Ln	(a)	Reference (b)		PK 16-17 Nov - Apr (c)
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**			
2	**d/b/a Liberty Utilities**			
3	**Peak 2016 - 2017 Winter Cost of Gas Filing**			
4	**Summary**			
5				
6				
7				
8				
9	**Anticipated Direct Cost of Gas**			
10	Purchased Gas:			
11	Demand Costs:	Sch. 5A, col (k), ln 43	$	7,527,898
12	Supply Costs	Sch. 6, col (i), ln 44		48,688,614
13				
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (k), ln 58	$	941,660
16	Commodity Costs:	Sch. 6, col (i), ln 47		4,026,000
17				
18	Produced Gas:	Sch. 6, col (i), ln 53	$	1,797,499
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**		$	62,981,672
24				
25	**Adjustments:**			
26				
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$	2,690,610
28	Interest 05/01/15 - 10//31/15	Sch. 3, col (q) ln 193		33,236
29	Prior Period Adjustments	Sch. 4, ln 26 col (b)		-
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		-
31	Broker Revenues	Sch. 4, ln 26 col (d)		(1,374,947)
32	Fuel Financing	Sch. 4, ln 26 col (e)		-
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		(29,471)
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)		(5,448,856)
36	Hedging Costs	Sch. 4, ln 26 col (j)		-
37	FPO Premium - Collection			
38	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		41,972
39				
40	**Total Adjustments**		$	(4,087,455)
41				
42	**Total Anticipated Direct Costs**	lns 23 + 40	$	58,894,216
43				
44	**Anticipated Indirect Cost of Gas**			
45	**Working Capital**			
46	Total Unadjusted Anticipated Cost of Gas	Ln 23	$	62,981,672
47	Lead Lag Days / 365	DG 10-017, 14.27 / 365		0.0391
48	Prime Rate			3.50%
49	Working Capital Percentage	per GTC 16(f), ln 47 * ln 48		0.137%
50	Working Capital	ln 46 * ln 49		86,199
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 100		(33,597)
52				
53	**Total Working Capital Allowance**	lns 50 + 51	$	52,603
54				
55	**Bad Debt**			
56	Total Unadjusted Anticipated Cost of Gas	ln 23	$	62,981,672
57	Less Refunds	ln 30		-
58	Plus Working Capital	ln 53		52,603
59	Plus Prior Period (Over) Under Recovery	ln 27		2,690,610
60	Subtotal		$	65,724,885
61	Bad Debt Percentage	per GTC 16(f)		4.04%
62				
63	Bad Debt Allowance	ln 60 * ln 61	$	2,655,285
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 181		(37,241)
65				
66	**Total Bad Debt Allowance**	lns 63 + 64	$	2,618,044
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		90,536
72	Divided by Total Sales	Sch. 10B, ln 23/1000		112,609
73	Ratio			80.40%
74				
75	**Miscellaneous Overhead**	lns 70 * 73	$	10,589
76				
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$	4,661,664
78				
79	**Total Cost of Gas**	lns 42 + 77	$	63,555,880
80				
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		89,920,078

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Ln	For Month of:		Peak Costs May 16 - Oct 16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Peak Period Nov - Apr
5											
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10										2,340,407	2.5%
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	1,697,133	13,653,493	19,461,903	20,682,445	17,666,408	12,462,769	5,623,288	91,247,439
13	Lost Gas (Unaccounted for)		-	246,198	410,629	507,515	455,933	377,569	221,329		2,219,173
14	Company Use		-	13,450	22,433	27,726	24,908	20,627	12,091		121,234
15	Unbilled Therms		-	8,425,976	3,230,670	1,405,998	(1,935,512)	(2,141,630)	(3,362,216)	(5,623,288)	(0)
16											
17	**Total Firm Volumes**	Sch. 6, ln 92	-	10,382,757	17,317,226	21,403,143	19,227,774	15,922,974	9,333,973		93,587,846
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 63	-	811,417	892,975	911,022	812,922	892,971	830,794		5,152,101
22	Niagara Supply	Sch. 6, ln 64	-	633,581	697,096	711,185	634,369	697,094	648,712		4,022,037
23	TGP Supply (Direct)	Sch. 6, ln 65	-	4,625,077	3,026,752	3,087,924	2,755,224	3,026,740	4,171,279		20,692,997
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	2,667,402	4,535,274	3,035,391	-	-		10,238,067
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	3,138,155	4,749,329	1,824,248	4,342,598	6,448,837	3,301,715		23,804,882
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	-	2,705	2,881	1,126,288	538,561	156,990	-		1,827,424
28	Propane Truck	Sch. 6, ln 70	-	-	-	166,776	-	-	-		166,776
29	PNGTS	Sch. 6, ln 71	-	55,447	78,495	88,898	74,760	69,133	47,078		413,812
30	TGP Supply (Z4)	Sch. 6, ln 72	-	1,630,272	1,794,591	1,830,861	1,633,827	1,794,584	1,702,436		10,386,571
31	Subtotal Pipeline Volumes		-	10,896,654	13,909,519	14,282,476	13,827,652	13,086,350	10,702,015		76,704,666
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 77	-	2,930,568	3,407,706	7,034,707	5,400,122	2,916,559	-		21,689,663
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 80	-	2,705	2,881	1,212,247	538,561	77,055	20,078		1,853,525
38	Propane	Sch. 6, ln 81	-	-	-	166,776	-	-	-		166,776
39	Subtotal Produced Gas		-	2,705	2,881	1,379,023	538,561	77,055	20,078		2,020,301
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 86	-	(2,705)	(2,881)	(1,126,288)	(538,561)	(156,990)	-		(1,827,424)
43	Propane	Sch. 6, ln 87	-	-	-	(166,776)	-	-	-		(166,776)
44	TGP Storage Refill	Sch. 6, ln 88	-	(3,444,465)	-	-	-	-	(1,388,119)		(4,832,584)
45	Subtotal Refills		-	(3,447,170)	(2,881)	(1,293,064)	(538,561)	(156,990)	(1,388,119)		(6,826,784)
46											
47	Total Firm Sendout Volumes	lns 31 + 34 + 39 + 45	-	10,382,757	17,317,226	21,403,143	19,227,774	15,922,974	9,333,973		93,587,846
48											

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Ln			Peak Costs May 16 - Oct 16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Peak Period Nov - Apr
7	For Month of:										
49	**II. Gas Costs**										**REDACTED**
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		$ 1,311,842	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986		$ 9,339,761
74	Less Capacity Credit		(478,822)	(385,340)	(385,340)	(385,340)	(385,340)	(385,340)	(385,340)		(2,790,863)
75	Net Pipeline Demand Costs		$ 833,020	$ 952,646	$ 952,646	$ 952,646	$ 952,646	$ 952,646	$ 952,646		$ 6,548,898
76											
77	Peaking Supply:										
78	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 34	[redacted]								
79	Granite Ridge Demand	Sch.5A, ln 35									
80	GDF Suez Demand NSB041	Sch.5A, ln 36									
81	Subtotal Peaking Demand		$ -	$ -	$ 458,333	$ 458,333	$ 458,333	$ -	$ -		$ 1,375,000
82	Less Capacity Credit		-	-	(132,000)	(132,000)	(132,000)	-	-		(396,000)
83	Net Peaking Supply Demand Costs		$ -	$ -	$ 326,333	$ 326,333	$ 326,333	$ -	$ -		$ 979,000
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		$ 699,079	$ 116,513	$ 116,513	$ 116,513	$ 116,513	$ 116,513	$ 116,513		$ 1,398,159
94	Less Capacity Credit		(255,164)	(33,556)	(33,556)	(33,556)	(33,556)	(33,556)	(33,556)		(456,499)
95	Net Storage Demand Costs		$ 443,915	$ 82,957	$ 82,957	$ 82,957	$ 82,957	$ 82,957	$ 82,957		$ 941,660
96											
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 2,010,922	$ 1,454,500	$ 1,912,833	$ 1,912,833	$ 1,912,833	$ 1,454,500	$ 1,454,500		$ 12,112,919
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(733,986)	(418,896)	(550,896)	(550,896)	(550,896)	(418,896)	(418,896)		(3,643,362)
99	Net Demand Charges		$ 1,276,935	$ 1,035,604	$ 1,361,937	$ 1,361,937	$ 1,361,937	$ 1,035,604	$ 1,035,604		$ 8,469,558
100											
101											

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Line			Peak Costs May 16 - Oct 16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Peak Period Nov - Apr
5											
6											
7	For Month of:										
102	**B. Commodity Costs**										**REDACTED**
103	Pipeline:										
104	Dawn Supply	Sch. 6, ln 12	[redacted]								
105	Niagara Supply	Sch. 6, ln 13									
106	TGP Supply (Direct)	Sch. 6, ln 14									
107	Dracut Supply 1 - Baseload	Sch. 6, ln 15									
108	Dracut Supply 2 - Swing	Sch. 6, ln 16									
109	City Gate Delivered Supply	Sch. 6, ln 17									
110	LNG Truck	Sch. 6, ln 18									
111	Propane Truck	Sch. 6, ln 19									
112	PNGTS	Sch. 6, ln 20									
113	TGP Supply (Z4)	Sch. 6, ln 21									
114	Subtotal Pipeline Commodity Costs		$ -	$ 3,575,229	$ 9,588,167	$ 12,222,590	$ 13,935,540	$ 8,453,662	$ 2,897,151		$ 50,672,339
115											
116	Storage:										
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ 543,967	$ 632,533	$ 1,305,771	$ 1,002,362	$ 541,367	$ -		$ 4,026,000
118											
119	Produced Gas Costs:										
120	LNG Vapor	Sch. 6, ln 50	[redacted]								
121	Propane	Sch. 6, ln 51									
122	Subtotal Produced Gas Costs		$ -	$ 1,721	$ 1,844	$ 1,267,603	$ 446,189	$ 63,576	$ 16,566		$ 1,797,499
123											
124	Less Storage Refills:										
125	LNG Truck	Sch. 6, ln 37	[redacted]								
126	Propane	Sch. 6, ln 38									
127	TGP Storage Refill	Sch. 6, ln 39									
128	Storage Refill (Trans.)	Sch. 6, ln 40									
129	Subtotal Storage Refill		$ -	$ (1,130,676)	$ (2,350)	$ (1,085,908)	$ (446,860)	$ (129,393)	$ (462,398)		$ (3,257,585)
130											
131	Total Supply Commodity Costs		$ -	$ 2,990,241	$ 10,220,195	$ 13,710,056	$ 14,937,231	$ 8,929,212	$ 2,451,318		$ 53,238,254
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		$ -	$ 192,427	$ 159,534	$ 159,696	$ 150,759	$ 150,833	$ 177,177		$ 990,425
140											
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ 38,296	$ 44,531	$ 91,928	$ 70,567	$ 38,113	$ -		$ 283,435
142											
143	Total Supply Volumetric Trans. Costs	lns 139 + 141	$ -	$ 230,723	$ 204,065	$ 251,624	$ 221,326	$ 188,946	$ 177,177		$ 1,273,861
144											
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 3,220,963	$ 10,424,260	$ 13,961,680	$ 15,158,558	$ 9,118,158	$ 2,628,495		$ 54,512,114
146											
147											

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

Line			Peak Costs May 16 - Oct 16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Peak Period Nov - Apr
7	For Month of:										
148	**D. Supply and Demand Costs by Source**										**REDACTED**
149											
150	Purchased Gas Demand Costs										
151	Pipeline Gas Demand Costs	lns 54 + 73	$ 1,311,842	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986		$ 9,339,761
152	Peaking Gas Demand Costs	ln 81	-	-	458,333	458,333	458,333	-	-		1,375,000
153	Subtotal Purchased Gas Demand Costs		$ 1,311,842	$ 1,337,986	$ 1,796,320	$ 1,796,320	$ 1,796,320	$ 1,337,986	$ 1,337,986		$ 10,714,761
154	Less Capacity Credit	lns 55 + 74 + 82	(478,822)	(385,340)	(517,340)	(517,340)	(517,340)	(385,340)	(385,340)		(3,186,863)
155	Net Purchased Gas Demand Costs		$ 833,020	$ 952,646	$ 1,278,980	$ 1,278,980	$ 1,278,980	$ 952,646	$ 952,646		$ 7,527,898
156											
157	Storage Gas Demand Costs										
158	Storage Demand	ln 93	$ 699,079	$ 116,513	$ 116,513	$ 116,513	$ 116,513	$ 116,513	$ 116,513		$ 1,398,159
159	Less Capacity Credit	ln 94	(255,164)	(33,556)	(33,556)	(33,556)	(33,556)	(33,556)	(33,556)		(456,499)
160	Net Storage Demand Costs		$ 443,915	$ 82,957	$ 82,957	$ 82,957	$ 82,957	$ 82,957	$ 82,957		$ 941,660
161											
162	**Total Demand Costs**	lns 155 + 160	$ 1,276,935	$ 1,035,604	$ 1,361,937	$ 1,361,937	$ 1,361,937	$ 1,035,604	$ 1,035,604		$ 8,469,558
163											
164	Purchased Gas Supply										
165	Commodity Costs	ln 114	$ -	$ 3,575,229	$ 9,588,167	$ 12,222,590	$ 13,935,540	$ 8,453,662	$ 2,897,151		$ 50,672,339
166	Less Storage Inj.(TGP Storage)	ln 127	[redacted]								
167	Less Storage Transportation	ln 128									
168	Less LNG Truck	ln 125									
169	Less Propane Truck	ln 126									
170	Plus Transportation Costs	ln 139									
171	Subtotal Purchased Gas Supply		$ -	$ 2,636,979	$ 9,745,352	$ 11,296,378	$ 13,639,439	$ 8,475,102	$ 2,611,929		$ 48,405,179
172											
173	Storage Commodity Costs										
174	Commodity Costs	ln 117	$ -	$ 543,967	$ 632,533	$ 1,305,771	$ 1,002,362	$ 541,367	$ -		$ 4,026,000
175	Transportation Costs	ln 141	-	38,296	44,531	91,928	70,567	38,113	-		283,435
176	Subtotal Storage Commodity Costs		$ -	$ 582,263	$ 677,064	$ 1,397,699	$ 1,072,929	$ 579,480	$ -		$ 4,309,436
177											
178	Produced Gas Commodity Costs	ln 122	$ -	$ 1,721	$ 1,844	$ 1,267,603	$ 446,189	$ 63,576	$ 16,566		$ 1,797,499
179											
180	**Subtotal Commodity Costs**	lns 171 + 176 + 178	$ -	$ 3,220,963	$ 10,424,260	$ 13,961,680	$ 15,158,558	$ 9,118,158	$ 2,628,495		$ 54,512,114
181											
182	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
183											
184	**Total Commodity Costs**	lns 180 + 182	$ -	$ 3,220,963	$ 10,424,260	$ 13,961,680	$ 15,158,558	$ 9,118,158	$ 2,628,495		$ 54,512,114
185											
186	**Total Demand Costs**	ln 99	$ 1,276,935	$ 1,035,604	$ 1,361,937	$ 1,361,937	$ 1,361,937	$ 1,035,604	$ 1,035,604		$ 8,469,558
187	**Total Supply Costs**	ln 184	-	3,220,963	10,424,260	13,961,680	15,158,558	9,118,158	2,628,495		54,512,114
188											
189	**Total Direct Gas Costs**	lns 186 + 187	$ 1,276,935	$ 4,256,567	$ 11,786,197	$ 15,323,617	$ 16,520,495	$ 10,153,762	$ 3,664,099		$ 62,981,672
190											
191											

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

Peak 2016 - 2017 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	[redacted]
Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	[redacted]
Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	[redacted]
National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	[redacted]
Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	[redacted]
Dominion - Demand	GSS 300076	Storage	MDQ	934	[redacted]
National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	[redacted]
National Fuel	FST N02358	Transportation	MDQ	6,098	[redacted]
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	[redacted]
Honeoye - Demand	SS-NY	Storage	MDQ	1,362	[redacted]
Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	[redacted]
Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	[redacted]
Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	[redacted]
Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	[redacted]
Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	[redacted]
Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	[redacted]
Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	[redacted]
Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	[redacted]
ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	[redacted]
Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	[redacted]
Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	[redacted]
Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	[redacted]
GDF Suez Liquid Demand Charge	NSB041	Peaking	MDQ	4,500	[redacted]
Supply Costs - Commodity					
TGP Supply (Z4)		Pipeline	Dkt	1,038,657	[redacted]
Niagara Supply		Pipeline	Dkt	402,204	[redacted]
City Gate Delivered Supply		Pipeline	Dkt	-	[redacted]
TGP Supply (Direct)		Pipeline	Dkt	2,069,300	[redacted]
Dawn Supply		Pipeline	Dkt	515,210	[redacted]
TGP Storage		Storage	Dkt	2,168,966	[redacted]
PNGTS		Pipeline	Dkt	41,381	[redacted]
Dracut Supply 1 - Baseload		Pipeline	Dkt	1,023,807	[redacted]
LNG Vapor (Storage)		Produced	Dkt	185,353	[redacted]
LNG Truck		Pipeline	Dkt	182,742	[redacted]
Propane Truck		Pipeline	Dkt	16,678	[redacted]
Dracut Supply 2 - Swing		Pipeline	Dkt	2,380,488	[redacted]
Propane		Produced	Dkt	16,678	[redacted]
Supply Costs - Volumetric Transportation					
Dracut Supply 1 - Baseload		Pipeline	Dkt	1,023,807	[redacted]
Dracut Supply 2 - Swing		Pipeline	Dkt	2,380,488	[redacted]
Niagara Supply		Pipeline	Dkt	402,204	[redacted]
Dawn Supply		Pipeline	Dkt	515,210	[redacted]
TGP Storage - Withdrawals		Pipeline	Dkt	2,168,966	[redacted]
TGP Supply (Direct)		Pipeline	Dkt	2,069,300	[redacted]

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Ln			Prior Period Bal Apr-16 Ending Bal Plus May Billings	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Peak Period
8		Days in Month		31	30	31	31	30	31	30	31	31	29	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/	**$ 2,690,610**	$ 2,690,610	$ 2,268,044	$ 1,904,737	$ 1,426,943	$ 955,542	$ 409,309	$ 8,386	$ (2,288,895)	$ (1,747,102)	$ (316,402)	$ 3,898,946	$ 3,576,923	$ 1,156,376	$ 2,690,610
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		212,823	212,823	212,823	212,823	212,823	212,823	4,256,567	11,786,197	15,323,617	16,520,495	10,153,762	3,664,099	-	62,981,672
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	331,836	331,836	331,836	331,836	331,836	331,836		1,991,017
15	Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(966,128)	(8,792,762)	(12,594,947)	(13,393,914)	(11,419,616)	(8,013,313)	(3,681,004)	(58,861,683)
16	Projected Unbilled Revenue									(5,660,459)	(7,920,071)	(8,985,252)	(7,863,081)	(6,605,986)	(4,549,894)		(41,584,744)
17	Reverse Prior Month Unbilled										5,660,459	7,920,071	8,985,252	7,863,081	6,605,986	4,549,894	41,584,744
18	Prior Period Adjustment-Unbilled				-					-							-
19	Add Net Adjustments	Schedule 4		(642,748)	(582,123)	(695,561)	(687,760)	(761,016)	(614,365)	(255,822)	(517,877)	(561,562)	(370,214)	(656,196)	(466,058)	-	(6,811,301)
20	Gas Cost Billed	Account 1920-1740 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Monthly (Over)/Under Recovery		$ 2,690,610	$ 2,260,685	$ 1,898,744	$ 1,421,999	$ 952,006	$ 407,349	$ 7,766	$ (2,285,620)	$ (1,741,113)	$ (313,340)	$ 3,893,972	$ 3,565,828	$ 1,149,578	$ 2,025,266	$ 1,990,314
22	Average Monthly Balance	(ln 12 + 21)/2		$ 2,475,647	$ 2,083,394	$ 1,663,368	$ 1,189,475	$ 681,445	$ 208,538	$ (1,138,617)	$ (2,015,004)	$ (1,030,221)	$ 1,788,785	$ 3,732,387	$ 2,363,250	$ 1,590,821	
24	Interest Rate	Prime Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%		
26	Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 7,359	$ 5,993	$ 4,945	$ 3,536	$ 1,960	$ 620	$ (3,275)	$ (5,990)	$ (3,062)	$ 4,974	$ 11,095	$ 6,798	$ -	$ 34,953
28	**(Over)/Under Balance**	ln 21 + ln 26	$ 2,690,610	$ 2,268,044	$ 1,904,737	$ 1,426,943	$ 955,542	$ 409,309	$ 8,386	$ (2,288,895)	$ (1,747,102)	$ (316,402)	$ 3,898,946	$ 3,576,923	$ 1,156,376	$ 2,025,266	2,025,266
31	**Calculation of COG with Interest**																
33	**Beginning Balance**	ln 12	$ 2,690,610	$ 2,690,610	$ 2,268,044	$ 1,904,737	$ 1,426,943	$ 955,542	$ 409,309	$ 8,386	$ (2,292,955)	$ (1,757,947)	$ (335,643)	$ 3,872,150	$ 3,543,844	$ 1,119,566	$ 2,690,610
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		212,823	212,823	212,823	212,823	212,823	212,823	4,256,567	11,786,197	15,323,617	16,520,495	10,153,762	3,664,099	-	62,981,672
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	331,836	331,836	331,836	331,836	331,836	331,836	-	1,991,017
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(966,719)	(8,798,135)	(12,602,643)	(13,402,098)	(11,426,594)	(8,018,210)	(3,683,253)	(58,897,651)
37	Projected Unbilled Revenue									(5,663,918)	(7,924,911)	(8,990,743)	(7,867,886)	(6,610,022)	(4,552,675)		(41,610,155)
38	Reverse Prior Month Unbilled										5,663,918	7,924,911	8,990,743	7,867,886	6,610,022	4,552,675	41,610,155
39	Add Net Adjustments	ln 19		(642,748)	(582,123)	(695,561)	(687,760)	(761,016)	(614,365)	(255,822)	(517,877)	(561,562)	(370,214)	(656,196)	(466,058)	-	(6,811,301)
40	Gas Cost Billed	ln 20	-		-	-	-	-	-	-	-	-	-	-	-	-	-
41	Add Interest	ln 26		-	-	-	-	-	-	(3,275)	(5,990)	(3,062)	4,974	11,095	6,798	-	10,540
42	**(Over)/Under Balance**		$ 2,690,610	$ 2,260,685	$ 1,898,744	$ 1,421,999	$ 952,006	$ 407,349	$ 7,766	$ (2,292,944)	$ (1,757,916)	$ (335,594)	$ 3,872,207	$ 3,543,917	$ 1,119,657	$ 1,988,988	$ 1,964,885
44	Average Monthly Balance			$ 2,475,647	$ 2,083,394	$ 1,663,368	$ 1,189,475	$ 681,445	$ 208,538	$ (1,142,279)	$ (2,025,435)	$ (1,046,770)	$ 1,768,282	$ 3,708,033	$ 2,331,751	$ 1,554,277	
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		7,359	5,993	4,945	3,536	1,960	620	(3,286)	(6,021)	(3,112)	4,917	11,023	6,708	-	34,642
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ 2,690,610	$ 2,268,044	$ 1,904,737	$ 1,426,943	$ 955,542	$ 409,309	$ 8,386	$ (2,292,955)	$ (1,757,947)	$ (335,643)	$ 3,872,150	$ 3,543,844	$ 1,119,566	$ 1,988,988	1,988,988
51	Forecast Sendout Therms	Sch 1								10,382,757	17,317,226	21,403,143	19,227,774	15,922,974	9,333,973		93,587,846
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								1,475,906	13,432,266	19,240,676	20,461,218	17,445,182	12,241,542	5,623,288	89,920,078
53	Less Forecast Unaccounted For	Sch 1								246,198	410,629	507,515	455,933	377,569	221,329		2,219,173
54	Less Forecast Company Use	Sch 1								13,450	22,433	27,726	24,908	20,627	12,091		121,234
55	Unbilled Volumes									8,647,203	3,451,897	1,627,225	-1,714,285	-1,920,403	-3,140,989	-5,623,288	1,327,361
56	Gross Unbilled									8,647,203	12,099,100	13,726,325	12,012,040	10,091,637	6,950,648	1,327,361	
59	COB w/o Interest	Sch. 3, pg. 4, ln 211 col. (c)								$0.6546	$0.6546	$0.6546	$0.6546	$0.6546	$0.6546	$0.6546	
61	COG With Interest	Sch. 3, pg. 4, ln 211 col. (d)								$0.6550	$0.6550	$0.6550	$0.6550	$0.6550	$0.6550	$0.6550	

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

Ln			Prior Period Bal Apr-16 Ending Bal + May Collections	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Peak Period
73		Days in Month		31	30	31	31	30	31	30	31	31	29	31	30	31	Total
74	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
76	**Account 1163-1422 Working Capital (Over)/Under Balance - Interest Calculation**																
78	**Beginning Balance**	Account 1163-1422 1/	**$ (33,597)**	$ (33,597)	$ (33,405)	$ (33,209)	$ (33,016)	$ (32,823)	$ (32,626)	$ (32,431)	$ (32,773)	$ (26,860)	$ (18,476)	$ (7,149)	$ (2,581)	$ (3,035)	$ (33,597)
80	Days Lag			0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391		
81	Prime Rate			3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%		
82	Forecast Working Capital	ln 34 * 0.091%		291	291	291	291	291	291	5,826	16,131	20,973	22,611	13,897	5,015	-	86,199
84	Projected Revenues w/o Int.	ln 121 * ln 125		-	-	-	-	-	-	(886)	(8,059)	(11,544)	(12,277)	(10,467)	(7,345)	(3,374)	(53,952)
85	Projected Unbilled Revenue									(5,188)	(7,259)	(8,236)	(7,207)	(6,055)	(4,170)		(38,116)
86	Reverse Prior Month Unbilled										5,188	7,259	8,236	7,207	6,055	4,170	38,116
88	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Working Capital Billed	Account 1163-1422 2/	-														-
92	Monthly (Over)/Under Recovery		$ (33,597)	$ (33,306)	$ (33,114)	$ (32,918)	$ (32,725)	$ (32,532)	$ (32,334)	$ (32,679)	$ (26,772)	$ (18,409)	$ (7,113)	$ (2,567)	$ (3,027)	$ (2,239)	$ (1,349)
94	Average Monthly Balance	(ln 78 + ln 92)/2		$ (33,451)	$ (33,259)	$ (33,064)	$ (32,871)	$ (32,677)	$ (32,480)	$ (32,555)	$ (29,772)	$ (22,635)	$ (12,795)	$ (4,858)	$ (2,804)	$ (2,637)	
96	Interest Rate	Prime Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%		
98	Interest Applied	ln 94 * ln 96 / 365 * Days of Month		$ (99)	$ (96)	$ (98)	$ (98)	$ (94)	$ (97)	$ (94)	$ (89)	$ (67)	$ (36)	$ (14)	$ (8)	$ -	$ (889)
100	**(Over)/Under Balance**	ln 92 + ln 98	$ (33,597)	$ (33,405)	$ (33,209)	$ (33,016)	$ (32,823)	$ (32,626)	$ (32,431)	$ (32,773)	$ (26,860)	$ (18,476)	$ (7,149)	$ (2,581)	$ (3,035)	$ (2,239)	(2,239)

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

103	**Calculation of Working Capital with Interest**															
104																
105	**Beginning Balance**	ln 78	(33,597)	(33,597)	(33,405)	(33,209)	(33,016)	(32,823)	(32,626)	(32,431)	(32,773)	(26,861)	(18,476)	(7,149)	(2,582)	(3,035)	(33,597)
106	Forecast Working Capital	ln 82		291	291	291	291	291	291	5,826	16,131	20,973	22,611	13,897	5,015	-	86,199
107	Projected Rev. with interest	ln 121 * ln 127		-	-	-	-	-	-	(886)	(8,059)	(11,544)	(12,277)	(10,467)	(7,345)	(3,374)	(53,952)
108	Projected Unbilled Revenue									(5,188)	(7,259)	(8,236)	(7,207)	(6,055)	(4,170)		(38,116)
109	Reverse Prior Month Unbilled										5,188	7,259	8,236	7,207	6,055	4,170	38,116
110	Add Net Adjustments	ln 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital Billed	ln 90	-	-	-	-	-	-	-								-
112	Add Interest	ln 98		-	-	-	-	-	-	(94)	(89)	(67)	(36)	(14)	(8)	-	(308)
113	Monthly (Over)/Under Recovery		(33,597)	(33,306)	(33,114)	(32,918)	(32,725)	(32,532)	(32,334)	(32,773)	(26,861)	(18,476)	(7,149)	(2,582)	(3,035)	(2,239)	(1,657)
114																
115	Average Monthly Balance			(33,451)	(33,259)	(33,064)	(32,871)	(32,677)	(32,480)	(32,602)	(29,817)	(22,668)	(12,813)	(4,866)	(2,809)	(2,637)	
116																
117	Interest Applied	ln 96 * ln 115 / 365 * Days of Month		(99)	(96)	(98)	(98)	(94)	(97)	(94)	(89)	(67)	(36)	(14)	(8)	-	(890)
118																
119	**(Over)/Under Balance**	-ln 112 +ln 113 + ln 117	(33,597)	(33,405)	(33,209)	(33,016)	(32,823)	(32,626)	(32,431)	(32,773)	(26,861)	(18,476)	(7,149)	(2,582)	(3,035)	(2,239)	(2,239)
120																
121	Forecast Therm Sales	ln 52								1,475,906	13,432,266	19,240,676	20,461,218	17,445,182	12,241,542	5,623,288	89,920,078
122	Unbilled Therm	ln 55								8,647,203	3,451,897	1,627,225	(1,714,285)	(1,920,403)	(3,140,989)		
123	Gross Unbilled									8,647,203	12,099,100	13,726,325	12,012,040	10,091,637	6,950,648		
124																
125	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 228 col. (c)								$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
126																
127	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 228 col. (d)								$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
128	1/ Beginning Balance for Acct 1163-1422. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.															
129	2/ Working Capital Billed Acct 1163-1422. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.															
130			Prior Period Bal													
131			Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	DemandPeriod
132		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	29	31	30	31	Total
133	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
134																
135	**Account 1920-1743 Bad Debt (Over)/Under Balance - Interest Calculation**															
136																
137	Forecast Direct Gas Costs	ln 34		212,823	212,823	212,823	212,823	212,823	212,823	4,256,567	$11,786,197	$15,323,617	$16,520,495	$10,153,762	3,664,099	-	62,981,672
138	Forecast Working Capital	ln 106		291	291	291	291	291	291	(27,771)	16,131	20,973	22,611	13,897	5,015		52,603
139	Prior Period Balance	ln 42								448,435	448,435	448,435	448,435	448,435	448,435		2,690,610
140	Total Forecast Direct Gas Costs & Working Capital			213,114	213,114	213,114	213,114	213,114	213,114	4,677,231	12,250,763	15,793,025	16,991,540	10,616,094	4,117,549	-	63,034,275
141																
142	**Beginning Balance**	Account 1920-1743 1/	(37,241)	(37,241)	(28,729)	(20,190)	(11,627)	(3,039)	5,574	14,214	(91,520)	(88,185)	(57,619)	83,339	60,672	(37,772)	(37,241)
143																
144	Forecast Bad Debt	ln 140 * 0.0404		8,610	8,610	8,610	8,610	8,610	8,610	188,960	494,931	638,038	686,458	428,890	166,349		2,655,285
145																
146	Projected Revenues w/o int	ln 183 * ln 187		-	-	-	-	-	-	(42,949)	(390,879)	(559,904)	(595,421)	(507,655)	(356,229)	(163,638)	(2,616,674)
147	Projected Unbilled Revenue									(251,634)	(352,084)	(399,436)	(349,550)	(293,667)	(202,264)		(1,848,634)
148	Reverse Prior Month Unbilled										251,634	352,084	399,436	349,550	293,667	202,264	1,848,634
149																
150	Bad Debt Billed	Account 1920-1743 2/	-		-	-	-	-	-		-	-	-	-	-	-	-
151																
152	Add Net Adjustments		-	-	-	-	-	-	-		-	-	-	-	-	-	-
153																
154	Monthly (Over)/Under Recovery		(37,241)	(28,631)	(20,119)	(11,580)	(3,017)	5,571	14,184	(91,409)	(87,918)	(57,402)	83,304	60,458	(37,805)	854	1,370
155																
156	Average Monthly Balance	(ln 142 + ln 154)/2		(32,936)	(24,424)	(15,885)	(7,322)	1,266	9,879	(38,598)	(89,719)	(72,794)	12,842	71,899	11,434	(18,459)	
157																
158	Interest Rate	Prime Rate		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%		
159																
160	Interest Applied	ln 156 * ln 158 / 365 * Days of Month		(98)	(70)	(47)	(22)	4	29	(111)	(267)	(216)	36	214	33		(516)
161																
162	**(Over)/Under Balance**	ln 154 + ln 160	(37,241)	(28,729)	(20,190)	(11,627)	(3,039)	5,574	14,214	(91,520)	(88,185)	(57,619)	83,339	60,672	(37,772)	854	854
163																
164																
165	**Calculation of Bad Debt with Interest**															
166																
167	**Beginning Balance**	ln 142	(37,241)	(37,241)	(28,729)	(20,190)	(11,627)	(3,039)	5,574	14,214	(91,520)	(88,185)	(57,619)	83,339	60,672	(37,773)	(37,241)
168	Forecast Bad Debt	ln 144		8,610	8,610	8,610	8,610	8,610	8,610	188,960	494,931	638,038	686,458	428,890	166,349	-	2,655,285
169	Projected Revenues with int.	ln 183 * ln 189		-	-	-	-	-	-	(42,949)	(390,879)	(559,904)	(595,421)	(507,655)	(356,229)	(163,638)	(2,616,674)
170	Projected Unbilled Revenue									(251,634)	(352,084)	(399,436)	(349,550)	(293,667)	(202,264)		(1,848,634)
171	Reverse Prior Month Unbilled										251,634	352,084	399,436	349,550	293,667	202,264	1,848,634
172	Bad Debt Billed	ln 150	-		-	-	-	-	-	-	-	-	-	-	-	-	0
173	Add Interest	ln 160		-	-	-	-	-	-	(111)	(267)	(216)	36	214	33	-	(312)
174	Add Net Adjustments	ln 152	-							-	-	-	-	-	-	-	0
175	Monthly (Over)/Under Recovery		(37,241)	(28,631)	(20,119)	(11,580)	(3,017)	5,571	14,184	(91,520)	(88,185)	(57,619)	83,339	60,672	(37,773)	854	1,058
176																
177	Average Monthly Balance			(32,936)	(24,424)	(15,885)	(7,322)	1,266	9,879	(38,653)	(89,852)	(72,902)	12,860	72,005	11,449	(18,460)	
178																
179	Interest Applied	ln 158 * ln 177 / 365 * Days of Month		(98)	(70)	(47)	(22)	4	29	(111)	(267)	(216)	36	214	33	-	(516)
180																
181	**(Over)/Under Balance**	-ln 173 +ln 175 + ln 179	(37,241)	(28,729)	(20,190)	(11,627)	(3,039)	5,574	14,214	(91,520)	(88,185)	(57,619)	83,339	60,672	(37,773)	854	854
182																
183	Forecast Term Sales	ln 52								1,475,906	13,432,266	19,240,676	20,461,218	17,445,182	12,241,542	5,623,288	89,920,078
184	Unbilled Therm	ln 55								8,647,203	3,451,897	1,627,225	(1,714,285)	(1,920,403)	(3,140,989)		
185	Gross Unbilled									8,647,203	12,099,100	13,726,325	12,012,040	10,091,637	6,950,648		
186																
187	COG Rate Without Interest	Sch. 3, pg. 4, ln 245 col. (c)								$0.0291	$0.0291	$0.0291	$0.0291	$0.0291	$0.0291	$0.0291	
188																
189	COG With Interest	Sch. 3, pg. 4, ln 245 col. (d)								$0.0291	$0.0291	$0.0291	$0.0291	$0.0291	$0.0291	$0.0291	
190	1/ Beginning Balance for Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.															
191	2/ Bad Debt Billed Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.															
194	**Total Interest**	lns 46 + 117 + 179	-	7,162	5,827	4,799	3,416	1,870	553	(3,491)	(6,377)	(3,395)	4,917	11,222	6,733	-	33,236

