ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing

Table of Contents

Ln	Description	Reference	PK 12-13 Nov - Apr
1	**ENERGY NORTH NATURAL GAS, INC.**		
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**		
4	**Summary**		
5			PK 12-13
6		Reference	Nov - Apr
7	(a)	(b)	(c)
9	**Anticipated Direct Cost of Gas**		
10	Purchased Gas:		
11	Demand Costs:	Sch. 5A, col (j), ln 43	$ 9,446,057
12	Supply Costs	Sch. 6, col (i), ln 44	26,630,667
14	Storage Gas:		
15	Demand, Capacity:	Sch. 5A, col (k), ln 58	$ 1,092,898
16	Commodity Costs:	Sch. 6, col (i), ln 47	9,121,704
18	Produced Gas:	Sch. 6, col (i), ln 53	$ 291,366
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$ 1,941,641
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 172	$ -
23	**Total Unadjusted Cost of Gas**		$ 48,524,333
25	**Adjustments:**		
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$ 1,606,569
28	Interest 10/31/12 - 04//30/13	Sch. 3, col (q) ln 193	73,865
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)	(396,197)
32	Fuel Financing	Sch. 4, ln 26 col (e)	109,724
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)	(8,224)
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)	(1,130,619)
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)	40,691
40	**Total Adjustments**		$ 295,808
42	**Total Anticipated Direct Costs**	lns 23 + 40	$ 48,820,141
44	**Anticipated Indirect Cost of Gas**		
45	**Working Capital**		
46	Total Unadjusted Anticipated Cost of Gas	Ln 23	$ 48,524,333
47	Lead Lag Days / 365	DG 10-017, 14.27 / 365	0.0391
48	Prime Rate		3.25%
49	Working Capital Percentage	per GTC 16(f), ln 47 * ln 48	0.127%
50	Working Capital	ln 46 * ln 49	61,669
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 78	(541)
53	**Total Working Capital Allowance**	lns 50 + 51	$ 61,128
55	**Bad Debt**		
56	Total Unadjusted Anticipated Cost of Gas	ln 23	$ 48,524,333
57	Less Refunds	ln 30	-
58	Plus Working Capital	ln 53	61,128
59	Plus Prior Period (Over) Under Recovery	ln 27	1,606,569
60	Subtotal		$ 50,192,030
61	Bad Debt Percentage	per GTC 16(f)	2.50%
63	Bad Debt Allowance	ln 60 * ln 61	$ 1,254,801
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 162	113,348
66	**Total Bad Debt Allowance**	lns 63 + 64	$ 1,368,148
68	**Production and Storage Capacity**	per GTC16(f)	$ 1,980,428
70	**Miscellaneous Overhead**	per GTC 16(f)	$ 13,170
71	Sales Volume	Sch. 10B, ln 23/1000	77,826
72	Divided by Total Sales	Sch. 10B, ln 23/1000	95,484
73	Ratio		81.51%
75	**Miscellaneous Overhead**	lns 70 * 73	$ 10,735
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$ 3,420,439
79	**Total Cost of Gas**	lns 42 + 77	$ 52,240,580
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52	77,755,617

Ln		(b)	Peak Costs May 12 - Oct 12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Peak Period Nov - Apr
1	**ENERGY NORTH NATURAL GAS, INC.**										
2											
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 12 - Oct 12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10										1,999,709	2.5%
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	2,033,163	11,289,618	16,713,541	17,879,201	15,456,597	10,384,290	3,999,207	77,755,617
13	Lost Gas (Unaccounted for)		-	166,779	253,405	299,313	261,339	228,891	134,772		1,344,499
14	Company Use		-	81,276	123,491	145,863	127,357	111,545	65,678		655,210
15	Unbilled Therms		-	7,641,002	3,409,316	648,303	(2,720,057)	(2,179,583)	(2,566,730)	(3,999,207)	233,044
16											
17	**Total Firm Volumes**	Sch. 6, ln 92	-	9,922,220	15,075,830	17,807,020	15,547,840	13,617,450	8,018,010		79,988,370
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 63	-	924,000	926,310	954,800	862,400	954,800	820,050		5,442,360
22	Niagara Supply	Sch. 6, ln 64	-	721,490	745,360	745,360	672,980	745,360	721,490		4,352,040
23	TGP Supply (Direct)	Sch. 6, ln 65	-	5,292,980	5,155,150	5,155,150	4,656,190	5,155,150	5,272,190		30,686,810
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	2,380,840	2,380,840	2,150,610	-	-		6,912,290
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	3,531,220	957,880	1,983,520	2,142,140	3,002,230	3,362,590		14,979,580
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	-	21,560	22,330	680,680	-	44,660	-		769,230
28	Propane Truck	Sch. 6, ln 70	-	-	-	-	-	-	-		-
29	PNGTS	Sch. 6, ln 71	-	58,520	76,230	83,160	71,610	66,990	46,970		403,480
30	Granite Ridge	Sch. 6, ln 72	-	-	-	-	-	-	-		-
31	Subtotal Pipeline Volumes		-	10,549,770	10,264,100	11,983,510	10,555,930	9,969,190	10,223,290		63,545,790
32											
33	Storage Gas:										
34	TGP Storage	Sch. 6, ln 77	-	1,223,530	4,811,730	5,793,480	4,971,120	3,670,590	52,360		20,522,810
35											
36	Produced Gas:										
37	LNG Vapor	Sch. 6, ln 80	-	21,560	22,330	710,710	20,790	22,330	21,560		819,280
38	Propane	Sch. 6, ln 81	-	-	-	-	-	-	-		-
39	Subtotal Produced Gas		-	21,560	22,330	710,710	20,790	22,330	21,560		819,280
40											
41	Less - Gas Refill:										
42	LNG Truck	Sch. 6, ln 86	-	(21,560)	(22,330)	(680,680)	-	(44,660)	-		(769,230)
43	Propane	Sch. 6, ln 87	-	-	-	-	-	-	-		-
44	TGP Storage Refill	Sch. 6, ln 88	-	(1,851,080)	-	-	-	-	(2,279,200)		(4,130,280)
45	Subtotal Refills		-	(1,872,640)	(22,330)	(680,680)	-	(44,660)	(2,279,200)		(4,899,510)
46											
47	Total Firm Sendout Volumes	lns 31 + 34 + 39 + 45	-	9,922,220	15,075,830	17,807,020	15,547,840	13,617,450	8,018,010		79,988,370
48											

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Line		Reference	Peak Costs May 12 - Oct 12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Peak Period Nov - Apr
1	**ENERGY NORTH NATURAL GAS, INC.**										
2											
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6											
7	For Month of:										
49	**II. Gas Costs**										
50											
51	**A. Demand Costs**										
52	Supply										
53	Niagra 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		$ 1,363,979	$ 1,071,942	$ 1,071,942	$ 1,071,942	$ 1,071,942	$ 1,071,942	$ 1,071,942		$ 7,795,631
74	Less Capacity Credit		(349,417)	(231,914)	(231,914)	(231,914)	(231,914)	(231,914)	(231,914)		(1,740,900)
75	Net Pipeline Demand Costs		$ 1,014,563	$ 840,028	$ 840,028	$ 840,028	$ 840,028	$ 840,028	$ 840,028		$ 6,054,731
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	DOMAC Demand NSB041	Sch.5A, ln 36									
81	Subtotal Peaking Demand		$ 2,026,707	$ 316,420	$ 441,170	$ 441,170	$ 441,170	$ 441,170	$ 316,420		$ 4,424,227
82	Less Capacity Credit		(519,190)	(68,457)	(95,447)	(95,447)	(95,447)	(95,447)	(68,457)		(1,037,892)
83	Net Peaking Supply Demand Costs		$ 1,507,517	$ 247,963	$ 345,723	$ 345,723	$ 345,723	$ 345,723	$ 247,963		$ 3,386,335
84											
85	Storage:										
86	Dominion - Demand	Sch.5A, ln 46	[redacted]								
87	Dominion - Storage	Sch.5A, ln 47									
88	Honeoye - Demand	Sch.5A, ln 48									
89	National Fuel - Demand	Sch.5A, ln 49									
90	National Fuel - Capacity	Sch.5A, ln 50									
91	Tenn Gas Pipeline - Demand	Sch.5A, ln 51									
92	Tenn Gas Pipeline - Capacity	Sch.5A, ln 52									
93	Subtotal Storage Demand		$ 715,492	$ 119,249	$ 119,249	$ 119,249	$ 119,249	$ 119,249	$ 119,249		$ 1,430,985
94	Less Capacity Credit		(183,291)	(25,799)	(25,799)	(25,799)	(25,799)	(25,799)	(25,799)		(338,087)
95	Net Storage Demand Costs		$ 532,202	$ 93,449	$ 93,449	$ 93,449	$ 93,449	$ 93,449	$ 93,449		$ 1,092,898
96											
97	Total Demand Charges	lns 54 + 73 + 81 + 93	$ 4,106,179	$ 1,508,666	$ 1,633,452	$ 1,633,452	$ 1,633,346	$ 1,633,452	$ 1,508,666		$ 13,657,212
98	Total Capacity Credit	lns 55 + 74 + 82 + 94	(1,051,898)	(326,399)	(353,396)	(353,396)	(353,373)	(353,396)	(326,399)		(3,118,258)
99	Net Demand Charges		$ 3,054,281	$ 1,182,267	$ 1,280,055	$ 1,280,055	$ 1,279,973	$ 1,280,055	$ 1,182,267		$ 10,538,954
100											
101											

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1	**ENERGY NORTH NATURAL GAS, INC.**									
2										
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**									
4	**Summary of Supply and Demand Forecast**									
5										
6			Peak Costs								Peak Period
7	For Month of:		May 12 - Oct 12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Nov - Apr
102	**B. Commodity Costs**										
103	Pipeline:										
104	Dawn Supply	Sch. 6, ln 12	[redacted]								
105	Niagara Supply	Sch. 6, ln 13									
106	TGP Supply (Direct)	Sch. 6, ln 14									
107	Dracut Supply 1 - Baseload	Sch. 6, ln 15									
108	Dracut Supply 2 - Swing	Sch. 6, ln 16									
109	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	Granite Ridge	Sch. 6, ln 21									
114	Subtotal Pipeline Commodity Costs		$ -	$ 3,596,339	$ 4,307,613	$ 6,064,958	$ 5,085,096	$ 3,830,237	$ 3,683,307		$ 26,567,550
115											
116	Storage:										
117	TGP Storage - Withdrawals	Sch. 6, ln 47	$ -	$ 543,878	$ 2,138,887	$ 2,575,290	$ 2,209,739	$ 1,631,633	$ 22,276		$ 9,121,704
118											
119	Produced Gas Costs:										
120	LNG Vapor	Sch. 6, ln 50	[redacted]								
121	Propane	Sch. 6, ln 51									
122	Subtotal Produced Gas Costs		$ -	$ 8,385	$ 8,483	$ 251,683	$ 7,362	$ 7,862	$ 7,591		$ 291,366
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		$ -	$ (655,834)	$ (7,528)	$ (238,320)	$ -	$ (15,610)	$ (886,634)		$ (1,803,927)
130											
131	Total Supply Commodity Costs		$ -	$ 3,492,768	$ 6,447,455	$ 8,653,611	$ 7,302,197	$ 5,454,121	$ 2,826,540		$ 34,176,693
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		$ -	$ 250,777	$ 252,463	$ 265,685	$ 240,581	$ 251,813	$ 254,506		$ 1,515,825
140											
141	TGP Storage - Withdrawals	Sch. 6, ln 32	$ -	$ 20,940	$ 82,349	$ 99,151	$ 85,077	$ 62,819	$ 884		$ 351,219
142											
143	Total Supply Volumetric Trans. Costs	lns 139 + 141	$ -	$ 271,717	$ 334,812	$ 364,836	$ 325,657	$ 314,632	$ 255,390		$ 1,867,044
144											
145	Total Commodity Gas & Trans. Costs	lns 131 + 143	$ -	$ 3,764,485	$ 6,782,267	$ 9,018,447	$ 7,627,855	$ 5,768,753	$ 3,081,930		$ 36,043,738
146											
147											

REDACTED

1 **ENERGY NORTH NATURAL GAS, INC.**
2
3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

