNSH**	5	8	10	12	8	7	6	4	3	3	3	3	72
LLF	**R-3 RSH**	390	739	1,129	1,267	898	760	381	196	128	102	104	171	6,265
LLF	**G-41 SL**	128	276	452	505	373	295	128	54	33	27	27	51	2,350
HLF	**G-51 SH**	27	39	51	56	37	34	33	24	20	18	18	22	380
LLF	**G-42 ML**	239	415	616	682	499	410	208	100	77	57	59	112	3,474
HLF	**G-52 MH**	57	76	95	89	100	87	71	60	45	40	40	46	805
LLF	**G-43 LL**	95	111	172	202	149	140	111	57	29	26	26	46	1,164
HLF	**G-53 LLL90**	80	83	109	136	102	104	85	78	68	55	79	67	1,047
HLF	**G-54 LLL110**	158	147	153	140	114	122	133	162	166	152	188	166	1,802
HLF	**G-63 LLG110**	-	-	-	0	-	0	0	0	-	-	-	-	0
	TOTAL	1,177	1,894	2,786	3,082	2,279	1,961	1,153	740	553	439	520	680	17,266

HLF	327	354	418	432	361	354	327	329	303	268	328	304	4,105
LLF	852	1,541	2,370	2,655	1,919	1,606	828	407	267	212	216	381	13,253

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2017 - 2018 Winter Cost of Gas Filing
Fixed Price Option

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6.0%				$0.3927	$0.3722	$ 943.37	$ 926.93	$ 16.44	1.77%	$0.3927	$0.3736	$ 1,570.86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9.0%				$0.4724	$0.4628	$ 679.85	$ 672.22	$ 7.63	1.13%	$0.4724	$0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20.0%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10.90%	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10.22%
4	Nov 01 - Apr 02	24.0%				$0.5141	$0.4818	$ 790.65	$ 760.55	$ 30.10	3.96%	$0.5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3.52%
5	Nov 02 - Apr 03	24.0%	$0.0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (19.11)	-2.27%	$0.5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	23.0%	$0.0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 35.09	3.25%	$0.8759	$0.8352	$ 1,798.38	$ 1,740.30	$ 58.08	3.34%
7	Nov 04 - Apr 05	29.6%	$0.0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142.96	$ 1,189.55	$ (46.60)	-3.92%	$0.9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3.51%
8	Nov 05 - Apr 06	29.8%	$0.0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 150.00	10.90%	$1.3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9.61%
9	Nov 06 - Apr 07	15.1%	$0.0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415.80	$ 93.99	6.64%	$1.2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	15.8%	$0.0200	14,078,553	$ 281,571	$1.2043	$1.1746	$ 1,433.09	$ 1,405.40	$ 27.69	1.97%	$1.2044	$1.1725	$ 2,232.39	$ 2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	15.2%	$0.0200	13,041,335	$ 260,827	$1.2835	$1.0888	$ 1,555.31	$ 1,373.85	$ 181.46	13.21%	$1.2836	$1.0958	$ 2,467.49	$ 2,199.54	$ 267.95	12.18%
12	Nov 09 - Apr 10	11.4%	$0.0200	8,405,413	$ 168,108	$0.9863	$0.9416	$ 1,250.80	$ 1,209.12	$ 41.69	3.45%	$0.9865	$0.9408	$ 1,984.29	$ 1,919.03	$ 65.26	3.40%
13	Nov 10 - Apr 11	12.6%	$0.0200	10,379,804	$ 207,596	$0.8420	$0.8029	$ 1,175.03	$ 1,138.58	$ 36.45	3.20%	$0.8434	$0.8030	$ 1,880.96	$ 1,823.34	$ 57.63	3.16%
14	Nov 11 - Apr 12	11.9%	$0.0200	7,835,197	$ 156,704	$0.8126	$0.7309	$ 1,165.61	$ 1,089.44	$ 76.17	6.99%	$0.8129	$0.7327	$ 1,845.28	$ 1,730.88	$ 114.40	6.61%
15	Nov 12 - Apr 13	10.9%	$0.0200	8,179,524	$ 163,590	$0.6919	$0.7680	$ 743.03	$ 792.48	$ (49.45)	-6.24%	$0.6936	$0.7724	$ 1,989.86	$ 2,132.90	$ (143.03)	-6.71%
16	Nov 13 - Apr 14	10.5%	$0.0200	8,930,779	$ 178,616	$0.9095	$1.1042	$ 857.72	$ 981.21	$ (123.49)	-12.59%	$0.9108	$1.1127	$ 2,662.63	$ 3,044.56	$ (381.93)	-12.54%
17	Nov 14 - Apr 15	15.1%	$0.0795	8,779,742	$ 697,989	$1.2425	$0.5905	$ 1,127.66	$ 948.07	$ 179.59	18.94%	$0.6847	$0.6647	$ 2,386.84	$ 2,349.01	$ 37.84	1.61%
18	Nov 15 - Apr 16	15.3%	$0.0200	4,941,157	$ 98,823	$0.7716	$0.7516	$ 869.15	$ 712.73	$ 156.42	21.95%						
19	Nov 16 - Apr 17	11.5%	$0.0106	5,419,967	$ 57,452	$0.7268	$0.7162	$ 827.14	$ 812.38	$ 14.76	1.82%						
20	Nov 17 - Apr 18					$0.6859	$0.6659	$ 878.70	$ 865.94	$ 12.76	1.47%						
21	Total									$ 721.74						$ 273.07	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2017 - 2018 Winter Cost of Gas Filing
Short-Term Debt Limitations