195	**Calculation of COG**		COG Rate Without Interest	COG Rate With Interest
196	(a)	(b)	(c)	(d)
197	(Over)Under Recovery Balance	ln 12, col. (g)	$ 2,690,610	$ 2,690,610
198				
199	Unadjusted Forecast of Gas Costs	ln 13, col. (g)	60,990,654	60,990,654
200				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

201	Production & Storage and Misc Overhead	ln 14, col. (g)	1,991,017	1,991,017
203	Adjustments	ln 19, col. (g)	(6,811,301)	(6,811,301)
205	Interest Nov -Apr	ln 46, col. (g)	-	$ 33,203
207	Total Gas To Be Recovered		$ 58,860,980	$ 58,894,183
209	Forecast Gas Sales (Nov - Apr)	ln 52, col. (g)	89,920,078	89,920,078
211	Preliminary COG Rate	ln. 207 / ln. 209	$0.6546	$0.6550
214	**Calculation of Working Capital Rate**		Working Capital Rate without interest	Working Capital Rate with Interest
215	(a)	(b)	(c)	(d)
216	(Over)Under Recovery Balance	ln 78, col. (g)	$ (33,597)	$ (33,597)
218	Unadjusted Working Capital Forecast	ln 82, col. (g)	86,161	86,161
220	Adjustments without interest	ln 88, col. (g)	-	-
222	Interest Nov -Apr	ln 117, col. (g)	-	$ 38
224	Total Gas To Be Recovered		$ 52,564	$ 52,603
226	Forecast Gas Sales (Nov - Apr)	ln 52, col. (g)	89,920,078	89,920,078
228	Preliminary Working Capital COG Rate		$0.0006	$0.0006
231	**Calculation of Bad Debt Rate**		Bad Debt Rate without Interest	Bad Debt Rate with interest
232	(a)	(b)	(c)	
233	(Over)Under Recovery Balance	ln 142, col. (g)	$ (37,241)	$ (37,241)
235	Unadjusted Bad Debt Forecast	ln 144, col. (g)	2,651,311	2,651,311
237	Adjustments without interest	ln 152, col. (g)	-	-
239	Interest Nov -Apr	ln 179, col. (g)	-	$ 3,974
241	Total Gas To Be Recovered		$ 2,614,070	$ 2,618,044
243	Forecast Gas Sales (Nov - Apr)	ln 52, col. (g)	89,920,078	89,920,078
245	Preliminary Bad Debt COG Rate		$0.0291	$0.0291

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 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-16		$ -	$ -	(149,932)	$ -	$ -	$ -	[redacted]		$ -	$ -	$ (642,748)
10	Jun-16		-	-	-	-	-	-			-	-	(582,123)
11	Jul-16	1/	-	-	(121,624)	-	-	-			-	-	(695,561)
12	Aug-16	1/	-	-	(112,714)	-	-	-			-	-	(687,760)
13	Sep-16	1/	-	-	374	-	-	-			-	-	(761,016)
14	Oct-16	1/	-	-	-	-	-	-			-	-	(614,365)
15	Nov-16	1/	-	-	2,313	-	(3,560)	-			-	41,972	(255,822)
16	Dec-16	1/	-	-	(199,232)	-	(4,529)	-			-	-	(517,877)
17	Jan-17	1/	-	-	(241,474)	-	(5,669)	-			-	-	(561,562)
18	Feb-17	1/	-	-	(51,254)	-	(5,945)	-			-	-	(370,214)
19	Mar-17	1/	-	-	(341,913)	-	(5,306)	-			-	-	(656,196)
20	Apr-17	1/	-	-	(159,491)	-	(4,461)	-			-	-	(466,058)
21													
22	Subtotal May 16 - Oct 16		$ -	$ -	$ (383,895)	$ -	$ -	$ -	$ -	$ (3,599,677)	$ -	$ -	$ (3,983,572)
23													
24	Subtotal Nov 16 - Apr 17		$ -	$ -	$ (991,052)	$ -	$ (29,471)	$ -	$ -	$ (1,849,179)	$ -	$ 41,972	$ (2,827,729)
25													
26	Total Peak Period		$ -	$ -	$ (1,374,947)	$ -	$ (29,471)	$ -	$ -	$ (5,448,856)	$ -	$ 41,972	$ (6,811,301)
27													

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

REDACTED

Line	(a)	Peak (b)	Reference (c)	Deferred to Peak May 16 -Oct 16 (d)	Nov-16 (e)	Dec-16 (f)	Jan-17 (g)	Feb-17 (h)	Mar-17 (i)	Apr-17 (j)	Peak Nov-Apr Total (k)
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2016 - 2017 Winter Cost of Gas Filing**										
4	**Demand Costs**										
5											
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			$ 1,311,842	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 1,337,986	$ 9,339,761
32											
33	**Peaking Supply**										
34	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 28 * Sch 5C ln 26 x days	[redacted]							
35	Granite Ridge Demand	peak	Sch 5B, ln 29 * Sch 5C ln 47 x days								
36	GDF Suez Demand NSB041	peak	Per Contract								
37	Subtotal Peaking Demand Charges			$ -	$ -	$ 458,333	$ 458,333	$ 458,333	$ -	$ -	$ 1,375,000
38											
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 1,311,842	$ 1,337,986	$ 1,796,320	$ 1,796,320	$ 1,796,320	$ 1,337,986	$ 1,337,986	$ 10,714,761
40											
41	Less Transportation Capacity Credit			$ (478,822)	$ (385,340)	$ (517,340)	$ (517,340)	$ (517,340)	$ (385,340)	$ (385,340)	$ (3,186,863)
42											
43	**Total Supply, Pipeline & Peaking Demand**			$ 833,020	$ 952,646	$ 1,278,980	$ 1,278,980	$ 1,278,980	$ 952,646	$ 952,646	$ 7,527,898
44											
45											
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 51 x days	$ 10,434	$ 1,739	$ 1,739	$ 1,739	$ 1,739	$ 1,739	$ 1,739	$ 20,867
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	89,015	14,836	14,836	14,836	14,836	14,836	14,836	178,030
50	National Fuel - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 58 x days	150,125	25,021	25,021	25,021	25,021	25,021	25,021	300,250
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 61 x days	196,177	32,696	32,696	32,696	32,696	32,696	32,696	392,353
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**			$ 699,079	$ 116,513	$ 116,513	$ 116,513	$ 116,513	$ 116,513	$ 116,513	$ 1,398,159
55											
56	Less Transportation Capacity Credit			$ (255,164)	$ (33,556)	$ (33,556)	$ (33,556)	$ (33,556)	$ (33,556)	$ (33,556)	$ (456,499)
57											
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 443,915	$ 82,957	$ 82,957	$ 82,957	$ 82,957	$ 82,957	$ 82,957	$ 941,660
59											
60	**Total Demand Charges**		ln 39 + ln 54	$ 2,010,922	$ 1,454,500	$ 1,912,833	$ 1,912,833	$ 1,912,833	$ 1,454,500	$ 1,454,500	$ 12,112,919
61											
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (733,986)	$ (418,896)	$ (550,896)	$ (550,896)	$ (550,896)	$ (418,896)	$ (418,896)	$ (3,643,362)
63											
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 1,276,935	$ 1,035,604	$ 1,361,937	$ 1,361,937	$ 1,361,937	$ 1,035,604	$ 1,035,604	$ 8,469,558
65											
66											

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2016 - 2017 Winter Cost of Gas Filing
<u>Demand Volumes</u>

	Peak	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply								
Niagara Supply			3,199	3,199	3,199	3,199	3,199	3,199
Pipeline								
Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
Tenn Gas Pipeline		95346 Z5-Z6	4,000	4,000	4,000	4,000	4,000	4,000
Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
Tenn Gas Pipeline (Concord Lateral)		Firm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
Portland Natural Gas Trans Service		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
ANE (TransCanada via Union to Iroquois)		Union Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
National Fuel	peak	FST N02358	6,098	6,098	6,098	6,098	6,098	6,098
Peaking								
Tenn Gas Pipeline (Concord Lateral)	peak		0	0	0	0	0	0
Granite Ridge Demand	peak		0	0	0	0	0	0
GDF Suez Liquid Demand Charge	peak	NSB041	4,500	4,500	4,500	4,500	4,500	0
Storage								
Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
Honeoye - Capacity	peak	SS-NY	245,380	245,380	245,380	245,380	245,380	245,380
National Fuel - Demand	peak	FSS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
National Fuel - Capacity Reservation	peak	FSS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
Tenn Gas Pipeline - Demand	peak	FS-MA 523	21,844	21,844	21,844	21,844	21,844	21,844
Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA 523	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Liberty Utilities (EnergyNorth Natural Gas) Corp. **REDACTED**
d/b/a Liberty Utilities
Peak 2016 - 2017 Winter Cost of Gas Filing
Demand Rates

				Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Nov - Apr
Tariff Rates				30	31	31	29	31	30	182
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagara Supply		[redacted]		[redacted]						
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$6.5971	First Revised Sheet No. 4	$0.2199	$0.2128	$0.2128	$0.2275	$0.2128	$0.2199	$0.2176
Tenn Gas Pipeline	95346 Z5-Z6	$7.1551	9th Rev Sheet No. 14	$0.2385	$0.2308	$0.2308	$0.2467	$0.2308	$0.2385	$0.2360
Tenn Gas Pipeline	2302 Z5-Z6	$7.1551	9th Rev Sheet No. 14	$0.2385	$0.2308	$0.2308	$0.2467	$0.2308	$0.2385	$0.2360
Tenn Gas Pipeline	8587 Z0-Z6	$23.2157	FT-A (Z0 - Z6)	$0.7739	$0.7489	$0.7489	$0.8005	$0.7489	$0.7739	$0.7658
Tenn Gas Pipeline	8587 Z1-Z6	$20.6076	FT-A (Z1 - Z6)	$0.6869	$0.6648	$0.6648	$0.7106	$0.6648	$0.6869	$0.6798
Tenn Gas Pipeline	8587 Z4-Z6	$8.1463	FT-A (Z4 - Z6)	$0.2715	$0.2628	$0.2628	$0.2809	$0.2628	$0.2715	$0.2687
TGP Dracut	42076 FTA Z6-Z6	$4.7435	9th Rev Sheet No. 14	$0.1581	$0.1530	$0.1530	$0.1636	$0.1530	$0.1581	$0.1565
TGP Concord Lateral	Firm Transportatio	$12.1898	Per contract	$0.4063	$0.3932	$0.3932	$0.4203	$0.3932	$0.4063	$0.4021
Portland Natural Gas	FT-1999-001	$25.9843	Part 4.1 v.5.0.0	$0.8661	$0.8382	$0.8382	$0.8960	$0.8382	$0.8661	$0.8572
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.1463	9th Rev Sheet No. 14	$0.2715	$0.2628	$0.2628	$0.2809	$0.2628	$0.2715	$0.2687
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.1463	9th Rev Sheet No. 14	$0.2715	$0.2628	$0.2628	$0.2809	$0.2628	$0.2715	$0.2687
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.1551	9th Rev Sheet No. 14	$0.2385	$0.2308	$0.2308	$0.2467	$0.2308	$0.2385	$0.2360
National Fuel	FST N02358	$3.7049	4.010 Version 14.0.0 Pg 1	$0.1235	$0.1195	$0.1195	$0.1278	$0.1195	$0.1235	$0.1222
ANE Union Gas		$2.8830								
TransCanada Pipelines Limited		$15.09945	Union Parkway to Iroquois							
Delivery Pressure Demand Charge		1.0123	Union Parkway to Iroquois							
Sub Total Demand Charges		18.9947								
Conversion rate GJ to MMBTU		1.0551								
Conversion rate to US$		1.3361	updated 7/28/16							
Demand Rate/US$		$15.0001		$0.5000	$0.4839	$0.4839	$0.5172	$0.4839	$0.5000	$0.4948
Peaking										
Granite Ridge Demand		[redacted]		[redacted]						
GDF Suez Demand NSB041										
Storage										
Dominion - Demand	GSS 300076	$1.8618	Rec No 10.30 Ver 16.0.0	$0.0621	$0.0601	$0.0601	$0.0642	$0.0601	$0.0621	$0.0613
Dominion - Capacity	GSS 300076	$0.0145	Rec No 10.30 Ver 16.0.0	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
		$1.8763		$0.0625	$0.0605	$0.0605	$0.0647	$0.0605	$0.0625	$0.0618
Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0.2071	$0.2071	$0.2213	$0.2071	$0.2140	$0.2113
National Fuel - Demand	FSS-1 2357	$2.4329	4.020 Version 10.0.0 Pg 1	$0.0811	$0.0785	$0.0785	$0.0839	$0.0785	$0.0811	$0.0801
National Fuel - Capacity	FSS-1 2357	$0.0373	4.020 Version 10.0.0 Pg 1	$0.0012	$0.0012	$0.0012	$0.0013	$0.0012	$0.0012	$0.0012
		$2.4702		$0.0823	$0.0797	$0.0797	$0.0852	$0.0797	$0.0823	$0.0813
Tenn Gas Pipeline	FS-MA 523	$1.4968	12th Rev Sheet No.61	$0.0499	$0.0483	$0.0483	$0.0516	$0.0483	$0.0499	$0.0493
Tenn Gas Pipeline - Space	FS-MA 523	$0.0205	12th Rev Sheet No.61	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007
		$1.5173		$0.0506	$0.0489	$0.0489	$0.0523	$0.0489	$0.0506	$0.0499

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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	$5.5609		$11.5992	$15.5956	$15.8712	$17.4373	$18.5077	$23.2157
L		$4.9391						
1	$8.3615		$8.0160	$10.6611	$15.0943	$14.8658	$16.7627	$20.6076
2	$15.5957		$10.5972	$5.5212	$5.1625	$6.6001	$9.0702	$11.7028
3	$15.8712		$8.3982	$5.5656	$4.0207	$6.1655	$11.1347	$12.8635
4	$20.1457		$18.5742	$7.0906	$10.7654	$5.2796	$5.7082	$8.1463
5	$24.0171		$16.8823	$7.4370	$8.9946	$5.8630	$5.5008	$7.1551
6	$27.7801		$19.3876	$13.3494	$14.7043	$10.3924	$5.4766	$4.7435

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 $0.0198.

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	$0.0039		$0.0122	$0.0184	$0.0226	$0.2675	$0.2553	$0.3037
L		$0.0019						
1	$0.0049		$0.0088	$0.0154	$0.0186	$0.2276	$0.2320	$0.2648
2	$0.0174		$0.0094	$0.0019	$0.0035	$0.0741	$0.1185	$0.1312
3	$0.0214		$0.0176	$0.0033	$0.0009	$0.0989	$0.1365	$0.1489
4	$0.0257		$0.0212	$0.0094	$0.0112	$0.0461	$0.0649	$0.1048
5	$0.0291		$0.0263	$0.0107	$0.0125	$0.0646	$0.0640	$0.0794
6	$0.0353		$0.0307	$0.0150	$0.0170	$0.0991	$0.0540	$0.0331

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 $0.0007.

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RATES PER DEKATHERM

AUTHORIZED OVERRUN RATES
FOR RATE SCHEDULE FT-A

Maximum
Commodity Rates 1/, 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1868		$0.3933	$0.5306	$0.5438	$0.8408	$0.8638	$1.0670
L		$0.1644						
1	$0.2797		$0.2721	$0.3655	$0.5143	$0.7164	$0.7832	$0.9423
2	$0.5297		$0.3576	$0.1835	$0.1732	$0.2911	$0.4168	$0.5160
3	$0.5427		$0.2933	$0.1863	$0.1331	$0.3016	$0.5027	$0.5719
4	$0.6873		$0.6313	$0.2423	$0.3649	$0.2197	$0.2526	$0.3726
5	$0.8178		$0.5807	$0.2549	$0.3079	$0.2575	$0.2449	$0.3147
6	$0.9476		$0.6672	$0.4535	$0.5000	$0.4407	$0.2340	$0.1891

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 PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000 Daily Reservation.

4/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0007 Daily Reservation, $0.0007Commodity.

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RATES PER DEKATHERM

FT-A EXTENDED TRANSPORTATION SERVICE

Base Daily Reservation Rates

EXTENSION ZONE - EXTENDED DELIVERIES/ EXTENDED ZONE - EXTENDED RECEIPTS

	EXTENDED ZONE - EXTENDED DELIVERIES/ EXTENSION ZONE - EXTENDED RECEIPTS						
	0	1	2	3	4	5	6
0		$0.3807	$0.5121	$0.5212	$0.5726	$0.6078	$0.7626
1	$0.2742		$0.3499	$0.4956	$0.4881	$0.5505	$0.6768
2	$0.5121	$0.3477		$0.1691	$0.2163	$0.2976	$0.3841
3	$0.5212	$0.2755	$0.1824		$0.2021	$0.3655	$0.4222
4	$0.6616	$0.6100	$0.2324	$0.3533		$0.1870	$0.2671
5	$0.7889	$0.5545	$0.2438	$0.2951	$0.1922		$0.2346
6	$0.9127	$0.6367	$0.4382	$0.4828	$0.3410	$0.1794	

Maximum Daily Reservation Rates

EXTENSION ZONE - EXTENDED DELIVERIES/ EXTENDED ZONE - EXTENDED RECEIPTS

	EXTENDED ZONE - EXTENDED DELIVERIES/ EXTENSION ZONE - EXTENDED RECEIPTS						
	0	1	2	3	4	5	6
0		$0.3807	$0.5121	$0.5212	$0.5726	$0.6078	$0.7626
1	$0.2742		$0.3499	$0.4956	$0.4881	$0.5505	$0.6768
2	$0.5121	$0.3477		$0.1691	$0.2163	$0.2976	$0.3841
3	$0.5212	$0.2755	$0.1824		$0.2021	$0.3655	$0.4222
4	$0.6616	$0.6100	$0.2324	$0.3533		$0.1870	$0.2671
5	$0.7889	$0.5545	$0.2438	$0.2951	$0.1922		$0.2346
6	$0.9127	$0.6367	$0.4382	$0.4828	$0.3410	$0.1794	

Daily Reservation Rate for Tewksbury-Andover Lateral

Base	$0.2053
Maximum	$0.2053

FUEL AND EPCR

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.35%		1.05%	1.56%	1.91%	2.28%	2.57%	3.05%
L		0.18%						
1	0.44%		0.77%	1.32%	1.58%	1.93%	2.34%	2.66%
2	1.56%		0.82%	0.18%	0.32%	0.58%	0.97%	1.30%
3	1.91%		1.58%	0.32%	0.10%	0.80%	1.14%	1.50%
4	2.28%		1.80%	0.81%	0.97%	0.33%	0.50%	0.85%
5	2.64%		2.39%	0.97%	1.15%	0.49%	0.49%	0.62%
6	3.14%		2.66%	1.31%	1.50%	0.80%	0.39%	0.21%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0025		$0.0095	$0.0147	$0.0183	$0.0221	$0.0251	$0.0301
L		$0.0008						
1	$0.0033		$0.0067	$0.0122	$0.0149	$0.0185	$0.0227	$0.0260
2	$0.0147		$0.0072	$0.0008	$0.0022	$0.0048	$0.0087	$0.0120
3	$0.0183		$0.0149	$0.0022	$0.0000	$0.0070	$0.0104	$0.0138
4	$0.0221		$0.0171	$0.0071	$0.0086	$0.0023	$0.0040	$0.0075
5	$0.0251		$0.0227	$0.0087	$0.0104	$0.0039	$0.0039	$0.0052
6	$0.0301		$0.0260	$0.0120	$0.0138	$0.0070	$0.0029	$0.0011

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.05%.
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 0.05%.
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.

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	1.37%	$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	1.37%	$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 0.03%.

RATES PER DEKATHERM

INTERRUPTIBLE STORAGE SERVICE
RATE SCHEDULE IS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA				
Space Rate	$0.1019	$0.1019 1/		
Injection Rate	$0.0073	$0.0073	1.37%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA				
Space Rate	$0.0821	$0.0821 1/		
Injection Rate	$0.0087	$0.0087	1.37%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		

Notes:

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
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 0.03%.

RATES PER DEKATHERM

INTERRUPTIBLE TRANSPORTATION RATES (IT)

Base Rates 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1854		$0.3919	$0.5292	$0.5424	$0.8394	$0.8624	$1.0656
L		$0.1630						
1	$0.2783		$0.2707	$0.3641	$0.5129	$0.7150	$0.7818	$0.9409
2	$0.5283		$0.3562	$0.1821	$0.1718	$0.2897	$0.4154	$0.5146
3	$0.5413		$0.2919	$0.1849	$0.1317	$0.3002	$0.5013	$0.5705
4	$0.6859		$0.6299	$0.2409	$0.3635	$0.2183	$0.2512	$0.3712
5	$0.8164		$0.5793	$0.2535	$0.3065	$0.2561	$0.2435	$0.3133
6	$0.9462		$0.6658	$0.4521	$0.4986	$0.4393	$0.2326	$0.1877

Minimum Rates 3/, 4/

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 Rates 1/, 2/, 3/, 4/, 5/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1868		$0.3933	$0.5306	$0.5438	$0.8408	$0.8638	$1.0670
L		$0.1644						
1	$0.2797		$0.2721	$0.3655	$0.5143	$0.7164	$0.7832	$0.9423
2	$0.5297		$0.3576	$0.1835	$0.1732	$0.2911	$0.4168	$0.5160
3	$0.5427		$0.2933	$0.1863	$0.1331	$0.3016	$0.5027	$0.5719
4	$0.6873		$0.6313	$0.2423	$0.3649	$0.2197	$0.2526	$0.3726
5	$0.8178		$0.5807	$0.2549	$0.3079	$0.2575	$0.2449	$0.3147
6	$0.9476		$0.6672	$0.4535	$0.5000	$0.4407	$0.2340	$0.1891

Notes:

1/ The IT rate for each zone will be the respective 100% load factor equivalent of the maximum FT-A demand and commodity rates.

2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000 Daily Reservation.

3/ 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.

4/ 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.

5/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0007 Daily Reservation, $0.0007 Commodity.

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-BH

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$2.7705							
L		$2.4596						
1	$4.1708		$3.9980					
2	$7.7879		$5.2886	$2.7506				
3	$7.9257		$4.1892	$2.7729	$2.0004			
4	$10.0630		$9.2772	$3.5354	$5.3728	$2.6299		
5	$11.9986		$8.4312	$3.7086	$4.4874	$2.9215	$2.7405	
6	$13.8801		$9.6839	$6.6649	$7.3422	$5.1863	$2.7284	$2.3619

Daily Base Reservation Rates 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0911							
L		$0.0809						
1	$0.1371		$0.1314					
2	$0.2560		$0.1739	$0.0904				
3	$0.2606		$0.1377	$0.0912	$0.0658			
4	$0.3308		$0.3050	$0.1162	$0.1766	$0.0865		
5	$0.3945		$0.2772	$0.1219	$0.1475	$0.0960	$0.0901	
6	$0.4563		$0.3184	$0.2191	$0.2414	$0.1705	$0.0897	$0.0777

Maximum Reservation Rates 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$2.7804							
L		$2.4695						
1	$4.1807		$4.0079					
2	$7.7978		$5.2985	$2.7605				
3	$7.9356		$4.1991	$2.7828	$2.0103			
4	$10.0729		$9.2871	$3.5453	$5.3827	$2.6398		
5	$12.0085		$8.4411	$3.7185	$4.4973	$2.9314	$2.7504	
6	$13.8900		$9.6938	$6.6748	$7.3521	$5.1962	$2.7383	$2.3718

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 $0.0099.

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED** Schedule 6
2 **d/b/a Liberty Utilities** Page 1 of 5
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

5									Peak
6	For Month of:	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**<u>Supply and Commodity Costs</u>**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 63 * ln 102	[redacted]						
13	Niagara Supply	ln 64 * ln 107							
14	TGP Supply (Direct)	ln 65 * ln 123							
15	Dracut Supply 1 - Baseload	ln 66 * ln 112							
16	Dracut Supply 2 - Swing	ln 67 * ln 117							
17	City Gate Delivered Supply	ln 68 * ln 129							
18	LNG Truck	ln 69 * ln 131							
19	Propane Truck	ln 70 * ln 133							
20	PNGTS	ln 71 * ln 138							
21	TGP Supply (Z4)	ln 72 * ln 143							
22									
23	Subtotal Pipeline Gas Costs		$ 3,575,229	$ 9,588,167	$ 12,222,590	$ 13,935,540	$ 8,453,662	$ 2,897,151	$ 50,672,339
24									
25	**Volumetric Transportation Costs**								
26	Dawn Supply	ln 63 * ln 176	[redacted]						
27	Niagara Supply	ln 64 * ln 187							
28	TGP Supply (Direct)	ln 65 * ln 214							
29	Dracut Supply 1 - Baseload	ln 66 * ln 235							
30	Dracut Supply 2 - Swing	ln 67 * ln 235							
31	City Gate Delivered Supply	ln 68 * ln 235							
32	TGP Storage - Withdrawals	ln 77 * ln 165							
33									
34	**Total Volumetric Transportation Costs**		$ 230,723	$ 204,065	$ 251,624	$ 221,326	$ 188,946	$ 177,177	$ 1,273,861
35									
36	**Less - Gas Refill:**								
37	LNG Truck	ln 86 * ln 150	[redacted]						
38	Propane	ln 87 * ln 151							
39	TGP Storage Refill	ln 88 * ln 121							
40	Storage Refill (Trans.)	ln 88 * ln 214							
41									
42	Subtotal Refills		$ (1,130,676)	$ (2,350)	$ (1,085,908)	$ (446,860)	$ (129,393)	$ (462,398)	$ (3,257,585)
43									
44	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 34 + ln 42	$ 2,675,275	$ 9,789,883	$ 11,388,306	$ 13,710,007	$ 8,513,215	$ 2,611,929	$ 48,688,614
45									
46	**Storage Gas:**								
47	TGP Storage - Withdrawals	ln 77 * ln 157	$ 543,967	$ 632,533	$ 1,305,771	$ 1,002,362	$ 541,367	$ -	$ 4,026,000
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	$ 1,721	$ 1,844	$ 1,267,603	$ 446,189	$ 63,576	$ 16,566	$ 1,797,499
54									
55									
56	**Total Commodity Gas & Trans. Costs**	ln 44 + ln 47 + ln 53	$ 3,220,963	$ 10,424,260	$ 13,961,680	$ 15,158,558	$ 9,118,158	$ 2,628,495	$ 54,512,114
57									$ 93,587,846
58									

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

Line	For Month of:	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Peak 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		811,417	892,975	911,022	812,922	892,971	830,794	5,152,101
64	Niagara Supply		633,581	697,096	711,185	634,369	697,094	648,712	4,022,037
65	TGP Supply (Direct)		4,625,077	3,026,752	3,087,924	2,755,224	3,026,740	4,171,279	20,692,997
66	Dracut Supply 1 - Baseload		-	2,667,402	4,535,274	3,035,391	-	-	10,238,067
67	Dracut Supply 2 - Swing		3,138,155	4,749,329	1,824,248	4,342,598	6,448,837	3,301,715	23,804,882
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		2,705	2,881	1,126,288	538,561	156,990	-	1,827,424
70	Propane Truck		-	-	166,776	-	-	-	166,776
71	PNGTS		55,447	78,495	88,898	74,760	69,133	47,078	413,812
72	TGP Supply (Z4)		1,630,272	1,794,591	1,830,861	1,633,827	1,794,584	1,702,436	10,386,571
73									
74	Subtotal Pipeline Volumes		10,896,654	13,909,519	14,282,476	13,827,652	13,086,350	10,702,015	76,704,666
75									
76	**Storage Gas:**								
77	TGP Storage		2,930,568	3,407,706	7,034,707	5,400,122	2,916,559	-	21,689,663
78									
79	**Produced Gas:**								
80	LNG Vapor		2,705	2,881	1,212,247	538,561	77,055	20,078	1,853,525
81	Propane		-	-	166,776	-	-	-	166,776
82									
83	Subtotal Produced Gas		2,705	2,881	1,379,023	538,561	77,055	20,078	2,020,301
84									
85	**Less - Gas Refill:**								
86	LNG Truck		(2,705)	(2,881)	(1,126,288)	(538,561)	(156,990)	-	(1,827,424)
87	Propane		-	-	(166,776)	-	-	-	(166,776)
88	TGP Storage Refill		(3,444,465)	-	-	-	-	(1,388,119)	(4,832,584)
89									
90	Subtotal Refills		(3,447,170)	(2,881)	(1,293,064)	(538,561)	(156,990)	(1,388,119)	(6,826,784)
91									
92	**Total Sendout Volumes**		10,382,757	17,317,226	21,403,143	19,227,774	15,922,974	9,333,973	93,587,846
93									
94									
95									