#			Peak Costs May 12 - Oct 12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Peak Period Nov - Apr
7	For Month of:										
148	**D. Supply and Demand Costs by Source**										
149											
150	Purchased Gas Demand Costs										
151	Pipeline Gas Demand Costs	lns 54 + 73	$ 1,363,979	$ 1,072,998	$ 1,073,033	$ 1,073,033	$ 1,072,927	$ 1,073,033	$ 1,072,998		$ 7,802,000
152	Peaking Gas Demand Costs	ln 81	2,026,707	316,420	441,170	441,170	441,170	441,170	316,420		4,424,227
153	Subtotal Purchased Gas Demand Costs		$ 3,390,686	$ 1,389,418	$ 1,514,203	$ 1,514,203	$ 1,514,097	$ 1,514,203	$ 1,389,418		$ 12,226,227
154	Less Capacity Credit	lns 55 + 74 + 82	(868,607)	(300,600)	(327,597)	(327,597)	(327,574)	(327,597)	(300,600)		(2,780,171)
155	Net Purchased Gas Demand Costs		$ 2,522,079	$ 1,088,818	$ 1,186,606	$ 1,186,606	$ 1,186,523	$ 1,186,606	$ 1,088,818		$ 9,446,057
156											
157	Storage Gas Demand Costs										
158	Storage Demand	ln 93	$ 715,492	$ 119,249	$ 119,249	$ 119,249	$ 119,249	$ 119,249	$ 119,249		$ 1,430,985
159	Less Capacity Credit	ln 94	(183,291)	(25,799)	(25,799)	(25,799)	(25,799)	(25,799)	(25,799)		(338,087)
160	Net Storage Demand Costs		$ 532,202	$ 93,449	$ 93,449	$ 93,449	$ 93,449	$ 93,449	$ 93,449		$ 1,092,898
161											
162	**Total Demand Costs**	lns 155 + 160	$ 3,054,281	$ 1,182,267	$ 1,280,055	$ 1,280,055	$ 1,279,973	$ 1,280,055	$ 1,182,267		$ 10,538,954
163											
164	Purchased Gas Supply										
165	Commodity Costs	ln 114	$ -	$ 3,596,339	$ 4,307,613	$ 6,064,958	$ 5,085,096	$ 3,830,237	$ 3,683,307		$ 26,567,550
166	Less Storage Inj.(TGP Storage)	ln 127	[redacted]								
167	Less Storage Transportation	ln 128									
168	Less LNG Truck	ln 125									
169	Less Propane Truck	ln 126									
170	Plus Transportation Costs	ln 139									
171	Subtotal Purchased Gas Supply		$ -	$ 3,191,282	$ 4,552,548	$ 6,092,323	$ 5,325,677	$ 4,066,439	$ 3,051,179		$ 26,279,448
172											
173	Storage Commodity Costs										
174	Commodity Costs	ln 117	$ -	$ 543,878	$ 2,138,887	$ 2,575,290	$ 2,209,739	$ 1,631,633	$ 22,276		$ 9,121,704
175	Transportation Costs	ln 141	-	20,940	82,349	99,151	85,077	62,819	884		351,219
176	Subtotal Storage Commodity Costs		$ -	$ 564,817	$ 2,221,236	$ 2,674,441	$ 2,294,815	$ 1,694,452	$ 23,161		$ 9,472,923
177											
178	Produced Gas Commodity Costs	ln 122	$ -	$ 8,385	$ 8,483	$ 251,683	$ 7,362	$ 7,862	$ 7,591		$ 291,366
179											
180	**SubTotal Commodity Costs**	lns 171 + 176 + 178	$ -	$ 3,764,485	$ 6,782,267	$ 9,018,447	$ 7,627,855	$ 5,768,753	$ 3,081,930		$ 36,043,738
181											
182	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ 341,683	$ 338,706	$ 315,594	$ 323,001	$ 420,983	$ 201,674		$ 1,941,641
183											
184	**Total Commodity Costs**	lns 180 + 182	$ -	$ 4,106,169	$ 7,120,973	$ 9,334,041	$ 7,950,856	$ 6,189,736	$ 3,283,604		$ 37,985,379
185											
186	**Total Demand Costs**	ln 99	$ 3,054,281	$ 1,182,267	$ 1,280,055	$ 1,280,055	$ 1,279,973	$ 1,280,055	$ 1,182,267		$ 10,538,954
187	**Total Supply Costs**	ln 184	-	4,106,169	7,120,973	9,334,041	7,950,856	6,189,736	3,283,604		37,985,379
188											
189	**Total Direct Gas Costs**	lns 186 + 187	$ 3,054,281	$ 5,288,436	$ 8,401,028	$ 10,614,096	$ 9,230,829	$ 7,469,791	$ 4,465,871		$ 48,524,333
190											
191											

1 **ENERGY NORTH NATURAL GAS, INC.**

2

3 **Peak 2012 - 2013 Winter Cost of Gas Filing**

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

Line	Supplier	Contract	Contract Type	Contract Unit	Unit Dth (MDQ/ACQ)	Peak Period Cost per Unit Dth
7	(a)	(b)	(c)	(d)	(e)	(f)
8						
9	**Demand Costs**					
10	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	[redacted]
11	Tenn Gas Pipeline - Cap. Reservations	FS-MA	Storage	ACQ	1,560,391	
12	National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
13	Niagra Supply		Supply	MDQ	3,199	
14	Tenn Gas Pipeline - Demand	FS-MA	Storage	MDQ	21,844	
15	Dominion - Demand	GSS 300076	Storage	MDQ	934	
16	National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
17	National Fuel	FST 2358	Transportation	MDQ	6,098	
18	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
19	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
20	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
21	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
22	Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
23	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
24	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
25	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
26	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
27	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	72694 Z6-Z6	Transportation	MDQ	30,000	
28	ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	
29	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
30	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
31	Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
32	DOMAC Liquid Demand Charge	NSB041	Peaking	MDQ	-	
33	Granite Ridge Demand		Peaking	MDQ	-	
34						
35	**Supply Costs - Commodity**					
36	City Gate Delivered Supply		Pipeline	Dkt	-	[redacted]
37	LNG Truck		Pipeline	Dkt	76,923	
38	TGP Supply (Direct)		Pipeline	Dkt	3,068,681	
39	LNG Vapor (Storage)		Produced	Dkt	81,928	
40	Dawn Supply		Pipeline	Dkt	544,236	
41	Niagara Supply		Pipeline	Dkt	435,204	
42	PNGTS		Pipeline	Dkt	40,348	
43	Granite Ridge		Pipeline	Dkt	-	
44	Dracut Supply 2 - Swing		Pipeline	Dkt	1,497,958	
45	Dracut Supply 1 - Baseload		Pipeline	Dkt	691,229	
46	TGP Storage		Storage	Dkt	2,052,281	
47	Propane		Produced	Dkt	-	
48	Propane Truck		Pipeline	Dkt	-	
49						
50	**Supply Costs - Volumetric Transportation**					
51	Dracut Supply 1 - Baseload		Pipeline	Dkt	691,229	[redacted]
52	Dracut Supply 2 - Swing		Pipeline	Dkt	1,497,958	
53	Niagara Supply		Pipeline	Dkt	435,204	
54	Dawn Supply		Pipeline	Dkt	544,236	
55	TGP Storage - Withdrawals		Pipeline	Dkt	2,052,281	
56	TGP Supply (Direct)		Pipeline	Dkt	3,068,681	

Ln																
1	**ENERGY NORTH NATURAL GAS, INC.**															
2																
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**															
4	**COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**															
5			Prior Period Balance													
6			Apr-12													
7			Ending Bal	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Peak Period
8		Days in Month	Plus May Billings	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
10	**Accunt 175.20 COG (Over)/Under Balance - Interest Calculation**																
11																	
12	**Beginning Balance**	Account 175.20 1/	**$ 2,076,323**	$ 1,606,569	$ 2,099,536	$ 2,284,820	$ 2,564,516	$ 2,889,180	$ 3,291,182	$ 3,680,549	$ 2,964,304	$ 2,045,049	$ 1,612,140	$ 1,212,023	$ 316,146	$ (79,762)	$ 2,076,323
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		509,047	509,047	509,047	509,047	509,047	509,047	5,288,436	8,401,028	10,614,096	9,230,829	7,469,791	4,465,871	-	48,524,333
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	331,860	331,860	331,860	331,860	331,860	331,860	-	1,991,163
15	Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(1,326,639)	(7,366,476)	(10,905,586)	(11,666,178)	(10,085,430)	(6,775,749)	(2,609,483)	(50,735,540)
16	Projected Unbilled Revenue									(4,985,754)	(7,210,333)	(7,633,350)	(5,858,513)	(4,436,335)	(2,761,544)		(32,885,829)
17	Reverse Prior Month Unbilled										4,985,754	7,210,333	7,633,350	5,858,513	4,436,335	2,761,544	32,885,829
18	Prior Period Adjustment-Unbilled				-					-							-
19	Add Net Adjustments	Schedule 4		(21,835)	(329,611)	(236,034)	(191,899)	(115,288)	(129,289)	(33,012)	(67,993)	(55,303)	(74,980)	(36,384)	(92,997)	-	(1,384,626)
20	Gas Cost Billed	Account 175.20 2/	(469,754)	-	-	-	-	-	-	-	-	-	-	-	-	-	(469,754)
21	Monthly (Over)/Under Recovery		$ 1,606,569	$ 2,093,781	$ 2,278,972	$ 2,557,832	$ 2,881,664	$ 3,282,939	$ 3,670,940	$ 2,955,441	$ 2,038,145	$ 1,607,100	$ 1,208,507	$ 314,039	$ (80,077)	$ 72,299	$ 1,898
22	Average Monthly Balance	(ln 12 + 21)/2		$ 2,085,052	$ 2,189,254	$ 2,421,326	$ 2,723,090	$ 3,086,059	$ 3,481,061	$ 3,317,995	$ 2,501,225	$ 1,826,075	$ 1,410,324	$ 763,031	$ 118,034	$ (3,731)	
23																	
24	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
25																	
26	Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 5,755	$ 5,848	$ 6,684	$ 7,516	$ 8,244	$ 9,609	$ 8,863	$ 6,904	$ 5,040	$ 3,516	$ 2,106	$ 315	$ -	$ 70,401
27																	
28	**(Over)/Under Balance**	ln 21 + ln 26	$ 1,606,569	$ 2,099,536	$ 2,284,820	$ 2,564,516	$ 2,889,180	$ 3,291,182	$ 3,680,549	$ 2,964,304	$ 2,045,049	$ 1,612,140	$ 1,212,023	$ 316,146	$ (79,762)	$ 72,299	72,299
29																	
30																	
31	**Calculation of COG with Interest**																
32																	
33	**Beginning Balance**	ln 12	$ 2,076,323	$ 1,606,569	$ 2,099,536	$ 2,284,820	$ 2,564,516	$ 2,889,180	$ 3,291,182	$ 3,680,549	$ 2,955,598	$ 2,023,081	$ 1,574,471	$ 1,160,604	$ 252,622	$ (150,500)	$ 2,076,323
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		509,047	509,047	509,047	509,047	509,047	509,047	5,288,436	8,401,028	10,614,096	9,230,829	7,469,791	4,465,871	-	48,524,333
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	331,860	331,860	331,860	331,860	331,860	331,860	-	1,991,163
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(1,328,468)	(7,376,636)	(10,920,628)	(11,682,270)	(10,099,341)	(6,785,095)	(2,613,082)	(50,805,520)
37	Projected Unbilled Revenue									(4,992,631)	(7,220,278)	(7,643,879)	(5,866,594)	(4,442,454)	(2,765,353)		(32,931,189)
38	Reverse Prior Month Unbilled										4,992,631	7,220,278	7,643,879	5,866,594	4,442,454	2,765,353	32,931,189
39	Add Net Adjustments	ln 19		(21,835)	(329,611)	(236,034)	(191,899)	(115,288)	(129,289)	(33,012)	(67,993)	(55,303)	(74,980)	(36,384)	(92,997)	-	(1,384,626)
40	Gas Cost Billed	ln 20	(469,754)		-	-	-	-	-	-	-	-	-	-	-	-	(469,754)
41	Add Interest	ln 26		-	-	-	-	-	-	8,863	6,904	5,040	3,516	2,106	315	-	26,745
42	**(Over)/Under Balance**		$ 1,606,569	$ 2,093,781	$ 2,278,972	$ 2,557,832	$ 2,881,664	$ 3,282,939	$ 3,670,940	$ 2,955,597	$ 2,023,114	$ 1,574,546	$ 1,160,711	$ 252,777	$ (150,321)	$ 1,771	$ (41,336)
43																	
44	Average Monthly Balance			$ 2,085,052	$ 2,189,254	$ 2,421,326	$ 2,723,090	$ 3,086,059	$ 3,481,061	$ 3,318,073	$ 2,489,356	$ 1,798,814	$ 1,367,591	$ 706,691	$ 51,150	$ (74,365)	
45																	
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		5,755	5,848	6,684	7,516	8,244	9,609	8,863	6,871	4,965	3,410	1,951	137	-	69,852
47																	
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ 1,606,569	$ 2,099,536	$ 2,284,820	$ 2,564,516	$ 2,889,180	$ 3,291,182	$ 3,680,549	$ 2,955,598	$ 2,023,081	$ 1,574,471	$ 1,160,604	$ 252,622	$ (150,500)	$ 1,771	1,771
49																	
50																	
51	Forecast Sendout Therms	Sch 1								9,922,220	15,075,830	17,807,020	15,547,840	13,617,450	8,018,010		79,988,370
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								2,033,163	11,289,618	16,713,541	17,879,201	15,456,597	10,384,290	3,999,207	77,755,617
53	Less Forecast Unaccounted For	Sch 1								166,779	253,405	299,313	261,339	228,891	134,772		1,344,499
54	Less Forecast Company Use	Sch 1								81,276	123,491	145,863	127,357	111,545	65,678		655,210
55	Unbilled Volumes									7,641,002	3,409,316	648,303	-2,720,057	-2,179,583	-2,566,730	-3,999,207	233,044
56	Gross Unbilled									7,641,002	11,050,318	11,698,621	8,978,565	6,798,981	4,232,251	233,044	
57																	
58																	
59	COB w/o Interest	Sch. 3, pg. 4, ln 211 col. (c)								$0.6525	$0.6525	$0.6525	$0.6525	$0.6525	$0.6525	$0.6525	
60																	
61	COG With Interest	Sch. 3, pg. 4, ln 211 col. (d)								$0.6534	$0.6534	$0.6534	$0.6534	$0.6534	$0.6534	$0.6534	