	For Purposes of Fuel Financing	
Total Direct Gas Costs	$	54,437,427
Total Indirect Gas Costs		2,095,304
Total Gas Costs	$	56,532,731
% of Debt to Total Gas Costs		30%
Short Term Debt	$	16,959,819

	For Purposes Other Than Fuel Financing	
12/31/2018 Projected Net Plant	**$**	**437,967,786**
% of Debt to Net Plant		20%
Short Term Debt	$	87,593,557

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
2017 - 2018 Winter Cost of Gas Filing

Company Allowance Calculation

	Jul-2016	Aug-2016	Sep-2016	Oct-2016	Nov-2016	Dec-2016	Jan-2017	Feb-2017	Mar-2017	Apr-2017	May-2017	Jun-2017	Total
Total Sendout- Therms	5,060,230	5,299,330	5,819,310	10,335,310	15,747,440	24,977,150	24,776,010	20,923,130	24,467,660	11,873,910	9,105,000	5,959,950	164,344,430
Total Throughput- Therms	5,581,324	4,804,245	5,173,547	6,419,450	10,853,467	18,253,381	24,184,090	23,291,389	22,231,603	20,848,167	10,907,162	8,400,536	160,948,361
Variance	(521,094)	495,085	645,763	3,915,860	4,893,973	6,723,769	591,920	(2,368,259)	2,236,057	(8,974,257)	(1,802,162)	(2,440,586)	3,396,069
Company Allowance													**2.07%**

Lost and Unaccounted For Gas ("LAUF") Calculation

	Jul-2016	Aug-2016	Sep-2016	Oct-2016	Nov-2016	Dec-2016	Jan-2017	Feb-2017	Mar-2017	Apr-2017	May-2017	Jun-2017	Total
Total Sendout- Therms	5,060,230	5,299,330	5,819,310	10,335,310	15,747,440	24,977,150	24,776,010	20,923,130	24,467,660	11,873,910	9,105,000	5,959,950	164,344,430
Total Throughput- Therms	5,581,324	4,804,245	5,173,547	6,419,450	10,853,467	18,253,381	24,184,090	23,291,389	22,231,603	20,848,167	10,907,162	8,400,536	160,948,361
Company Use	5,172	3,753	4,162	8,427	19,255	49,208	35,727	41,766	55,228	31,611	14,755	8,872	277,936
Variance	(526,266)	491,332	641,601	3,907,433	4,874,718	6,674,561	556,193	(2,410,025)	2,180,829	(9,005,868)	(1,816,917)	(2,449,458)	3,118,133
LAUF													**1.90%**