Line	For Month of:	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Peak Nov- Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty Utilities**								
3	**Peak 2016 - 2017 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
96	**Gas Costs and Volumetric Transportation Rates**								
97									
98	**Pipeline Gas:**								
99	**Dawn Supply**								Average Rate
100	NYMEX Price	Sch 7, ln 10/10	[redacted]						
101	Basis Differential								
102	**Net Commodity Costs**								
103									
104	**Niagara Supply**								
105	NYMEX Price	Sch 7, ln 10/10	[redacted]						
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Dracut Supply 1 - Baseload**								
110	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 2 - Swing**								
115	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119									
120	**TGP Supply (Direct)**								
121	NYMEX Price	Sch 7, ln 10/10	[redacted]						
122	Basis Differential								
123	**Net Commodity Costs**								
124									
125									
126	**City Gate Delivered Supply**								
127	NYMEX Price	Sch 7, ln 10/10	[redacted]						
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131	**LNG Truck**	Sch 7, ln 10/10	**$0.7845**	**$0.8157**	**$0.8309**	**$0.8297**	**$0.8242**	**$0.7960**	**$0.8135**
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	**$0.6363**	**$0.6403**	**$0.8117**	**$0.8285**	**$0.8251**	**$0.8251**	**$0.7612**
146									
147	**Propane**	Sch 16, ln 66 /10	**$1.2414**	**$1.2414**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.7005**	**$1.5475**
148									
149	**Storage Refill:**								
150	**LNG Truck**	ln 131	**$0.7845**	**$0.8157**	**$0.8309**	**$0.8297**	**$0.8242**	**$0.7960**	**$0.7612**
151	**Propane**	ln 133	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$0.9000**	**$1.5475**
152									
153					**THIS PAGE HAS BEEN REDACTED**				

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

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2 **d/b/a Liberty Utilities**

3 **Peak 2016 - 2017 Winter Cost of Gas Filing**

4 **Supply and Commodity Costs, Volumes and Rates**

Ln									
5									Peak
6	For Month of:	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	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	$0.1856	$0.1856	$0.1856	$0.1856	$0.1856	$0.2144	$0.1904
158									
159	TGP - Max Commodity - Z 4-6	12th Rev Sheet No. 15	$0.01048	$0.01048	$0.01048	$0.01048	$0.01048	$0.01048	$0.01048
160	TGP - Max Comm. ACA Rate - Z 4-6	12th Rev Sheet No. 15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
161	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.01062	$0.01062	$0.01062	$0.01062	$0.01062	$0.01062	$0.01062
162	TGP - Fuel Charge % - Z 4-6	11th Rev Sheet No. 32	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%
163	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00158	$0.00158	$0.00158	$0.00158	$0.00158	$0.00182	$0.00162
164	TGP - Withdrawal Charge	12th 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)**		$0.01307	$0.01307	$0.01307	$0.01307	$0.01307	$0.01331	$0.01311
166									
167	**Total TGP - Comm. & Vol. Trans. Rate**	ln 157 + ln 165	**$0.19869**	**$0.19869**	**$0.19869**	**$0.19869**	**$0.19869**	**$0.22768**	**$0.20352**
168									
169									
156	**Per Unit Volumetric Transportation Rates**								
157	**Dawn Supply Volumetric Transportation Charge**								
158	**Commodity Costs**	ln 102	**$0.3256**	**$0.3424**	**$0.3557**	**$0.3571**	**$0.3598**	**$0.3119**	**$0.3421**
159									
160	TransCanada - Commodity Rate/GJ	Union Parkway to Iroquois	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
161	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
162	Conversion Rate to US$	updated 7/28/16	1.3361	1.3361	1.3361	1.3361	1.3361	1.3361	1.3361
163	Commodity Rate/US$	ln 160 x ln 161 x ln 162	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
164	TransCanada Fuel %	Union Parkway to Iroquois	1.37%	2.46%	2.29%	2.76%	1.29%	1.38%	1.92%
165	TransCanada Fuel * Percentage	ln 158 x ln 164	$0.00446	$0.00843	$0.00814	$0.00986	$0.00465	$0.00429	$0.00664
166	Subtotal TransCanada		**$0.00446**	**$0.00843**	**$0.00814**	**$0.00986**	**$0.00465**	**$0.00429**	**$0.00664**
167	IGTS - Z1 RTS Commodity	First Revised Sheet No. 4	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
168	IGTS - Z1 RTS ACA Rate Commodity	Fifth Revised Sheet 4A	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
169	IGTS - Z1 RTS Deferred Asset Surcharge	Fifth Revised Sheet 4A	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
170	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**	**$0.00044**
171	TGP NET-NE - Comm. Segments 3 & 4	12th Rev Sheet No. 15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
172	IGTS -Fuel Use Factor - Percentage	Fifth Revised Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
173	IGTS -Fuel Use Factor - Fuel * Percentage	ln 158 x ln 172	**$0.00326**	**$0.00342**	**$0.00356**	**$0.00357**	**$0.00360**	**$0.00312**	**$0.00342**
174	TGP FTA Fuel Charge % Z 5-6	11th Rev Sheet No. 32	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%
175	TGP FTA Fuel * Percentage	ln 158 x ln 174	**$0.00202**	**$0.00212**	**$0.00221**	**$0.00221**	**$0.00223**	**$0.00193**	**$0.00212**
176	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01032**	**$0.01455**	**$0.01448**	**$0.01622**	**$0.01105**	**$0.00993**	**$0.01276**
177									
178									
179	**Niagara Supply Volumetric Transportation Charge**								
180	**Commodity Costs**	Ln 107	[redacted]						
181									
182	TGP FTA - FTA Z 5-6 Comm. Rate	12th Rev Sheet No. 15	$0.00794	$0.00794	$0.00794	$0.00794	$0.00794	$0.00794	$0.00794
183	TGP FTA - FTA Z 5-6 - ACA Rate	12th Rev Sheet No. 15	$0.00014	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
184	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00808**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**
185	TGP FTA Fuel Charge % Z 5-6	11th Rev Sheet No. 32	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%
186	TGP FTA Fuel * Percentage	ln 180 x ln 185	[redacted]						
187	**Total Volumetric Transportation Rate - Niagara Supply**								
188									
189									
190									

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1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2016 - 2017 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	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	12th Rev Sheet No. 15	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037
197	TGP - Max Commodity ACA Rate - Z 0-6	12th Rev Sheet No. 15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
198	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03051	$0.03051	$0.03051	$0.03051	$0.03051	$0.03051	$0.03051
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	12th Rev Sheet No. 15	$0.02648	$0.02648	$0.02648	$0.02648	$0.02648	$0.02648	$0.02648
202	TGP - Max Commodity ACA Rate - Z 1-6	12th Rev Sheet No. 15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
203	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662	$0.02662
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		**$0.01794**	**$0.01794**	**$0.01794**	**$0.01794**	**$0.01794**	**$0.01794**	**$0.01794**
206	TGP - Fuel Charge % - Z 0 -6	11th Rev Sheet No. 32	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%	3.05%
207	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
208	Prorated TGP Fuel Charge % - Z 0-6		0.99%	0.99%	0.99%	0.99%	0.99%	0.99%	0.99%
209	TGP - Fuel Charge % - Z 1 -6	11th Rev Sheet No. 32	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%	2.66%
210	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
211	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%
212	TGP - Fuel Charge % - Z 0-6	ln 194 x ln 208	**$0.00290**	**$0.00306**	**$0.00316**	**$0.00315**	**$0.00311**	**$0.00295**	**$0.00306**
213	TGP - Fuel Charge % - Z 1-6	ln 194 x ln 211	**$0.00523**	**$0.00551**	**$0.00570**	**$0.00569**	**$0.00561**	**$0.00532**	**$0.00551**
214	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.03602**	**$0.03646**	**$0.03674**	**$0.03673**	**$0.03661**	**$0.03616**	**$0.03645**
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	12th Rev Sheet No. 15	$0.00331	$0.00331	$0.00331	$0.00331	$0.00331	$0.00331	$0.00331
220	TGP - Max Commodity ACA Rate - Z 6-6	12th Rev Sheet No. 15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
221	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**
222	TGP - Fuel Charge % - Z 6-6	11th Rev Sheet No. 32	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
223	TGP - Fuel Charge	ln 217 x ln 222	**$0.00015**	**$0.00015**	**$0.00016**	**$0.00016**	**$0.00016**	**$0.00015**	**$0.00015**
224	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00360**	**$0.00360**	**$0.00361**	**$0.00361**	**$0.00361**	**$0.00360**	**$0.00360**
225									
226									
227	**TGP Dracut**								
228	**Commodity Costs - NYMEX Price**	Ln 112	[redacted]						
229									
230	TGP - Trans Charge - Comm. - Z 6-6	12th Rev Sheet No. 15	$0.00331	$0.00331	$0.00331	$0.00331	$0.00331	$0.00331	$0.00331
231	TGP - Trans Charge - ACA Rate - Z6-6	12th Rev Sheet No. 15	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014
232	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**	**$0.00345**
233	TGP - Fuel Charge % - Z 6-6	11th Rev Sheet No. 32	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
234	TGP - Fuel Charge	ln 228 x ln 233	[redacted]						
235	**Total Volumetric Transportation Rate - TGP Dracut**								
236									
237									

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line		Reference		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Peak Strip Average
5										
6	For Month of:	Reference		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**									
9	Opening Prices (15 day average)			2.9163	3.0743	3.1769	3.1714	3.1281	2.9695	$ 3.0727
10	NYMEX	ln 201	**Filed COG**	2.9163	3.0743	3.1769	3.1714	3.1281	2.9695	$ 3.0727
11										
12										
13										
14										
15										
16										
17										
18										
19										
20	**II. Development of Hedging Costs and Savings**									
21										
22	**TGP (Direct) Volumes**									Total
23	Hedged Volumes (Dth)	ln 83		-	-	-	-	-	-	-
24	Market Priced Volumes (Dth)			-	-	-	-	-	-	-
25	Total Volumes (Dth)	Sch 6, lns 63 - 68 / 10		-	-	-	-	-	-	-
26										
27										Weighted Average
28	Hedge Price	ln 170		$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	NYMEX Price	ln 10		$ 2.9163	$ 3.0743	$ 3.1769	$ 3.1714	$ 3.1281	$ 2.9695	$ -
30										
31	Hedged Volumes at Hedged Price	ln 23 * ln 28		$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Less Hedged Volumes at NYMEX	ln 24 * ln 29		-	-	-	-	-	-	-
33										
34	Hedge Contract (Savings)/Loss	ln 31 - ln 32		$ -	$ -	$ -	$ -	$ -	$ -	$ -
35										
36	Total Financial Hedge	ln 23		-	-	-	-	-	-	-
37	Total Underground Storage	Sch 6, Ln 77		-	-	-	-	-	-	-
38	Sub Total			-	-	-	-	-	-	-
39	Total Throughput	Sch 6, ln 92		10,382,757	17,317,226	21,403,143	19,227,774	15,922,974	9,333,973	93,587,846
40	Hedge Percentage	ln 38 / ln 39		0%	0%	0%	0%	0%	0%	0%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**
5

Line	For Month of:			Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Peak Strip Average
7			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41											
42	Hedged Volumes (Dth)										
43	Hedge #	1	Trade Date	Swaps	-	-	-	-	-	-	-
44	Hedge #	2	Trade Date	Swaps	-	-	-	-	-	-	-
45	Hedge #	3	Trade Date	Swaps	-	-	-	-	-	-	-
46	Hedge #	4	Trade Date	Swaps	-	-	-	-	-	-	-
47	Hedge #	5	Trade Date	Swaps	-	-	-	-	-	-	-
48	Hedge #	6	Trade Date	Swaps	-	-	-	-	-	-	-
49	Hedge #	7	Trade Date	Swaps	-	-	-	-	-	-	-
50	Hedge #	8	Trade Date	Swaps	-	-	-	-	-	-	-
51	Hedge #	9	Trade Date	Swaps	-	-	-	-	-	-	-
52	Hedge #	10	Trade Date	Swaps	-	-	-	-	-	-	-
53	Hedge #	11	Trade Date	Swaps	-	-	-	-	-	-	-
54	Hedge #	12	Trade Date	Swaps	-	-	-	-	-	-	-
55	Hedge #	13	Trade Date	Swaps	-	-	-	-	-	-	-
56	Hedge #	14	Trade Date	Swaps	-	-	-	-	-	-	-
57	Hedge #	15	Trade Date	Swaps	-	-	-	-	-	-	-
58	Hedge #	16	Trade Date	Swaps	-	-	-	-	-	-	-
59	Hedge #	17	Trade Date	Swaps	-	-	-	-	-	-	-
60	Hedge #	18	Trade Date	Swaps	-	-	-	-	-	-	-
61	Hedge #	19	Trade Date	Swaps	-	-	-	-	-	-	-
62	Hedge #	20	Trade Date	Swaps	-	-	-	-	-	-	-
63	Hedge #	21	Trade Date	Swaps	-	-	-	-	-	-	-
64	Hedge #	22	Trade Date	Swaps	-	-	-	-	-	-	-
65	Hedge #	23	Trade Date	Swaps	-	-	-	-	-	-	-
66	Hedge #	24			-	-	-	-	-	-	-
67	Hedge #	25			-	-	-	-	-	-	-
68	Hedge #	26									-
69	Hedge #	27									-
70	Hedge #	28									-
71	Hedge #	29									-
72	Hedge #	30									-
73											-
74											-
75											
76											
77											
78											
79											
80	Subtotal Hedge Volumes				-	-	-	-	-	-	-
81	Remaining				-	-	-	-	-	-	-
82	Total Volumes				-	-	-	-	-	-	-
83											
84											

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line											
5											Peak
6	For Month of:			Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Strip Average
7			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
85	Strike Price										
											Weighted Average
86	Hedge #	1	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
87	Hedge #	2	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
88	Hedge #	3	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
89	Hedge #	4	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
90	Hedge #	5	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
91	Hedge #	6	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
92	Hedge #	7	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
93	Hedge #	8	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
94	Hedge #	9	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
95	Hedge #	10	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
96	Hedge #	11	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
97	Hedge #	12	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
98	Hedge #	13	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
99	Hedge #	14	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
100	Hedge #	15	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
101	Hedge #	16	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
102	Hedge #	17	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
103	Hedge #	18	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
104	Hedge #	19	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
105	Hedge #	20	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
106	Hedge #	21	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
107	Hedge #	22	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
108	Hedge #	23	Trade Date	Swaps	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
109	Hedge #	24			$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
110	Hedge #	25			$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
111	Hedge #	26									
112	Hedge #	27									
113	Hedge #	28									
114	Hedge #	29									
115	Hedge #	30									
116											
117											
118											
119											
120											
121											
122											
123	Subtotal Weighted Average Hedge Prices				#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
124	NYMEX				$2.9163	$3.0743	$3.1769	$3.1714	$3.1281	$2.9695	#DIV/0!
125											
126											

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line												Peak
5												
6	For Month of:				Reference	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
127	Hedge Dollars											
128	Hedge #	1	Trade Date	0-Jan-00	Swaps	$ -	$ -	$ -	$ -	$ -	$ -	$ -
129	Hedge #	2	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
130	Hedge #	3	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
131	Hedge #	4	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
132	Hedge #	5	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
133	Hedge #	6	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
134	Hedge #	7	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
135	Hedge #	8	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
136	Hedge #	9	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
137	Hedge #	10	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
138	Hedge #	11	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
139	Hedge #	12	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
140	Hedge #	13	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
141	Hedge #	14	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
142	Hedge #	15	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
143	Hedge #	16	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
144	Hedge #	17	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
145	Hedge #	18	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
146	Hedge #	19	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
147	Hedge #	20	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
148	Hedge #	21	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
149	Hedge #	22	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
150	Hedge #	23	Trade Date	0-Jan-00	Swaps	-	-	-	-	-	-	-
151	Hedge #	24				-	-	-	-	-	-	-
152	Hedge #	25				-	-	-	-	-	-	-
153	Hedge #	26										
154	Hedge #	27										
155	Hedge #	28										
156	Hedge #	29										
157	Hedge #	30										
158												
159												
160												
161												
162												
163												
164												
165	Subtotal Hedge Dollars					$0	$0	$0	$0	$0	$0	$0
166	Remaining					-	-	-	-	-	-	-
167												
168			Target Hedged Dollars			$0	$0	$0	$0	$0	$0	$0
169												
170			Weighted Average Hedged Cost per Unit			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
171												
172												

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2016 - 2017 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**

Line										Peak
6	For Month of:	Reference		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
173	NYMEX Settlement - 15 Day Average									
174		Days	Date							
175		1	20-Aug	2.8740	3.0260	3.1260	3.1240	3.0830	2.9320	
176		2	19-Aug	2.8360	2.9890	3.0880	3.0880	3.0490	2.9060	
177		3	18-Aug	2.8390	3.0000	3.1020	3.1000	3.0600	2.9150	
178		4	17-Aug	2.8720	3.0380	3.1400	3.1360	3.0940	2.9470	
179		5	14-Aug	2.9390	3.0980	3.1980	3.1920	3.1480	2.9910	
180										
181										
182		6	13-Aug	2.9240	3.0850	3.1850	3.1790	3.1360	2.9790	
183		7	12-Aug	3.0490	3.1930	3.2880	3.2790	3.2310	3.0470	
184		8	11-Aug	2.9730	3.1280	3.2290	3.2220	3.1750	3.0000	
185		9	10-Aug	2.9720	3.1310	3.2330	3.2260	3.1780	3.0030	
186		10	7-Aug	2.9250	3.0820	3.1860	3.1790	3.1340	2.9740	
187										
188										
189		11	6-Aug	2.9300	3.0810	3.1840	3.1780	3.1330	2.9730	
190		12	5-Aug	2.9140	3.0690	3.1750	3.1680	3.1230	2.9610	
191		13	4-Aug	2.9410	3.0980	3.2040	3.1960	3.1520	2.9820	
192		14	3-Aug	2.8880	3.0540	3.1640	3.1580	3.1170	2.9660	
193		15	31-Jul	2.8680	3.0420	3.1520	3.1460	3.1080	2.9660	
194			1-Aug							
195			2-Aug							
196			3-Aug							
197			4-Aug							
198			5-Aug							
199			6-Aug							
200										
201			15 Day Average	2.9163	3.0743	3.1769	3.1714	3.1281	2.9695	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2016 - 2017 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 15 - Apr 16 vs Nov 16 - Apr 17 - Residential Heating Rate R-3

November 1, 2016 - April 30, 2017 / **May 1, 2016 - October 31, 2016**
Residential Heating (R3)

PROPOSED									**Winter**							**Summer**	**Total**
			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**
average Usage (Therms)			51	95	117	141	130	74	608	57	28	19	15	14	22	156	763
	5/1/2016	7/1/2016															
Winter:																	
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	$17.86	$33.20	$34.95	$34.95	$34.95	$25.80	$181.71								
Tailblock	$0.2885	$0.2892	$0.00	$0.00	$4.93	$11.88	$8.53	$0.00	$25.34								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$22.04	$22.10								$22.04	$22.04	$22.10	$22.10	$22.10	$22.10	$132.48	$265.08
Headblock	$0.3486	$0.3495								$6.97	$6.97	$6.64	$5.23	$5.05	$6.99	$37.85	$219.56
Tailblock	$0.2885	$0.2892								$10.80	$2.24	$0.00	$0.00	$0.00	$0.55	$13.59	$38.94
HB Threshold	20	20															
Total Base Rate Amount			$39.96	$55.30	$61.98	$68.93	$65.58	$47.90	$339.65	$39.81	$31.25	$28.74	$27.33	$27.15	$29.64	$183.93	$523.58
COG Rate - (Seasonal)			$0.7068	$0.7068	$0.7068	$0.7068	$0.7068	$0.7068	$0.7068	$0.4117	$0.4400	$0.4400	$0.4200	$0.4200	$0.4200	$0.4229	$0.6489
COG amount			$36.11	$67.14	$82.72	$99.72	$91.54	$52.19	$429.41	$23.65	$12.22	$8.36	$6.29	$6.07	$9.20	$65.78	$495.19
LDAC			$0.0553	$0.0553	$0.0640	$0.0640	$0.0640	$0.0640	$0.0619	$0.1014	$0.1014	$0.1014	$0.1014	$0.1014	$0.1014	$0.1014	$0.0699
LDAC amount			$2.83	$5.25	$7.49	$9.03	$8.29	$4.72	$37.60	$5.82	$2.82	$1.93	$1.52	$1.46	$2.22	$15.77	$53.37
Total Bill			**$78.89**	**$127.68**	**$152.19**	**$177.68**	**$165.41**	**$104.81**	**$806.66**	**$69.29**	**$46.29**	**$39.03**	**$35.14**	**$34.68**	**$41.06**	**$265.48**	**$1,072.14**

November 1, 2015 - April 30, 2016 / **May 1, 2015 - October 31, 2015**
Residential Heating (R3)

CURRENT									**Winter**							**Summer**	**Total**
			Nov-15	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**Nov-Apr**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**May-Oct**	**Nov-Oct**
average Usage (Therms)			51	95	117	141	130	74	608	57	28	19	15	14	22	156	763
Winter:	5/1/2015	7/1/2015															
Cust. Chg	$19.85	$22.04	$22.04	$22.04	$22.04	$22.04	$22.04	$22.04	$132.24								
Headblock	$0.3140	$0.3486	$17.81	$33.11	$34.86	$34.86	$34.86	$25.74	$181.24								
Tailblock	$0.2594	$0.2885	$0.00	$0.00	$4.91	$11.85	$8.51	$0.00	$25.28								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$19.85	$22.04								$19.85	$19.85	$22.04	$22.04	$22.04	$22.04	$127.86	$260.10
Headblock	$0.3140	$0.3486								$6.28	$6.28	$6.62	$5.22	$5.03	$6.97	$36.41	$217.65
Tailblock	$0.2594	$0.2885								$9.71	$2.02	$0.00	$0.00	$0.00	$0.55	$12.28	$37.56
HB Threshold	20	20															
Total Base Rate Amount			$39.85	$55.15	$61.81	$68.75	$65.41	$47.78	$338.76	$35.84	$28.15	$28.66	$27.26	$27.07	$29.56	$176.55	$515.31
COG Rate - (Seasonal)			$0.7516	$0.7516	$0.6256	$0.4436	$0.2634	$0.4423	$0.5141	$0.3073	$0.3246	$0.3421	$0.3421	$0.3421	$0.3796	$0.3314	$0.4769
COG amount			$38.40	$71.39	$73.22	$62.59	$34.11	$32.66	$312.36	$17.65	$9.01	$6.50	$5.12	$4.94	$8.32	$51.54	$363.91
LDAC			$0.1014	$0.1014	$0.1014	$0.1014	$0.1014	$0.1014	0.1014	$0.0772	$0.0772	$0.0937	$0.0937	$0.0937	$0.0937	$0.0847	$0.0980
LDAC amount			$5.18	$9.63	$11.87	$14.31	$13.13	$7.49	$61.60	$4.43	$2.14	$1.78	$1.40	$1.35	$2.05	$13.17	$74.77
Total Bill			**$83.43**	**$136.17**	**$146.90**	**$145.65**	**$112.66**	**$87.92**	**$712.73**	**$57.93**	**$39.30**	**$36.94**	**$33.78**	**$33.37**	**$39.93**	**$241.25**	**$953.99**

DIFFERENCE:

Total Bill	**($4.54)**	**($8.49)**	**$5.29**	**$32.03**	**$52.75**	**$16.89**	**$93.93**	**$11.36**	**$6.98**	**$2.08**	**$1.35**	**$1.31**	**$1.13**	**$24.22**	**$118.16**
% Change	**-5.44%**	**-6.23%**	**3.60%**	**21.99%**	**46.82%**	**19.21%**	**13.18%**	**19.61%**	**17.77%**	**5.64%**	**4.01%**	**3.92%**	**2.84%**	**10.04%**	**12.39%**
Base Rate	$0.11	$0.15	$0.16	$0.18	$0.17	$0.13	$0.89	$3.97	$3.11	$0.08	$0.07	$0.07	$0.08	$7.38	$8.27
% Change	0.27%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	11.08%	11.04%	0.27%	0.27%	0.27%	0.27%	4.18%	1.61%
COG & LDAC	($4.64)	($8.63)	$5.12	$31.85	$52.58	$16.77	$93.04	$7.39	$3.88	$2.01	$1.28	$1.24	$1.05	$16.84	$109.88
% Change	-12.09%	-12.09%	7.00%	50.90%	154.13%	51.34%	29.79%	41.85%	43.01%	30.87%	25.02%	25.02%	12.67%	32.67%	30.20%
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 2016 - 2017 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 15 - Apr 16 vs Nov 16 - Apr 17 - Commercial Rate G-41

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

PROPOSED									**Winter**							**Summer**	**Total**
			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**
average Usage (Therms)			121	251	293	429	390	202	1,685	145	56	51	27	26	39	344	2,029
Winter:	7/1/2016	5/1/2016															
Cust. Chg	$48.36	$48.24	$48.36	$48.36	$48.36	$48.36	$48.36	$48.36	$290.16								
Headblock	$0.3965	$0.3956	$39.65	$39.65	$39.65	$39.65	$39.65	$39.65	$237.90								
Tailblock	$0.2663	$0.2657	$5.50	$40.15	$51.45	$87.54	$77.11	$27.26	$289.01								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$48.36	$48.24								$48.24	$48.24	$48.36	$48.36	$48.36	$48.36	$289.92	$580.08
Headblock	$0.3965	$0.3956								$7.91	$7.91	$7.93	$7.93	$7.93	$7.93	$47.54	$285.44
Tailblock	$0.2663	$0.2657								$33.12	$9.58	$8.25	$1.92	$1.62	$5.00	$59.51	$348.52
HB Threshold	20	20															
Total Base Rate Amount			$93.51	$128.16	$139.46	$175.55	$165.12	$115.27	$817.07	$89.27	$65.74	$64.54	$58.21	$57.91	$61.29	$396.97	$1,214.04
COG Rate - (Seasonal)			$0.7026	$0.7026	$0.7026	$0.7026	$0.7026	$0.7026	$0.7026	$0.3976	$0.4259	$0.4259	$0.4059	$0.4059	$0.4059	$0.4086	$0.6528
COG amount			$84.78	$176.19	$206.01	$301.22	$273.71	$142.17	$1,184.08	$57.51	$23.88	$21.71	$11.05	$10.59	$15.75	$140.50	$1,324.57
LDAC			$0.0370	$0.0370	$0.0450	$0.0450	$0.0450	$0.0450	0.0432	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0475
LDAC amount			$4.46	$9.28	$13.20	$19.29	$17.53	$9.11	$72.87	$9.91	$3.84	$3.49	$1.87	$1.79	$2.66	$23.55	$96.42
Total Bill			**$182.75**	**$313.62**	**$358.67**	**$496.06**	**$456.36**	**$266.54**	**$2,074.02**	**$156.69**	**$93.45**	**$89.75**	**$71.13**	**$70.30**	**$79.70**	**$561.02**	**$2,635.03**

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

CURRENT									**Winter**							**Summer**	**Total**
			Nov-15	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**Nov-Apr**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**May-Oct**	**Nov-Oct**
average Usage (Therms)			121	251	293	429	390	202	1,685	145	56	51	27	26	39	344	2,029
Winter:	5/1/2015	7/1/2015															
Cust. Chg	$46.71	$48.24	$48.24	$48.24	$48.24	$48.24	$48.24	$48.24	$289.44								
Headblock	$0.3727	$0.3956	$39.56	$39.56	$39.56	$39.56	$39.56	$39.56	$237.36								
Tailblock	$0.2424	$0.2657	$5.49	$40.06	$51.34	$87.34	$76.94	$27.19	$288.36								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$46.71	$48.24								$46.71	$46.71	$48.24	$48.24	$48.24	$48.24	$286.38	$575.82
Headblock	$0.3727	$0.3956								$7.45	$7.45	$7.91	$7.91	$7.91	$7.91	$46.56	$283.92
Tailblock	$0.2424	$0.2657								$30.21	$8.74	$8.23	$1.92	$1.62	$4.99	$55.72	$344.08
HB Threshold	20	20															
Total Base Rate Amount			$93.29	$127.86	$139.14	$175.14	$164.74	$114.99	$815.16	$84.38	$62.91	$64.38	$58.07	$57.77	$61.15	$388.66	$1,203.82
COG Rate - (Seasonal)			$0.7454	$0.7454	$0.6194	$0.4374	$0.2572	$0.4361	$0.4951	$0.3210	$0.3383	$0.3558	$0.3558	$0.3558	$0.3933	$0.3425	$0.4693
COG amount			$89.94	$186.92	$181.62	$187.52	$100.20	$88.25	$834.44	$46.43	$18.97	$18.14	$9.69	$9.29	$15.26	$117.77	$952.21
LDAC			$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	0.0685	$0.0628	$0.0628	$0.0793	$0.0793	$0.0793	$0.0793	$0.0697	$0.0687
LDAC amount			$8.27	$17.18	$20.09	$29.37	$26.69	$13.86	$115.44	$9.08	$3.52	$4.04	$2.16	$2.07	$3.08	$23.95	$139.39
Total Bill			**$191.49**	**$331.95**	**$340.84**	**$392.03**	**$291.62**	**$217.10**	**$1,765.04**	**$139.89**	**$85.40**	**$86.57**	**$69.92**	**$69.13**	**$79.48**	**$530.38**	**$2,295.42**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($8.74)**	**($18.33)**	**$17.83**	**$104.03**	**$164.74**	**$49.44**	**$308.97**	**$16.80**	**$8.06**	**$3.18**	**$1.21**	**$1.17**	**$0.22**	**$30.63**	**$339.61**
% Change	**-4.57%**	**-5.52%**	**5.23%**	**26.54%**	**56.49%**	**22.77%**	**17.51%**	**12.01%**	**9.44%**	**3.67%**	**1.73%**	**1.69%**	**0.28%**	**5.78%**	**14.80%**
Base Rate	$0.22	$0.30	$0.33	$0.41	$0.38	$0.27	$1.91	$4.89	$2.83	$0.16	$0.14	$0.14	$0.15	$8.31	$10.22
% Change	0.24%	0.23%	0.23%	0.23%	0.23%	0.24%	0.23%	5.80%	4.50%	0.24%	0.25%	0.25%	0.24%	2.14%	0.85%
COG & LDAC	($8.97)	($18.63)	$17.51	$103.62	$164.36	$49.17	$307.06	$11.90	$5.23	$3.02	$1.07	$1.03	$0.07	$22.32	$329.39
% Change	-9.97%	-9.97%	9.64%	55.26%	164.04%	55.72%	36.80%	25.64%	27.58%	16.67%	11.05%	11.05%	0.46%	18.96%	34.59%
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 2016 - 2017 Winter Cost of Gas Filing**
4 **Annual Bill Comparisons, Nov 15 - Apr 16 vs Nov 16 - Apr 17 - Commercial Rate G-42**
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7 **November 1, 2016 - April 30, 2017** — **May 1, 2016 - October 31, 2016**
8 **C&I High Winter Use Medium G-42**

										Winter							Summer	Total
9	**PROPOSED**									**Winter**							**Summer**	**Total**
10				**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**
11	**average Usage (Therms)**			1,009	1,009	2,228	2,686	2,426	1,378	10,737	1,116	492	485	1,166	280	444	3,983	14,720
12		7/1/2016	5/1/2016															
13	**Winter:**																	
14	Cust. Chg	$145.08	$144.73	$145.08	$145.08	$145.08	$145.08	$145.08	$145.08	$870.48								
15	Headblock	$0.3606	$0.3598	$360.60	$360.60	$360.60	$360.60	$360.60	$360.60	$2,163.60								
16	Tailblock	$0.2402	$0.2396	$2.25	$2.25	$294.99	$404.93	$342.58	$90.77	$1,137.76								
17	HB Threshold	1,000	1,000															
18																		
19	**Summer:**																	
20	Cust. Chg	$145.08	$144.73								$144.73	$144.73	$145.08	$145.08	$145.08	$145.08	$869.78	$1,740.26
21	Headblock	$0.3606	$0.3598								$143.92	$143.92	$144.24	$144.24	$100.90	$144.24	$821.46	$2,985.06
22	Tailblock	$0.2402	$0.2396								$171.53	$22.03	$20.53	$183.92	$0.00	$10.62	$408.64	$1,546.40
23	HB Threshold	400	400															
24																		
25	Total Base Rate Amount			$507.93	$507.93	$800.67	$910.61	$848.26	$596.45	$4,171.84	$460.18	$310.68	$309.85	$473.24	$245.98	$299.94	$2,099.87	$6,271.72
26																		
27	COG Rate - (Seasonal)			$0.7026	$0.7026	$0.7026	$0.7026	$0.7026	$0.7026	$0.7026	$0.3976	$0.4259	$0.4259	$0.4059	$0.4059	$0.4059	$0.4085	$0.6230
28	COG amount			$709.17	$709.17	$1,565.46	$1,887.05	$1,704.66	$968.12	$7,543.63	$443.69	$209.52	$206.76	$473.16	$113.57	$180.30	$1,627.01	$9,170.64
29																		
30	LDAC			$0.0370	$0.0370	$0.0450	$0.0450	$0.0450	$0.0450	0.0435	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0503
31	LDAC amount			$37.35	$37.35	$100.27	$120.87	$109.18	$62.01	$467.02	$76.44	$33.70	$33.25	$79.85	$19.17	$30.43	$272.84	$739.86
32																		
33	**Total Bill**			**$1,254.45**	**$1,254.45**	**$2,466.40**	**$2,918.53**	**$2,662.10**	**$1,626.58**	**$12,182.50**	**$980.31**	**$553.91**	**$549.87**	**$1,026.25**	**$378.72**	**$510.66**	**$3,999.72**	**$16,182.22**