62
63
64
65 1/ Beginning Balance for Acct 175.20. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
66 2/ Gas Cost Billed Acct 175.20. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.
67
68

1 **ENERGY NORTH NATURAL GAS, INC.**
2
3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line	(a)	Days in Month (b)	Prior Period Balance Apr-12 Ending Bal Plus May Collections	May-12 31 (c)	Jun-12 30 (d)	Jul-12 31 (e)	Aug-12 31 (f)	Sep-12 30 (g)	Oct-12 31 (h)	Nov-12 30 (i)	Dec-12 31 (j)	Jan-13 31 (k)	Feb-13 28 (l)	Mar-13 31 (m)	Apr-13 30 (n)	May-13 31 (o)	Peak Period Total (p)
75																	
76	**Accunt 142.20 Working Capital (Over)/Under Balance - Interest Calculation**																
77																	
78	**Beginning Balance**	Account 142.20 1/	$ 64	$ (541)	$ 106	$ 754	$ 1,404	$ 2,056	$ 2,709	$ 3,365	$ 2,354	$ 1,277	$ 879	$ 485	$ (644)	$ (1,224)	$ 64
79																	
80	Days Lag			0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391		
81	Prime Rate			3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
82	Forecast Working Capital	ln 34 * 0.091%		647	647	647	647	647	647	6,721	10,677	13,489	11,731	9,493	5,676	-	61,669
83																	
84	Projected Revenues w/o Int.	ln 121 * ln 125		-	-	-	-	-	-	(1,627)	(9,032)	(13,371)	(14,303)	(12,365)	(8,307)	(3,199)	(62,204)
85	Projected Unbilled Revenue									(6,113)	(8,840)	(9,359)	(7,183)	(5,439)	(3,386)		(40,320)
86	Reverse Prior Month Unbilled										6,113	8,840	9,359	7,183	5,439	3,386	40,320
87																	
88	Add Net Adjustments			-	-	-	-	-	-	-	-	-	-	-	-	-	-
89																	
90	Working Capital Billed	Account 142.20 2/	(604)														(604)
91																	
92	Monthly (Over)/Under Recovery		$ (541)	$ 106	$ 753	$ 1,401	$ 2,051	$ 2,703	$ 3,356	$ 2,346	$ 1,272	$ 876	$ 483	$ (643)	$ (1,222)	$ (1,038)	$ (1,076)
93																	
94	Average Monthly Balance	(ln 78 + ln 92)/2		$ 85	$ 430	$ 1,078	$ 1,728	$ 2,380	$ 3,033	$ 2,856	$ 1,813	$ 1,076	$ 681	$ (79)	$ (933)	$ (1,131)	
95																	
96	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
97																	
98	Interest Applied	ln 94 * ln 96 / 365 * Days of Month		$ 0	$ 1	$ 3	$ 5	$ 6	$ 8	$ 8	$ 5	$ 3	$ 2	$ (0)	$ (2)	$ -	$ 38
99																	
100	**(Over)/Under Balance**	ln 92 + ln 98	$ (541)	$ 106	$ 754	$ 1,404	$ 2,056	$ 2,709	$ 3,365	$ 2,354	$ 1,277	$ 879	$ 485	$ (644)	$ (1,224)	$ (1,038)	(1,038)
101																	
102																	
103	**Calculation of Working Capital with Interest**																
104																	
105	**Beginning Balance**	ln 78	$ 64	$ (541)	$ 106	$ 754	$ 1,404	$ 2,056	$ 2,709	$ 3,365	$ 2,354	$ 1,277	$ 879	$ 485	$ (644)	$ (1,224)	$ 64
106	Forecast Working Capital	ln 82		647	647	647	647	647	647	6,721	10,677	13,489	11,731	9,493	5,676	-	61,669
107	Projected Rev. with interest	ln 121 * ln 127		-	-	-	-	-	-	(1,627)	(9,032)	(13,371)	(14,303)	(12,365)	(8,307)	(3,199)	(62,204)
108	Projected Unbilled Revenue									(6,113)	(8,840)	(9,359)	(7,183)	(5,439)	(3,386)		(40,320)
109	Reverse Prior Month Unbilled										6,113	8,840	9,359	7,183	5,439	3,386	40,320
110	Add Net Adjustments	ln 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital Billed	ln 90	(604)	-	-	-	-	-	-								(604)
112	Add Interest	ln 98		-	-	-	-	-	-	8	5	3	2	(0)	(2)	-	15
113	Monthly (Over)/Under Recovery		$ (541)	$ 106	$ 753	$ 1,401	$ 2,051	$ 2,703	$ 3,356	$ 2,354	$ 1,277	$ 879	$ 485	$ (644)	$ (1,224)	$ (1,038)	$ (1,062)
114																	
115	Average Monthly Balance			$ 85	$ 430	$ 1,078	$ 1,728	$ 2,380	$ 3,033	$ 2,859	$ 1,815	$ 1,078	$ 682	$ (79)	$ (934)	$ (1,131)	
116																	
117	Interest Applied	ln 96 * ln 115 / 365 * Days of Month		0	1	3	5	6	8	8	5	3	2	(0)	(2)	-	$ 38
118																	
119	**(Over)/Under Balance**	-ln 112 +ln 113 + ln 117	$ (541)	$ 106	$ 754	$ 1,404	$ 2,056	$ 2,709	$ 3,365	$ 2,354	$ 1,277	$ 879	$ 485	$ (644)	$ (1,224)	$ (1,038)	$ (1,038)
120																	
121	Forecast Therm Sales	ln 52								2,033,163	11,289,618	16,713,541	17,879,201	15,456,597	10,384,290	3,999,207	77,755,617
122	Unbilled Therm	ln 55								7,641,002	3,409,316	648,303	(2,720,057)	(2,179,583)	(2,566,730)		
123	Gross Unbilled									7,641,002	11,050,318	11,698,621	8,978,565	6,798,981	4,232,251		
124																	
125	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 228 col. (c)								$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
126																	
127	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 228 col. (d)								$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	

128 1/ Beginning Balance for Acct 142.20. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.
129 2/ Working Capital Billed Acct 142.20. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.

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1 **ENERGY NORTH NATURAL GAS, INC.**

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3 **Peak 2012 - 2013 Winter Cost of Gas Filing**

4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line	(a)	Days in Month (b)	Prior Period Balance Apr-12 Ending Bal Plus May Collections	May-12 31 (c)	Jun-12 30 (d)	Jul-12 31 (e)	Aug-12 31 (f)	Sep-12 30 (g)	Oct-12 31 (h)	Nov-12 30 (i)	Dec-12 31 (j)	Jan-13 31 (k)	Feb-13 28 (l)	Mar-13 31 (m)	Apr-13 30 (n)	May-13 31 (o)	DemandPeriod Total (p)
134																	
135	**Accunt 175.52 Bad Debt (Over)/Under Balance - Interest Calculation**																
136																	
137	Forecast Direct Gas Costs	ln 34		$ 509,047	$ 509,047	$ 509,047	$ 509,047	$ 509,047	$ 509,047	$ 5,288,436	$ 8,401,028	$ 10,614,096	$ 9,230,829	$ 7,469,791	$ 4,465,871	$ -	48,524,333
138	Forecast Working Capital	ln 106		647	647	647	647	647	647	6,180	10,677	13,489	11,731	9,493	5,676		61,128
139	Prior Period Balance	ln 42								267,761	267,761	267,761	267,761	267,761	267,761		1,606,569
140	Total Forecast Direct Gas Costs & Working Capital			509,694	509,694	509,694	509,694	509,694	509,694	5,562,378	8,679,466	10,895,347	9,510,321	7,747,046	4,739,308	-	48,585,461
141																	
142	**Beginning Balance**	Account 175.52 1/	$ 124,588	$ 113,348	$ 126,436	$ 139,533	$ 152,678	$ 165,860	$ 179,062	$ 192,316	$ 161,582	$ 120,256	$ 87,358	$ 58,496	$ 18,603	$ (479)	$ 124,588
143																	
144	Forecast Bad Debt	ln 140 * 0.025		12,742	12,742	12,742	12,742	12,742	12,742	139,059	216,987	272,384	237,758	193,676	118,483		1,254,801
145																	
146	Projected Revenues w/o int	ln 183 * ln 187		-	-	-	-	-	-	(35,784)	(198,697)	(294,158)	(314,674)	(272,036)	(182,764)	(70,386)	(1,368,499)
147	Projected Unbilled Revenue									(134,482)	(194,486)	(205,896)	(158,023)	(119,662)	(74,488)		(887,035)
148	Reverse Prior Month Unbilled										134,482	194,486	205,896	158,023	119,662	74,488	887,035
149																	
150	Bad Debt Billed	Account 175.52 2/	(11,241)		-	-	-	-	-		-	-	-	-	-	-	(11,241)
151																	
152	Add Net Adjustments		-	-	-	-	-	-	-		-	-	-	-	-	-	-
153																	
154	Monthly (Over)/Under Recovery		$ 113,348	$ 126,090	$ 139,178	$ 152,275	$ 165,421	$ 178,602	$ 191,804	$ 161,110	$ 119,868	$ 87,071	$ 58,315	$ 18,497	$ (503)	$ 3,623	$ (350)
155																	
156	Average Monthly Balance	(ln 142 + ln 154)/2		$ 125,339	$ 132,807	$ 145,904	$ 159,049	$ 172,231	$ 185,433	$ 176,713	$ 140,725	$ 103,664	$ 72,836	$ 38,497	$ 9,050	$ 1,572	
157																	
158	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
159																	
160	Interest Applied	ln 156 * ln 158 / 365 * Days of Month		$ 346	$ 355	$ 403	$ 439	$ 460	$ 512	$ 472	$ 388	$ 286	$ 182	$ 106	$ 24		$ 3,973
161																	
162	**(Over)/Under Balance**	ln 154 + ln 160	$ 113,348	$ 126,436	$ 139,533	$ 152,678	$ 165,860	$ 179,062	$ 192,316	$ 161,582	$ 120,256	$ 87,358	$ 58,496	$ 18,603	$ (479)	$ 3,623	3,623
163																	
164																	
165	**Calculation of Bad Debt with Interest**																
166																	
167	**Beginning Balance**	ln 142	$ 124,588	$ 113,348	$ 126,436	$ 139,533	$ 152,678	$ 165,860	$ 179,062	$ 192,316	$ 161,583	$ 120,257	$ 87,359	$ 58,497	$ 18,604	$ (478)	$ 124,588
168	Forecast Bad Debt	ln 144		12,742	12,742	12,742	12,742	12,742	12,742	139,059	216,987	272,384	237,758	193,676	118,483	-	1,254,801
169	Projected Revenues with int.	ln 183 * ln 189		-	-	-	-	-	-	(35,784)	(198,697)	(294,158)	(314,674)	(272,036)	(182,764)	(70,386)	(1,368,499)
170	Projected Unbilled Revenue									(134,482)	(194,486)	(205,896)	(158,023)	(119,662)	(74,488)		(887,035)
171	Reverse Prior Month Unbilled										134,482	194,486	205,896	158,023	119,662	74,488	887,035
172	Bad Debt Billed	ln 150	(11,241)		-	-	-	-	-	-	-	-	-	-	-	-	(11,241)
173	Add Interest	ln 160		-	-	-	-	-	-	472	388	286	182	106	24	-	1,459
174	Add Net Adjustments	ln 152	-							-	-	-	-	-	-	-	0
175	Monthly (Over)/Under Recovery		$ 113,348	$ 126,090	$ 139,178	$ 152,275	$ 165,421	$ 178,602	$ 191,804	$ 161,582	$ 120,257	$ 87,359	$ 58,497	$ 18,604	$ (478)	$ 3,624	$ 1,108
176																	
177	Average Monthly Balance			$ 125,339	$ 132,807	$ 145,904	$ 159,049	$ 172,231	$ 185,433	$ 176,949	$ 140,920	$ 103,808	$ 72,928	$ 38,551	$ 9,063	$ 1,573	
178																	
179	Interest Applied	ln 158 * ln 177 / 365 * Days of Month		346	355	403	439	460	512	473	389	286	182	106	24	-	$ 3,974
180																	
181	**(Over)/Under Balance**	-ln 173 +ln 175 + ln 179	$ 113,348	$ 126,436	$ 139,533	$ 152,678	$ 165,860	$ 179,062	$ 192,316	$ 161,583	$ 120,257	$ 87,359	$ 58,497	$ 18,604	$ (478)	$ 3,624	$ 3,624
182																	
183	Forecast Term Sales	ln 52								2,033,163	11,289,618	16,713,541	17,879,201	15,456,597	10,384,290	3,999,207	77,755,617
184	Unbilled Therm	ln 55								7,641,002	3,409,316	648,303	(2,720,057)	(2,179,583)	(2,566,730)		
185	Gross Unbilled									7,641,002	11,050,318	11,698,621	8,978,565	6,798,981	4,232,251		
186																	
187	COG Rate Without Interest	Sch. 3, pg. 4, ln 245 col. (c)								$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	
188																	
189	COG With Interest	Sch. 3, pg. 4, ln 245 col. (d)								$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	$0.0176	

190 1/ Beginning Balance for Acct 175.52. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.

191 2/ Bad Debt Billed Acct 175.52. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.

192

Line	(a)	(b)	Prior Period	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Total
193	**Total Interest**	lns 46 + 117 + 179	$ -	$ 6,102	$ 6,204	$ 7,089	$ 7,960	$ 8,710	$ 10,129	$ 9,344	$ 7,265	$ 5,254	$ 3,593	$ 2,057	$ 158	$ -	$ 73,865

1 **ENERGY NORTH NATURAL GAS, INC.**

3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line				
194			COG Rate Without Interest	COG Rate With Interest
195	**Calculation of COG**			
196	(a)	(b)	(c)	(d)
197	(Over)Under Recovery Balance	ln 12, col. (q)	$ 2,076,323	$ 2,076,323
199	Unadjusted Forecast of Gas Costs	ln 13, col. (q)	48,524,333	48,524,333
201	Production & Storage and Misc Overhea	ln 14, col. (q)	1,991,163	1,991,163
203	Adjustments	ln 19, col. (q)	(1,854,380)	(1,854,380)
205	Interest Nov -Apr	ln 46, col. (q)	-	$ 69,852
207	Total Gas To Be Recovered		$ 50,737,438	$ 50,807,291
209	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	77,755,617	77,755,617
211	Preliminary COG Rate	ln. 207 / ln. 209	$0.6525	$0.6534
213			Working Capital Rate without interest	Working Capital Rate with Interest
214	**Calculation of Working Capital Rate**			
215	(a)	(b)	(c)	(d)
216	(Over)Under Recovery Balance	ln 78, col. (q)	$ 64	$ 64
218	Unadjusted Working Capital Forecast	ln 82, col. (q)	61,669	61,669
220	Adjustments without interest	ln 88, col. (q)	(604)	(604)
222	Interest Nov -Apr	ln 117, col. (q)	-	$ 38
224	Total Gas To Be Recovered		$ 61,128	$ 61,166
226	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	77,755,617	77,755,617
228	Preliminary Working Capital COG Rate		$0.0008	$0.0008
230			Bad Debt Rate without Interest	Bad Debt Rate with interest
231	**Calculation of Bad Debt Rate**			
232	(a)	(b)	(c)	
233	(Over)Under Recovery Balance	ln 142, col. (q)	$ 124,588	$ 124,588
235	Unadjusted Bad Debt Forecast	ln 144, col. (q)	1,254,801	1,254,801
237	Adjustments without interest	ln 152, col. (q)	(11,241)	(11,241)
239	Interest Nov -Apr	ln 179, col. (q)	-	$ 3,974
241	Total Gas To Be Recovered		$ 1,368,148	$ 1,372,123
243	Forecast Gas Sales (Nov - Apr)	ln 52, col. (q)	77,755,617	77,755,617
245	Preliminary Bad Debt COG Rate		$0.0176	$0.0176

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1 **ENERGY NORTH NATURAL GAS, INC.**

2

3 **Peak 2012 - 2013 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	PCB Refunds	Fixed Price Option Administrative Costs	Total Adjustments
7	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8													
9	May-12		$ -	$ -	$ (13,826)	$ 15,018	$ -	[redacted]			$ -	$ -	$ (21,835)
10	Jun-12		-	-	(23,720)	14,847	-				-	-	(329,611)
11	Jul-12	1/	-	-	(64,173)	5,636	-				-	-	(236,034)
12	Aug-12	1/	-	-	(3,179)	4,564	-				-	-	(191,899)
13	Sep-12	1/	-	-	(16,097)	4,422	-				-	-	(115,288)
14	Oct-12	1/	-	-	(24,412)	6,667	-				-	-	(129,289)
15	Nov-12	1/	-	-	(59,962)	13,915	(947)				-	40,691	(33,012)
16	Dec-12	1/	-	-	(52,719)	13,194	(1,279)				-	-	(67,993)
17	Jan-13	1/	-	-	(37,893)	11,178	(1,616)				-	-	(55,303)
18	Feb-13	1/	-	-	(51,607)	8,679	(1,714)				-	-	(74,980)
19	Mar-13	1/	-	-	(10,518)	6,151	(1,503)				-	-	(36,384)
20	Apr-13	1/	-	-	(38,091)	5,453	(1,165)				-	-	(92,997)
21													
22	Subtotal May 12 - Oct 12		$ -	$ -	$ (145,407)	$ 51,154	$ -	$ -	$ (264,466)	$ (665,237)	$ -	$ -	$ (1,023,956)
23													
24	Subtotal Nov 12 - Apr 13		$ -	$ -	$ (250,790)	$ 58,570	$ (8,224)	$ -	$ (9,497)	$ (191,419)	$ -	$ 40,691	$ (360,669)
25													
26	Total Peak Period		$ -	$ -	$ (396,197)	$ 109,724	$ (8,224)	$ -	$ (273,963)	$ (856,656)	$ -	$ 40,691	$ (1,384,626)
27													

1/ Estimates are based on prior years actual. Exception: Transportation Revenue is calculated on Schedule 17 and Inventory Finance Charges for Nov 12 - Apr 13 calculated on Schedule 16.

2/ Credits from Repsol of $14,166.66 and BG Energy of $10,944.92 per month are included in Column (i), contracts for 11/01/2012 through 04/30/2013.

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	(a)	Peak (b)	Reference (c)	Peak Costs May 12 -Oct 12 (d)	Nov-12 (e)	Dec-12 (f)	Jan-13 (g)	Feb-13 (h)	Mar-13 (i)	Apr-13 (j)	Peak May -Apr Total (k)
1	**ENERGY NORTH NATURAL GAS, INC.**										
2											
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**										
4	**Demand Costs**										
5											
10											
11	**Supply**										
12	Niagra 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			$ 1,363,979	$ 1,071,942	$ 1,071,942	$ 1,071,942	$ 1,071,942	$ 1,071,942	$ 1,071,942	$ 7,795,631
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	DOMAC Demand NSB041	peak	Per Contract								
37	Subtotal Peaking Demand Chargs			$ 2,026,707	$ 316,420	$ 441,170	$ 441,170	$ 441,170	$ 441,170	$ 316,420	$ 4,424,227
38											
39	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 31 + ln 37	$ 3,390,686	$ 1,389,418	$ 1,514,203	$ 1,514,203	$ 1,514,097	$ 1,514,203	$ 1,389,418	$ 12,226,227
40											
41	Less Transportation Capacity Credit			$ (868,607)	$ (300,600)	$ (327,597)	$ (327,597)	$ (327,574)	$ (327,597)	$ (300,600)	$ (2,780,171)
42											
43	**Total Supply, Pipeline & Peaking Demand**			$ 2,522,079	$ 1,088,818	$ 1,186,606	$ 1,186,606	$ 1,186,523	$ 1,186,606	$ 1,088,818	$ 9,446,057
44											
45	**Storage**										
46	Dominion - Demand	peak	Sch 5B, ln 33 * Sch 5C ln 51 x days	$ 10,529	$ 1,755	$ 1,755	$ 1,755	$ 1,755	$ 1,755	$ 1,755	$ 21,058
47	Dominion - Storage	peak	Sch 5B, ln 34 * Sch 5C ln 52 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
48	Honeoye - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 55 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
49	National Fuel - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 57 x days	90,833	15,139	15,139	15,139	15,139	15,139	15,139	181,667
50	National Fuel - Capacity	peak	Sch 5B, ln 38 * Sch 5C ln 58 x days	153,345	25,557	25,557	25,557	25,557	25,557	25,557	306,690
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 61 x days	201,839	33,640	33,640	33,640	33,640	33,640	33,640	403,677
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 62 x days	197,546	32,924	32,924	32,924	32,924	32,924	32,924	395,091
53											
54	**Subtotal Storage Demand Costs**			$ 715,492	$ 119,249	$ 119,249	$ 119,249	$ 119,249	$ 119,249	$ 119,249	$ 1,430,985
55											
56	Less Transportation Capacity Credit			$ (183,291)	$ (25,799)	$ (25,799)	$ (25,799)	$ (25,799)	$ (25,799)	$ (25,799)	$ (338,087)
57											
58	**Total Storage Demand Costs**		ln 54 + ln 56	$ 532,202	$ 93,449	$ 93,449	$ 93,449	$ 93,449	$ 93,449	$ 93,449	$ 1,092,898
59											
60	**Total Demand Charges**		ln 39 + ln 54	$ 4,106,179	$ 1,508,666	$ 1,633,452	$ 1,633,452	$ 1,633,346	$ 1,633,452	$ 1,508,666	$ 13,657,212
61											
62	Total Transportation Capacity Credit		ln 41 + ln 56	$ (1,051,898)	$ (326,399)	$ (353,396)	$ (353,396)	$ (353,373)	$ (353,396)	$ (326,399)	$ (3,118,258)
63											
64	**Total Demand Charges less Cap. Cr.**		ln 60 + ln 62	$ 3,054,281	$ 1,182,267	$ 1,280,055	$ 1,280,055	$ 1,279,973	$ 1,280,055	$ 1,182,267	$ 10,538,954
65											
66											

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ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing

<u>Demand Volumes</u>

	(a)	Peak (b)	Reference (c)	Nov-12 (d)	Dec-12 (e)	Jan-13 (f)	Feb-13 (g)	Mar-13 (h)	Apr-13 (i)
Supply									
	Niagra 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)		72694 Z6-Z6	4,000	4,000	4,000	4,000	4,000	4,000
	Portland Natural Gas Trans Service		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
	ANE (TransCanada via Union to Iroquois)		Union Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
	Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
	Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
	Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
	National Fuel	peak	FST 2358	6,098	6,098	6,098	6,098	6,098	6,098
Peaking									
	Tenn Gas Pipeline (Concord Lateral)	peak		26,000	26,000	26,000	26,000	26,000	26,000
	Granite Ridge Demand	peak		0	0	0	0	0	0
	DOMAC Liquid Demand Charge	peak	NSB041	0	2,850	2,850	2,850	2,850	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	246,240	246,240	246,240	246,240	246,240	246,240
	National Fuel - Demand	peak	FSS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
	National Fuel - Capacity Reservation	peak	FSS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
	Tenn Gas Pipeline - Demand	peak	FS-MA	21,844	21,844	21,844	21,844	21,844	21,844
	Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Schedule 5C
Page 1 of 1

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ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Demand Rates