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35 **November 1, 2015 - April 30, 2016** — **May 1, 2015 - October 31, 2015**
36 **C&I High Winter Use Medium G-42**

37	**CURRENT**									**Winter**							**Summer**	**Total**
38				**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**Nov-Apr**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**May-Oct**	**Nov-Oct**
39	**average Usage (Therms)**			1,009	1,009	2,228	2,686	2,426	1,378	10,737	1,116	492	485	1,166	280	444	3,983	14,720
40		5/1/2015	7/1/2015															
41	**Winter:**																	
42	Cust. Chg	$140.13	$144.73	$144.73	$144.73	$144.73	$144.73	$144.73	$144.73	$868.38								
43	Headblock	$0.3483	$0.3598	$359.80	$359.80	$359.80	$359.80	$359.80	$359.80	$2,158.80								
44	Tailblock	$0.2302	$0.2396	$2.24	$2.24	$294.25	$403.92	$341.72	$90.55	$1,134.92								
45	HB Threshold	1,000	1,000															
46																		
47	**Summer:**																	
48	Cust. Chg	$140.13	$144.73								$140.13	$140.13	$144.73	$144.73	$144.73	$144.73	$859.18	$1,727.56
49	Headblock	$0.3483	$0.3598								$139.32	$139.32	$143.92	$143.92	$100.67	$143.92	$811.07	$2,969.87
50	Tailblock	$0.2302	$0.2396								$164.80	$22.03	$20.48	$183.46	$0.00	$10.59	$401.37	$1,536.29
51	HB Threshold	400	400															
52																		
53	Total Base Rate Amount			$506.77	$506.77	$798.78	$908.45	$846.25	$595.08	$4,162.10	$444.25	$301.48	$309.13	$472.11	$245.40	$299.24	$2,071.62	$6,233.73
54																		
55	COG Rate - (Seasonal)			$0.7454	$0.7454	$0.6194	$0.4374	$0.2572	$0.4361	$0.4922	$0.3210	$0.3383	$0.3558	$0.3558	$0.3558	$0.3933	$0.3481	$0.4532
56	COG amount			$752.37	$752.37	$1,380.08	$1,174.77	$624.02	$600.90	$5,284.53	$358.21	$166.43	$172.73	$414.76	$99.55	$174.70	$1,386.39	$6,670.92
57																		
58	LDAC			$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	0.0685	$0.0628	$0.0628	$0.0793	$0.0793	$0.0793	$0.0793	$0.0726	$0.0696
59	LDAC amount			$69.14	$69.14	$152.62	$183.98	$166.20	$94.39	$735.47	$70.08	$30.89	$38.50	$92.44	$22.19	$35.22	$289.33	$1,024.79
60																		
61	**Total Bill**			**$1,328.29**	**$1,328.29**	**$2,331.49**	**$2,267.20**	**$1,636.47**	**$1,290.37**	**$10,182.10**	**$872.54**	**$498.81**	**$520.36**	**$979.31**	**$367.15**	**$509.17**	**$3,747.33**	**$13,929.44**
62																		
63	**DIFFERENCE:**																	
64	**Total Bill**			**($73.84)**	**($73.84)**	**$134.91**	**$651.33**	**$1,025.63**	**$336.21**	**$2,000.40**	**$107.77**	**$55.10**	**$29.51**	**$46.94**	**$11.57**	**$1.50**	**$252.39**	**$2,252.79**
65	% Change			**-5.56%**	**-5.56%**	**5.79%**	**28.73%**	**62.67%**	**26.06%**	**19.65%**	**12.35%**	**11.05%**	**5.67%**	**4.79%**	**3.15%**	**0.29%**	**6.74%**	**16.17%**
66																		
67	**Base Rate**			$1.16	$1.16	$1.89	$2.16	$2.01	$1.38	$9.74	$15.93	$9.20	$0.72	$1.13	$0.57	$0.70	$28.25	$37.99
68	% Change			0.23%	0.23%	0.24%	0.24%	0.24%	0.23%	0.23%	3.59%	3.05%	0.23%	0.24%	0.23%	0.23%	1.36%	0.61%
69																		
70	**COG & LDAC**			($75.00)	($75.00)	$133.02	$649.17	$1,023.63	$334.83	$1,990.66	$91.84	$45.90	$28.79	$45.81	$11.00	$0.80	$224.14	$2,214.79
71	% Change			-9.97%	-9.97%	9.64%	55.26%	164.04%	55.72%	37.67%	25.64%	27.58%	16.67%	11.05%	11.05%	0.46%	16.17%	33.20%
	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 2016 - 2017 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 15 - Apr 16 vs Nov 16 - Apr 17 - Commercial Rate G-52

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

PROPOSED			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)			1,129	1,453	1,821	1,383	1,955	1,367	9,108	1,263	1,003	799	788	758	847	5,458	14,566
Winter:	7/1/2016	5/1/2016															
Cust. Chg	$145.08	$144.73	$145.08	$145.08	$145.08	$145.08	$145.08	$145.08	$870.48								
Headblock	$0.2052	$0.2047	$205.20	$205.20	$205.20	$205.20	$205.20	$205.20	$1,231.20								
Tailblock	$0.1367	$0.1364	$17.69	$61.91	$112.22	$52.34	$130.50	$50.23	$424.88								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$145.08	$144.73								$144.73	$144.73	$145.08	$145.08	$145.08	$145.08	$869.78	$1,740.26
Headblock	$0.1487	$0.1484								$148.40	$148.40	$118.75	$117.10	$112.75	$125.97	$771.36	$2,002.56
Tailblock	$0.0845	$0.0843								$22.22	$0.27	$0.00	$0.00	$0.00	$0.00	$22.50	$447.38
HB Threshold	1,000	1,000															
Total Base Rate Amount			$367.97	$412.19	$462.50	$402.62	$480.78	$400.51	$2,526.56	$315.35	$293.40	$263.83	$262.18	$257.83	$271.05	$1,663.64	$4,190.21
COG Rate - (Seasonal)			$0.7210	$0.7210	$0.7210	$0.7210	$0.7210	$0.7210	$0.7210	$0.4415	$0.4698	$0.4698	$0.4498	$0.4498	$0.4498	$0.4545	$0.6211
COG amount			$814.30	$1,047.52	$1,312.88	$997.06	$1,409.29	$985.92	$6,566.97	$557.61	$471.33	$375.17	$354.22	$341.04	$381.04	$2,480.41	$9,047.38
LDAC			$0.0370	$0.0370	$0.0450	$0.0450	$0.0450	$0.0450	0.0427	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0524
LDAC amount			$41.79	$53.76	$81.94	$62.23	$87.96	$61.54	$389.22	$86.52	$68.72	$54.70	$53.94	$51.94	$58.03	$373.85	$763.07
Total Bill			**$1,224.06**	**$1,513.47**	**$1,857.32**	**$1,461.91**	**$1,978.03**	**$1,447.97**	**$9,482.75**	**$959.48**	**$833.46**	**$693.71**	**$670.35**	**$650.80**	**$710.11**	**$4,517.91**	**$14,000.66**

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

CURRENT			Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	Winter Nov-Apr	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			1,129	1,453	1,821	1,383	1,955	1,367	9,108	1,263	1,003	799	788	758	847	5,458	14,566
Winter:	5/1/2015	7/1/2015															
Cust. Chg	$140.13	$144.73	$144.73	$144.73	$144.73	$144.73	$144.73	$144.73	$868.38								
Headblock	$0.1929	$0.2047	$204.70	$204.70	$204.70	$204.70	$204.70	$204.70	$1,228.20								
Tailblock	$0.1309	$0.1364	$17.65	$61.77	$111.97	$52.22	$130.21	$50.12	$423.95								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$140.13	$144.73								$140.13	$140.13	$144.73	$144.73	$144.73	$144.73	$859.18	$1,727.56
Headblock	$0.1417	$0.1484								$141.70	$141.70	$118.51	$116.87	$112.52	$125.71	$757.01	$1,985.21
Tailblock	$0.0816	$0.0843								$21.46	$0.27	$0.00	$0.00	$0.00	$0.00	$21.73	$445.68
HB Threshold	1,000	1,000															
Total Base Rate Amount			$367.08	$411.20	$461.40	$401.65	$479.64	$399.55	$2,520.53	$303.29	$282.10	$263.24	$261.60	$257.25	$270.44	$1,637.91	$4,158.44
COG Rate - (Seasonal)			$0.7647	$0.7647	$0.6387	$0.4567	$0.2765	$0.4554	$0.5415	$0.2728	$0.2901	$0.3076	$0.3076	$0.3076	$0.3451	$0.3022	$0.4518
COG amount			$863.65	$1,111.01	$1,163.02	$631.56	$540.46	$622.73	$4,932.43	$344.54	$291.04	$245.64	$242.24	$233.22	$292.34	$1,649.04	$6,581.47
LDAC			$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	0.0685	$0.0628	$0.0628	$0.0793	$0.0793	$0.0793	$0.0793	$0.0724	$0.0700
LDAC amount			$77.36	$99.52	$124.73	$94.73	$133.89	$93.67	$623.91	$79.32	$63.00	$63.33	$62.45	$60.13	$67.18	$395.40	$1,019.31
Total Bill			**$1,308.10**	**$1,621.74**	**$1,749.15**	**$1,127.94**	**$1,153.99**	**$1,115.95**	**$8,076.87**	**$727.15**	**$636.14**	**$572.21**	**$566.28**	**$550.60**	**$629.96**	**$3,682.35**	**$11,759.22**

DIFFERENCE:

Total Bill			**($84.04)**	**($108.27)**	**$108.17**	**$333.97**	**$824.04**	**$332.02**	**$1,405.88**	**$232.33**	**$197.31**	**$121.49**	**$104.07**	**$100.21**	**$80.15**	**$835.56**	**$2,241.44**
% Change			**-6.42%**	**-6.68%**	**6.18%**	**29.61%**	**71.41%**	**29.75%**	**17.41%**	**31.95%**	**31.02%**	**21.23%**	**18.38%**	**18.20%**	**12.72%**	**22.69%**	**19.06%**
Base Rate			$0.89	$0.99	$1.10	$0.96	$1.14	$0.96	$6.03	$12.06	$11.31	$0.59	$0.59	$0.58	$0.60	$25.73	$31.76
% Change			0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	3.98%	4.01%	0.22%	0.22%	0.22%	0.22%	1.57%	0.76%
COG & LDAC			($84.93)	($109.26)	$107.07	$333.00	$822.90	$331.06	$1,399.85	$220.27	$186.00	$120.91	$103.48	$99.63	$79.54	$809.83	$2,209.68
% Change			-9.83%	-9.83%	9.21%	52.73%	152.26%	53.16%	28.38%	63.93%	63.91%	49.22%	42.72%	42.72%	27.21%	49.11%	33.57%
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 2016 - 2017 Winter Cost of Gas Filing
Residential Heating

	Winter 2015-16	Winter 2016-17
Customer Charge	$22.04	$22.10
First 100 Therms	$0.3486	$0.3495
Excess 100 Therms	$0.2885	$0.2892
LDAC	$0.1014	$0.0619
COG	$0.5141	$0.7068
Total Adjust	$0.6155	$0.7687

		Winter 2015-16 COG @	Winter 2016-17 COG @	Total		Base Rate		COG		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$0.6155	$0.7687	$0.15	25%						
Cooking alone	5	$26.86	$27.63	$0.77	3%	$0.00	0%	$0.96	3%	-$0.20	-1%
	10	$31.68	$33.21	$1.53	5%	$0.00	0%	$1.93	6%	-$0.40	-1%
	20	$41.32	$44.39	$3.06	7%	$0.00	0%	$3.85	9%	-$0.79	-2%
Water Heating alone	30	$50.96	$55.56	$4.59	9%	$0.00	0%	$5.78	10%	-$1.19	-2%
	45	$65.43	$72.32	$6.89	11%	$0.00	0%	$8.67	12%	-$1.78	-3%
	50	$70.25	$77.90	$7.66	11%	$0.00	0%	$9.63	12%	-$1.98	-3%
Heating Alone	80	$94.35	$105.84	$11.49	12%	$0.00	0%	$14.45	14%	-$2.96	-3%
	125	$148.29	$168.66	$20.37	14%	$0.00	0%	$25.62	15%	-$5.25	-4%
	150	$163.66	$186.63	$22.97	14%	$0.00	0%	$28.90	15%	-$5.93	-4%
	200	$208.86	$239.49	$30.63	15%	$0.00	0%	$38.53	16%	-$7.90	-4%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2016 - 2017 Winter Cost of Gas Filing
Variance Analysis of the Components of the Winter 2014-15 Actual Results vs Proposed Winter 2014-15 Cost of Gas Rate

	WINTER 2015-16 ACTUAL RESULTS (6 months actual)			**WINTER 2016-17 (6 months Proposed)**		
Therm Sales	67,964,080			89,920,078		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 9,401,686	$ 0.1383		$ 8,469,558	$ 0.0942
Purchased Gas		$ 29,925,538	0.4403	69,877,882	48,688,614	0.5415
Storage/Produced Gas		812,244	0.0120	23,709,964	5,823,500	0.0648
Hedging (Gain)/Loss		0	0.0000		0	0.0000
Total Volumes and Cost	70,583,150	$ 40,139,468	$ 0.5906	93,587,846	$ 62,981,672	$ 0.7004
Direct Costs						
Prior Period Balance		$ (549,989)	$ (0.0081)		2,690,610	$ 0.0299
Interest		126,749	0.0019		33,236	0.0004
Prior Period Adjustment		-	-		-	-
Broker Revenues		(991,052)	(0.0146)		(1,374,947)	(0.0153)
Refunds from Suppliers		(431,287)	(0.0063)		-	-
Fuel Financing		-	-		-	-
Transportation CGA Revenues		(33,912)	(0.0005)		(29,471)	(0.0003)
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		(1,849,179)	(0.0272)		(5,448,856)	(0.0606)
Hedging Costs		306,110	0.0045		-	-
FPO Admin Costs		9,528	0.0001		41,972	0.0005
Indirect Costs						
Misc Overhead		10,272	0.0002		10,589	0.0001
Occupant Disallowance/Credits		-	-		-	-
Production & Storage		1,980,428	0.0291		1,980,428	0.0220
Other Indirect Gas Costs		(125,396)	(0.0018)		2,670,647	0.0297
Cashout, Broker penalty, Canadian Managed,…		-	-		0	0
Total Adjusted Cost		$ 38,591,739	**$ 0.5678**		$ 63,555,880	**$ 0.7068**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2016 - 2017 Winter Cost of Gas Filing
Capacity Assignment Calculations 2015-2016
<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			535	527	0.3%		113	414
2	RATE R-3-Resi Htg			67,508	66,336	42.3%		4,182	62,154
3	RATE G-41 (T)			27,344	26,862	17.1%		1,311	25,551
4	RATE G-51 (S)			2,795	2,756	1.8%		658	2,097
5	RATE G-42 (V)			36,117	35,497	22.6%		2,653	32,845
6	RATE G-52			4,112	4,062	2.6%		1,433	2,629
7	RATE G-43			10,495	10,323	6.6%		1,156	9,166
8	RATE G-53			5,255	5,200	3.3%		2,320	2,880
9	RATE G-54			5,384	5,384	3.4%		5,384	-
10									
11	Total			159,544	156,947	100.0%		19,210	137,737
12									-
13	Residential Total			68,043	66,863	**42.602%**		4,295	62,568
14	LLF Total			73,956	72,682	**46.310%**		5,120	67,562
15	HLF Total			17,545	17,402	**11.088%**		9,795	7,607
16	Total			159,544	156,947	100.0%		19,210	137,737
17									
18	C&I Breakdown								
19	LLF Total							5,120	67,562
20	HLF Total							9,795	7,607
21	Total							14,915	75,169
22									
23	C&I Breakdown Percentage								
24	LLF Total							34.328%	89.881%
25	HLF Total							65.672%	10.119%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$13,614,436	79,718	$14.2319			
30	Storage			$4,054,486	28,115	$12.0176			
31									
32	Peaking			$1,375,000					
33	Peaking Additional Costs			$0					
34	Subtotal Peaking Costs			$1,375,000	49,114	$2.3330			
35	Total			$19,043,922	156,947	$10.1117			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			3,280,696	19,210	$14.2319			
39	Pipeline - Remaining			10,333,740	60,508	$14.2319			
40	Storage			4,054,486	28,115	$12.0176			
41	Peaking			1,375,000	49,114	$2.3330			
42	Total			19,043,922	156,947	$10.1117			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**42.602%**	1,397,642	8,184	$14.2319			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**42.602%**	4,402,391	25,778	$14.2319			
48	Storage	Line 40 * Line 13 Col C	**42.602%**	1,727,297	11,978	$12.0176			
49	Peaking	Line 41 * Line 13 Col C	**42.602%**	585,788	20,924	$2.3330			
50	Total		**42.602%**	8,113,184	66,863	$10.1117			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2016 - 2017 Winter Cost of Gas Filing
Capacity Assignment Calculations 2015-2016
Derivation of Class Assignments and Weightings

51							
52							**Ratios for COG**
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		1,883,054	11,026	$14.2319	
55	Pipeline - Remaining	Line 39 - Line 47		5,931,349	34,731	$14.2318	
56	Storage	Line 40 - Line 48		2,327,189	16,137	$12.0175	
57	Peaking	Line 41 - Line 49		789,212	28,190	$2.3330	
58	Total		**57.398%**	10,930,803	90,084	$10.1117	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		646,406	3,785	$14.2317	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		5,331,130	31,216	$14.2318	
64	Storage	Line 56 * Line 24 Col F		2,091,691	14,504	$12.0179	
65	Peaking	Line 57 * Line 24 Col F		709,348	25,337	$2.3330	
66	Total		**46.0965%**	8,778,575	74,842	$9.7746	**0.9667**
67			34.328%	80%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		1,236,648	7,241	$14.2320	
71	Pipeline - Remaining	Line 55 - Line 63		600,219	3,515	$14.2299	
72	Storage	Line 56 - Line 64		235,498	1,633	$12.0177	
73	Peaking	Line 57 - Line 65		79,864	2,853	$2.3327	
74	Total		**11.3014%**	2,152,229	15,242	$11.7670	**1.1637**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 14.2319	$ 14.2319	$ 14.2319	
80	Storage			$ 12.0176	$ 12.0176	$ 12.0176	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 10.1117	$ 9.7746	$ 11.7670	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			50.79%	**46.77%**	**70.57%**	
88	Storage			17.91%	**19.38%**	**10.71%**	
89	Peaking			31.29%	**33.85%**	**18.72%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			42.60%	43.91%	13.49%	100.00%
96	Storage			42.60%	51.59%	5.81%	100.00%
97	Peaking			42.60%	51.59%	5.81%	100.00%

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

Ln		d	e	f	g	h	i	
8	Data Source: Schedule 10B							Total
9		Nov	Dec	Jan	Feb	Mar	Apr	Sales
10								
11	G-41	1,182,681	2,076,272	2,833,652	3,132,273	2,619,842	1,717,413	13,562,134
12	G-42	1,158,334	2,007,033	2,694,459	2,814,245	2,343,733	1,662,403	12,680,207
13	G-43	292,288	408,803	594,036	677,602	592,583	484,867	3,050,179
14	High Winter Use	2,633,303	4,492,108	6,122,147	6,624,120	5,556,159	3,864,682	29,292,519
15								
16	G-51	181,300	237,351	290,632	303,571	280,033	216,865	1,509,752
17	G-52	180,848	226,248	277,604	294,560	277,520	220,752	1,477,531
18	G-53	310,728	494,059	1,221,012	1,008,283	914,775	819,021	4,767,878
19	G-54	87,595	91,233	96,493	101,807	102,951	94,473	574,551
21	Low Winter Use	760,471	1,048,890	1,885,740	1,708,221	1,575,279	1,351,112	8,329,713
22								
23	Gross Total	3,393,774	5,540,998	8,007,887	8,332,341	7,131,438	5,215,793	37,622,232

Ln			
26	Total Sales	37,622,232	
27	Low Winter Use	8,329,713	
28	Winter Ratio for Low Winter Use	**1.1637**	Schedule 10A p 2, ln 74
29	High Winter Use	29,292,519	
30	Winter Ratio for High Winter Use	**0.9667**	Schedule 10A p 2, ln 66

32 Correction Factor = Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use

33 Correction Factor = **98.9789%**

36 **Allocation Calculation for Miscellaneous Overhead**

38	Projected Winter Sales Volume	11/1/16 - 4/30/17	90,536,024	Sch.10B, ln 23
39	Projected Annual Sales Volume	11/1/16 - 10/31/17	112,608,831	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales		80.40%	

Line		Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Subtotal PK 16-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Subtotal OP 17	Total
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**															
2	**d/b/a Liberty Utilities**															
3	**Peak 2016 - 2017 Winter Cost of Gas Filing**															
4	**2016 - 2017 Winter Cost of Gas Filing**															
5																
6		**Dry Therms**														
7	**Firm Sales**															
8																
9	R-1	70,459	88,846	103,149	106,011	97,065	73,827	539,357	53,415	36,398	28,158	29,691	38,681	52,367	238,709	778,066
10	R-3	4,031,132	7,387,727	10,476,622	11,219,378	9,505,345	6,391,881	49,012,084	3,681,061	1,768,932	1,003,835	979,123	1,477,984	2,652,634	11,563,570	60,575,654
11	R-4	219,774	414,696	653,018	803,488	711,334	560,041	3,362,351	352,526	174,140	88,379	77,475	95,094	146,564	934,178	4,296,529
12	Total Residential.	4,321,365	7,891,268	11,232,789	12,128,877	10,313,744	7,025,749	52,913,792	4,087,002	1,979,470	1,120,372	1,086,288	1,611,759	2,851,565	12,736,457	65,650,248
13																
14	G-41	1,182,681	2,076,272	2,833,652	3,132,273	2,619,842	1,717,413	13,562,134	716,847	324,784	197,846	150,839	162,644	411,815	1,964,774	15,526,908
15	G-42	1,158,334	2,007,033	2,694,459	2,814,245	2,343,733	1,662,403	12,680,207	968,195	595,209	298,747	150,160	96,945	294,744	2,404,000	15,084,206
16	G-43	292,288	408,803	594,036	677,602	592,583	484,867	3,050,179	246,438	160,408	109,128	85,854	98,369	155,659	855,857	3,906,036
17	G-51	181,300	237,351	290,632	303,571	280,033	216,865	1,509,752	153,560	99,000	74,804	75,187	94,881	126,663	624,095	2,133,847
18	G-52	180,848	226,248	277,604	294,560	277,520	220,752	1,477,531	162,163	109,216	84,998	85,026	104,188	133,224	678,815	2,156,346
19	G-53	310,728	494,059	1,221,012	1,008,283	914,775	819,021	4,767,878	577,253	408,013	327,515	310,877	341,376	400,426	2,365,460	7,133,338
20	G-54	87,595	91,233	96,493	101,807	102,951	94,473	574,551	87,034	71,183	62,417	65,305	76,650	80,762	443,351	1,017,903
21	Total C/I	3,393,774	5,540,998	8,007,887	8,332,341	7,131,438	5,215,793	37,622,232	2,911,489	1,767,812	1,155,455	923,248	975,054	1,603,291	9,336,351	46,958,583
22																
23	**Sales Volume**	**7,715,139**	**13,432,266**	**19,240,676**	**20,461,218**	**17,445,182**	**12,241,542**	**90,536,024**	**6,998,491**	**3,747,283**	**2,275,828**	**2,009,537**	**2,586,813**	**4,454,856**	**22,072,807**	**112,608,831**
24																
25	Transportation Sales															
26																
27	G-41	552,973	786,788	1,066,119	1,150,430	954,542	749,125	5,259,977	429,916	229,720	129,993	133,351	181,628	315,177	1,419,785	6,679,762
28	G-42	1,815,257	2,629,105	3,606,269	3,908,155	3,239,795	2,539,566	17,738,147	1,423,880	728,455	369,012	343,352	472,634	924,582	4,261,915	22,000,062
29	G-43	834,384	1,224,810	1,575,340	1,740,346	1,607,545	1,273,791	8,256,216	872,826	537,779	355,445	305,090	346,787	523,955	2,941,882	11,198,099
30	G-51	140,704	155,399	182,693	212,005	201,812	194,177	1,086,790	165,595	143,064	136,675	163,925	188,666	170,935	968,859	2,055,649
31	G-52	491,914	519,764	571,141	614,471	596,043	550,670	3,344,002	493,435	452,960	460,516	563,273	662,650	620,779	3,253,613	6,597,615
32	G-53	511,053	669,423	863,104	973,343	968,363	886,780	4,872,066	733,736	525,181	360,375	294,550	280,236	348,520	2,542,597	7,414,663
33	G-54	1,704,041	1,711,976	1,770,549	1,505,866	1,449,738	1,387,328	9,529,499	1,353,780	1,374,214	1,358,987	1,485,751	1,566,278	1,686,025	8,825,035	18,354,534
34																
35	Total Trans. Sales	**6,050,326**	**7,697,264**	**9,635,215**	**10,104,616**	**9,017,838**	**7,581,437**	**50,086,696**	**5,473,168**	**3,991,372**	**3,171,004**	**3,289,291**	**3,698,879**	**4,589,974**	**24,213,686**	**74,300,383**
36																
37	Total All Sales	**13,765,466**	**21,129,531**	**28,875,891**	**30,565,834**	**26,463,020**	**19,822,979**	**140,622,721**	**12,471,659**	**7,738,654**	**5,446,831**	**5,298,828**	**6,285,692**	**9,044,830**	**46,286,493**	**186,909,214**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2016 - 2017 Winter Cost of Gas Filing
Normal and Design Year Volumes

Schedule 11A
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Volumes (Therms) **Normal Year**

For the Months of November 16 - April 17

	Nov-16	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**Peak Nov - Apr**
Pipeline Gas:							
Dawn Supply	811,417	892,975	911,022	812,922	892,971	830,794	5,152,101
Niagara Supply	633,581	697,096	711,185	634,369	697,094	648,712	4,022,037
TGP Supply (Gulf)	4,625,077	3,026,752	3,087,924	2,755,224	3,026,740	4,171,279	20,692,997
Dracut Supply 1 - Baseload	-	2,667,402	4,535,274	3,035,391	-	-	10,238,067
Dracut Supply 2 - Swing	3,138,155	4,749,329	1,824,248	4,342,598	6,448,837	3,301,715	23,804,882
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	2,705	2,881	1,126,288	538,561	156,990	-	1,827,424
Propane Truck	-	-	166,776	-	-	-	166,776
PNGTS	55,447	78,495	88,898	74,760	69,133	47,078	413,812
TGP Supply (Z4)	1,630,272	1,794,591	1,830,861	1,633,827	1,794,584	1,702,436	10,386,571
Subtotal Pipeline Volumes	10,896,654	13,909,519	14,282,476	13,827,652	13,086,350	10,702,015	76,704,666
Storage Gas:							
TGP Storage	2,930,568	3,407,706	7,034,707	5,400,122	2,916,559	-	21,689,663
Produced Gas:							
LNG Vapor	2,705	2,881	1,212,247	538,561	77,055	20,078	1,853,525
Propane	-	-	166,776	-	-	-	166,776
Subtotal Produced Gas	2,705	2,881	1,379,023	538,561	77,055	20,078	2,020,301
Less - Gas Refills:							
LNG Truck	(2,705)	(2,881)	(1,126,288)	(538,561)	(156,990)	-	(1,827,424)
Propane	-	-	(166,776)	-	-	-	(166,776)
TGP Storage Refill	(3,444,465)	-	-	-	-	(1,388,119)	(4,832,584)
Subtotal Refills	(3,447,170)	(2,881)	(1,293,064)	(538,561)	(156,990)	(1,388,119)	(6,826,784)
Total Sendout Volumes	10,382,757	17,317,226	21,403,143	19,227,774	15,922,974	9,333,973	93,587,846

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2016 - 2017 Winter Cost of Gas Filing
Normal and Design Year Volumes

Schedule 11B
Page 1 of 1

Volumes (Therms) **Design Year**

For the Months of November 16 - April 17

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	811,417	892,975	911,022	812,922	892,971	830,794	5,152,101
Niagara Supply	633,581	697,096	711,185	634,369	697,094	648,712	4,022,037
TGP Supply (Gulf)	4,625,077	3,026,752	3,087,924	2,755,224	3,026,740	4,098,585	20,620,302
Dracut Supply 1 - Baseload	-	2,667,402	4,535,274	3,035,391	-	-	10,238,067
Dracut Supply 2 - Swing	4,362,719	7,129,394	4,573,478	5,729,646	6,199,669	3,684,573	31,679,478
City Gate Delivered Supply	-	-	226,286	-	523,540	-	749,827
LNG Truck	2,705	106,581	387,919	633,643	681,971	-	1,812,819
Propane Truck	-	-	503,266	42,824	125,304	-	671,394
PNGTS	55,447	78,495	88,898	74,760	69,133	47,078	413,812
TGP Supply (Z4)	1,630,272	1,794,591	1,830,861	1,633,827	1,794,584	1,702,436	10,386,571
Subtotal Pipeline Volumes	12,121,218	16,393,285	16,856,114	15,352,605	14,011,007	11,012,178	85,746,407
Storage Gas:							
TGP Storage	2,943,415	3,058,438	7,061,891	5,237,538	3,733,196	156,466	22,190,944
Produced Gas:							
LNG Vapor	2,705	106,581	474,613	633,643	602,035	19,385	1,838,963
Propane	-	-	503,266	42,824	125,304	-	671,394
Subtotal Produced Gas	2,705	106,581	977,879	676,467	727,339	19,385	2,510,357
Less - Gas Refills:							
LNG Truck	(2,705)	(106,581)	(387,919)	(633,643)	(681,971)	-	(1,812,819)
Propane	-	-	(503,266)	(42,824)	(125,304)	-	(671,394)
TGP Storage Refill	(3,444,465)	-	-	-	-	(1,388,119)	(4,832,584)
Subtotal Refills	(3,447,170)	(106,581)	(891,185)	(676,467)	(807,275)	(1,388,119)	(7,316,797)
Total Sendout Volumes	11,620,168	19,451,723	24,004,699	20,590,143	17,664,268	9,799,911	103,130,911

Liberty Utilities (EnergyNorth Natural Gas) Corp. **Schedule 11C**

d/b/a Liberty Utilities **Page 1 of 1**

Peak 2016 - 2017 Winter Cost of Gas Filing

Capacity Utilization

Volumes (Therms)

	Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
Pipeline Gas:								
Dawn Supply	5,152,101	4,000	7,240,000	71%	5,152,101	4,000	7,240,000	71%
Niagara Supply	4,022,037	3,122	5,650,820	71%	4,022,037	3,122	5,650,820	71%
TGP Supply (Gulf + Z4)	31,079,567	21,596	39,088,760	80%	31,006,873	21,596	39,088,760	79%
Dracut Supply 1 & 2	34,042,949	50,000	90,500,000	38%	41,917,545	50,000	90,500,000	46%
LNG Truck	1,827,424	-	-	-	1,812,819	-	-	-
Propane Truck	166,776	-	-	-	671,394	-	-	-
PNGTS	413,812	1,000	1,810,000	23%	413,812	1,000	1,810,000	23%
Citygate Delivered Supply	-	-	-	-	749,827	-	-	-
Subtotal Pipeline Volumes	76,704,666				85,746,407			
Storage Gas:								
TGP Storage	21,689,663		25,791,710	84%	22,190,944		25,791,710	86%
Produced Gas:								
LNG Vapor	1,853,525				1,838,963			
Propane	166,775.8				671,394			
Subtotal Produced Gas	2,020,301				2,510,357			
Less - Gas Refills:								
LNG Truck	(1,827,424)				(1,812,819)			
Propane	(166,776)				(671,394)			
TGP Storage Refill	(4,832,584)				(4,832,584)			
Subtotal Refills	(6,826,784)				(7,316,797)			
Total Sendout Volumes	93,587,846				103,130,911			