Line	Tariff Rates				Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Nov - Apr
6					30	31	31	28	31	30	181
7					Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
8	**Supply**										
9	Niagra Supply		[redacted]		[redacted]						
11	**Pipeline**										
12	Iroquois Gas Trans Service	RTS 470-01	$6.5971	First Revised Sheet No. 4	$0.2199	$0.2128	$0.2128	$0.2356	$0.2128	$0.2199	$0.2190
14	Tenn Gas Pipeline	95346 Z5-Z6	$7.4396	Fifth Rev Sheet No.14	$0.2480	$0.2400	$0.2400	$0.2657	$0.2400	$0.2480	$0.2469
16	Tenn Gas Pipeline	2302 Z5-Z6	$7.4396	Fifth Rev Sheet No.14	$0.2480	$0.2400	$0.2400	$0.2657	$0.2400	$0.2480	$0.2469
18	Tenn Gas Pipeline	8587 Z0-Z6	$24.4547	Fifth Rev Sheet No.14	$0.8152	$0.7889	$0.7889	$0.8734	$0.7889	$0.8152	$0.8117
20	Tenn Gas Pipeline	8587 Z1-Z6	$21.6916	Fifth Rev Sheet No.14	$0.7231	$0.6997	$0.6997	$0.7747	$0.6997	$0.7231	$0.7200
22	Tenn Gas Pipeline	8587 Z4-Z6	$8.4896	Fifth Rev Sheet No.14	$0.2830	$0.2739	$0.2739	$0.3032	$0.2739	$0.2830	$0.2818
24	TGP Dracut	42076 FTA Z6-Z6	$4.8846	Fifth Rev Sheet No.14	$0.1628	$0.1576	$0.1576	$0.1745	$0.1576	$0.1628	$0.1621
26	TGP Concord Lateral	72694 Z6-Z6	$12.1700	Per contract	$0.4057	$0.3926	$0.3926	$0.4346	$0.3926	$0.4057	$0.4040
28	Portland Natural Gas	FT-1999-001	$40.2456	Part 4.1 v.3.0.0	$1.3415	$1.2982	$1.2982	$1.4373	$1.2982	$1.3415	$1.3359
30	Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.4896	Fifth Rev Sheet No.14	$0.2830	$0.2739	$0.2739	$0.3032	$0.2739	$0.2830	$0.2818
32	Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.4896	Fifth Rev Sheet No.14	$0.2830	$0.2739	$0.2739	$0.3032	$0.2739	$0.2830	$0.2818
34	Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.4396	Fifth Rev Sheet No.14	$0.2480	$0.2400	$0.2400	$0.2657	$0.2400	$0.2480	$0.2469
36	National Fuel	FST 2358	$3.7805	4.010 Version 4.0.0 Pg 1	$0.1260	$0.1220	$0.1220	$0.1350	$0.1220	$0.1260	$0.1255
38	ANE Union Gas		$2.3117								
39	TransCanada PipeLines Limited		$10.1678	Union Parkway to Iroquois							
40	Delivery Pressure Demand Charge		1.0379	Union Parkway to Iroquois							
41	Sub Total Demand Charges		13.5173								
42	Conversion rate GJ to MMBTU		1.0551								
43	Conversion rate to US$		0.9940	07/27/2012							
44	Demand Rate/US$		$14.3482		$0.4783	$0.4628	$0.4628	$0.5124	$0.4628	$0.4783	$0.4763
46	**Peaking**										
47	Granite Ridge Demand		[redacted]		[redacted]						
48	DOMAC Demand NSB041										
50	**Storage**										
51	Dominion - Demand	GSS 300076	$1.8788	Rec No 10.30 Ver 5.0.0	$0.0626	$0.0606	$0.0606	$0.0671	$0.0606	$0.0626	$0.0623
52	Dominion - Capacity	GSS 300076	$0.0145	Rec No 10.30 Ver 5.0.0	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005	$0.0005
53			$1.8933		$0.0631	$0.0611	$0.0611	$0.0676	$0.0611	$0.0631	$0.0628
55	Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0.2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129
57	National Fuel - Demand	FSS-1 2357	$2.4826	4.020 Version 3.0.2 Pg 1	$0.0828	$0.0801	$0.0801	$0.0887	$0.0801	$0.0828	$0.0823
58	National Fuel - Capacity	FSS-1 2357	$0.0381	4.020 Version 3.0.2 Pg 1	$0.0013	$0.0012	$0.0012	$0.0014	$0.0012	$0.0013	$0.0013
59			$2.5207		$0.0840	$0.0813	$0.0813	$0.0900	$0.0813	$0.0840	$0.0836
61	Tenn Gas Pipeline	FS-MA	$1.5400	Seventh Rev Sheet No.61	$0.0513	$0.0497	$0.0497	$0.0550	$0.0497	$0.0513	$0.0511
62	Tenn Gas Pipeline - Space	FS-MA	$0.0211	Seventh Rev Sheet No.61	$0.0007	$0.0007	$0.0007	$0.0008	$0.0007	$0.0007	$0.0007
63			$1.5611		$0.0520	$0.0504	$0.0504	$0.0558	$0.0504	$0.0520	$0.0518

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APPLICABLE TO SETTLING PARTIES PURSUANT TO THE MARCH 29, 2005, STIPULATION
IN DOCKET NOS. RP97-406, RP00-15, RP00-344 and RP00-632
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)
RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule (1)	Rate Component (2)	Base Tariff Rate [1] (3)	Current Acct 858 Base (4)	Current EPCA Base (5)	TCRA [5] Surcharge (6)	EPCA [6] Surcharge (7)	FERC ACA (8)	Current Rate (9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0664	$0.0255	($0.0054)	$0.0043	-	$1.8892
	Storage Capacity	$0.0145	-	-	-	-	-	$0.0145
	Injection Charge	$0.0154	-	$0.0081	$0.0001	$0.0006	-	$0.0242
	Withdrawal Charge	$0.0154	-	-	$0.0001	$0.0006	$0.0019	$0.0180
	GSS-TE Surcharge [3]	-	$0.0046	-	$0.0007	-	-	$0.0053
	Demand Charge Adjustment	$21.5808	$0.7968	$0.3060	($0.0648)	$0.0516	-	$22.6704
	From Customers Balance	$0.6163	$0.0147	$0.0056	($0.0011)	$0.0016	$0.0019	$0.6390
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0664	$0.0255	($0.0054)	$0.0043	-	$2.3021
	Storage Capacity	$0.0369	-	-	-	-	-	$0.0369
	Injection Charge	$0.0154	-	$0.0081	$0.0001	$0.0006	-	$0.0242
	Withdrawal Charge	$0.0154	-	-	$0.0001	$0.0006	$0.0019	$0.0180
	Authorized Overruns	$1.0657	$0.0147	$0.0056	($0.0011)	$0.0016	$0.0019	$1.0884
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0008	($0.0002)	$0.0001	-	$0.0765
	Injection Charge	$0.0154	-	$0.0081	$0.0001	$0.0006	-	$0.0242
	Withdrawal Charge	$0.0154	-	-	$0.0001	$0.0006	$0.0019	$0.0180
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0147	$0.0056	($0.0011)	$0.0016	$0.0019	$0.6390
	Excess Injection Charge	$0.2245	-	$0.0081	$0.0001	$0.0006	-	$0.2333

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.28% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 2.56%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6210. Daily Capacity Release Rate for GSS-E per Dt is $1.0704.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.

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

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

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

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

3. RATE

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

4. MINIMUM BILL

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

5. COMPRESSOR FUEL ALLOWANCE

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

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

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

		Non-Settlement Recourse & Eastchester	------------------ Settlement Recourse Rates ---------------------				
			---- Applicable to Non-Eastchester/Non-Contesting Shippers 2/ ----				
	Minimum	Initial Rates 3/	Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

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

(Footnotes continued on Sheet 4.01)

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

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

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

4/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

RATES FOR TRANSPORTATION SERVICES*

Rate Sch. (1)	Rate Component [1/] (2)		Base Rate (3)	TSCA (4)	TSCA Surch. (5)	FERC ACA (6)	Current Rate [2/] (7)
FT/FT-S							
	Reservation	(Max)	$3.7805	-	-	-	$ 3.7805
		(Min)	0.0000	-	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	0.0018	$0.0153
		(Min)	0.0135	-	-	0.0018	$0.0153
	Overrun	(Max)	0.1378	-	-	0.0018	$0.1396
		(Min)	0.0135	-	-	0.0018	$0.0153
	Maximum Volumetric Rate		0.1378	-	-	0.0018	$0.1396
EFT	Reservation	(Max)	3.9653	0.0000	(0.0036)	-	$3.9617
		(Min)	0.0000	0.0000	(0.0036)	-	$(0.0036)
	Commodity	(Max)	0.0148	0.0000	0.0000	0.0018	$0.0166
		(Min)	0.0148	0.0000	0.0000	0.0018	$0.0166
	Overrun	(Max)	0.1452	-	-	0.0018	$0.1470
		(Min)	0.0148	-	-	0.0018	$0.0166
	Maximum Volumetric Rate		0.1452	0.0000	(0.0001)	0.0018	$0.1469
FST	Reservation	(Max)	3.7805	-	-		$ 3.7805
		(Min)	0.0000	-	-		$0.0000
	Commodity	(Max)	0.0135	-	-	0.0018	$0.0153
		(Min)	0.0135	-	-	0.0018	$0.0153
	Overrun	(Max)	0.1378	-	-	0.0018	$0.1396
		(Min)	0.0135	-	-	0.0018	$0.0153
	Maximum Volumetric Rate		0.1378	-	-	0.0018	$0.1396
IT	Commodity	(Max)	$0.1378	-	-	0.0018	$ 0.1396
		(Min)	0.0000	-	-	0.0018	$0.0018
	Overrun	(Max)	0.1378	-		0.0018	$0.1396
		(Min)	0.0000	-	-	0.0018	$0.0018

*The rates and retention factors set forth in this section are subject to surcharge or direct bill under the conditions set forth in the order of the Chief Administrative Law Judge in Docket No. RP12-88 granting Transporter's motion to place settlement rates into effect on an interim basis. Gathering rates applicable to Transporter's transportation services are set forth in Section 4.040.

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.
2/ All rates exclusive of Fuel and Company Use retention and Transportation LAUF retention. Fuel and Company Use retention for all applicable rate schedules is 1.15%. Transportation LAUF retention for all applicable rate schedules is 0.25%. Provided, however, that effective as of (i) the first day of the month following an order by the Chief Administrative Law Judge accepting this tariff record issued at least five (5) business days prior to the end of a calendar month or (ii) the first day of the second month following an order by the Chief Administrative Law Judge accepting this tariff record issued within the last five (5) business days of a calendar month, the Fuel and Company Use retention for all applicable rate schedules is 0.71% and the Transportation LAUF retention for all applicable rate schedules is 0.05%. Transporter may from time to time identify point pair transactions where the Fuel and Company Use retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF retention.

RATES FOR PART 284 STORAGE SERVICES*

Rate Sch. (1)	Rate Component [1/] (2)			Base Rate (3)	FERC ACA (4)	Current Rate [2/] (5)
ESS	Demand	(Max)		$2.5959	-	$ 2.5959
		(Min)		0.0000	-	$0.0000
	Capacity	(Max)		0.0404	-	$0.0404
		(Min)		0.0000	-	$0.0000
	Injection/	(Max)		0.0411	0.0018	$0.0429
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate [4/]			0.0853	0.0018	$0.0871
	Max. Volumetric Cap. Rate [5/]			0.0013	-	$0.0013
	Storage Balance Transfer	(Max)	6/	3.8600	-	$3.8600
		(Min)	6/	0.0000	-	$0.0000
ISS	Injection	(Max)		0.9923	0.0018	$0.9941
		(Min)		0.0000	-	$0.0000
	Storage Balance Transfer	(Max)	6/	3.8600	-	$3.8600
		(Min)	6/	0.0000	-	$0.0000
FSS	Demand	(Max)		2.4826	-	$ 2.4826
		(Min)		0.0000	-	$0.0000
	Capacity	(Max)		0.0381	-	$0.0381
		(Min)		0.0000	-	$0.0000
	Injection/	(Max)		0.0391	0.0018	$0.0409
	Withdrawal	(Min)		0.0000	-	$0.0000
	Max. Volumetric Dem. Rate 4/			0.0816	0.0018	$0.0834
	Max. Volumetric Cap. Rate 5/			0.0013	-	$ 0.0013
	Storage Balance Transfer	(Max)	6/	3.8600	-	$3.8600
		(Min)	6/	0.0000	-	$0.0000

* The rates and retention factors set forth in this section are subject to surcharge or direct bill under the conditions set forth in the order of the Chief Administrative Law Judge in Docket No. RP12-88 granting Transporter's motion to place settlement rates into effect on an interim basis.