Forecast of Upcoming Winter Period
Design Day Report
2016 / 17 Heating Season
(Therms)

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

Requirements	
Firm Sales	1,115,143
Interruptible Sales	0
Firm Transportation	454,327
Interruptible Transportation	0
Total Requirements	1,569,470
Resources	
Purchased Pipeline Gas	797,180
Underground Storage Gas	281,150
Propane Air Production	346,000
LNG Produced Gas	126,000
Third-Party Supply	19,140
Total Resources	1,569,470

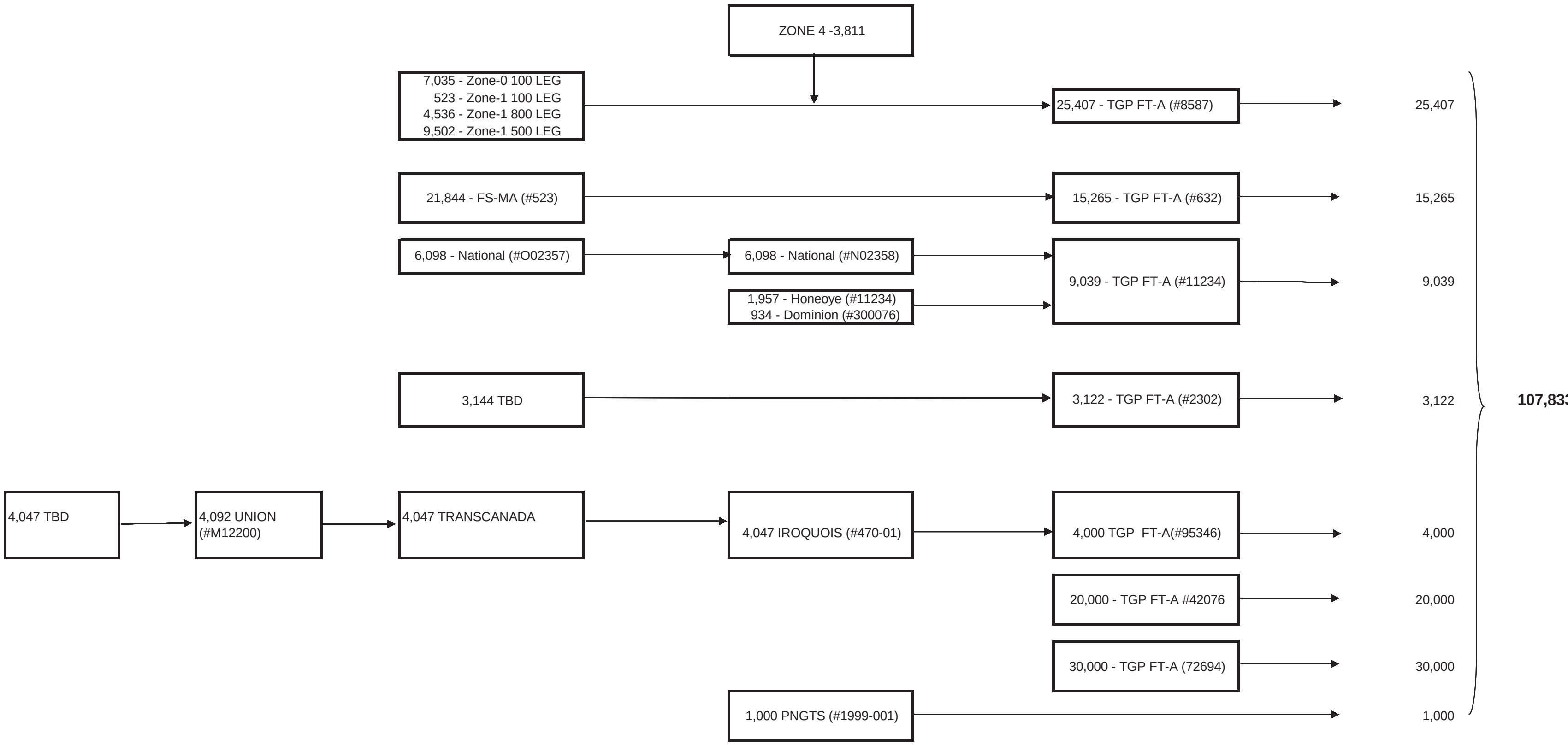
Please refer to the ENGI 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

F. Chico DaFonte
Vice President, Energy Procurement

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

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2016 - 2017 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2016 - 2017 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Niagara	NA	NA	Supply	3,144	1,147,560	3/31/2017	N/a	Terminates
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/a	Terminates
GDF Suez	FLS		Liquid Refill	Up to 5 trucks	250,000	3/31/2017 Peak Only	-	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,427,000	2/29/2017	-	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2017	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	3/31/2018	3/31/2017	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2018	3/31/2017	Evergreen Provision
Iroquois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11/1/2017	11/1/2016	Evergreen Provision
Portland Natural Gas Transmission System	FT 1999-01	1999-001	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2021	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	29600	Transportation	4,047	1,477,155	10/31/2022	10/31/2021	Evergreen Provision
Union Gas Limited	M12	M12100	Transportation	4,092	1,493,580	10/31/2018	10/31/2016	Evergreen Provision

* MAQ is calculated on a 365 day calendar year.

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2016 - 2017 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	15,097,695	40.08%	71.84%
G-42	14,157,418	37.59%	42.38%
G-43	1,754,809	4.66%	15.99%
G-51	2,451,345	6.51%	64.77%
G-52	2,129,403	5.65%	29.38%
G-53	590,479	1.57%	5.77%
G-54	1,483,102	3.94%	8.38%
Total C/I	37,664,251	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	5,916,625	8.87%	28.16%
G-42	19,251,327	28.86%	57.62%
G-43	9,219,065	13.82%	84.01%
G-51	1,333,349	2.00%	35.23%
G-52	5,118,701	7.67%	70.62%
G-53	9,644,965	14.46%	94.23%
G-54	16,224,874	24.32%	91.62%
Total C/I	66,708,907	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	21,014,321	20.13%	100.00%
G-42	33,408,745	32.01%	100.00%
G-43	10,973,874	10.51%	100.00%
G-51	3,784,694	3.63%	100.00%
G-52	7,248,104	6.94%	100.00%
G-53	10,235,444	9.81%	100.00%
G-54	17,707,976	16.97%	100.00%
Total C/I	104,373,158	100.00%	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2016 - 2017 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)	
Pipeline Deliveries	17,644,890	55,877,720	73,522,610	
All Others	-	1,480,580	1,480,580	
	17,644,890	57,358,300	75,003,190	
				Ratio
Total Winter Supplies				57,358,300
Total Pipeline Deliveries				73,522,610
Ratio Winter Supplies to Pipeline Supplies				0.780

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2016 - 2017 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-15**	**Aug-15**	**Jul - Aug Total**	**Total Annual**	**% of Jul-Aug to Total**
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	367,323	187,260	554,583	15,097,695	3.67%
G-42	440,249	1,060,758	1,501,007	14,157,418	10.60%
G-43	24,873	123,494	148,367	1,754,809	8.45%
G-51	135,700	125,713	261,413	2,451,345	10.66%
G-52	130,410	115,056	245,465	2,129,403	11.53%
G-53	29,597	16,293	45,890	590,479	7.77%
G-54	94,901	84,212	179,113	1,483,102	12.08%
Total C/I	1,223,054	1,712,786	2,935,840	37,664,251	7.79%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **Peak 2016 - 2017 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	Description	Reference	May-16 (Actual)	Jun-16 (Actual)	Jul-16 (Actual)	Aug-16 (Estimate)	Sep-16 (Estimate)	Oct-16 (Estimate)	Nov-16 (Estimate)	Dec-16 (Estimate)	Jan-17 (Estimate)	Feb-17 (Estimate)	Mar-17 (Estimate)	Apr-17 (Estimate)	Total
9	Beginning Balance (MMBtu)		901,504	1,070,851	1,267,731	1,460,893	1,632,861	1,804,828	1,976,796	2,028,186	1,687,415	983,944	443,932	152,276	901,504
11	Injections (MMBtu)	Sch 11A ln 37 /10	200,310	196,880	194,675	171,968	171,968	171,968	344,447	-	-	-	-	138,812	1,591,026
13	Subtotal		1,101,814	1,267,731	1,462,406	1,632,861	1,804,828	1,976,796	2,321,243	2,028,186	1,687,415	983,944	443,932	291,088	
15	Storage Sale		-					-							
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(30,963)	-	(1,513)	-	-	-	(293,057)	(340,771)	(703,471)	(540,012)	(291,656)	-	(2,201,442)
19	Ending Balance (MMBtu)		1,070,851	1,267,731	1,460,893	1,632,861	1,804,828	1,976,796	2,028,186	1,687,415	983,944	443,932	152,276	291,088	291,088
22	Beginning Balance		$ 1,664,768	$ 1,886,615	$ 2,182,725	$ 2,598,555	$ 2,942,491	$ 3,269,229	$ 3,578,771	$ 3,764,686	$ 3,132,153	$ 1,826,382	$ 824,020	$ 282,653	1,664,768
24	Injections	ln 11 * ln 36	$ 276,665	$ 296,110	$ 418,549	$ 343,935	$ 326,739	$ 309,542	$ 729,882	$ -	$ -	$ -	$ -	$ 341,338	$ 3,042,760
26	Subtotal		$ 1,941,434	$ 2,182,725	$ 2,601,274	$ 2,942,491	$ 3,269,229	$ 3,578,771	$ 4,308,653	$ 3,764,686	$ 3,132,153	$ 1,826,382	$ 824,020	$ 623,991	
28	Storage Sale		$ -					$ -							
30	Withdrawals	ln 17 * ln 34	$ (54,819)	$ -	$ (2,718)	$ -	$ -	$ -	$ (543,967)	$ (632,533)	$ (1,305,771)	$ (1,002,362)	$ (541,367)	$ -	(4,083,537)
32	Ending Balance		$ 1,886,615	$ 2,182,725	$ 2,598,555	$ 2,942,491	$ 3,269,229	$ 3,578,771	$ 3,764,686	$ 3,132,153	$ 1,826,382	$ 824,020	$ 282,653	$ 623,991	$ 623,991
34	Average Rate For Withdrawals	ln 22 /ln 9	$1.7620	$1.7218	$1.7788	$1.8020	$1.8114	$1.8104	$1.8562	$1.8562	$1.8562	$1.8562	$1.8562	$2.1437	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$1.3812	$1.5040	$2.1500	$2.0000	$1.9000	$1.8000	$2.1190	$2.4700	$2.7020	$2.7220	$2.6540	$2.4590	

Ln	Description	Reference	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
38	For Informational Purposes					Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
39	Summer Hedge Contracts - Vols Dth					-	-	-	-	-	-	-
40	Average Hedge Price					$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
41	NYMEX					$2.9163	$3.0743	$3.1769	$3.1714	$3.1281	$2.9695	
43	Hedged Volumes at Hedged Price					$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX					-	-	-	-	-	-	-
45	Hedge (Savings)/Loss					$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	Month Dollar Average	ln (22 + ln 32) /2	$ 2,770,523	$ 3,105,860	$ 3,424,000	$ 3,671,728	$ 3,448,419	$ 2,479,267	$ 1,325,201	$ 553,336	$ 453,322	
49	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
51	Inventory Finance Charge	ln 47 * ln 49	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
52	Financial Expenses		0	0	0	0	0	0	0	0	0	
53	Total Inventory Finance Charges		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

54
55
38

Ln			May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
40	**Liquid Propane Gas (LPG)**														
42			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
43	Beginning Balance		55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656
45	Injections	Sch 11A ln 36 /10	-	-	-	-	-	-	-	-	16,678	-	-	-	16,678
47	Subtotal		55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	72,334	55,656	55,656	55,656	
49	Withdrawals	Sch 11A ln 31 /10	-	-	-	-	-	-	-	-	(16,678)	-	-	-	(16,678)
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656	55,656
56	Beginning Balance		$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 531,615	$ 531,615	$ 531,615	$ 690,916
58	Injections	ln 45 * ln 68	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Subtotal		$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 531,615	$ 531,615	$ 531,615	
62	Withdrawals	ln 51 * ln 66	-	-	-	-	-	-	-	-	(159,301)	-	-	-	(159,301)
64	Ending Balance		$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 531,615	$ 531,615	$ 531,615	$ 531,615	$ 531,615
66	Average Rate For Withdrawals		$12.4140	$12.4140	$12.4140	$12.4140	$12.4140	$12.4140	$12.4140	$12.4140	$9.5518	$9.5518	$9.5518	$9.5518	
68	Propane Rate for Injections	Actual or Sch. 6, ln 151 * 10	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
71	Month Dollar Average	ln (56 + ln 64) /2				$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 690,916	$ 611,265	$ 531,615	$ 531,615	$ 531,615	
73	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	

Line			May-16 (Actual)	Jun-16 (Actual)	Jul-16 (Actual)	Aug-16 (Estimate)	Sep-16 (Estimate)	Oct-16 (Estimate)	Nov-16 (Estimate)	Dec-16 (Estimate)	Jan-17 (Estimate)	Feb-17 (Estimate)	Mar-17 (Estimate)	Apr-17 (Estimate)	Total
71															
72	**Liquid Natural Gas (LNG)**														
73															
74	Beginning Balance		9,724	7,592	9,367	7,270	9,045	10,820	12,595	12,595	12,595	3,999	3,999	11,993	9,724
75															
76	Injections	Sch 11A ln 35 /10	-	3,632	-	3,632	3,632	3,632	270	288	112,629	53,856	15,699	-	197,270
77															
78	Subtotal		9,724	11,224	9,367	10,902	12,677	14,452	12,865	12,883	125,224	57,855	19,698	11,993	
79															
80	Withdrawals	Sch 11A ln 30 /10	(2,132)	(1,857)	(2,097)	(1,857)	(1,857)	(1,857)	(270)	(288)	(121,225)	(53,856)	(7,705)	(2,008)	(197,010)
81															
82	Ending Balance		7,592	9,367	7,270	9,045	10,820	12,595	12,595	12,595	3,999	3,999	11,993	9,985	9,985
83															
84															
85	Beginning Balance		$ 61,360	$ 47,908	$ 59,747	$ 45,402	$ 56,889	$ 68,329	$ 79,739	$ 80,140	$ 80,645	$ 32,461	$ 33,132	$ 98,948	$ 61,360
86															
87	Injections	ln 76 * ln 97	-	24,543	-	23,167	23,167	23,167	2,122	2,350	935,810	446,860	129,393	-	1,610,577
88															
89	Subtotal		$ 61,360	$ 72,451	$ 59,747	$ 68,569	$ 80,056	$ 91,495	$ 81,861	$ 82,489	$ 1,016,455	$ 479,321	$ 162,524	$ 98,948	
90															
91	Withdrawals	ln 80 * ln 95	(13,452)	(12,704)	(14,345)	(11,680)	(11,727)	(11,757)	(1,721)	(1,844)	(983,994)	(446,189)	(63,576)	(16,566)	(1,589,555)
92															
93	Ending Balance		$ 47,908	$ 59,747	$ 45,402	$ 56,889	$ 68,329	$ 79,739	$ 80,140	$ 80,645	$ 32,461	$ 33,132	$ 98,948	$ 82,383	$ 82,383
94															
95	Average Rate For Withdrawals		$6.3102	$6.4550	$6.3785	$6.2896	$6.3150	$6.3310	$6.3628	$6.4029	$8.1171	$8.2848	$8.2508	$8.2508	
96															
97	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	$6.3102	$6.7575	$6.3785	$6.3785	$6.3785	$6.3785	$7.8454	$8.1570	$8.3088	$8.2973	$8.2421	$7.9604	
98															
99															
100	Month Dollar Average	ln (85 + ln 93) /2				$ 51,146	$ 62,609	$ 74,034	$ 79,939	$ 80,392	$ 56,553	$ 32,796	$ 66,040	$ 90,666	
101															
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%	
103															
104	Inventory Finance Charge	ln 100 * ln 102				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
105															
106															
107	Total Fuel Financing	lns 53 + 75 + 104				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2016 - 2017 Winter Cost of Gas Filing
Peak 2016 - 2017 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-16	6,050,326	$0.0006	$ 3,560
Dec-16	7,697,264	0.0006	4,529
Jan-17	9,635,215	0.0006	5,669
Feb-17	10,104,616	0.0006	5,945
Mar-17	9,017,838	0.0006	5,306
Apr-17	7,581,437	0.0006	4,461
Total	**50,086,696**		**$ 29,471**

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

1	August 1, 2016 Balance of Acct. 8840-2-0000-10-1930-1745	$46,132
2	Estimated August 2016 - October 2016 Recovery	($292,028)
3	Estimated August 2016 - October 2016 Interest	($761)
4		
5	Estimated Balance November 1, 2016	($246,658)
6	Estimated November 2016 - December 2016 Interest	($791)
7		
8	Estimated Remaining Recovery	($247,449)
9		
10	Estimated November 2016 - December 2016 Sales (therms)	34,894,997
11		
12	RCE rate per therm November 2016 - December 2016	($0.0071)

Liberty Utilities (EnergyNorth Natural Gas) Corp.

AUGUST 2016 THROUGH DECEMBER 2016
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Total**
2	**DAYS IN MONTH**	**31**	**30**	**31**	**30**	**31**	
3	Beginning Balance	$ 46,132	$ (35,844)	$ (122,961)	$ (246,658)	$ (149,613)	$ 3,272,868
4							
5	Add: Actual Costs	-	-	-	-	-	-
6							
7	Less: Collected Revenue	(81,991)	(86,888)	(123,149)	97,614	149,835	(2,676,495)
8							
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-
10							
11	Ending Balance Pre-Interest	$ (35,860)	$ (122,733)	$ (246,109)	$ (149,044)	$ 222	**$ 596,372**
12							
13	Month's Average Balance	$ 5,136	$ (79,289)	$ (184,535)	$ (197,851)	$ (74,695)	
14							
15	Interest Rate	3.50%	3.50%	3.50%	3.50%	3.50%	
16							
17	Interest Applied	$ 15	$ (228)	$ (549)	$ (569)	$ (222)	**73,956**
18							
19	Ending Balance	**$ (35,844)**	**$ (122,961)**	**$ (246,658)**	**$ (149,613)**	**$ (0)**	

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

	Residential	
1	October 31, 2016 Balance	$0
2	Calculated Lost Distribution Revenue - January 2017 through October 2017	$83,023
3	Calculated Interest - January 2017 through October 2017	$1,339
4		
5	Total to be recovered	$84,362
6		
7	Estimated January 2017 - October 2017 Sales (therms)	53,437,615
8		
9	LRAM residential rate per therm January 2017 - October 2017	$0.0016
	Commercial & Industrial	
10	October 31, 2016 Balance	$0
11	Calculated Lost Distribution Revenue - January 2017 through October 2017	$87,511
12	Calculated Interest - January 2017 through October 2017	$1,411
13		
14	Total to be recovered	$88,921
15		
16	Estimated January 2017 - October 2017 Sales (therms)	98,576,602
17		
18	LRAM C&I rate per therm January 2017 - October 2017	$0.0009

Liberty Utilities (EnergyNorth Natural Gas) Corp.

JANUARY 2017 THROUGH OCTOBER 2017
LOST REVENUE ADJUSTMENT MECHANISM

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**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**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
	RESIDENTIAL											
3	Beginning Balance	$ -	$ 10,350	$ 19,864	$ 28,549	$ 38,980	$ 48,297	$ 56,485	$ 64,588	$ 71,393	$ 76,888	**$ 415,395**
4												
5	Add: Lost Distribution Revenues	10,335	9,474	8,612	10,335	9,187	8,038	7,923	6,603	5,282	7,234	**83,023**
6												
7	Less: Lost Distribution Revenue Collections	-	-	-	-	-	-	-	-	-	-	-
8												
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-
10												
11	Ending Balance Pre-Interest	$ 10,335	$ 19,824	$ 28,477	$ 38,883	$ 48,167	$ 56,335	$ 64,409	$ 71,191	$ 76,675	$ 84,123	**$ 498,418**
12												
13	Month's Average Balance	$ 5,167	$ 15,087	$ 24,171	$ 33,716	$ 43,574	$ 52,316	$ 60,447	$ 67,890	$ 74,034	$ 80,505	
14												
15	Interest Rate	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
16												
17	Interest Applied	$ 15	$ 41	$ 72	$ 97	$ 130	$ 150	$ 180	$ 202	$ 213	$ 239	**1,339**
18												
19	Ending Balance	**$ 10,350**	**$ 19,864**	**$ 28,549**	**$ 38,980**	**$ 48,297**	**$ 56,485**	**$ 64,588**	**$ 71,393**	**$ 76,888**	**$ 84,362**	
	COMMERCIAL & INDUSTRIAL											
3	Beginning Balance	$ -	$ 10,910	$ 20,938	$ 30,092	$ 41,087	$ 50,907	$ 59,538	$ 68,079	$ 75,252	$ 81,044	**$ 437,846**
4												
5	Add: Lost Distribution Revenues	10,893	9,986	9,078	10,893	9,683	8,473	8,352	6,960	5,568	7,625	**87,511**
6												
7	Less: Lost Distribution Revenue Collections	-	-	-	-	-	-	-	-	-	-	-
8												
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-
10												
11	Ending Balance Pre-Interest	$ 10,893	$ 20,895	$ 30,016	$ 40,985	$ 50,770	$ 59,380	$ 67,890	$ 75,039	$ 80,819	$ 88,669	**$ 525,357**
12												
13	Month's Average Balance	$ 5,447	$ 15,902	$ 25,477	$ 35,538	$ 45,929	$ 55,143	$ 63,714	$ 71,559	$ 78,035	$ 84,857	
14												
15	Interest Rate	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
16												
17	Interest Applied	$ 16	$ 43	$ 76	$ 102	$ 137	$ 159	$ 189	$ 213	$ 224	$ 252	**1,411**
18												
19	Ending Balance	**$ 10,910**	**$ 20,938**	**$ 30,092**	**$ 41,087**	**$ 50,907**	**$ 59,538**	**$ 68,079**	**$ 75,252**	**$ 81,044**	**$ 88,921**	

2017 Therm Savings	Residential (29%)	C&I (71%)
1,234,839	358,103	876,736

Savings Achieved by Quarter	Residential	C&I
Q1 - 15%	53,715	131,510
Q2 - 20%	71,621	175,347
Q3 - 23%	82,364	201,649
Q4 - 42%	150,403	368,229

Average Distribution Rate ($ per therm)	Residential	C&I
	0.5772	0.2485

Months In Service	12	11	10	9	8	7	6	5	4	3
Residential (therms)	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
Incremental Annual Savings	17,905	17,905	17,905	23,874	23,874	23,874	27,455	27,455	27,455	50,134
Incremental Monthly Savings	17,905	16,413	14,921	17,905	15,916	13,926	13,727	11,439	9,152	12,534
C&I (therms)	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
Incremental Annual Savings	43,837	43,837	43,837	58,449	58,449	58,449	67,216	67,216	67,216	122,743
Incremental Monthly Savings	43,837	40,184	36,531	43,837	38,966	34,095	33,608	28,007	22,405	30,686

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 22.1000	$ 0.3495	$ 0.2892		
3	R-4 Rate at 40% of R-3	$ 8.8400	$ 0.1398	$ 0.1156		
4	Program Subsidy	$ 13.2600	$ 0.2097	$ 0.1736		
5	Average Annual Therms		504	125	630	
6						
7	Peak Period RLIAP Subsidy	$ 79.56	$ 105.76	$ 21.73	$ 207.05	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 22.1000	$ 0.3495	$ 0.2892		
11	R-4 Rate at 40% of R-3	$ 8.8400	$ 0.1398	$ 0.1156		
12	Program Subsidy	$ 13.2600	$ 0.2097	$ 0.1736		
13	Average Annual Therms		100	52	153	
14						
15	Off Peak Period RLIAP Subsidy	$ 79.56	$ 21.04	$ 9.06	$ 109.66	
16						
17	Estimated Annual Subsidy	$ 159.12	$ 126.81	$ 30.79	$ 316.72	
18						
19	Number of Estimated 2016/17 Participants				5,003	1/
20						
21	Annual Subsidy times Number of Participants (Ln 17 * Ln 19)				$ 1,584,540	
22	Prior Year Ending Balance - RLIAP Page 2				(331,025)	
23	Estimated Annual Administrative Costs				-	
24	Total Program Costs				$ 1,253,515	
25						
26	Estimated weather normalized firm therms billed for the					
27	twelve months ended 10/31/17 sales and transportation				186,909,214	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0067**	

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.

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

		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ 159,628	$ 150,585	$ 74,104	$ (31,216)	$ (163,233)	$ (271,264)	$ (320,913)	$ (323,472)	$ (328,751)	$ (328,131)	$ (321,739)	$ (320,755)	$ 159,628
4														
5	Add: Actual Costs	99,553	151,389	187,517	215,040	201,900	189,338	167,842	92,853	84,146	78,526	78,750	87,578	1,634,431
6														
7	Less: Collected Revenue	(109,009)	(228,179)	(292,902)	(346,788)	(309,288)	(238,139)	(169,447)	(97,197)	(82,553)	(71,170)	(76,843)	(96,880)	(2,118,396)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ 150,171	$ 73,795	$ (31,280)	$ (162,964)	$ (270,621)	$ (320,065)	$ (322,518)	$ (327,817)	$ (327,159)	$ (320,775)	$ (319,833)	$ (330,058)	**$ (324,337)**
12														
13	Month's Average Balance	$ 154,900	$ 112,190	$ 21,412	$ (97,090)	$ (216,927)	$ (295,665)	$ (321,716)	$ (325,644)	$ (327,955)	$ (324,453)	$ (320,786)	$ (325,407)	
14														
15	Interest Rate	3.25%	3.25%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
16														
17	Interest Applied	$ 414	$ 310	$ 64	$ (269)	$ (643)	$ (848)	$ (954)	$ (934)	$ (972)	$ (964)	$ (923)	$ (967)	**(6,688)**
18														
19	Ending Balance	**$ 150,585**	**$ 74,104**	**$ (31,216)**	**$ (163,233)**	**$ (271,264)**	**$ (320,913)**	**$ (323,472)**	**$ (328,751)**	**$ (328,131)**	**$ (321,739)**	**$ (320,755)**	**$ (331,025)**	**$ (331,025)**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential Non-Heating and Heating Classes
November 1, 2016 - October 31, 2017
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 16	Actual	(788,573)	($0.0585)	(232,212)	243,235	302,108	87,050	69,881	(561,746)	(675,159)	3.50%	(2,007)	(563,753)	3,349,634	3,970,573	31
June 16	Actual	(563,753)	($0.0585)	(111,791)	243,235	134,280	4,167	14,589	(522,508)	(543,130)	3.50%	(1,562)	(524,070)	1,984,898	1,908,251	30
July 16	Forecast	(524,070)	($0.0585)	(73,281)	243,235	0	0		(354,115)	(439,093)	3.50%	(1,305)	(355,421)	1,252,661	0	31
August 16	Forecast	(355,421)	($0.0585)	(61,815)	243,235	0	0		(174,001)	(264,711)	3.50%	(787)	(174,788)	1,056,675	0	31
September 16	Forecast	(174,788)	($0.0585)	(66,872)	243,235	0	0		1,575	(86,606)	3.50%	(249)	1,326	1,143,113	0	30
October 16	Forecast	1,326	($0.0585)	(99,072)	243,235	0	0		145,489	73,407	3.50%	218	145,707	1,693,533	0	31
November 16	Forecast	145,707	($0.0402)	(173,719)	243,235	0	0		215,223	180,465	3.50%	519	215,743	4,321,365	0	30
December 16	Forecast	215,743	($0.0402)	(317,229)	243,235	0	0		141,749	178,746	3.50%	531	142,280	7,891,268	0	31
January 17	Forecast	142,280	($0.0402)	(451,558)	201,740	0	0		(107,538)	17,371	3.50%	52	(107,486)	11,232,789	0	31
February 17	Forecast	(107,486)	($0.0402)	(487,581)	201,740	0	0		(393,326)	(250,406)	3.50%	(672)	(393,999)	12,128,877	0	28
March 17	Forecast	(393,999)	($0.0402)	(414,612)	201,740	0	0		(606,871)	(500,435)	3.50%	(1,488)	(608,358)	10,313,744	0	31
April 17	Forecast	(608,358)	($0.0402)	(282,435)	201,740	0	0		(689,053)	(648,706)	3.50%	(1,866)	(690,919)	7,025,749	0	30
May 17	Forecast	(690,919)	($0.0402)	(164,297)	201,740	0	0		(653,476)	(672,198)	3.50%	(1,998)	(655,474)	4,087,002	0	31
June 17	Forecast	(655,474)	($0.0402)	(79,575)	201,740	0	0		(533,309)	(594,392)	3.50%	(1,710)	(535,019)	1,979,470	0	30
July 17	Forecast	(535,019)	($0.0402)	(45,039)	201,740	0	0		(378,317)	(456,668)	3.50%	(1,357)	(379,675)	1,120,372	0	31
August 17	Forecast	(379,675)	($0.0402)	(43,669)	201,740	0	0		(221,603)	(300,639)	3.50%	(894)	(222,497)	1,086,288	0	31
September 17	Forecast	(222,497)	($0.0402)	(64,793)	201,740	0	0		(85,549)	(154,023)	3.50%	(443)	(85,992)	1,611,759	0	30
October 17	Forecast	(85,992)	($0.0402)	(114,633)	201,740	0	0		1,116	(42,438)	3.50%	(126)	989	2,851,565	0	31
November 17	Forecast	989	($0.0402)	(173,719)	201,740	0	0		29,011	15,000	3.50%	43	29,054	4,321,365	0	30
December 17	Forecast	29,054	($0.0402)	(317,229)	201,740	0	0		(86,434)	(28,690)	3.50%	(85)	(86,520)	7,891,268	0	31

Estimated Residential Conservation Charge **Effective November 1, 2016 - October 31, 2017**		
Beginning Balance	$	145,707
Program Budget Nov 16-Oct 17		**2,503,875**
Projected Interest		(10,441)
Projected Budget with Interest	$	2,639,140
Total Charges	**$**	**2,639,140**
Projected Therm Sales		**65,650,248**
Residential Rate		**$0.0402**
Total Charges with Interest	**$**	**2,639,140**
Projected Therm Sales		**65,650,248**
Residential Rate		**$0.0402**

Residential Non Heating Therm Sales	0%	774,552	778,066	0%
Residential Heating Therm Sales	34%	62,664,604	64,872,183	35%
C&I Therm Sales	66%	120,954,108	121,258,966	65%
Total Therms	100%	**184,393,264**	**186,909,214**	100%

	Budget **2016**	Budget **2017**
Low-Income Program Budget	$ 895,000	$ 1,005,700
Other Refund	-	-
Total Shared Budget	**$ 895,000**	**$ 1,005,700**
Residential Program Budget	$ 2,023,815	$ 1,907,420
Residential Program Incentive @ 70%	$163,454	$160,222
Total Residential Program Budget	**$ 2,187,269**	**$ 2,067,642**
Commercial/Industrial Program Budget	$ 2,703,000	$ 3,000,600
Commercial/Industrial Program Incentive at 70%	$143,772	$165,033
Total Commercial/Industrial Program Budget	**$ 2,846,772**	**$ 3,165,633**
Total Program Budget	**$ 5,929,040**	**$ 6,238,975**
Shared Expenses Allocation to Residential	$ 314,361	$ 353,243
Shared Expenses Allocation to C&I	580,639	652,457
Total Allocated Shared Expenses	**$ 895,000**	**$ 1,005,700**
Total Residential (including allocation of Shared Budget)	$ 2,501,630	$ 2,420,885
Total C&I (including allocation of Shared Budget)	3,427,411	3,818,090
Total Budget	**$ 5,929,040**	**$ 6,238,975**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2016 - October 31, 2017
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 16	Actual	(1,778,733)	($0.0256)	(197,579)	225,250	243,803	115,391	64,764	(1,552,354)	(1,665,544)	3.50%	(4,951)	(1,557,305)	6,537,363	7,720,335	31
June 16	Actual	(1,557,305)	($0.0256)	(122,794)	225,250	264,637	5,524	13,520	(1,396,418)	(1,476,862)	3.50%	(4,249)	(1,400,667)	5,092,563	4,791,008	30
July 16	Forecast	(1,400,667)	($0.0256)	(102,624)	225,250	0	0		(1,278,041)	(1,339,354)	3.50%	(3,981)	(1,282,022)	4,008,754	0	31
August 16	Forecast	(1,282,022)	($0.0256)	(98,600)	225,250	0	0		(1,155,373)	(1,218,698)	3.50%	(3,623)	(1,158,995)	3,851,567	0	31
September 16	Forecast	(1,158,995)	($0.0256)	(106,404)	225,250	0	0		(1,040,149)	(1,099,572)	3.50%	(3,163)	(1,043,313)	4,156,413	0	30
October 16	Forecast	(1,043,313)	($0.0256)	(127,689)	225,250	0	0		(945,752)	(994,532)	3.50%	(2,956)	(948,708)	4,987,864	0	31
November 16	Forecast	(948,708)	($0.0229)	(216,270)	225,250	0	0		(939,728)	(944,218)	3.50%	(2,716)	(942,444)	9,444,101	0	30
December 16	Forecast	(942,444)	($0.0219)	(289,918)	225,250	0	0		(1,007,112)	(974,778)	3.50%	(2,898)	(1,010,010)	13,238,262	0	31
January 17	Forecast	(1,010,010)	($0.0219)	(386,384)	318,174	0	0		(1,078,220)	(1,044,115)	3.50%	(3,104)	(1,081,324)	17,643,102	0	31
February 17	Forecast	(1,081,324)	($0.0219)	(403,769)	318,174	0	0		(1,166,919)	(1,124,121)	3.50%	(3,018)	(1,169,937)	18,436,957	0	28
March 17	Forecast	(1,169,937)	($0.0219)	(353,669)	318,174	0	0		(1,205,432)	(1,187,684)	3.50%	(3,531)	(1,208,963)	16,149,276	0	31
April 17	Forecast	(1,208,963)	($0.0219)	(280,259)	318,174	0	0		(1,171,048)	(1,190,005)	3.50%	(3,423)	(1,174,471)	12,797,230	0	30
May 17	Forecast	(1,174,471)	($0.0219)	(183,624)	318,174	0	0		(1,039,921)	(1,107,196)	3.50%	(3,291)	(1,043,212)	8,384,657	0	31
June 17	Forecast	(1,043,212)	($0.0219)	(126,126)	318,174	0	0		(851,164)	(947,188)	3.50%	(2,725)	(853,889)	5,759,184	0	30
July 17	Forecast	(853,889)	($0.0219)	(94,749)	318,174	0	0		(630,464)	(742,177)	3.50%	(2,206)	(632,670)	4,326,459	0	31
August 17	Forecast	(632,670)	($0.0219)	(92,255)	318,174	0	0		(406,751)	(519,711)	3.50%	(1,545)	(408,296)	4,212,539	0	31
September 17	Forecast	(408,296)	($0.0219)	(102,359)	318,174	0	0		(192,481)	(300,388)	3.50%	(864)	(193,345)	4,673,933	0	30
October 17	Forecast	(193,345)	($0.0219)	(135,633)	318,174	0	0		(10,803)	(102,074)	3.50%	(303)	(11,107)	6,193,265	0	31
November 17	Forecast	(11,107)	($0.0219)	(206,826)	318,174	0	0		100,241	44,567	3.50%	128	100,370	9,444,101	0	30
December 17	Forecast	100,370	($0.0219)	(289,918)	318,174	0	0		128,626	114,498	3.50%	340	128,966	13,238,262	0	31

Estimated C&I Conservation Charge November 1, 2016 - October 31, 2017	
Beginning Balance	(948,708)
Program Budget Nov 16-Oct 17	**3,632,241**
Projected Interest	(27,962)
Program Budget with Interest	2,655,571
Total Charges	**$2,655,571**
Projected Therm Sales	**121,258,966**
C&I Rate	$0.0219
Total Charges with Interest	**$2,655,571**
Projected Therm Sales	**121,258,966**
C&I Rate	**$0.0219**
C&I Rate from Prior Programs	**$0.0000**
Combined C&I Rate	**$0.0219**

$1

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2016 - October 31, 2017
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	C&I	Low-Income	Total	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Plus Interest Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Therm Sales	Actual Therm Sales	# of Days
May 16	Actual	(2,567,306)	n/a	(429,791)	468,485	302,108	243,803	202,441	748,352	134,645	(2,114,100)	(2,340,703)	**3.50%**	(6,958)	(2,121,058)	9,886,997	11,690,908	31
June 16	Actual	(2,121,058)	n/a	(234,585)	468,485	134,280	264,637	9,691	408,608	28,109	(1,918,926)	(2,019,992)	3.50%	(5,811)	(1,924,737)	7,077,460	6,699,259	30
July 16	Forecast	(1,924,737)	n/a	(175,905)	468,485	0	0	0	0		(1,632,156)	(1,778,447)	3.50%	(5,287)	(1,637,443)	5,261,414	0	31
August 16	Forecast	(1,637,443)	n/a	(160,416)	468,485	0	0	0	0		(1,329,374)	(1,483,408)	3.50%	(4,410)	(1,333,783)	4,908,241	0	31
September 16	Forecast	(1,333,783)	n/a	(173,276)	468,485	0	0	0	0		(1,038,574)	(1,186,179)	3.50%	(3,412)	(1,041,987)	5,299,526	0	30
October 16	Forecast	(1,041,987)	n/a	(226,761)	468,485	0	0	0	0		(800,263)	(921,125)	3.50%	(2,738)	(803,001)	6,681,398	0	31
November 16	Forecast	(803,001)	n/a	(389,989)	468,485	0	0	0	0		(724,505)	(763,753)	3.50%	(2,197)	(726,702)	13,765,466	0	30
December 16	Forecast	(726,702)	n/a	(607,147)	468,485	0	0	0	0		(865,364)	(796,033)	3.50%	(2,366)	(867,730)	21,129,531	0	31
January 17	Forecast	(867,730)	n/a	(837,942)	519,915	0	0	0	0		(1,185,758)	(1,026,744)	3.50%	(3,052)	(1,188,810)	28,875,891	0	31
February 17	Forecast	(1,188,810)	n/a	(891,350)	519,915	0	0	0	0		(1,560,245)	(1,374,527)	3.50%	(3,691)	(1,563,936)	30,565,834	0	28
March 17	Forecast	(1,563,936)	n/a	(768,282)	519,915	0	0	0	0		(1,812,303)	(1,688,119)	3.50%	(5,018)	(1,817,321)	26,463,020	0	31
April 17	Forecast	(1,817,321)	n/a	(562,694)	519,915	0	0	0	0		(1,860,101)	(1,838,711)	3.50%	(5,289)	(1,865,390)	19,822,979	0	30
May 17	Forecast	(1,865,390)	n/a	(347,921)	519,915	0	0	0	0		(1,693,397)	(1,779,394)	3.50%	(5,289)	(1,698,687)	12,471,659	0	31
June 17	Forecast	(1,698,687)	n/a	(205,701)	519,915	0	0	0	0		(1,384,473)	(1,541,580)	3.50%	(4,435)	(1,388,907)	7,738,654	0	30
July 17	Forecast	(1,388,907)	n/a	(139,788)	519,915	0	0	0	0		(1,008,781)	(1,198,844)	3.50%	(3,564)	(1,012,345)	5,446,831	0	31
August 17	Forecast	(1,012,345)	n/a	(135,923)	519,915	0	0	0	0		(628,354)	(820,349)	3.50%	(2,439)	(630,792)	5,298,828	0	31
September 17	Forecast	(630,792)	n/a	(167,152)	519,915	0	0	0	0		(278,030)	(454,411)	3.50%	(1,307)	(279,337)	6,285,692	0	30
October 17	Forecast	(279,337)	n/a	(250,265)	519,915	0	0	0	0		(9,688)	(144,512)	3.50%	(430)	(10,117)	9,044,830	0	31
November 17	Forecast	(10,117)	n/a	(380,545)	519,915	0	0	0	0		129,252	59,568	3.50%	171	129,424	13,765,466	0	30
December 17	Forecast	129,424	n/a	(607,147)	519,915	0	0	0	0		42,191	85,808	3.50%	255	42,446	21,129,531	0	31

0

Residential (R-1 & R-3) and C & I Conservation Charge November 1, 2016 - October 31, 2017		
Beginning Balance	$	(803,001)
Program Budget Nov 16-Oct 17	$	6,136,116
Projected Interest	$	(38,404)
Program Budget with Interest	$	5,294,711
Total Charges		**$5,294,711**

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants		
Required annual Environmental increase	$2,893,504	
DG 10-17 Base Rate Revision Collections	$0	
Environmental Subtotal	$2,893,504	
Overall Annual Net Increase to Rates	$2,893,504	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/17 - sales and transportation	186,909,214	therms
Surcharge per therm	$0.0155	per therm
Total Environmental Surcharge	$0.0155	

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

CONCORD FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of the Work Plan on September 16, 2010. ENGI obtained access to 4 properties in the vicinity of the site in order to conduct the supplemental investigation activities, which included soil, ground water and soil vapor sampling, along with further investigation of the brick tar sewer. ENGI submitted a revised Work Plan with revised sampling locations to NHDES in November 2011; the revision was necessary because site access was not granted by the property owners for some of the originally proposed locations. The investigation work was completed in July 2012, and summarized in a Supplement Data Collection Report that was submitted in August 2013, in preparation for submittal of the Remedial Action Plan. This Supplement Data Collection Report was accepted by NHDES on October 24, 2013, and ENGI was authorized to prepare a RAP and Groundwater Management Permit (GMP) application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014.

On 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 .**

ENGI met with City officials to discuss the options for the brick gas holder as it works into the remedial design. Coincidentally, 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 awaits receipt of their conceptual plan to develop a cap design that might accommodate it.

Concord Pond: ENGI has continued to monitor groundwater semiannually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003, 2007 and 2012, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit.

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

The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. ENGI met with the regulatory permitting agencies in October 2010. The agencies requested that ENGI modify the remedial design to include an upland cap versus a wetland cap to minimize the impacts of the project. The cap was redesigned and ENGI met with the stakeholders in December 2010. At a subsequent meeting in January 2011, the City of Concord requested that the design be further modified to relocate the City's storm water outfall location.

ENGI met with the City in March 2011 to present the feasibility evaluation that was conducted for several alternatives, and concluded that the original design was the appropriate design. Contact was reconvened with the City in 2013, and adjustments to the original design 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, so ENGI and the City will once again work toward implementation of the joint remedial design for late summer 2018.**

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

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

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE:

Concord MGP: In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the MGP site. ENGI submitted the scope to NHDES in May 2004 and implemented the work between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was subsequently approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. In addition, ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. The Supplemental Data Collection report summarizing the investigation activities was accepted in October 2013, authorizing ENGI to prepare a RAP and GMP Application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014. On March 31, 2015, ENGI submitted a proposed RAP, and NHDES approved the RAP with conditions. A Remedial Design Report, summarizing pre-design investigations, is to be provided to NHDES by the end of 2015**.**

Concord Pond: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI undertook a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT and ENGI. ENGI met with these parties on several occasions in 2010 and 2011. The Company reinitiated discussion with the City in July 2014 regarding access to the site to implement the approved design of the wetland cap. **The design was adjusted to accommodate the City's desire to simplify maintenance of the storm water system, and ENGI and the City continue to work toward implementation of the design in late summer 2018.**

LINE
NO.

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.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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

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

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

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

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NO.

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

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

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

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

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

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

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

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: On December 10, 2012, ENGI submitted a Conceptual Remedial Design Report to NHDES describing the approach for full removal. NHDES approved this Conceptual RAP Addendum design on December 18, 2012, and ENGI withdrew their appeal before the New Hampshire Waste Management Council on December 19, 2012. A public meeting was held in the Town of Gilford to present the approved Conceptual Remedial Design on January 23, 2013. The pre-design investigation to confirm extent and depth of contamination commenced on February 20, 2013 and was completed first week in April 2013. A public meeting was held on September 25, 2013 to present the design to the Town. The Remedial Design Report was finalized and approved by NHDES in December 2013. Plans and Specifications were developed concurrently, and the bidding process commenced in September 2013 with a Request for Information to ten (10) prospective contractors. On October 28, six (6) contractors were selected to participate in the bidding for the construction, with bids due back on December 6, 2013. On January 9, 2014, three (3) of the bidders were interviewed and Charter Environmental of Boston, MA (the Contractor) was selected for the project. A public meeting took place on February 12, 2014 to further

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 this year, 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.**

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

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

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

LINE
NO.

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.

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

MANCHESTER FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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NO.

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

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

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

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

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

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NO.

- 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 is preparing a plan to address these concerns.**

  In August 2015, a developer who purchased the development rights at the downstream “off-site” contacted ENGI about monitoring wells that were in the area where they were planning to drive piles for the construction of three apartment buildings. ENGI responded immediately and worked with the

construction team to ensure that any MGP-impacted media that was encountered was handled properly. The buildings are nearly complete and very little impacts were encountered. A number of monitoring wells in the area that are no longer in use were retired by ENGI.

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 is preparing a plan to address these concerns and implementation of the remedial activities on-site and off-site will likely occur 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

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NO.

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

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

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

NASHUA FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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NO.

- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.

- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.

- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.

- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.

- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.

- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.

- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.

- ENGI submitted a letter to NHDES in August 2000 discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and PSNH/NU, along with a proposed schedule for implementation of the work.

- NHDES approved the Revised Phase II Work Plan for the site at the end of August 2000.

- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.

- ENGI submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

LINE
NO.

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

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

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

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

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

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

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

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

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

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

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

LINE
NO.

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

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

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

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

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

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

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

LINE
NO.

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

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

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

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

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

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

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

LINE
NO.

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

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

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

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

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

LINE
NO.

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

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

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

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

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

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

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

LINE
NO.

- **ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. ENGI awaits NHDES acceptance of both documents.**

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, and awaits NHDES response.**

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

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

NASHUA FORMER MGP

LINE
NO.

$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.

REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS

2016 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	-	37,889.72	-	-	5,314.21	43,203.93	[redacted]	[redacted]	34,589.99
2	Concord MGP	DEF077	-	81,643.42	-	-	33,105.91	114,749.33	[redacted]	[redacted]	95,552.82
3	Laconia/Liberty Hill	DEF086	-	507,872.17	2,484,151.12	-	189,258.37	3,181,281.66	[redacted]	[redacted]	3,181,281.66
4	Manchester MGP	DEF057	3,942.50	47,898.46	-	-	19,170.22	71,011.18	[redacted]	[redacted]	22,689.50
5	Nashua MGP	DEF054	-	104,482.58	-	-	1,646.22	106,128.80	[redacted]	[redacted]	62,434.55
6	General Expenses	DEF064	-	-	-	-	11,879.11	11,879.11	[redacted]	[redacted]	11,879.11
	Total Pool Activity		**3,942.50**	**779,786.35**	**783,728.85**	**-**	**260,374.04**	**3,528,254.01**	**-**	**(119,826.38)**	**3,408,427.63**

REDACTED

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

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11914		2,388.22				2,388.22	[redacted]	[redacted]	2,388.22
2	CLEAN HARBORS	1001081362					286.00	286.00	[redacted]	[redacted]	286.00
3	EverSource	PSNH N-Q2-2015						0.00	[redacted]	[redacted]	(10,786.56)
4	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11944		2,972.31				2,972.31	[redacted]	[redacted]	2,972.31
5	INNOVATIVE ENGINEERING SOLUTIONS, INC.	11982		4,393.12				4,393.12	[redacted]	[redacted]	4,393.12
6	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12043		9,186.71				9,186.71	[redacted]	[redacted]	9,186.71
7	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 103015					674.72	674.72	[redacted]	[redacted]	674.72
8	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12056		19,193.58				19,193.58	[redacted]	[redacted]	19,193.58
9	Eversource	PSNH N-Q3-2015						0.00	[redacted]	[redacted]	(1,149.91)
10	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12087		6,557.53				6,557.53	[redacted]	[redacted]	6,557.53
11	GZA GEOENVIRONMENTAL INC	709651		13,920.58				13,920.58	[redacted]	[redacted]	13,920.58
12	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12115		7,344.75				7,344.75	[redacted]	[redacted]	7,344.75
13	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 199810022					35.66	35.66	[redacted]	[redacted]	35.66
14	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12149		6,497.40				6,497.40	[redacted]	[redacted]	6,497.40
15	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12176		2,792.94				2,792.94	[redacted]	[redacted]	2,792.94
16	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12199		3,384.76				3,384.76	[redacted]	[redacted]	3,384.76
17	EVERSOURCE	N-Q4-2015						0.00	[redacted]	[redacted]	(15,783.77)
18	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12271		6,757.33				6,757.33	[redacted]	[redacted]	6,757.33
19	EVERSOURCE	N-Q1-2016						0.00	[redacted]	[redacted]	(15,974.01)
20	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12244		19,093.35				19,093.35	[redacted]	[redacted]	19,093.35
21								0.00	[redacted]	[redacted]	0.00
22								0.00	[redacted]	[redacted]	0.00
23								0.00	[redacted]	[redacted]	0.00
24								0.00	[redacted]	[redacted]	0.00
25	Environmental Staff Time						649.84	649.84	[redacted]	[redacted]	649.84
	Total Pool Activity		**-**	**104,482.58**	**-**	**-**	**1,646.22**	**106,128.80**	**-**	**(43,694.25)**	**62,434.55**

REDACTED

154

REDACTED

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	GEI CONSULTANTS, INC.	62571		2,130.90				2,130.90	[redacted]	[redacted]	2,130.90
2	GEI CONSULTANTS, INC.	62189		4,975.85				4,975.85	[redacted]	[redacted]	4,975.85
3	GEI CONSULTANTS, INC.	62335		3,015.93				3,015.93	[redacted]	[redacted]	3,015.93
4	CLEAN HARBORS	1001032082					682.00	682.00	[redacted]	[redacted]	682.00
5	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 4042 0724					476.34	476.34	[redacted]	[redacted]	476.34
6	UGI	C-Q2-2015						0.00	[redacted]	[redacted]	(3,152.33)
7	GEI CONSULTANTS, INC.	62768		2,259.96				2,259.96	[redacted]	[redacted]	2,259.96
8	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 103015					355.77	355.77	[redacted]	[redacted]	355.77
9	GEI CONSULTANTS, INC.	62946		2,508.53				2,508.53	[redacted]	[redacted]	2,508.53
10	CLEAN HARBORS	1001157084					609.95	609.95	[redacted]	[redacted]	609.95
11	UGI	UGI C-Q3-2015						0.00	[redacted]	[redacted]	(1,692.15)
12	GEI CONSULTANTS, INC.	63324		4,571.79				4,571.79	[redacted]	[redacted]	4,571.79
13	GEI CONSULTANTS, INC.	63570		7,964.66				7,964.66	[redacted]	[redacted]	7,964.66
14	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 199212014 4042					17.47	17.47	[redacted]	[redacted]	17.47
15	CASEY MARY	01/01 THRU 01/31/16					54.50	54.50	[redacted]	[redacted]	54.50
16	CLEAN HARBORS	1001249513					792.83	792.83	[redacted]	[redacted]	792.83
17	GEI CONSULTANTS, INC.	63739		3,942.77				3,942.77	[redacted]	[redacted]	3,942.77
18	GEI CONSULTANTS, INC.	3000952		2,051.33				2,051.33	[redacted]	[redacted]	2,051.33
19	UGI	UGI C-Q4-2015						0.00	[redacted]	[redacted]	(1,545.93)
20	CITY OF CONCORD	2016-50460156					1,440.00	1,440.00	[redacted]	[redacted]	1,440.00
21	GEI CONSULTANTS, INC.	3002491		2,130.38				2,130.38	[redacted]	[redacted]	2,130.38
22	GEI CONSULTANTS, INC.	3003094		2,337.62				2,337.62	[redacted]	[redacted]	2,337.62
23	UGI	C-Q1-2015						0.00	[redacted]	[redacted]	(2,223.53)
24								0.00	[redacted]	[redacted]	0.00
25								0.00	[redacted]	[redacted]	0.00
26								0.00	[redacted]	[redacted]	0.00
27								0.00	[redacted]	[redacted]	0.00
28	Environmental Staff Time						885.35	885.35	[redacted]	[redacted]	885.35
	Total Pool Activity		**0.00**	**37,889.72**	**0.00**	**0.00**	**5,314.21**	**43,203.93**	**0.00**	**(8,613.94)**	**34,589.99**

REDACTED

REDACTED

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	MCLANE, GRAF, RAULERSON & MIDDLETON PA	2015090832	3,942.50					3,942.50	[redacted]		3,942.50
2	GZA GEOENVIRONMENTAL INC	708081		3,016.55				3,016.55	[redacted]		3,016.55
3	GZA GEOENVIRONMENTAL INC	704990		6,028.70				6,028.70	[redacted]		6,028.70
4	CASEY MARY	08/01 THRU 08/31/15					133.60	133.60	[redacted]		133.60
5	CLEAN HARBORS	1001026278					2,481.97	2,481.97	[redacted]		2,481.97
6	CLEAN HARBORS	1001045786					1,643.40	1,643.40	[redacted]		1,643.40
7	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 9890 0724					1,763.29	1,763.29	[redacted]		1,763.29
8	ESMI OF NH	1012653					520.00	520.00	[redacted]		520.00
9	CENTURY INDMNITY	M-CEN-Q2-2015						0.00	[redacted]		(3,669.41)
10	UGI	M-Q2-2015						0.00	[redacted]		(14,677.62)
11	ESMI OF NH	1012827					2,252.60	2,252.60	[redacted]		2,252.60
12	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 103015					5,621.40	5,621.40	[redacted]		5,621.40
13	CENTURY INDMNITY	M-CEN-Q3-2015						0.00	[redacted]		(2,042.88)
14	UGI	M-UGI-Q3-2015						0.00	[redacted]		(7,323.75)
15	GZA GEOENVIRONMENTAL INC	712443		33,112.62				33,112.62	[redacted]		33,112.62
16	NH DEPT OF ENVIRONMENTAL SERVICES	2000003011 9890					1,389.85	1,389.85	[redacted]		1,389.85
17	ESMI OF NH	1012758					600.00	600.00	[redacted]		600.00
18	CLEAN HARBORS	1001249515					402.60	402.60	[redacted]		402.60
19	CENTURY INDEMNITY	M-CEN-Q4-2015						0.00	[redacted]		(950.13)
20	UGI	M-UGI Q4-2015						0.00	[redacted]		(2,952.72)
21	GZA GEOENVIRONMENTAL INC	717403		4,442.63				4,442.63	[redacted]		4,442.63
22	CLEAN HARBORS	1001360984					415.80	415.80	[redacted]		415.80
23	CASEY MARY	10/01 THRU 10/31/15					57.28	57.28	[redacted]		57.28
24	CENTURY	M-CEN-Q1-2016						0.00	[redacted]		(3,369.29)
25	UGI	M-Q1-2016						0.00	[redacted]		(13,335.88)
26	GZA GEOENVIRONMENTAL INC	719726		1,297.96				1,297.96	[redacted]		1,297.96
27								0.00	[redacted]		0.00
28								0.00	[redacted]		0.00
29								0.00	[redacted]		0.00
30								0.00	[redacted]		0.00
31	Environmental Staff Time						**1,888.43**	1,888.43	[redacted]		1,888.43
	Total Pool Activity		**3,942.50**	**47,898.46**	**0.00**	**0.00**	**19,170.22**	**71,011.18**	**0.00**	**(48,321.68)**	**22,689.50**

REDACTED

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
PROJECT DEF064

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	ALLEGRA MARKETING PRINT MAIL	28930					279.00	279.00			279.00
2	CASEY MARY	08/01 THRU 08/31/15					53.93	53.93			53.93
3	CASEY MARY	07/01 THRU 07/31/15					34.49	34.49			34.49
4	CASEY MARY	04/01 THRU 04/30/16					47.74	47.74			47.74
5								0.00			0.00
6								0.00			0.00
7								0.00			0.00
8								0.00			0.00
9								0.00			0.00
10								0.00			0.00
11								0.00			0.00
12								0.00			0.00
13								0.00			0.00
14								0.00			0.00
15								0.00			0.00
16	Environmental Staff Time						11,463.95	11,463.95			11,463.95
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**11,879.11**	**11,879.11**	**0.00**	**0.00**	**11,879.11**

REDACTED

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

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CASEY MARY	06/01 THRU 06/30/15					39.70	39.70	[redacted]	[redacted]	39.70
3	GZA GEOENVIRONMENTAL INC	705323		8,888.63				8,888.63	[redacted]	[redacted]	8,888.63
4	CLEAN HARBORS	1001032082					645.70	645.70	[redacted]	[redacted]	645.70
5	JOE GAUCI LANDSCAPING LLC	2015-7-3576					4,395.00	4,395.00	[redacted]	[redacted]	4,395.00
6	UGI	C-Q2-2015						0.00	[redacted]	[redacted]	(8,602.48)
7	GZA GEOENVIRONMENTAL INC	708082		6,936.61				6,936.61	[redacted]	[redacted]	6,936.61
8	GZA GEOENVIRONMENTAL INC	708083		281.65				281.65	[redacted]	[redacted]	281.65
9	JOE GAUCI LANDSCAPING LLC	2015-9-3576					536.00	536.00	[redacted]	[redacted]	536.00
10	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 103015					1,345.62	1,345.62	[redacted]	[redacted]	1,345.62
11	JOE GAUCI LANDSCAPING LLC	2015-10-3576					289.00	289.00	[redacted]	[redacted]	289.00
12	CLEAN HARBORS	101146679					1,311.20	1,311.20	[redacted]	[redacted]	1,311.20
13	CASEY MARY	10/01 THRU 10/31/15					105.11	105.11	[redacted]	[redacted]	105.11
14	UGI	UGI C-Q3-2015						0.00	[redacted]	[redacted]	(3,178.10)
15	GZA GEOENVIRONMENTAL INC	712444		12,676.73				12,676.73	[redacted]	[redacted]	12,676.73
16	GZA GEOENVIRONMENTAL INC	712445		12,368.21				12,368.21	[redacted]	[redacted]	12,368.21
17	CLEAN HARBORS	1001212116					18,253.29	18,253.29	[redacted]	[redacted]	18,253.29
18	NH DEPT OF ENVIRONMENTAL SERVICES	SITE 198904063					127.94	127.94	[redacted]	[redacted]	127.94
19	JOE GAUCI LANDSCAPING LLC	2016-1-3576					220.00	220.00	[redacted]	[redacted]	220.00
20	CLEAN HARBORS	1001249042					2,144.16	2,144.16	[redacted]	[redacted]	2,144.16
21	UGI	UGI-Q4-2015						0.00	[redacted]	[redacted]	(4,304.12)
22	CASEY MARY	03/01 THRU 03/31/16					78.65	78.65	[redacted]	[redacted]	78.65
23	GZA GEOENVIRONMENTAL INC	717405		1,726.23				1,726.23	[redacted]	[redacted]	1,726.23
24	GZA GEOENVIRONMENTAL INC	717404		37,959.38				37,959.38	[redacted]	[redacted]	37,959.38
25	CITY OF CONCORD	2016-50460156					600.00	600.00	[redacted]	[redacted]	600.00
26	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 050516					259.73	259.73	[redacted]	[redacted]	259.73
27	CASEY MARY	04/01 THRU 04/30/16					38.55	38.55	[redacted]	[redacted]	38.55
28	JOE GAUCI LANDSCAPING LLC	2016-2-3576					275.00	275.00	[redacted]	[redacted]	275.00
29	UGI	C-Q1-2016						0.00	[redacted]	[redacted]	(3,111.81)
30	GZA GEOENVIRONMENTAL INC	719728		805.98				805.98	[redacted]	[redacted]	805.98
31	JOE GAUCI LANDSCAPING LLC	2016-5-3576					413.00	413.00	[redacted]	[redacted]	413.00
32	CLEAN HARBORS	1001426709					188.65	188.65	[redacted]	[redacted]	188.65
33								0.00	[redacted]	[redacted]	0.00
34								0.00	[redacted]	[redacted]	0.00
35	Environmental Staff Time						1,839.61	1,839.61	[redacted]	[redacted]	1,839.61
	Total Pool Activity		**0.00**	**81,643.42**	**0.00**	**0.00**	**33,105.91**	**114,749.33**	**0.00**	**(19,196.51)**	**95,552.82**

REDACTED

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUB-TOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	DE MAXIMIS, INC.	151469		$ 28,216.12				28,216.12			28,216.12
2	CHARTER ENVIRONMENTAL INC	APP 12 LIBERTY HILL			$ 335,467.11			335,467.11			335,467.11
3	ESMI OF NH	1012485			$ 224,548.49			224,548.49			224,548.49
4	OSTROW & PARTNERS INC	07 15 01					$ 1,635.00	1,635.00			1,635.00
5	EVERSOURCE	56382976025 0715					$ 185.23	185.23			185.23
6	EVERSOURCE	56549986081 0715					$ 160.48	160.48			160.48
7	EVERSOURCE	56272196049 0715					$ 162.36	162.36			162.36
8	ESMI OF NH	1012522			$ 190,458.82			190,458.82			190,458.82
9	NH DEPT OF ENVIRONMENTAL SERVICES	200411113 14262 0724					$ 2,671.79	2,671.79			2,671.79
10	CASEY MARY	07/14 THRU 07/15/15					$ 70.85	70.85			70.85
11	CASEY MARY	06/01 THRU 06/30/15					$ 475.01	475.01			475.01
13	GEI CONSULTANTS, INC.	61944		$ 52,490.69				52,490.69			52,490.69
14	ESMI OF NH	1012523			$ 115,491.38			115,491.38			115,491.38
15	GEI CONSULTANTS, INC.	62187		$ 46,728.23				46,728.23			46,728.23
16	AIRLOGICS LLC	705840			$ 8,100.00			8,100.00			8,100.00
17	DE MAXIMIS, INC.	151846		$ 29,401.15				29,401.15			29,401.15
18	ESMI OF NH	1012544			$ 128,250.39			128,250.39			128,250.39
19	BLUE CHIP FILMS LLC	1265					$ 887.50	887.50			887.50
20	BLUE CHIP FILMS LLC	1257					$ 1,262.50	1,262.50			1,262.50
21	ESMI OF NH	1012548			$ 103,781.25			103,781.25			103,781.25
22	EVERSOURCE	56382976025 0815					$ 145.85	145.85			145.85
23	EVERSOURCE	56272196049 0815					$ 49.58	49.58			49.58
24	EVERSOURCE	56549986081 0815					$ 170.25	170.25			170.25
25	OSTROW & PARTNERS INC	08 15 01					$ 1,147.50	1,147.50			1,147.50
26	ESMI OF NH	1012580			$ 92,653.86			92,653.86			92,653.86
27	CHARTER ENVIRONMENTAL INC	APP 13 LIBERTY HILL			$ 299,245.47			299,245.47			299,245.47
28	CASEY MARY	07/28 THRU 07/28/15					$ 70.85	70.85			70.85
29	CASEY MARY	08/13 THRU 08/14/15					$ 70.85	70.85			70.85
30	CASEY MARY	07/01 THRU 07/31/15					$ 268.66	268.66			268.66
31	AIRLOGICS LLC	707243			$ 5,949.00			5,949.00			5,949.00
32	NEW HAMPSHIRE PICKET FENCES	DEPOSIT 090115					$ 3,110.50	3,110.50			3,110.50
33	ESMI OF NH	1012629			$ 1,381.48			1,381.48			1,381.48
34	ESMI OF NH	1012605			$ 4,214.64			4,214.64			4,214.64
35	DE MAXIMIS, INC.	152029		$ 32,731.71				32,731.71			32,731.71
36	EVERSOURCE	56549986081 0915					$ 240.87	240.87			240.87
37	EVERSOURCE	56272196049 0915					$ 58.99	58.99			58.99
38	BLUE CHIP FILMS LLC	1274					$ 725.00	725.00			725.00
39	GEI CONSULTANTS, INC.	62333		$ 60,648.01				60,648.01			60,648.01
40	CHARTER ENVIRONMENTAL INC	APP 14 LIBERTY HILL			$ 239,519.33			239,519.33			239,519.33
41	CASEY MARY	08/01 THRU 08/31/15					$ 519.15	519.15			519.15
42	CASEY MARY	09/08 THRU 09/09/15					$ 70.85	70.85			70.85
43	DE MAXIMIS, INC.	152282		28,266.73				28,266.73			28,266.73
44	EVERSOURCE	56382976025 0915					53.70	53.70			53.70
45	CASEY MARY	09/14 THRU 09/14/15					49.85	49.85			49.85
46	AIRLOGICS LLC	704395			8,100.00			8,100.00			8,100.00
47	NEW HAMPSHIRE PICKET FENCES	2212					3,260.50	3,260.50			3,260.50