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.
2/ All rates exclusive of Surface Operating Allowance and Storage LAUF retention, where applicable. Surface Operating Allowance for all applicable rate schedules is 1.17%. Storage LAUF retention for all applicable rate schedules is 0.23%. Provided, however, that effective as of (i) the first day of the month following an order by the Chief Administrative Law Judge issued at least five (5) business days prior to the end of a calendar month accepting this tariff record or (ii) the first day of the second month following an order by the Chief Administrative Law Judge issued within the last five (5) business days of a calendar month, the Surface Operating Allowance for all applicable rate schedules is 1.20% and the Storage LAUF retention for all applicable rate schedules is 0.11%.
3/ Unit Dth Rates per day.
4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
5/ Assessed per dekatherm per day on storage balance.
6/ Rate per nomination.

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$40.2456	---------	$40.2456
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$76.4666	---------	$76.4666
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0018	$00.0018
	-- Minimum	$00.0000	$00.0018	$00.0018
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$27.0128	---------	$27.0128
	--Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.4350	$00.0018	$00.4369
	--Minimum	$00.0000	$00.0018	$00.0018

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

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

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	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

Daily Base Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1891		$0.3986	$0.5372	$0.5468	$0.6033	$0.6406	$0.8040
L		$0.1675						
1	$0.2862		$0.2742	$0.3660	$0.5198	$0.5137	$0.5798	$0.7131
2	$0.5372		$0.3638	$0.1877	$0.1752	$0.2258	$0.3119	$0.4030
3	$0.5468		$0.2875	$0.1892	$0.1356	$0.2107	$0.3838	$0.4434
4	$0.6951		$0.6406	$0.2421	$0.3696	$0.1798	$0.1948	$0.2791
5	$0.8294		$0.5819	$0.2541	$0.3082	$0.2002	$0.1875	$0.2446
6	$0.9595		$0.6683	$0.4588	$0.5058	$0.3573	$0.1861	$0.1606

Maximum Reservation Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

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 $0.0000.

RATE SCHEDULE NET 284 1/, 2/
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Notes:

1/ The rates for service under Rate Schedule NET-284 shall be equal to the applicable rates for service under Rate Schedule FT-A in the Summary of Rates and Charges on Sheet Nos. 14 – 17.

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.8100	$2.8100 1/		
Space Rate	$0.0286	$0.0286 1/		
Injection Rate	$0.0073	$0.0073	1.91%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.3372	$0.3372 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.5400	$1.5400 1/		
Space Rate	$0.0211	$0.0211 1/		
Injection Rate	$0.0087	$0.0087	1.91%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1848	$0.1848 1/		

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.21%.

uniongas

TRANSPORTATION RATES

(A) Applicability

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

(B) Services

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

(C) Rates

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

	Monthly Demand Charge (applied to daily contract demand) Rate/GJ	Commodity and Fuel Charges Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1)				
Dawn to Oakville/Parkway	$2.323			
Dawn to Kirkwall	$1.978	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Kirkwall to Parkway	$0.345			
Parkway to Dawn	n/a			
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway	$2.868	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)				
Dawn to Parkway – Maximum	$5.576	Monthly fuel rates and ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$5.576			
Parkway (TCPL) to Parkway (Cons) (2)		0.328%		

Authorized Overrun (3)

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

Transportation Overrun	If Union supplies fuel Commodity Charge Rate/GJ	Commodity and Fuel Charges Fuel Ratio %	AND	Commodity Charge Rate/GJ
Dawn to Parkway				$0.076
Dawn to Kirkwall		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.065
Kirkwall to Parkway				$0.011
Parkway to Dawn				$0.076
Parkway (TCPL) Overrun (4)	n/a	0.256%		n/a
M12-X Firm Transportation				
Between Dawn, Kirkwall and Parkway		Monthly fuel rates and ratios shall be in accordance with schedule "C".		$0.094

TransCanada
In business to deliver

Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

System Average Unit Cost of Transportation

Line No	Particulars	Net Revenue Requirement ($000's)	Allocation Base		Annual Unit Cost		Daily Unit Cost	
	(a)	(b)	(c)		(d)		(e)	
1	Fixed Energy	76,148	3,938,676	GJ	19.3333983638	$/GJ	0.0529682147	$/GJ
2	Transmission - Fixed	1,169,509	4,862,440,154	GJ-KM	0.2405190214	$/GJ-Km	0.0006589562	$/GJ-Km
3	Transmission - Variable	48,954	1,053,676,682,785	GJ-KM	-	$/GJ-Km	0.0000464601	$/GJ-Km

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
4	Centram MDA	4.46187	0.00722	0.1539
5	Union WDA	31.41463	0.06896	1.1018
6	Union NDA	12.30579	0.02546	0.4300
7	Union EDA	8.00131	0.01505	0.2781
8	KPUC EDA	7.70246	0.01412	0.2674
9	GMIT EDA	14.16801	0.02929	0.4951
10	Enbridge CDA	1.69730	0.00024	0.0560
11	Enbridge EDA	4.84530	0.00757	0.1669
12	Cornwall	10.94987	0.02165	0.3816
13	Philipsburg	14.44301	0.02974	0.5046

Firm Transportation - Short Notice

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
14	Kirkwall to Thorold - CDA	3.87336	0.00487	0.1322
15	Parkway to Goreway - CDA	2.39507	0.00144	0.0802
16	Parkway to Victoria Square #2 CDA	3.17490	0.00326	0.1077
17	Parkway to Schomberg #2 CDA	3.12397	0.00314	0.1059

*(1) The Daily Equivalent Toll represents the minimum bid floor for ST-SN service.

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent *(2) ($/GJ)
	(a)	(b)	(c)	(d)
18	Emerson - 1 (Viking)	0.09571	0.00000	0.0032
19	Emerson - 2 (Great Lakes)	0.14114	0.00000	0.0046
20	Dawn	0.08038	0.00000	0.0026
21	Niagara Falls	0.59443	0.00000	0.0195
22	Iroquois	1.03785	0.00000	0.0341
23	Chippawa	1.03444	0.00000	0.0340
24	East Hereford	4.54054	0.03226	0.1815

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

Union Dawn Receipt Point Surcharge

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
25	Union Dawn Receipt Point Surcharge	0.09828	0.00000	0.0032

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) ii (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Parkway Belt	Centrat MDA	40.47278	0.09008	1.4207	1.5628
2	Union Parkway Belt	Union WDA	31.16449	0.06841	1.0930	1.2023
3	Union Parkway Belt	Nipigon WDA	27.37231	0.05971	0.9596	1.0556
4	Union Parkway Belt	Union NDA	12.30620	0.02546	0.4301	0.4731
5	Union Parkway Belt	Calstock NDA	20.74300	0.04435	0.7264	0.7990
6	Union Parkway Belt	Tunis NDA	15.52374	0.03225	0.5427	0.5970
7	Union Parkway Belt	GMIT NDA	11.69247	0.02319	0.4076	0.4484
8	Union Parkway Belt	Union SSMDA	18.35505	0.03881	0.6423	0.7065
9	Union Parkway Belt	Union NCDA	5.29747	0.00861	0.1828	0.2011
10	Union Parkway Belt	Union CDA	2.07011	0.00053	0.0686	0.0755
11	Union Parkway Belt	Enbridge CDA	3.14523	0.00350	0.1069	0.1176
12	Union Parkway Belt	Union EDA	8.15784	0.01535	0.2836	0.3120
13	Union Parkway Belt	Enbridge EDA	10.97773	0.02175	0.3827	0.4210
14	Union Parkway Belt	GMIT EDA	14.26643	0.02945	0.4985	0.5484
15	Union Parkway Belt	KPUC EDA	7.70246	0.01412	0.2673	0.2940
16	Union Parkway Belt	North Bay Junction	8.81626	0.01670	0.3065	0.3372
17	Union Parkway Belt	Enbridge SWDA	6.15853	0.01054	0.2130	0.2343
18	Union Parkway Belt	Union SWDA	6.36578	0.01079	0.2201	0.2421
19	Union Parkway Belt	Spruce	40.47278	0.09008	1.4207	1.5628
20	Union Parkway Belt	Emerson 1	38.02790	0.08441	1.3346	1.4681
21	Union Parkway Belt	Emerson 2	38.02790	0.08441	1.3346	1.4681
22	Union Parkway Belt	St. Clair	6.63616	0.01165	0.2299	0.2529
23	Union Parkway Belt	Dawn Export	6.15853	0.01054	0.2130	0.2343
24	Union Parkway Belt	Kirkwall	2.37697	0.00178	0.0799	0.0879
25	Union Parkway Belt	Niagara Falls	4.27106	0.00617	0.1466	0.1613
26	Union Parkway Belt	Chippawa	4.31896	0.00628	0.1483	0.1631
27	Union Parkway Belt	Iroquois	10.16778	0.01983	0.3541	0.3895
28	Union Parkway Belt	Cornwall	11.01681	0.02180	0.3840	0.4224
29	Union Parkway Belt	Napierville	14.09626	0.02894	0.4923	0.5415
30	Union Parkway Belt	Philipsburg	14.44621	0.02975	0.5047	0.5552
31	Union Parkway Belt	East Hereford	18.15642	0.03835	0.6353	0.6988
32	Union Parkway Belt	Welwyn	46.28071	0.10354	1.6251	1.7876
33	Union NCDA	Empress	56.87397	0.12803	1.9978	2.1976
34	Union NCDA	Transgas SSDA	48.16057	0.10875	1.6922	1.8614
35	Union NCDA	Centram SSDA	44.61612	0.09962	1.5664	1.7230
36	Union NCDA	Centram MDA	39.26096	0.08782	1.3786	1.5165
37	Union NCDA	Centrat MDA	36.78642	0.08147	1.2909	1.4200
38	Union NCDA	Union WDA	27.47814	0.05979	0.9632	1.0595
39	Union NCDA	Nipigon WDA	23.68595	0.05110	0.8298	0.9128
40	Union NCDA	Union NDA	8.61984	0.01685	0.3003	0.3303
41	Union NCDA	Calstock NDA	17.05665	0.03574	0.5965	0.6562
42	Union NCDA	Tunis NDA	11.83738	0.02364	0.4128	0.4541
43	Union NCDA	GMIT NDA	8.00632	0.01458	0.2778	0.3056
44	Union NCDA	Union SSMDA	22.04140	0.04742	0.7720	0.8492
45	Union NCDA	Union NCDA	1.61112	0.00000	0.0530	0.0583
46	Union NCDA	Union CDA	5.75646	0.00915	0.1985	0.2184
47	Union NCDA	Enbridge CDA	5.20928	0.00836	0.1797	0.1977
48	Union NCDA	Union EDA	9.89018	0.01945	0.3447	0.3792
49	Union NCDA	Enbridge EDA	11.86043	0.02382	0.4137	0.4551
50	Union NCDA	GMIT EDA	15.84503	0.03319	0.5541	0.6095
51	Union NCDA	KPUC EDA	9.52199	0.01840	0.3315	0.3647
52	Union NCDA	North Bay Junction	5.12991	0.00809	0.1768	0.1945
53	Union NCDA	Enbridge SWDA	9.84488	0.01915	0.3429	0.3772
54	Union NCDA	Union SWDA	10.05213	0.01940	0.3499	0.3849
55	Union NCDA	Spruce	36.78642	0.08147	1.2909	1.4200
56	Union NCDA	Emerson 1	39.62795	0.08806	1.3909	1.5300
57	Union NCDA	Emerson 2	39.62795	0.08806	1.3909	1.5300
58	Union NCDA	St. Clair	10.32252	0.02026	0.3597	0.3957
59	Union NCDA	Dawn Export	9.84488	0.01915	0.3429	0.3772
60	Union NCDA	Kirkwall	6.06332	0.01039	0.2097	0.2307
61	Union NCDA	Niagara Falls	7.95741	0.01478	0.2764	0.3040
62	Union NCDA	Chippawa	8.00531	0.01489	0.2781	0.3059
63	Union NCDA	Iroquois	11.79008	0.02368	0.4113	0.4524
64	Union NCDA	Cornwall	12.59522	0.02554	0.4396	0.4836
65	Union NCDA	Napierville	15.67466	0.03268	0.5480	0.6028
66	Union NCDA	Philipsburg	16.02462	0.03349	0.5603	0.6163
67	Union NCDA	East Hereford	19.73483	0.04209	0.6909	0.7600
68	Union NCDA	Welwyn	44.61612	0.09962	1.5664	1.7230
69	Union SSMDA	Empress	45.07892	0.10076	1.5828	1.7411
70	Union SSMDA	Transgas SSDA	36.36551	0.08147	1.2771	1.4048
71	Union SSMDA	Centram SSDA	32.82107	0.07234	1.1513	1.2664
72	Union SSMDA	Centram MDA	27.43845	0.06048	0.9626	1.0589
73	Union SSMDA	Centrat MDA	27.41259	0.05981	0.9610	1.0571
74	Union SSMDA	Union WDA	37.50337	0.08335	1.3164	1.4480
75	Union SSMDA	Nipigon WDA	40.51306	0.09017	1.4221	1.5643
76	Union SSMDA	Union NDA	29.05013	0.06427	1.0194	1.1213
77	Union SSMDA	Calstock NDA	37.48693	0.08316	1.3156	1.4472
78	Union SSMDA	Tunis NDA	32.26767	0.07106	1.1320	1.2452

Daily currency converter

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

Currency Converter

Amount: 1.00 cash rate: ☐

From: Canadian Dollar

To: U.S. dollar

Convert

Answer: 0.99

Exchange Rate: 0.9940

Summary: On July 27, 2012, 1.00 Canadian Dollar(s) = 0.99 U.S. dollar(s), at an exchange rate of 0.9940 (using nominal rate).