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

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

Concord Pond

DEF056

	(thru - 9/98) pool #1 & #2	10/98 - 9/15/99 pool #3	(9/99 - 9/00) pool #4	(9/03 - 9/04) pool #5	(9/04 - 9/05) pool #6	(9/05 - 9/06) pool #7	(9/06 - 9/07) pool #8	(9/07 - 9/08) pool #9	(9/08 - 9/09) pool #10	(9/09 - 9/10) pool #11	(9/10 - 9/11) pool #12	(9/11 - 9/12) pool #13	(9/12 - 6/13) pool #14	(7/13 - 6/14) pool #15	(7/14 - 6/15) pool #16	(7/15 - 6/16) pool #16	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	6,837,512
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	6,837,512
																	-
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)	(2,179,279)
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)	(2,001,480)
																	-
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	4,836,033
																	-
																	-
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)	(191,270)
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)	(3,966,003)
D Net balance to be recovered (A-B+C)	21,038	38,548	45,088	50,734	60,721	116,708	246,787	329,540	102,675	123,791	118,448	47,608	45,345	18,376	64,062	20,185	870,029
E Allocation of Litigated Recovery				-		-		(329,540)	(102,675)	(123,791)	(106,106)	-	-	-	-	-	(662,112)
Surcharge calculation																	
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	12,343	20,403	25,911	13,126	54,910	20,184.97	146,878
remaining life	-	-	-	24	36	48	60	72	84	84	24	36	48	60	72	84	
one year	-	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-		-	-	-	6,171	6,801	6,478	2,625	9,152	2,884	34,111
Required annual increase in rates:																	
smaller of D or F	-	-	-	-	-	-		-	-	-	6,171	6,801	6,478	2,625	9,152	2,884	34,111
forecasted therm sales	368,786,526	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214
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	$0.0000	$0.0000	$0.0000	$0.0002

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

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

REDACTED

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

Laconia & Liberty Hill

	i.o. no. 500005													DEF086	
	(thru - 9/00)	(9/00 - 9/01)	(9/04 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	(9/10 - 9/11)	(9/11 - 9/12)	(9/12 - 6/13)	(7/13 - 6/14)	(7/14 - 6/15)	(7/15 - 6/16)	
	pool #1 & #2	pool #3	pool #4	pool #5	pool #6	pool #7	pool #8	pool #9	pool #10	pool #11	pool #12	pool #13	pool #14	pool #15	subtotal
						Incl. Audit Corr	Incl. Audit Corr								
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	[redacted]			
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	[redacted]			
Cash recoveries (i.o. 500061)	-	-	-	-	-	-	-					[redacted]			
Cash recoveries (i.o. 500004)	-	-	-	-	-	-	-					[redacted]			
Recovery costs (i.o. 500004)	-	-			11,643	21,729	-	-				[redacted]			
Transfer Credit from Gas Restructuring					-	-	-					[redacted]			
B Subtotal - net recoveries	-	-	-	-	11,643	21,729	-	-	-	-	-	[redacted]			
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	[redacted]			
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		-	-	147,219	-	-	-	-	
C Surcharge Subtotal	(4,531,075)	(588,664)	111,336	(188,958)	2,141,596	4,242,438	-	-	(63,313)	37,166	(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	306,447	516,153	[redacted]			
E Allocation of Litigated Recovery						(4,692,393)	(607,876)	(262,678)	-	-	-	[redacted]			
Surcharge calculation												[redacted]			
Unrecovered costs (D+E)	-	-	-			-	-	-	-	131,334	73,736	[redacted]			
remaining life	-	-	36	48	60	72	84	84	48	36	48	[redacted]			
one year	-	-	12	12	12	12	12	12	12	12	12	[redacted]			
F amortization	-	-	-	-	-	-	-	-	-	43,778	18,434	[redacted]			
Required annual increase in rates:												[redacted]			
smaller of D or F	-	-	-	-		-	-	-	-	43,778	18,434	[redacted]			
forecasted therm sales	368,786,526	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$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
Tariff page 80

Manchester

DEF057

	(9/00 - 9/03) pool #1 & #2	(9/02 - 9/03) pool #3 (withdrawn 2/1/04)	(9/03 - 9/04) pool #4	(9/04 - 9/05) pool #5	(9/05 - 9/06) pool #6	(9/06 - 9/07) pool #7	(9/07 - 9/08) pool #8 Incl. Audit Corr	(9/08 - 9/09) pool #9	(9/09 - 9/10) pool #10	(9/10 - 9/11) pool #11	(9/11 - 9/12) pool #12	(9/12 - 6/13) pool #13	(7/13 - 6/14) pool #14	(7/14 - 6/15) pool #15	(7/15 - 6/16) pool #16	subtotal
1 Remediation costs (i.o. 500061)	-		335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	10,073,344
Remediation costs (i.o. 500005)	825,092															825,092
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	10,898,436
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)	(2,625,461)
Cash recoveries (i.o. 500004)	-															-
Recovery costs (i.o. 500004)	-		1,242,326			2,546	-									1,244,872
Transfer Credit from Gas Restructuring						-	-									-
B Subtotal - net recoveries	-	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(1,380,589)
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	9,517,847
																-
																-
Surcharge revenue:																-
Act June 1998 - October 1998	-	-	-													-
Act November 1998 - October 1999	-	-	-													-
Act November 1999 - October 2000	-	-	-													-
Act November 2000 - October 2001	-	-	-													-
Act November 2001 - October 2002	(73,543)	-	-													(73,543)
Act November 2002 - October 2003	(75,984)	-	-													(75,984)
Act November 2003 - October 2004	(97,251)	(41,325)	-													(138,576)
Act November 2004- October 2005	(113,437)	-	(212,695)	-			-	-	-	-	-	-	-	-	-	(326,132)
Act November 2005- October 2006	(96,247)	-	(206,243)	(261,242)			-	-	-	-	-	-	-	-	-	(563,732)
Act November 2006- October 2007	(126,817)	-	(211,361)	(281,815)	(42,272)											(662,265)
Act November 2007- October 2008																-
Act November 2012- October 2013											(40,012)					(40,012)
Act November 2013- October 2014											(50,994)					(50,994)
Act Nov 2009-Oct 2010 Base Rate Rev										-						-
Act Nov 2010-Oct 2011 Base Rate Rev										-						-
Act Nov 2011-Oct 2012 Base Rate Rev										-						-
Act Nov 2012-Oct 2013 Base Rate Rev										-	(23,337)					(23,337)
Act Nov 2013-Oct 2014 Base Rate Rev																-
Act Nov 2014-Oct 2015 Base Rate Rev																
AES collections																-
Gas Street overcollection																-
Prior Period Pool under/overcollection	76,393	318,206	276,881	1,224,246	2,671,037	2,958,927	3,302,330	-	-	-						
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)
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	7,563,271
E Allocation of Litigated Recovery		-	-	-			(6,562,539)	(312,185)	(328,678)	(209,831)	-	-	-	-	-	(7,413,233)
Surcharge calculation																
Unrecovered costs (D+E)	-	-	-	-	-		-	-	-	(72,242)	140,552	(107,782)	43,721	64,663	22,690	91,601
remaining life	-	-	24	36	48	60	70	84	84	24	36	48	60	72	84	
one year	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	(36,121)	46,851	(26,946)	8,744	10,777	3,241	
Required annual increase in rates:																
smaller of D or F	-	-	-	-	-		-	-	-	-	46,851	(26,946)	8,744	10,777	3,241	42,668
forecasted therm sales	368,786,526	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0002

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
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	Nashua															
						Corrected per 2/08 Audit									DEF054	
	(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	(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	subtotal
1 Remediation costs (i.o. 500061)	-	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	1,458,224
Remediation costs (i.o. 500005)	1,596,389	175,178														1,771,567
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	3,229,790
																-
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)	(505,079)
Cash recoveries (i.o. 500004)	-	-														-
Recovery costs (i.o. 500004)	-	-			5,449	12,938	-	-								18,388
Transfer Credit from Gas Restructuring						-	-	-								-
B Subtotal - net recoveries	-	-	-		(13,131)	8,787	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(486,692)
																-
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	2,743,099
Surcharge revenue:																
Act June 1998 - October 1998	-	-	-													-
Act November 1998 - October 1999	-	-	-													-
Act November 1999 - October 2000	-	-	-													-
Act November 2000 - October 2001	-	-	-													-
Act November 2001 - October 2002	(183,857)	-	-													(183,857)
Act November 2002 - October 2003	(243,150)	-	-													(243,150)
Act November 2003 - October 2004	(218,505)	(29,134)	-													(247,639)
Act November 2004- October 2005	(212,695)	(28,359)	-													(241,054)
Act November 2005- October 2006	(219,993)	(27,499)	-	(27,499)			-	-	-	-	-	-	-	-	-	(274,991)
Act November 2006- October 2007	(225,452)	(28,181)	-	(28,181)	-											(281,815)
Act November 2007- October 2008																-
Act November 2012- October 2013											(40,012)					(40,012)
Act November 2013- October 2014											(38,246)					(38,246)
Act Nov 2009-Oct 2010 Base Rate Rev										-						-
Act Nov 2010-Oct 2011 Base Rate Rev										-						-
Act Nov 2011-Oct 2012 Base Rate Rev										-						-
Act Nov 2012-Oct 2013 Base Rate Rev										-	(20,916)					(20,916)
Act Nov 2013-Oct 2014 Base Rate Rev																-
Act Nov 2014-Oct 2015 Base Rate Rev																
AES collections																-
Gas Street overcollection																-
Prior Period Pool under/overcollection	188,463	481,201	543,205	554,046	704,732	714,955	733,479	-	-	-	(25,889)	-	-	-	-	
C Surcharge Subtotal	(1,115,188)	368,027	543,205	498,365	704,732	714,955	733,479	-	-	-	(125,062)	-	-	-	-	(1,571,680)
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	271,349	(80,241)	35,950	65,217	62,435	1,171,419
E Allocation of Litigated Recovery	-	-	-	-	-	-	(830,669)	(16,289)	(98,975)	(59,239)	-	-	-	-	-	(1,005,173)
Surcharge calculation																
Unrecovered costs (D+E)	-	-	-	-	-		-	-	-		116,292	(45,852)	25,679	55,901	62,435	214,454
remaining life	-	12	24	36	48	60	72	84	84	72	36	48	60	72	84	
one year	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-	-	-	-	-	-	38,764	(11,463)	5,136	9,317	8,919	
Required annual increase in rates:																
smaller of D or F	-	-	-	-	-		-	-	-	-	38,764	(11,463)	5,136	9,317	8,919	50,673
forecasted therm sales	368,786,526	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214
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	$0.0000	$0.0000	$0.0003

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

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

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	(7/15 - 6/16) 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	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
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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	(7/15 - 6/16) 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			
A Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
Cash recoveries (i.o. 500061)	-												
Cash recoveries (i.o. 500004)	-												
Recovery costs (i.o. 500004)			18,831	823	-	-	-	-					
Transfer Credit from Gas Restructuring				-	-	-							
B Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-			
A-B Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400			
													-
													-
Surcharge revenue:													-
Act June 1998 - October 1998	-												-
Act November 1998 - October 1999	-												-
Act November 1999 - October 2000	-												-
Act November 2000 - October 2001	-												-
Act November 2001 - October 2002	-												-
Act November 2002 - October 2003	-												-
Act November 2003 - October 2004	-												-
Act November 2004- October 2005	-	-				-	-	-	-	-	-	-	-
Act November 2005- October 2006	-	-				-	-	-	-	-	-	-	-
Act November 2006- October 2007	-	-	(14,091)										(14,091)
Act November 2007- October 2008													-
Act November 2012- October 2013													-
Act November 2013- October 2014													-
Act Nov 2009-Oct 2010 Base Rate Rev													-
Act Nov 2010-Oct 2011 Base Rate Rev													-
Act Nov 2011-Oct 2012 Base Rate Rev													-
Act Nov 2012-Oct 2013 Base Rate Rev													-
Act Nov 2013-Oct 2014 Base Rate Rev													-
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)	-	-	-	-			
Surcharge calculation													
Unrecovered costs (D+E)	-	-	-			-	-	-	209	800			
remaining life	24	36	48	60	72	84	84	84	36	48			
one year	12	12	12	12	12	12	12	12	12	12			
F amortization	-	-	-	-	-	-	-	-	70	200			
Required annual increase in rates:													
smaller of D or F	-	-	-			-	-	-	70	200	[redacted]		
forecasted therm sales	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

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

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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation - MGPs
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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	(7/13 - 6/14) pool #12	(7/15 - 6/16) pool #13	subtotal
1 Remediation costs (i.o. 500061)	-													-
Remediation costs (i.o. 500005)	22,191	220,932	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749	1,527,620
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	1,527,620
														-
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)	(211,504)
Cash recoveries (i.o. 500004)	-													-
Recovery costs (i.o. 500004)					1,432	(1,007)								425
Transfer Credit from Gas Restructuring			-											-
B Subtotal - net recoveries	-	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)	(211,079)
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	1,316,541
														-
														-
Surcharge revenue:														-
Act June 1998 - October 1998	-													-
Act November 1998 - October 1999	-													-
Act November 1999 - October 2000	-													-
Act November 2000 - October 2001	-													-
Act November 2001 - October 2002	-													-
Act November 2002 - October 2003	-													-
Act November 2003 - October 2004	-													-
Act November 2004- October 2005														-
Act November 2005- October 2006	-	(27,499)			-	-	-	-	-	-	-	-	-	(27,499)
Act November 2006- October 2007	-	(28,181)	-											(28,181)
Act November 2007- October 2008														-
Act November 2012- October 2013								(20,006)	(20,006)					(40,012)
Act November 2013- October 2014								(12,749)	(25,497)					(38,246)
Act Nov 2009-Oct 2010 Base Rate Rev								($1,891)						(1,891)
Act Nov 2010-Oct 2011 Base Rate Rev								($13,816)						(13,816)
Act Nov 2011-Oct 2012 Base Rate Rev								($12,164)						(12,164)
Act Nov 2012-Oct 2013 Base Rate Rev								($6,794)	($6,794)					(13,588)
Act Nov 2013-Oct 2014 Base Rate Rev														-
Act Nov 2014-Oct 2015 Base Rate Rev														
AES collections														-
Gas Street overcollection														-
Prior Period Pool under/overcollection		22,191	187,442	209,549	271,214	-	-	-	-	-	-	-	-	
C Surcharge Subtotal	-	(33,490)	187,442	209,549	271,214	-	-	(67,420)	(52,297)	-	-	-	-	(175,398)
D Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	92,679	46,190	100,919	205,231	45,384	123,355	163,783	95,553	1,141,144
														-
E Allocation of Litigated Recovery	-	-	-	-	(268,051)	(92,679)	(46,190)	(26,982)	-	-	-	-	-	(433,901)
														-
Surcharge calculation														-
Unrecovered costs (D+E)	-	-	-		-	-	-	100,919	87,956	25,934	88,110	140,386	95,553	538,858
remaining life	36	48	60		72	84	84	24	36	48	60	72	84	
one year	12	12	12		12	12	12	12	12	12	12	12	12	
F amortization	-	-	-		-	-	-	50,459	29,319	6,483	17,622	23,398	13,650	
Required annual increase in rates:														
smaller of D or F	-	-	-		-	-	-	50,459	29,319	6,483	17,622	23,398	13,650	140,932
forecasted therm sales	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214
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	$0.0008

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

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

REDACTED

Liberty Utilities (EnergyNorth Natural Gas) Corp.
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	General														
			Corrected per 1/24/07 Audit										DEF064		2016 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	(7/13 - 6/14) pool #13	(7/15 - 6/16) pool #14	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	882,081	[redacted]
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	882,081	[redacted]
Cash recoveries (i.o. 500061)	-			-	-	-								-	[redacted]
Cash recoveries (i.o. 500004)	-													-	[redacted]
Recovery costs (i.o. 500004)			290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	322,270	[redacted]
Transfer Credit from Gas Restructuring	(3,331)		-											(3,331)	[redacted]
B Subtotal - net recoveries	(3,331)	-	290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	318,939	[redacted]
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	1,201,020	[redacted]
															-
Surcharge revenue:															
Act June 1998 - October 1998	-													-	(54,889)
Act November 1998 - October 1999	-													-	(538,143)
Act November 1999 - October 2000	-													-	(912,804)
Act November 2000 - October 2001	-													-	(1,336,776)
Act November 2001 - October 2002	-													-	(1,679,228)
Act November 2002 - October 2003	-													-	(1,732,442)
Act November 2003 - October 2004	(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	-													-	(191,270)
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)	(13,919,656)
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	899,862	[redacted]
E Allocation of Litigated Recovery	-	-	-	-	(621,477)	2,931	(4,199)	(26,279)	-	-	-	-	-	(649,023)	[redacted]
Surcharge calculation															[redacted]
Unrecovered costs (D+E)	-	-	-		-	-	-	25,257	26,236	34,913	9,385	(6,547)	11,879	101,124	[redacted]
remaining life	36	48	60	72	84	84	84	24	36	48	60	72	84		[redacted]
one year	12	12	12	12	12	12	12	12	12	12	12	12	12		[redacted]
F amortization	-	-	-	-	-	-	-	12,629	8,745	8,728	1,877	(1,091)	1,697		[redacted]
Required annual increase in rates:															
smaller of D or F	-	-	-		-	-	-	12,629	8,745	8,728	1,877	(1,091)	1,697	32,585	
forecasted therm sales	368,786,526	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	186,909,214	**186,909,214**
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	$0.0002	**$0.0016**

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

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

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

Expense and Collection Summary per Year

	(thru 9/98)	(9/99 - 9/00)	(9/00 - 9/01)	(9/01 - 9/02)	(9/02 - 9/03)	(9/03 - 9/04)	(9/04 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	(9/10 - 9/11)	(9/11 - 9/12)	(9/12 - 9/13)	(9/13 - 9/14)	(9/14 - 9/15)	Total
1 Remediation costs (i.o. 500061)	5,420,852	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	686,515	993,434	-	-	-	[redacted]
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	-	-	-	
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	-	-	-	
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)	-	-	-	
Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	-	
Recovery costs (i.o. 500004)	623,784	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	-	(14,068)	-	-	-	
Transfer Credit from Gas Restructuring	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
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)	-	-	-	
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	-	-	-	
Surcharge revenue:																		
Act June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
Act November 1998 - October 1999	(538,143)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
Act November 1999 - October 2000	(912,804)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
Act November 2000 - October 2001	(779,786)	(13,925)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(793,711)
Act November 2001 - October 2002	(759,943)	(24,514)	(110,314)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(894,771)
Act November 2002 - October 2003	(744,646)	(15,197)	(106,378)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(866,221)
Act November 2003 - October 2004	(422,442)	(14,567)	(101,969)	-	(99,593)	-	-	-	-	-	-	-	-	-	-	-	-	(638,571)
Act November 2004- October 2005	(184,336)	(14,180)	(85,078)	-	(56,719)	(226,875)	-	-	-	-	-	-	-	-	-	-	-	(567,186)
Act November 2005- October 2006	(141,176)	(6,875)	(96,247)	-	(54,998)	(213,118)	(343,739)	-	-	-	-	-	-	-	-	-	-	(856,153)
Act November 2006- October 2007	-	-	(98,635)	-	(56,363)	(211,361)	(366,359)	(429,768)	-	-	-	-	-	-	-	-	-	(1,162,487)
Act November 2007- October 2008													-	-	-	-	-	-
Act November 2012- October 2013									-	-	-	-	(30,009)	(130,039)	-	-	-	(160,048)
Act November 2013- October 2014													(38,246)	(165,731)	-	-	-	(203,977)
Act Nov 2009-Oct 2010 Base Rate Rev													(10,611)	-	-	-	-	(10,611)
Act Nov 2010-Oct 2011 Base Rate Rev													(77,509)	-	-	-	-	(77,509)
Act Nov 2011-Oct 2012 Base Rate Rev													(68,244)	-	-	-	-	(68,244)
Act Nov 2012-Oct 2013 Base Rate Rev													(8,937)	(67,398)	-	-	-	(76,335)
Act Nov 2013-Oct 2014 Base Rate Rev													-	(28,433)	-	-	-	(28,433)
Act Nov 2014-Oct 2015 Base Rate Rev													-	(21,909)	-	-	-	(21,909)
AES collections	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	-	-	-	(135,020)
Gas Street overcollection	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
Prior Period Pool under/overcollection																		
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)	-	-	-	(8,090,535)
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	-	-	-	[redacted]
E Allocation of Litigated Recovery																		
Surcharge calculation																		
Unrecovered costs (D+E)																		
remaining life																		
one year																		
F amortization																		
Required annual increase in rates:																		
smaller of D or F																		
forecasted therm sales																		
surcharge per therm																		

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Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2016-2017

Rate: $0.23 /MMBtu

	Rate	Volume	Total	
Injection Cost	$0.0087	**363,937**	$3,166	
Fuel (1.37%)	$0.0256	**363,937**	$9,302	
Withdrawal Cost	$0.0087	**315,584**	$2,746	
Delivery Rate	$0.0492	315,584	$15,530	
FTA Demand Charge	$0.2678	315,584	$84,521	
FTA Commodity Charge	$0.1137	315,584	$35,882	
Fuel (.85%)	$0.0159	315,584	$5,004	
		Total Cost	$156,151	
	Absolute Value of the	Sendout Error	**679,522**	MMBtu
		Rate	$ 0.23	/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	$1.4968	/ MMBtu per month
		$0.0492	/ MMBtu per day
	TGP Z4-6 Demand Charge	$8.1463	/ MMBtu per month
		$0.2678	/ MMBtu per day
	TGP Z4-6 Commodity Charge	$0.1137	/ MMBtu

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2016-2017
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	604	573	31	1,498,038	1,452,765	45,272	89,085	67,179	21,906
Dec	748	759	-11	1,798,479	1,820,060	-21,581	151,065	64,742	86,323
Jan	1,129	1,105	24	2,545,958	2,498,873	47,085	94,171	70,628	23,543
Feb	970	972	-2	2,212,664	2,216,588	-3,924	117,713	56,895	60,819
Mar	722	728	-6	1,672,715	1,682,379	-9,664	86,972	38,654	48,318
Apr	514	522	-8	1,094,737	1,106,029	-11,292	67,754	28,231	39,523
May	116	122	-6	475,578	477,946	-2,368	11,839	4,735	7,103
Jun	69	73	-4	410,176	411,669	-1,493	2,987	747	2,240
Jul	0	1	-1	539,282	539,282	0	0	0	0
Aug	0	0	0	539,282	539,282	0	0	0	0
Sep	46	57	-11	547,188	550,976	-3,788	5,166	689	4,477
Oct	443	434	9	1,095,597	1,085,492	10,105	52,771	31,438	21,333
Total	**5,361**	**5,346**	**15**	**14,429,693**	**14,381,340**	**48,353**	**679,522**	**363,937**	**315,584**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2016-2017
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Apr 1, 2015	30	31	-1	54,653	56,065	-1,412	1,412	0	1,412
Apr 2, 15	16	13	3	34,891	30,657	4,235	4,235	4,235	0
Apr 3, 15	10	12	-2	26,422	29,245	-2,823	2,823	0	2,823
Apr 4, 15	28	27	1	51,830	50,418	1,412	1,412	1,412	0
Apr 5, 15	26	27	-1	49,007	50,418	-1,412	1,412	0	1,412
Apr 6, 15	24	25	-1	46,184	47,595	-1,412	1,412	0	1,412
Apr 7, 15	26	26	0	49,007	49,007	0	0	0	0
Apr 8, 15	29	31	-2	53,241	56,065	-2,823	2,823	0	2,823
Apr 9, 15	28	30	-2	51,830	54,653	-2,823	2,823	0	2,823
Apr 10, 15	16	19	-3	34,891	39,126	-4,235	4,235	0	4,235
Apr 11, 15	19	20	-1	39,126	40,538	-1,412	1,412	0	1,412
Apr 12, 15	12	13	-1	29,245	30,657	-1,412	1,412	0	1,412
Apr 13, 15	6	2	4	20,776	15,130	5,646	5,646	5,646	0
Apr 14, 15	10	10	0	26,422	26,422	0	0	0	0
Apr 15, 15	15	13	2	33,480	30,657	2,823	2,823	2,823	0
Apr 16, 15	11	9	2	27,834	25,011	2,823	2,823	2,823	0
Apr 17, 15	7	11	-4	22,188	27,834	-5,646	5,646	0	5,646
Apr 18, 15	11	13	-2	27,834	30,657	-2,823	2,823	0	2,823
Apr 19, 15	15	16	-1	33,480	34,891	-1,412	1,412	0	1,412
Apr 20, 15	17	18	-1	36,303	37,715	-1,412	1,412	0	1,412
Apr 21, 15	13	14	-1	30,657	32,068	-1,412	1,412	0	1,412
Apr 22, 15	13	12	1	30,657	29,245	1,412	1,412	1,412	0
Apr 23, 15	21	24	-3	41,949	46,184	-4,235	4,235	0	4,235
Apr 24, 15	22	24	-2	43,361	46,184	-2,823	2,823	0	2,823
Apr 25, 15	19	18	1	39,126	37,715	1,412	1,412	1,412	0
Apr 26, 15	15	14	1	33,480	32,068	1,412	1,412	1,412	0
Apr 27, 15	15	15	0	33,480	33,480	0	0	0	0
Apr 28, 15	13	10	3	30,657	26,422	4,235	4,235	4,235	0
Apr 29, 15	13	12	1	30,657	29,245	1,412	1,412	1,412	0
Apr 30, 15	14	13	1	32,068	30,657	1,412	1,412	1,412	0
May 1, 15	15	18	-3	19,784	20,968	-1,184	1,184	0	1,184
May 2, 15	9	8	1	17,416	17,022	395	395	395	0
May 3, 15	1	1	0	14,259	14,259	0	0	0	0
May 4, 15	0	0	0	13,865	13,865	0	0	0	0
May 5, 15	2	0	2	14,654	13,865	789	789	789	0
May 6, 15	0	0	0	13,865	13,865	0	0	0	0
May 7, 15	0	0	0	13,865	13,865	0	0	0	0
May 8, 15	9	13	-4	17,416	18,995	-1,578	1,578	0	1,578
May 9, 15	0	0	0	13,865	13,865	0	0	0	0
May 10, 15	0	0	0	13,865	13,865	0	0	0	0
May 11, 15	6	8	-2	16,232	17,022	-789	789	0	789
May 12, 15	0	0	0	13,865	13,865	0	0	0	0
May 13, 15	10	11	-1	17,811	18,205	-395	395	0	395
May 14, 15	7	7	0	16,627	16,627	0	0	0	0
May 15, 15	3	4	-1	15,048	15,443	-395	395	0	395
May 16, 15	0	0	0	13,865	13,865	0	0	0	0
May 17, 15	0	0	0	13,865	13,865	0	0	0	0
May 18, 15	6	7	-1	16,232	16,627	-395	395	0	395
May 19, 15	2	0	2	14,654	13,865	789	789	789	0
May 20, 15	10	13	-3	17,811	18,995	-1,184	1,184	0	1,184
May 21, 15	5	4	1	15,838	15,443	395	395	395	0
May 22, 15	9	8	1	17,416	17,022	395	395	395	0
May 23, 15	9	8	1	17,416	17,022	395	395	395	0
May 24, 15	0	0	0	13,865	13,865	0	0	0	0
May 25, 15	0	0	0	13,865	13,865	0	0	0	0
May 26, 15	4	0	4	15,443	13,865	1,578	1,578	1,578	0
May 27, 15	0	0	0	13,865	13,865	0	0	0	0
May 28, 15	0	0	0	13,865	13,865	0	0	0	0
May 29, 15	0	0	0	13,865	13,865	0	0	0	0
May 30, 15	0	0	0	13,865	13,865	0	0	0	0
May 31, 15	9	12	-3	17,416	18,600	-1,184	1,184	0	1,184
Jun 1, 15	17	17	0	19,160	19,160	0	0	0	0
Jun 2, 15	15	15	0	18,414	18,414	0	0	0	0
Jun 3, 15	8	9	-1	15,800	16,174	-373	373	0	373
Jun 4, 15	6	8	-2	15,054	15,800	-747	747	0	747
Jun 5, 15	1	1	0	13,187	13,187	0	0	0	0
Jun 6, 15	3	2	1	13,934	13,561	373	373	373	0
Jun 7, 15	2	1	1	13,561	13,187	373	373	373	0
Jun 8, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 9, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 10, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 11, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 12, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 13, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 14, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 15, 15	8	8	0	15,800	15,800	0	0	0	0
Jun 16, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 17, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 18, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 19, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 20, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 21, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 22, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 23, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 24, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 25, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 26, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 27, 15	0	1	-1	12,814	13,187	-373	373	0	373
Jun 28, 15	9	11	-2	16,174	16,920	-747	747	0	747
Jun 29, 15	0	0	0	12,814	12,814	0	0	0	0
Jun 30, 15	0	0	0	12,814	12,814	0	0	0	0
Jul 1, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 2, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 3, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 4, 15	0	1	-1	17,396	17,396	0	0	0	0

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Jul 5, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 6, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 7, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 8, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 9, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 10, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 11, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 12, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 13, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 14, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 15, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 16, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 17, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 18, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 19, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 20, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 21, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 22, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 23, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 24, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 25, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 26, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 27, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 28, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 29, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 30, 15	0	0	0	17,396	17,396	0	0	0	0
Jul 31, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 1, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 2, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 3, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 4, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 5, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 6, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 7, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 8, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 9, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 10, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 11, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 12, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 13, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 14, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 15, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 16, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 17, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 18, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 19, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 20, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 21, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 22, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 23, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 24, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 25, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 26, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 27, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 28, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 29, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 30, 15	0	0	0	17,396	17,396	0	0	0	0
Aug 31, 15	0	0	0	17,396	17,396	0	0	0	0
Sep 1, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 2, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 3, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 4, 15	1	0	1	18,056	17,711	344	344	344	0
Sep 5, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 6, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 7, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 8, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 9, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 10, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 11, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 12, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 13, 15	2	3	-1	18,400	18,745	-344	344	0	344
Sep 14, 15	0	2	-2	17,711	18,400	-689	689	0	689
Sep 15, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 16, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 17, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 18, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 19, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 20, 15	4	6	-2	19,089	19,778	-689	689	0	689
Sep 21, 15	4	4	0	19,089	19,089	0	0	0	0
Sep 22, 15	6	7	-1	19,778	20,122	-344	344	0	344
Sep 23, 15	1	0	1	18,056	17,711	344	344	344	0
Sep 24, 15	1	2	-1	18,056	18,400	-344	344	0	344
Sep 25, 15	7	8	-1	20,122	20,467	-344	344	0	344
Sep 26, 15	10	13	-3	21,156	22,189	-1,033	1,033	0	1,033
Sep 27, 15	5	6	-1	19,434	19,778	-344	344	0	344
Sep 28, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 29, 15	0	0	0	17,711	17,711	0	0	0	0
Sep 30, 15	5	6	-1	19,434	19,778	-344	344	0	344
Oct 1, 15	12	9	3	32,770	29,402	3,368	3,368	3,368	0
Oct 2, 15	14	14	0	35,016	35,016	0	0	0	0
Oct 3, 15	16	15	1	37,261	36,139	1,123	1,123	1,123	0
Oct 4, 15	16	17	-1	37,261	38,384	-1,123	1,123	0	1,123
Oct 5, 15	12	14	-2	32,770	35,016	-2,246	2,246	0	2,246
Oct 6, 15	7	9	-2	27,156	29,402	-2,246	2,246	0	2,246
Oct 7, 15	7	5	2	27,156	24,911	2,246	2,246	2,246	0
Oct 8, 15	10	12	-2	30,525	32,770	-2,246	2,246	0	2,246