REDACTED

Line	For Month of: (a)	Reference (b)	Nov-12 (c)	Dec-12 (d)	Jan-13 (e)	Feb-13 (f)	Mar-13 (g)	Apr-13 (h)	Peak Nov- Apr (i)
1	**ENERGY NORTH NATURAL GAS, INC.**								
2									
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									
6	For Month of:	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 63 * ln 102	[redacted]						
13	Niagara Supply	ln 64 * ln 107							
14	TGP Supply (Direct)	ln 65 * ln 123							
15	Dracut Supply 1 - Baseload	ln 66 * ln 112							
16	Dracut Supply 2 - Swing	ln 67 * ln 117							
17	City Gate Delivered Supply	ln 68 * ln 129							
18	LNG Truck	ln 69 * ln 131							
19	Propane Truck	ln 70 * ln 133							
20	PNGTS	ln 71 * ln 138							
21	Granite Ridge	ln 72 * ln 143							
22									
23	Subtotal Pipeline Gas Costs		$ 3,596,339	$ 4,307,613	$ 6,064,958	$ 5,085,096	$ 3,830,237	$ 3,683,307	$ 26,567,550
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**		$ 271,717	$ 334,812	$ 364,836	$ 325,657	$ 314,632	$ 255,390	$ 1,867,044
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		$ (655,834)	$ (7,528)	$ (238,320)	$ -	$ (15,610)	$ (886,634)	$ (1,803,927)
43									
44	**Total Supply & Pipeline Commodity Costs**	ln 23 + ln 34 + ln 42	$ 3,212,222	$ 4,634,896	$ 6,191,474	$ 5,410,754	$ 4,129,258	$ 3,052,063	$ 26,630,667
45									
46	**Storage Gas:**								
47	TGP Storage - Withdrawals	ln 77 * ln 157	$ 543,878	$ 2,138,887	$ 2,575,290	$ 2,209,739	$ 1,631,633	$ 22,276	$ 9,121,704
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	$ 8,385	$ 8,483	$ 251,683	$ 7,362	$ 7,862	$ 7,591	$ 291,366
54									
55									
56	**Total Commodity Gas & Trans. Costs**	ln 44 + ln 47 + ln 53	$ 3,764,485	$ 6,782,267	$ 9,018,447	$ 7,627,855	$ 5,768,753	$ 3,081,930	$ 36,043,738
57									$ 79,988,370
58									

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1	**ENERGY NORTH NATURAL GAS, INC.**							**REDACTED**	
2									
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	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		924,000	926,310	954,800	862,400	954,800	820,050	5,442,360
64	Niagara Supply		721,490	745,360	745,360	672,980	745,360	721,490	4,352,040
65	TGP Supply (Direct)		5,292,980	5,155,150	5,155,150	4,656,190	5,155,150	5,272,190	30,686,810
66	Dracut Supply 1 - Baseload		-	2,380,840	2,380,840	2,150,610	-	-	6,912,290
67	Dracut Supply 2 - Swing		3,531,220	957,880	1,983,520	2,142,140	3,002,230	3,362,590	14,979,580
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		21,560	22,330	680,680	-	44,660	-	769,230
70	Propane Truck		-	-	-	-	-	-	-
71	PNGTS		58,520	76,230	83,160	71,610	66,990	46,970	403,480
72	Granite Ridge		-	-	-	-	-	-	-
73									
74	Subtotal Pipeline Volumes		10,549,770	10,264,100	11,983,510	10,555,930	9,969,190	10,223,290	63,545,790
75									
76	**Storage Gas:**								
77	TGP Storage		1,223,530	4,811,730	5,793,480	4,971,120	3,670,590	52,360	20,522,810
78									
79	**Produced Gas:**								
80	LNG Vapor		21,560	22,330	710,710	20,790	22,330	21,560	819,280
81	Propane		-	-	-	-	-	-	-
82									
83	Subtotal Produced Gas		21,560	22,330	710,710	20,790	22,330	21,560	819,280
84									
85	**Less - Gas Refill:**								
86	LNG Truck		(21,560)	(22,330)	(680,680)	-	(44,660)	-	(769,230)
87	Propane		-	-	-	-	-	-	-
88	TGP Storage Refill		(1,851,080)	-	-	-	-	(2,279,200)	(4,130,280)
89									
90	Subtotal Refills		(1,872,640)	(22,330)	(680,680)	-	(44,660)	(2,279,200)	(4,899,510)
91									
92	**Total Sendout Volumes**		9,922,220	15,075,830	17,807,020	15,547,840	13,617,450	8,018,010	79,988,370
93									
94									
95									

Schedule 6
Page 3 of 5

REDACTED

1	**ENERGY NORTH NATURAL GAS, INC.**								
2									
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	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, In 10/10	[redacted]						
101	Basis Differential								
102	**Net Commodity Costs**								
103									
104	**Niagara Supply**								
105	NYMEX Price	Sch 7, In 10/10	[redacted]						
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Dracut Supply 1 - Baseload**								
110	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10	[redacted]						
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 2 - Swing**								
115	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10	[redacted]						
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119									
120	**TGP Supply (Direct)**								
121	NYMEX Price	Sch 7, In 10/10	[redacted]						
122	Basis Differential								
123	**Net Commodity Costs**								
124									
125									
126	**City Gate Delivered Supply**								
127	NYMEX Price	Sch 7, In 10/10	[redacted]						
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131	**LNG Truck**	Sch 7, In 10/10	**$0.3106**	**$0.3371**	**$0.3501**	**$0.3515**	**$0.3495**	**$0.3475**	**$0.3411**
132									
133	**Propane Truck**	NYMEX - Propane	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
134									
135	**PNGTS**								
136	NYMEX Price	Sch 7, In 10/10	[redacted]						
137	Additional Cost								
138	**Net Commodity Cost**								
139									
140	**Granite Ridge**								
141	NYMEX Price	Sch 7, In 10/10	[redacted]						
142	Additional Cost								
143	**Net Commodity Cost**								
144									
145	**LNG Vapor (Storage)**	Sch 16, In 95 /10	**$0.3889**	**$0.3799**	**$0.3541**	**$0.3541**	**$0.3521**	**$0.3521**	**$0.3635**
146									
147	**Propane**	Sch 16, In 66 /10	**$1.4833**	**$1.4833**	**$1.4833**	**$1.4833**	**$1.4833**	**$1.4833**	**$1.4833**
148									
149	**Storage Refill:**								
150	**LNG Truck**	In 131	**$0.3106**	**$0.3371**	**$0.3501**	**$0.3515**	**$0.3495**	**$0.3475**	**$0.3635**
151	**Propane**	In 133	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$1.4833**
152									
153									

1	**ENERGY NORTH NATURAL GAS, INC.**								
2									
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
154									**REDACTED**
155									
156	**Per Unit Volumetric Transportation Rates**								
157	**Dawn Supply Volumetric Transportation Charge**								
158	**Commodity Costs**	In 102	**$0.3496**	**$0.3741**	**$0.3781**	**$0.3795**	**$0.3775**	**$0.3685**	**$0.3712**
159									
160	TransCanada - Commodity Rate/GJ	Union Parkway to Iroquois	$0.00198	$0.00198	$0.00198	$0.00198	$0.00198	$0.00198	$0.00198
161	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
162	Conversion Rate to US$	07/27/2012	0.9940	0.9940	0.9940	0.9940	0.9940	0.9940	0.9940
163	Commodity Rate/US$	In 160 x In 161 x In 162	$0.00208	$0.00208	$0.00208	$0.00208	$0.00208	$0.00208	$0.00208
164	TransCanada Fuel %	Union Parkway to Iroquois	1.20%	1.09%	1.36%	1.30%	1.00%	0.88%	1.14%
165	TransCanada Fuel * Percentage	In 158 x In 164	$0.00419	$0.00408	$0.00514	$0.00493	$0.00378	$0.00324	$0.00423
166	Subtotal TransCanada		**$0.00627**	**$0.00616**	**$0.00722**	**$0.00701**	**$0.00586**	**$0.00532**	**$0.00631**
167	IGTS - Z1 RTS Commodity	First Revised Sheet No. 4	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
168	IGTS - Z1 RTS ACA Rate Commodity	Third Revised Sheet 4A	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018
169	IGTS - Z1 RTS Deferred Asset Surcharge	Third Revised Sheet 4A	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
170	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00048**	**$0.00048**	**$0.00048**	**$0.00048**	**$0.00048**	**$0.00048**	**$0.00048**
171	TGP NET-NE - Comm. Segments 3 & 4	Seventh Rev Sheet No.15	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018
172	IGTS -Fuel Use Factor - Percentage	Third Revised Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
173	IGTS -Fuel Use Factor - Fuel * Percentage	In 158 x In 172	**$0.00350**	**$0.00374**	**$0.00378**	**$0.00380**	**$0.00378**	**$0.00369**	**$0.00371**
174	TGP NET-284 - Fuel Charge % Z 4-6	Sixth Rev Sheet No. 32	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%
175	TGP NET-284 -Fuel Use Factor - Fuel * %	In 158 x In 174	**$0.00318**	**$0.00340**	**$0.00344**	**$0.00345**	**$0.00344**	**$0.00335**	**$0.00338**
176	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01361**	**$0.01396**	**$0.01510**	**$0.01492**	**$0.01373**	**$0.01302**	**$0.01406**
177									
178									
179	**Niagara Supply Volumetric Transportation Charge**								
180	**Commodity Costs**	Ln 107	[redacted]						
181									
182	TGP FTA - FTA Z 5-6 Comm. Rate	Seventh Rev Sheet No.15							
183	TGP FTA - FTA Z 5-6 - ACA Rate	Seventh Rev Sheet No.15							
184	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate								
185	TGP FTA Fuel Charge % Z 5-6	Sixth Rev Sheet No. 32							
186	TGP FTA Fuel * Percentage	In 180 x In 185							
187	**Total Volumetric Transportation Rate - Niagra Supply**								
188									
189									
190									