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Oct 9, 15	8	10	-2	28,279	30,525	-2,246	2,246	0	2,246
Oct 10, 15	15	17	-2	36,139	38,384	-2,246	2,246	0	2,246
Oct 11, 15	8	7	1	28,279	27,156	1,123	1,123	1,123	0
Oct 12, 15	3	4	-1	22,665	23,788	-1,123	1,123	0	1,123
Oct 13, 15	4	4	0	23,788	23,788	0	0	0	0
Oct 14, 15	11	11	0	31,647	31,647	0	0	0	0
Oct 15, 15	12	13	-1	32,770	33,893	-1,123	1,123	0	1,123
Oct 16, 15	15	16	-1	36,139	37,261	-1,123	1,123	0	1,123
Oct 17, 15	24	23	1	46,244	45,121	1,123	1,123	1,123	0
Oct 18, 15	30	29	1	52,980	51,858	1,123	1,123	1,123	0
Oct 19, 15	23	21	2	45,121	42,875	2,246	2,246	2,246	0
Oct 20, 15	12	10	2	32,770	30,525	2,246	2,246	2,246	0
Oct 21, 15	12	11	1	32,770	31,647	1,123	1,123	1,123	0
Oct 22, 15	9	8	1	29,402	28,279	1,123	1,123	1,123	0
Oct 23, 15	23	25	-2	45,121	47,367	-2,246	2,246	0	2,246
Oct 24, 15	19	20	-1	40,630	41,753	-1,123	1,123	0	1,123
Oct 25, 15	18	15	3	39,507	36,139	3,368	3,368	3,368	0
Oct 26, 15	24	24	0	46,244	46,244	0	0	0	0
Oct 27, 15	21	23	-2	42,875	45,121	-2,246	2,246	0	2,246
Oct 28, 15	9	6	3	29,402	26,034	3,368	3,368	3,368	0
Oct 29, 15	9	6	3	29,402	26,034	3,368	3,368	3,368	0
Oct 30, 15	21	20	1	42,875	41,753	1,123	1,123	1,123	0
Oct 31, 15	19	16	3	40,630	37,261	3,368	3,368	3,368	0
Nov 1, 15	14	12	2	40,977	38,057	2,921	2,921	2,921	0
Nov 2, 15	15	15	0	42,438	42,438	0	0	0	0
Nov 3, 15	9	10	-1	33,675	35,136	-1,460	1,460	0	1,460
Nov 4, 15	11	12	-1	36,596	38,057	-1,460	1,460	0	1,460
Nov 5, 15	2	0	2	23,453	20,532	2,921	2,921	2,921	0
Nov 6, 15	2	0	2	23,453	20,532	2,921	2,921	2,921	0
Nov 7, 15	16	15	1	43,898	42,438	1,460	1,460	1,460	0
Nov 8, 15	21	22	-1	51,200	52,661	-1,460	1,460	0	1,460
Nov 9, 15	19	20	-1	48,279	49,740	-1,460	1,460	0	1,460
Nov 10, 15	16	16	0	43,898	43,898	0	0	0	0
Nov 11, 15	21	19	2	51,200	48,279	2,921	2,921	2,921	0
Nov 12, 15	16	16	0	43,898	43,898	0	0	0	0
Nov 13, 15	18	17	1	46,819	45,359	1,460	1,460	1,460	0
Nov 14, 15	27	12	15	59,963	38,057	21,906	21,906	21,906	0
Nov 15, 15	21	21	0	51,200	51,200	0	0	0	0
Nov 16, 15	24	23	1	55,581	54,121	1,460	1,460	1,460	0
Nov 17, 15	28	22	6	61,423	52,661	8,762	8,762	8,762	0
Nov 18, 15	26	21	5	58,502	51,200	7,302	7,302	7,302	0
Nov 19, 15	12	12	0	38,057	38,057	0	0	0	0
Nov 20, 15	22	20	2	52,661	49,740	2,921	2,921	2,921	0
Nov 21, 15	25	27	-2	57,042	59,963	-2,921	2,921	0	2,921
Nov 22, 15	25	24	1	57,042	55,581	1,460	1,460	1,460	0
Nov 23, 15	34	34	0	70,186	70,186	0	0	0	0
Nov 24, 15	32	33	-1	67,265	68,725	-1,460	1,460	0	1,460
Nov 25, 15	28	29	-1	61,423	62,883	-1,460	1,460	0	1,460
Nov 26, 15	18	16	2	46,819	43,898	2,921	2,921	2,921	0
Nov 27, 15	12	8	4	38,057	32,215	5,842	5,842	5,842	0
Nov 28, 15	26	29	-3	58,502	62,883	-4,381	4,381	0	4,381
Nov 29, 15	31	33	-2	65,804	68,725	-2,921	2,921	0	2,921
Nov 30, 15	33	35	-2	68,725	71,646	-2,921	2,921	0	2,921
Dec 1, 15	26	30	-4	61,686	69,534	-7,848	7,848	0	7,848
Dec 2, 15	23	24	-1	55,800	57,762	-1,962	1,962	0	1,962
Dec 3, 15	26	25	1	61,686	59,724	1,962	1,962	1,962	0
Dec 4, 15	26	26	0	61,686	61,686	0	0	0	0
Dec 5, 15	27	28	-1	63,648	65,610	-1,962	1,962	0	1,962
Dec 6, 15	25	26	-1	59,724	61,686	-1,962	1,962	0	1,962
Dec 7, 15	25	23	2	59,724	55,800	3,924	3,924	3,924	0
Dec 8, 15	31	28	3	71,496	65,610	5,886	5,886	5,886	0
Dec 9, 15	24	21	3	57,762	51,877	5,886	5,886	5,886	0
Dec 10, 15	20	21	-1	49,915	51,877	-1,962	1,962	0	1,962
Dec 11, 15	16	23	-7	42,067	55,800	-13,733	13,733	0	13,733
Dec 12, 15	19	17	2	47,953	44,029	3,924	3,924	3,924	0
Dec 13, 15	21	18	3	51,877	45,991	5,886	5,886	5,886	0
Dec 14, 15	13	18	-5	36,182	45,991	-9,809	9,809	0	9,809
Dec 15, 15	19	18	1	47,953	45,991	1,962	1,962	1,962	0
Dec 16, 15	26	26	0	61,686	61,686	0	0	0	0
Dec 17, 15	19	23	-4	47,953	55,800	-7,848	7,848	0	7,848
Dec 18, 15	27	26	1	63,648	61,686	1,962	1,962	1,962	0
Dec 19, 15	33	31	2	75,419	71,496	3,924	3,924	3,924	0
Dec 20, 15	32	30	2	73,457	69,534	3,924	3,924	3,924	0
Dec 21, 15	22	18	4	53,839	45,991	7,848	7,848	7,848	0
Dec 22, 15	20	22	-2	49,915	53,839	-3,924	3,924	0	3,924
Dec 23, 15	17	17	0	44,029	44,029	0	0	0	0
Dec 24, 15	11	16	-5	32,258	42,067	-9,809	9,809	0	9,809
Dec 25, 15	17	14	3	44,029	38,143	5,886	5,886	5,886	0
Dec 26, 15	22	20	2	53,839	49,915	3,924	3,924	3,924	0
Dec 27, 15	26	27	-1	61,686	63,648	-1,962	1,962	0	1,962
Dec 28, 15	35	40	-5	79,343	89,153	-9,809	9,809	0	9,809
Dec 29, 15	35	41	-6	79,343	91,114	-11,771	11,771	0	11,771
Dec 30, 15	34	35	-1	77,381	79,343	-1,962	1,962	0	1,962
Dec 31, 15	31	27	4	71,496	63,648	7,848	7,848	7,848	0
Jan 1, 16	33	31	2	75,419	71,496	3,924	3,924	3,924	0
Jan 2, 16	34	31	3	77,381	71,496	5,886	5,886	5,886	0
Jan 3, 16	34	34	0	77,381	77,381	0	0	0	0
Jan 4, 16	51	53	-2	110,733	114,657	-3,924	3,924	0	3,924
Jan 5, 16	47	49	-2	102,886	106,810	-3,924	3,924	0	3,924
Jan 6, 16	40	37	3	89,153	83,267	5,886	5,886	5,886	0
Jan 7, 16	35	37	-2	79,343	83,267	-3,924	3,924	0	3,924
Jan 8, 16	31	31	0	71,496	71,496	0	0	0	0
Jan 9, 16	26	28	-2	61,686	65,610	-3,924	3,924	0	3,924
Jan 10, 16	23	22	1	55,800	53,839	1,962	1,962	1,962	0
Jan 11, 16	40	40	0	89,153	89,153	0	0	0	0
Jan 12, 16	36	38	-2	81,305	85,229	-3,924	3,924	0	3,924

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Jan 13, 16	43	43	0	95,038	95,038	0	0	0	0
Jan 14, 16	41	42	-1	91,114	93,076	-1,962	1,962	0	1,962
Jan 15, 16	33	33	0	75,419	75,419	0	0	0	0
Jan 16, 16	34	31	3	77,381	71,496	5,886	5,886	5,886	0
Jan 17, 16	36	37	-1	81,305	83,267	-1,962	1,962	0	1,962
Jan 18, 16	47	46	1	102,886	100,924	1,962	1,962	1,962	0
Jan 19, 16	46	45	1	100,924	98,962	1,962	1,962	1,962	0
Jan 20, 16	43	40	3	95,038	89,153	5,886	5,886	5,886	0
Jan 21, 16	45	42	3	98,962	93,076	5,886	5,886	5,886	0
Jan 22, 16	44	42	2	97,000	93,076	3,924	3,924	3,924	0
Jan 23, 16	44	44	0	97,000	97,000	0	0	0	0
Jan 24, 16	38	35	3	85,229	79,343	5,886	5,886	5,886	0
Jan 25, 16	34	33	1	77,381	75,419	1,962	1,962	1,962	0
Jan 26, 16	25	21	4	59,724	51,877	7,848	7,848	7,848	0
Jan 27, 16	33	33	0	75,419	75,419	0	0	0	0
Jan 28, 16	31	30	1	71,496	69,534	1,962	1,962	1,962	0
Jan 29, 16	31	30	1	71,496	69,534	1,962	1,962	1,962	0
Jan 30, 16	29	27	2	67,572	63,648	3,924	3,924	3,924	0
Jan 31, 16	22	20	2	53,839	49,915	3,924	3,924	3,924	0
Feb 1, 16	24	23	1	57,762	55,800	1,962	1,962	1,962	0
Feb 2, 16	28	26	2	65,610	61,686	3,924	3,924	3,924	0
Feb 3, 16	15	14	1	40,105	38,143	1,962	1,962	1,962	0
Feb 4, 16	22	22	0	53,839	53,839	0	0	0	0
Feb 5, 16	38	41	-3	85,229	91,114	-5,886	5,886	0	5,886
Feb 6, 16	32	35	-3	73,457	79,343	-5,886	5,886	0	5,886
Feb 7, 16	31	32	-1	71,496	73,457	-1,962	1,962	0	1,962
Feb 8, 16	43	45	-2	95,038	98,962	-3,924	3,924	0	3,924
Feb 9, 16	41	43	-2	91,114	95,038	-3,924	3,924	0	3,924
Feb 10, 16	37	38	-1	83,267	85,229	-1,962	1,962	0	1,962
Feb 11, 16	48	52	-4	104,848	112,695	-7,848	7,848	0	7,848
Feb 12, 16	47	49	-2	102,886	106,810	-3,924	3,924	0	3,924
Feb 13, 16	63	65	-2	134,276	138,200	-3,924	3,924	0	3,924
Feb 14, 16	63	62	1	134,276	132,314	1,962	1,962	1,962	0
Feb 15, 16	37	44	-7	83,267	97,000	-13,733	13,733	0	13,733
Feb 16, 16	27	24	3	63,648	57,762	5,886	5,886	5,886	0
Feb 17, 16	33	33	0	75,419	75,419	0	0	0	0
Feb 18, 16	43	41	2	95,038	91,114	3,924	3,924	3,924	0
Feb 19, 16	31	29	2	71,496	67,572	3,924	3,924	3,924	0
Feb 20, 16	22	14	8	53,839	38,143	15,695	15,695	15,695	0
Feb 21, 16	27	25	2	63,648	59,724	3,924	3,924	3,924	0
Feb 22, 16	36	35	1	81,305	79,343	1,962	1,962	1,962	0
Feb 23, 16	30	31	-1	69,534	71,496	-1,962	1,962	0	1,962
Feb 24, 16	18	21	-3	45,991	51,877	-5,886	5,886	0	5,886
Feb 25, 16	22	21	1	53,839	51,877	1,962	1,962	1,962	0
Feb 26, 16	40	39	1	89,153	87,191	1,962	1,962	1,962	0
Feb 27, 16	30	29	1	69,534	67,572	1,962	1,962	1,962	0
Feb 28, 16	19	17	2	47,953	44,029	3,924	3,924	3,924	0
Feb 29, 16	23	22	1	55,800	53,839	1,962	1,962	1,962	0
Mar 1, 16	25	27	-2	56,712	59,933	-3,221	3,221	0	3,221
Mar 2, 16	37	38	-1	76,039	77,650	-1,611	1,611	0	1,611
Mar 3, 16	41	41	0	82,482	82,482	0	0	0	0
Mar 4, 16	37	39	-2	76,039	79,261	-3,221	3,221	0	3,221
Mar 5, 16	35	34	1	72,818	71,208	1,611	1,611	1,611	0
Mar 6, 16	32	32	0	67,986	67,986	0	0	0	0
Mar 7, 16	25	26	-1	56,712	58,323	-1,611	1,611	0	1,611
Mar 8, 16	19	17	2	47,049	43,827	3,221	3,221	3,221	0
Mar 9, 16	5	0	5	24,500	16,447	8,053	8,053	8,053	0
Mar 10, 16	10	10	0	32,553	32,553	0	0	0	0
Mar 11, 16	21	22	-1	50,270	51,880	-1,611	1,611	0	1,611
Mar 12, 16	16	15	1	42,217	40,606	1,611	1,611	1,611	0
Mar 13, 16	19	15	4	47,049	40,606	6,442	6,442	6,442	0
Mar 14, 16	25	26	-1	56,712	58,323	-1,611	1,611	0	1,611
Mar 15, 16	22	21	1	51,880	50,270	1,611	1,611	1,611	0
Mar 16, 16	15	16	-1	40,606	42,217	-1,611	1,611	0	1,611
Mar 17, 16	15	17	-2	40,606	43,827	-3,221	3,221	0	3,221
Mar 18, 16	26	27	-1	58,323	59,933	-1,611	1,611	0	1,611
Mar 19, 16	33	33	0	69,597	69,597	0	0	0	0
Mar 20, 16	31	33	-2	66,376	69,597	-3,221	3,221	0	3,221
Mar 21, 16	30	29	1	64,765	63,155	1,611	1,611	1,611	0
Mar 22, 16	22	20	2	51,880	48,659	3,221	3,221	3,221	0
Mar 23, 16	20	19	1	48,659	47,049	1,611	1,611	1,611	0
Mar 24, 16	25	30	-5	56,712	64,765	-8,053	8,053	0	8,053
Mar 25, 16	19	27	-8	47,049	59,933	-12,885	12,885	0	12,885
Mar 26, 16	25	26	-1	56,712	58,323	-1,611	1,611	0	1,611
Mar 27, 16	24	26	-2	55,102	58,323	-3,221	3,221	0	3,221
Mar 28, 16	24	23	1	55,102	53,491	1,611	1,611	1,611	0
Mar 29, 16	26	25	1	58,323	56,712	1,611	1,611	1,611	0
Mar 30, 16	16	14	2	42,217	38,996	3,221	3,221	3,221	0
Mar 31, 16	2	0	2	19,668	16,447	3,221	3,221	3,221	0
Apr	514	522	-8	1,094,737	1,106,029	-11,292	67,754	28,231	39,523
May	116	122	-6	475,578	477,946	-2,368	11,839	4,735	7,103
Jun	69	73	-4	410,176	411,669	-1,493	2,987	747	2,240
Jul	0	1	-1	539,282	539,282	0	0	0	0
Aug	0	0	0	539,282	539,282	0	0	0	0
Sep	46	57	-11	547,188	550,976	-3,788	5,166	689	4,477
Oct	443	434	9	1,095,597	1,085,492	10,105	52,771	31,438	21,333
Nov	604	573	31	1,498,038	1,452,765	45,272	89,085	67,179	21,906
Dec	748	759	-11	1,798,479	1,820,060	-21,581	151,065	64,742	86,323
Jan	1,129	1,105	24	2,545,958	2,498,873	47,085	94,171	70,628	23,543
Feb	970	972	-2	2,212,664	2,216,588	-3,924	117,713	56,895	60,819
Mar	722	728	-6	1,672,715	1,682,379	-9,664	86,972	38,654	48,318
Total	5,361	5,346	15	14,429,693	14,381,340	48,353	679,522	363,937	315,584

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		156,947	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		49,114	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$1,375,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,980,428		Summary Page Line 68
26	Granite Ridge		$0		Attachment B Page 3 Line 1
27	Total		$3,355,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$68.32		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$11.39**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	75.4%	48.3%
Storage	9.2%	19.3%
Peaking	15.4%	32.4%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2016:

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		$15.0001		10/31/2022	
	Iroquois	RTS to Wright	470-01	4,047		$6.5971		11/1/2017	
	TGP	NET-NE (Z5-Z6)	95346	4,000		$7.1551		11/30/2021	
	TGP	FT-A (Z5-Z6)	2302	3,122		$7.1551		10/31/2020	
	TGP	FT-A (Z0-Z6)	8587	7,035		$23.2157		10/31/2020	
	TGP	FT-A (Z1-Z6)	8587	14,561		$20.6076		10/31/2020	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4.7435		10/31/2020	
	TGP	FT-A (Z6-Z6)	72694	30,000		$12.1898		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		$8.1463		10/31/2020	
	TGP	FT-A (Z4-Z6)	8587	3,811		$8.1463		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		$8.1463		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		$7.1551		10/31/2020	
	Dominion	GSS (Storage)	300076*	934	102,700	$1.8618	$0.0145	3/31/2021	
	TGP	FT-A (Z4-Z6)	11234	932		$8.1463		10/31/2020	
Peaking									
	Energy North	LNG/Propane****		49,114	-	$11.3900	$0.0000		X

* All gas transferred for storage contracts will be based on LDC's monthly WACOG
**All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention. Demand charge applicable for 6 months

Note: **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/15. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the EnergyNorth Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $25.9843/dth.

ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

		Volume	Rate	Monthly Cost	Months/Year	Annual Cost	
1		[redacted]					
2							
3							
4	Concord Lateral	[redacted]					
5	GDF Suez						
6							
7	Subtotal					**$1,375,000**	*
8							
9	**Total**					**$1,375,000**	
10							

* Contract currently being negotiated for an effective date of November 1, 2016

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EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	Storage	Peaking	Total
G-41	**LAHW**	Low Annual C&I - High Winter Use	48.3%	19.3%	32.4%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	48.3%	19.3%	32.4%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	48.3%	19.3%	32.4%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	75.4%	9.2%	15.4%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	75.4%	9.2%	15.4%	100.0%

HLF	High Load Factor	75.39%	9.19%	15.43%	100%
LLF	Low Load Factor	48.31%	19.30%	32.40%	100%
	Total	51.42%	18.13%	30.45%	100%

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design HDD			71.389	
		Base load	Heat load	Total
HLF	R-1 RNSH	113	414	527
LLF	R-3 RSH	4,182	62,154	66,336
LLF	G-41 SL	1,311	25,551	26,862
HLF	G-51 SH	658	2,097	2,756
LLF	G-42 ML	2,653	32,845	35,497
HLF	G-52 MH	1,433	2,629	4,062
LLF	G-43 LL	1,156	9,166	10,323
HLF	G-53 LLL90	2,320	2,880	5,200
HLF	G-54 LLG90	5,384	-	5,384
	TOTAL	19,210	137,737	156,947

	Base load	Heat load	Total
HLF	9,908	8,021	17,929
LLF	9,302	129,717	139,018
Total	19,210	137,737	156,947

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	113	182	295	84	142	521
R-3 RSH	4,182	27,304	31,486	12,687	21,299	65,472
G-41 SL	1,311	11,225	12,536	5,216	8,756	26,507
G-51 SH	658	921	1,580	428	719	2,726
G-42 ML	2,653	14,429	17,081	6,704	11,255	35,041
G-52 MH	1,433	1,155	2,588	537	901	4,026
G-43 LL	1,156	4,027	5,183	1,871	3,141	10,195
G-53 LLL90	2,320	1,265	3,585	588	987	5,160
G-54 LLG90	5,384	-	5,384	-	-	5,384
TOTAL	19,210	60,508	79,718	28,115	47,200	155,033

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
HLF	9,908	3,523	13,432	1,637	2,749	17,817
LLF	9,302	56,985	66,286	26,478	44,451	137,216
Total	19,210	60,508	79,718	28,115	47,200	155,033

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	56.6%	16.2%	27.2%	100.0%
R-3 RSH	48.1%	19.4%	32.5%	100.0%
G-41 SL	47.3%	19.7%	33.0%	100.0%
G-51 SH	57.9%	15.7%	26.4%	100.0%
G-42 ML	48.7%	19.1%	32.1%	100.0%
G-52 MH	64.3%	13.3%	22.4%	100.0%
G-43 LL	50.8%	18.4%	30.8%	100.0%
G-53 LLL90	69.5%	11.4%	19.1%	100.0%
G-54 LLG90	100.0%	0.0%	0.0%	100.0%
TOTAL	51.4%	18.1%	30.4%	100.0%

	Pipeline	Storage	Peaking	Total
High Load Factor	75.39%	9.19%	15.43%	100%
Low Load Factor	48.31%	19.30%	32.40%	100%
Total	51.42%	18.13%	30.45%	100%

EnergyNorth Natural Gas, Inc

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 HDD 71.389

	Daily Baseload * 1000	March 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	113	5.907	422	535	21%	0.301%	113	414	527
R-3 RSH	4,182	887.059	63,326	67,508	6%	45.125%	4,182	62,154	66,336
G-41 SL	1,311	364.667	26,033	27,344	5%	18.551%	1,311	25,551	26,862
G-51 SH	658	29.934	2,137	2,795	24%	1.523%	658	2,097	2,756
G-42 ML	2,653	468.757	33,464	36,117	7%	23.846%	2,653	32,845	35,497
G-52 MH	1,433	37.526	2,679	4,112	35%	1.909%	1,433	2,629	4,062
G-43 LL	1,156	130.818	9,339	10,495	11%	6.655%	1,156	9,166	10,323
G-53 LLL90	2,320	41.101	2,934	5,255	44%	2.091%	2,320	2,880	5,200
G-54 LLG90	5,384	-	-	5,384	100%	0.000%	5,384	-	5,384
TOTAL	19,210	1,937.845	140,334	159,544		100.000%	19,210	137,737	156,947

HLF	9,908	114	8,172	18,080
LLF	9,302	1,823	132,162	141,464
Total	19,210	1,938	140,334	159,544

Design Day from 2015-2016 COG	**156,947**
Design Day from Billing Calculation	159,544
Variance	(2,597)

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

<u>CALCULATION OF NORMAL SALES VOLUMES</u>

Actual Volumes

Total Core Sales Volumes(000's) Dth

		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-15	Aug-15	Sep-15	Oct-15	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	5	8	9	9	10	7	5	4	4	3	3	3	70	3.505	0.113
LLF	R-3 RSH	365	732	936	1,042	963	699	384	198	148	111	109	157	5,845	129.635	4.182
LLF	G-41 SL	121	265	366	417	384	254	138	63	52	29	29	44	2,161	40.638	1.311
HLF	G-51 SH	27	39	46	50	48	38	29	24	21	20	19	20	381	20.403	0.658
LLF	G-42 ML	214	409	529	564	535	383	236	130	91	74	60	101	3,326	82.230	2.653
HLF	G-52 MH	58	77	71	81	84	72	58	50	45	44	44	46	729	44.415	1.433
LLF	G-43 LL	81	121	152	169	170	122	90	57	36	36	32	31	1,097	35.850	1.156
HLF	G-53 LLL90	83	93	107	110	103	101	78	75	76	68	73	71	1,038	71.931	2.320
HLF	G-54 LLL110	198	179	184	140	115	110	129	117	164	170	181	162	1,848	166.896	5.384
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	0	0.000	0.000
	TOTAL	1,151	1,923	2,399	2,582	2,410	1,786	1,148	719	638	553	549	635	16,495	595.502	19.210
	HLF	371	396	417	390	359	328	299	272	311	304	320	302	4,067	307.150	9.908
	LLF	780	1,528	1,983	2,192	2,051	1,458	849	448	327	250	229	333	12,429	288.353	9.302

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

		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-15	Aug-15	Sep-15	Oct-15	Total
		30	31	31	29	31	30	31	30	31	31	30	31	366
HLF	R-1 RNSH	3	4	4	3	4	3	4	3	4	3	3	3	41
LLF	R-3 RSH	125	130	130	121	130	125	130	125	148	111	109	130	1,531
LLF	G-41 SL	39	41	41	38	41	39	41	39	52	29	29	41	480
HLF	G-51 SH	20	20	20	19	20	20	20	20	21	20	19	20	241
LLF	G-42 ML	80	82	82	77	82	80	82	80	91	74	60	82	971
HLF	G-52 MH	43	44	44	42	44	43	44	43	45	44	43	44	524
LLF	G-43 LL	35	36	36	34	36	35	36	35	36	36	32	31	423
HLF	G-53 LLL90	70	72	72	67	72	70	72	70	76	68	70	71	849
HLF	G-54 LLL110	162	167	167	140	115	110	129	117	164	170	162	162	1,848
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	606	627	627	570	575	554	589	562	669	584	555	615	7,031
	HLF	297	307	307	271	255	245	269	253	311	304	296	301	3,504
	LLF	279	288	288	270	288	279	288	279	327	250	229	283	3,404

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Heating Volumes (= Actual Volumes - Baseload)

		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-15	Aug-15	Sep-15	Oct-15	Total
HLF	R-1 RNSH	1	4	5	6	6	4	2	1	0	0	0	0	29
LLF	R-3 RSH	240	602	806	921	833	574	255	73	0	0	0	27	4,315
LLF	G-41 SL	82	225	325	379	343	215	97	23	0	0	0	3	1,681
HLF	G-51 SH	7	18	26	31	27	18	8	4	0	0	0	0	141
LLF	G-42 ML	134	327	447	487	453	303	154	51	0	0	0	19	2,355
HLF	G-52 MH	15	33	26	39	39	29	13	7	0	0	1	2	205
LLF	G-43 LL	46	86	116	136	134	88	55	22	0	0	0	0	674
HLF	G-53 LLL90	13	21	35	43	31	31	6	6	0	0	3	0	188
HLF	G-54 LLL110	36	12	17	0	0	0	0	0	0	0	20	0	0
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	545	1,297	1,773	2,012	1,836	1,232	560	157	(31)	(31)	(6)	20	9,464

HLF	73	88	109	119	104	82	30	18	0	0	24	2	563
LLF	501	1,239	1,695	1,923	1,763	1,179	561	169	0	0	0	49	9,024

Actual BDD	503.5	666.0	932.0	1038.5	848.0	636.5	382.5	124.0	37.0	0.5	28.5	245.5	5442.5

Heat Factors

		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-15	Aug-15	Sep-15	Oct-15	Total	AVG	AVG Peak
HLF	R-1 RNSH	0.0030	0.0062	0.0057	0.0059	0.0071	0.0058	0.0051	0.0077	0.0000	0.0000	0.0000	0.0000		0.0039	0.0056
LLF	R-3 RSH	0.4764	0.9044	0.8648	0.8871	0.9824	0.9015	0.6662	0.5871	0.0000	0.0000	0.0000	0.1117		0.5318	0.8361
LLF	G-41 SL	0.1619	0.3374	0.3492	0.3647	0.4044	0.3372	0.2544	0.1893	0.0000	0.0000	0.0000	0.0128		0.2009	0.3258
HLF	G-51 SH	0.0147	0.0276	0.0279	0.0299	0.0323	0.0291	0.0220	0.0357	0.0000	0.0000	0.0000	0.0000		0.0183	0.0269
LLF	G-42 ML	0.2662	0.4904	0.4794	0.4688	0.5344	0.4765	0.4033	0.4080	0.0000	0.0000	0.0000	0.0770		0.3003	0.4526
HLF	G-52 MH	0.0304	0.0491	0.0281	0.0375	0.0463	0.0459	0.0352	0.0593	0.0000	0.0000	0.0236	0.0063		0.0301	0.0396
LLF	G-43 LL	0.0911	0.1285	0.1247	0.1308	0.1577	0.1378	0.1428	0.1770	0.0000	0.0000	0.0000	0.0000		0.0909	0.1284
HLF	G-53 LLL90	0.0262	0.0316	0.0377	0.0411	0.0366	0.0488	0.0154	0.0462	0.0000	0.0000	0.1205	0.0000		0.0337	0.0370
HLF	G-54 LLL110	0.0715	0.0183	0.0179	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6979	0.0000		0.0671	0.0179
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	1.0817	1.9468	1.9023	1.9378	2.1647	1.9354	1.4633	1.2684	-0.8378	-62.0000	-0.2106	0.0815		(4.1055)	1.8281

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	**503.5**	**666.0**	**932.0**	**1,038.5**	**848.0**	**636.5**	**382.5**	**124.0**	**37.0**	**0.5**	**28.5**	**245.5**	**5442.5**
Norm Billing DD	**567.0**	**891.6**	**1146.4**	**1140.8**	**977.0**	**706.2**	**373.3**	**142.9**	**30.8**	**9.7**	**66.7**	**269.7**	**6322.0**

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

		Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-15	Aug-15	Sep-15	Oct-15	Total
HLF	R-1 RNSH	5	9	10	10	10	7	5	4	4	3	3	3	75
LLF	R-3 RSH	396	936	1,121	1,133	1,089	762	378	209	148	111	109	160	6,553
LLF	G-41 SL	131	341	441	454	436	277	136	66	52	29	29	44	2,437
HLF	G-51 SH	28	45	52	53	52	40	29	25	21	20	19	20	404
LLF	G-42 ML	231	519	632	612	604	416	233	138	91	74	60	103	3,712
HLF	G-52 MH	60	88	77	84	90	75	58	51	45	44	45	46	763
LLF	G-43 LL	86	150	179	183	190	132	89	60	36	36	32	31	1,204
HLF	G-53 LLL90	84	100	115	114	108	104	78	76	76	68	78	71	1,072
HLF	G-54 LLL110	202	183	187	140	115	110	129	117	164	170	208	162	1,887
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	1,220	2,362	2,807	2,780	2,689	1,921	1,135	743	643	(18)	541	637	17,461

HLF	380	425	442	402	375	337	298	274	311	304	352	302	4,202
LLF	844	1,947	2,373	2,382	2,319	1,588	836	474	327	250	229	338	13,905

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2016 - 2017 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	$1.1009	$857.72	$981.21	$ (123.49)	-12.59%	$0.9108	$1.1115	$2,410.28	$2,748.56	$ (338.28)	-12.31%
17	Nov 14 - Apr 15	15.1%	$0.0795	8,779,742	$ 697,989	$1.2425	$0.5141	$1,127.66	$948.07	$ 179.59	18.94%						
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					$0.7268	$0.7068	$827.14	$806.66	$ 20.48	2.54%						
20	Total									$ 714.69						$ 316.72	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2016 - 2017 Winter Cost of Gas Filing
Short-Term Debt Limitations

	For Purposes of Fuel Financing	
Total Direct Gas Costs	$	58,894,216
Total Indirect Gas Costs		4,661,664
Total Gas Costs	$	63,555,880
% of Debt to Total Gas Costs		30%
Short Term Debt	$	19,066,764

	For Purposes Other Than Fuel Financing	
12/31/2017 Projected Net Plant	**$**	**348,057,079**
% of Debt to Net Plant		20%
Short Term Debt	$	69,611,416

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
2016 - 2017 Winter Cost of Gas Filing

Company Allowance Calculation

	Jul-2016	Aug-2015	Sep-2015	Oct-2015	Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Total
Total Sendout- Therms	5,060,230	5,464,570	5,599,050	11,029,130	14,761,110	17,747,750	25,984,560	22,760,830	17,113,820	13,354,190	8,159,060	5,510,040	152,544,340
Total Throughput- Therms	5,581,324	5,532,690	5,488,744	6,187,681	10,820,679	15,853,301	20,216,892	23,899,831	20,345,924	16,440,049	11,690,908	6,699,259	148,757,282
Variance	(521,094)	(68,120)	110,306	4,841,449	3,940,431	1,894,449	5,767,668	(1,139,001)	(3,232,104)	(3,085,859)	(3,531,848)	(1,189,219)	3,787,058
Company Allowance													**2.48%**

Lost and Unaccounted For Gas ("LAUF") Calculation

	Jul-2016	Aug-2015	Sep-2015	Oct-2015	Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Total
Total Sendout- Therms	5,060,230	5,464,570	5,599,050	11,029,130	14,761,110	17,747,750	25,984,560	22,760,830	17,113,820	13,354,190	8,159,060	5,510,040	152,544,340
Total Throughput- Therms	5,581,324	5,532,690	5,488,744	6,187,681	10,820,679	15,853,301	20,216,892	23,899,831	20,345,924	16,440,049	11,690,908	6,699,259	148,757,282
Company Use	5,172	1,809	1,945	2,160	3,185	18,630	39,756	42,663	23,055	17,436	8,220	5,866	169,897
Variance	(526,266)	(69,929)	108,361	4,839,289	3,937,246	1,875,819	5,727,912	(1,181,664)	(3,255,159)	(3,103,295)	(3,540,068)	(1,195,085)	3,617,161
LAUF													**2.37%**