REDACTED

REDACTED

Ln	For Month of:	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Peak Nov- Apr
1	**ENERGY NORTH NATURAL GAS, INC.**								
2									
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									
6	For Month of:	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
191									
192									
193	**TGP Direct Volumetric Transportation Charge**								Average Rate
194	**Commodity Costs**	Ln 121	[redacted]						
195									
196	TGP - Max Comm. Base Rate - Z 0-6	Seventh Rev Sheet No.15	$0.03124	$0.03124	$0.03124	$0.03124	$0.03124	$0.03124	$0.03124
197	TGP - Max Commodity ACA Rate - Z 0-6	Seventh Rev Sheet No.15	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018
198	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03142	$0.03142	$0.03142	$0.03142	$0.03142	$0.03142	$0.03142
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		**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**	**$0.01024**
201	TGP - Max Comm. Base Rate - Z 1-6	Seventh Rev Sheet No.15	$0.02723	$0.02723	$0.02723	$0.02723	$0.02723	$0.02723	$0.02723
202	TGP - Max Commodity ACA Rate - Z 1-6	Seventh Rev Sheet No.15	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018
203	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02741	$0.02741	$0.02741	$0.02741	$0.02741	$0.02741	$0.02741
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		**$0.01847**	**$0.01847**	**$0.01847**	**$0.01847**	**$0.01847**	**$0.01847**	**$0.01847**
206	TGP - Fuel Charge % - Z 0 -6	Sixth Rev Sheet No. 32	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
207	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
208	Prorated TGP Fuel Charge % - Z 0-6		1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%
209	TGP - Fuel Charge % - Z 1 -6	Sixth Rev Sheet No. 32	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%
210	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
211	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.37%	2.37%	2.37%	2.37%	2.37%	2.37%	2.37%
212	TGP - Fuel Charge % - Z 0-6	ln 194 x ln 208	**$0.00405**	**$0.00440**	**$0.00457**	**$0.00458**	**$0.00456**	**$0.00453**	**$0.00445**
213	TGP - Fuel Charge % - Z 1-6	ln 194 x ln 211	**$0.00735**	**$0.00798**	**$0.00828**	**$0.00832**	**$0.00827**	**$0.00822**	**$0.00807**
214	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.04011**	**$0.04109**	**$0.04157**	**$0.04162**	**$0.04154**	**$0.04147**	**$0.04123**
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	Seventh Rev Sheet No.15	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334	$0.00334
220	TGP - Max Commodity ACA Rate - Z 6-6	Seventh Rev Sheet No.15	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018	$0.00018
221	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00352**	**$0.00352**	**$0.00352**	**$0.00352**	**$0.00352**	**$0.00352**	**$0.00352**
222	TGP - Fuel Charge % - Z 6-6	Sixth Rev Sheet No. 32	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%
223	TGP - Fuel Charge	ln 217 x ln 222	**$0.00118**	**$0.00128**	**$0.00133**	**$0.00134**	**$0.00133**	**$0.00132**	**$0.00130**
224	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00470**	**$0.00480**	**$0.00485**	**$0.00486**	**$0.00485**	**$0.00484**	**$0.00482**
225									
226									
227	**TGP Dracut**								
228	**Commodity Costs - NYMEX Price**	Ln 112	[redacted]						
229									
230	TGP - Trans Charge - Comm. - Z 6-6	Seventh Rev Sheet No.15							
231	TGP - Trans Charge - ACA Rate - Z6-6	Seventh Rev Sheet No.15							
232	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6								
233	TGP - Fuel Charge % - Z 6-6	Sixth Rev Sheet No. 32							
234	TGP - Fuel Charge	ln 228 x ln 233							
235	**Total Volumetric Transportation Rate - TGP Dracut**								
236									
237									

RATES (All in $ Per Dth)

	Minimum	Non-Settlement Recourse & Eastchester Initial Rates 3/	Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/ Effective 1/1/2003	Effective 7/1/2004	Effective 1/1/2005	Effective 1/1/2006	Effective 1/1/2007
RTS DEMAND:							
Zone 1	$0.0000	$7.5637	$7.5637	$6.9586	$6.8514	$6.7788	$6.5971
Zone 2	$0.0000	$6.4976	$6.4976	$5.9778	$5.8857	$5.8233	$5.6673
Inter-Zone	$0.0000	$12.7150	$12.7150	$11.6978	$11.5177	$11.3956	$11.0902
Zone 1 (MFV) 1/	$0.0000	$5.3607	$5.3607	$4.9318	$4.8559	$4.8044	$4.6757
RTS COMMODITY:							
Zone 1	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030
Zone 2	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
Inter-Zone	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054	$0.0054
Zone 1 (MFV) 1/	$0.0300	$0.1506	$0.1506	$0.1386	$0.1364	$0.1350	$0.1314
ITS COMMODITY:							
Zone 1	$0.0030	$0.2517	$0.2517	$0.2318	$0.2283	$0.2259	$0.2199
Zone 2	$0.0024	$0.2160	$0.2160	$0.1989	$0.1959	$0.1938	$0.1887
Inter-Zone	$0.0054	$0.4234	$0.4234	$0.3900	$0.3840	$0.3800	$0.3700
Zone 1 (MFV) 1/	$0.0300	$0.3268	$0.3268	$0.3007	$0.2960	$0.2929	$0.2850
MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/:							
Zone 1	$0.0000	$0.2487	$0.2487	$0.2288	$0.2253	$0.2229	$0.2169
Zone 2	$0.0000	$0.2136	$0.2136	$0.1965	$0.1935	$0.1915	$0.1863
Inter-Zone	$0.0000	$0.4180	$0.4180	$0.3846	$0.3787	$0.3746	$0.3646
Zone 1 (MFV) 1/	$0.0000	$0.1762	$0.1762	$0.1621	$0.1596	$0.1580	$0.1537

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

(Footnotes continued on Sheet 4.01)

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

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

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

4/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity	0.0018

MEASUREMENT VARIANCE/FUEL USE FACTOR:

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

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

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

Minimum
Commodity Rates 1/, 2/

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

Maximum
Commodity Rates 1/, 2/, 3/

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

Notes:

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

RATE SCHEDULE NET 284 1/, 2/
==

Notes:

1/ The rates for service under Rate Schedule NET-284 shall be equal to the applicable rates for service under Rate Schedule FT-A in the Summary of Rates and Charges on Sheet Nos. 14 – 17.

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.

FUEL AND EPCR

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.56%		1.46%	2.11%	2.55%	3.02%	3.39%	4.00%
L		0.35%						
1	0.67%		1.10%	1.80%	2.13%	2.58%	3.09%	3.51%
2	2.15%		1.16%	0.34%	0.52%	0.86%	1.36%	1.77%
3	2.61%		2.17%	0.52%	0.24%	1.14%	1.57%	2.03%
4	3.10%		2.41%	1.15%	1.35%	0.53%	0.75%	1.20%
5	3.50%		3.09%	1.37%	1.58%	0.75%	0.74%	0.91%
6	4.15%		3.51%	1.79%	2.03%	1.13%	0.62%	0.38%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0035		$0.0134	$0.0208	$0.0258	$0.0312	$0.0355	$0.0426
L		$0.0012						
1	$0.0047		$0.0094	$0.0172	$0.0211	$0.0262	$0.0320	$0.0368
2	$0.0208		$0.0101	$0.0011	$0.0031	$0.0068	$0.0124	$0.0169
3	$0.0258		$0.0211	$0.0031	$0.0000	$0.0099	$0.0147	$0.0196
4	$0.0312		$0.0242	$0.0100	$0.0122	$0.0032	$0.0056	$0.0106
5	$0.0355		$0.0320	$0.0124	$0.0147	$0.0056	$0.0055	$0.0073
6	$0.0426		$0.0368	$0.0169	$0.0196	$0.0098	$0.0041	$0.0015

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.21%.
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 0.21%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$2.8100	$2.8100 1/		
Space Rate	$0.0286	$0.0286 1/		
Injection Rate	$0.0073	$0.0073	1.91%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.3372	$0.3372 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.5400	$1.5400 1/		
Space Rate	$0.0211	$0.0211 1/		
Injection Rate	$0.0087	$0.0087	1.91%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1848	$0.1848 1/		

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.21%.

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	$0.1050	$0.1050 1/		
Injection Rate	$0.0073	$0.0073	1.91%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA				
Space Rate	$0.0846	$0.0846 1/		
Injection Rate	$0.0087	$0.0087	1.91%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		

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 0.21%.

NET-284 RATE SCHEDULE (continued)

5. SHIPPERS

The Shippers to which this Rate Schedule is available, each Shipper's Transportation Quantity and the rate zone applicable to the transportation service provided by Transporter are as follows:

Shipper	Transportation Quantity (Dth)	Rate Zones Receipt	Rate Zones Delivery
Bay State (from Granite) - Pleasant St.	3,706	5	6
Bay State (from Granite) - Agawam	6,068	5	6
Boston Gas d/b/a National Grid	35,000	5	6
Boston Gas d/b/a National Grid	8,600	5	6
Barclays Bank PLC	14,010	5	6
EnergyNorth Natural Gas, Inc. d/b/a National Grid	4,000	5	6
Essex Gas Company d/b/a National Grid	2,000	5	6
Iroquois Gas Transmission (Connecticut Natural, Yankee Gas)	37,000	6	6
Lockport Energy Associates	13,184	1	5
New York State Electric & Gas Corp	14,816	1	5
Northern Utilities (from Granite) Pleasant St.	844	5	6
Northern Utilities (from Granite) Agawam	1,382	5	6
The Narragansett Electric Company d/b/a National Grid	1,000	5	6
Yankee Gas Services Company (Wright)	9,000	5	6
Total	150,610		

TransCanada
In business to deliver

Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

System Average Unit Cost of Transportation

Line No	Particulars	Net Revenue Requirement ($000's)	Allocation Base		Annual Unit Cost		Daily Unit Cost	
	(a)	(b)	(c)		(d)		(e)	
1	Fixed Energy	76,148	3,938,676	GJ	19.3333983638	$/GJ	0.0529682147	$/GJ
2	Transmission - Fixed	1,169,509	4,862,440,154	GJ-KM	0.2405190214	$/GJ-Km	0.0006589562	$/GJ-Km
3	Transmission - Variable	48,954	1,053,676,682,785	GJ-KM	-	$/GJ-Km	0.0000464601	$/GJ-Km

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
4	Centram MDA	4.46187	0.00722	0.1539
5	Union WDA	31.41463	0.06896	1.1018
6	Union NDA	12.30579	0.02546	0.4300
7	Union EDA	8.00131	0.01505	0.2781
8	KPUC EDA	7.70246	0.01412	0.2674
9	GMIT EDA	14.16801	0.02929	0.4951
10	Enbridge CDA	1.69730	0.00024	0.0560
11	Enbridge EDA	4.84530	0.00757	0.1669
12	Cornwall	10.94987	0.02165	0.3816
13	Philipsburg	14.44301	0.02974	0.5046

Firm Transportation - Short Notice

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
14	Kirkwall to Thorold - CDA	3.87336	0.00487	0.1322
15	Parkway to Goreway - CDA	2.39507	0.00144	0.0802
16	Parkway to Victoria Square #2 CDA	3.17490	0.00326	0.1077
17	Parkway to Schomberg #2 CDA	3.12397	0.00314	0.1059

*(1) The Daily Equivalent Toll represents the minimum bid floor for ST-SN service.

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent *(2) ($/GJ)
	(a)	(b)	(c)	(d)
18	Emerson - 1 (Viking)	0.09571	0.00000	0.0032
19	Emerson - 2 (Great Lakes)	0.14114	0.00000	0.0046
20	Dawn	0.08038	0.00000	0.0026
21	Niagara Falls	0.59443	0.00000	0.0195
22	Iroquois	1.03785	0.00000	0.0341
23	Chippawa	1.03444	0.00000	0.0340
24	East Hereford	4.54054	0.03226	0.1815

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

Union Dawn Receipt Point Surcharge

Line No	Particulars	Demand Toll ($/GJ/Month)	Commodity Toll ($/GJ)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)	(d)
25	Union Dawn Receipt Point Surcharge	0.09828	0.00000	0.0032

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	(FT, STFT Minimum Tolls) ii (100% LF FT Tolls) ($/GJ)	IT Bid Floor (110% FT Tolls) ($/GJ)
1	Union Parkway Belt	Centrat MDA	40.47278	0.09008	1.4207	1.5628
2	Union Parkway Belt	Union WDA	31.16449	0.06841	1.0930	1.2023
3	Union Parkway Belt	Nipigon WDA	27.37231	0.05971	0.9596	1.0556
4	Union Parkway Belt	Union NDA	12.30620	0.02546	0.4301	0.4731
5	Union Parkway Belt	Calstock NDA	20.74300	0.04435	0.7264	0.7990
6	Union Parkway Belt	Tunis NDA	15.52374	0.03225	0.5427	0.5970
7	Union Parkway Belt	GMIT NDA	11.69247	0.02319	0.4076	0.4484
8	Union Parkway Belt	Union SSMDA	18.35505	0.03881	0.6423	0.7065
9	Union Parkway Belt	Union NCDA	5.29747	0.00861	0.1828	0.2011
10	Union Parkway Belt	Union CDA	2.07011	0.00053	0.0686	0.0755
11	Union Parkway Belt	Enbridge CDA	3.14523	0.00350	0.1069	0.1176
12	Union Parkway Belt	Union EDA	8.15784	0.01535	0.2836	0.3120
13	Union Parkway Belt	Enbridge EDA	10.97773	0.02175	0.3827	0.4210
14	Union Parkway Belt	GMIT EDA	14.26643	0.02945	0.4985	0.5484
15	Union Parkway Belt	KPUC EDA	7.70246	0.01412	0.2673	0.2940
16	Union Parkway Belt	North Bay Junction	8.81626	0.01670	0.3065	0.3372
17	Union Parkway Belt	Enbridge SWDA	6.15853	0.01054	0.2130	0.2343
18	Union Parkway Belt	Union SWDA	6.36578	0.01079	0.2201	0.2421
19	Union Parkway Belt	Spruce	40.47278	0.09008	1.4207	1.5628
20	Union Parkway Belt	Emerson 1	38.02790	0.08441	1.3346	1.4681
21	Union Parkway Belt	Emerson 2	38.02790	0.08441	1.3346	1.4681
22	Union Parkway Belt	St. Clair	6.63616	0.01165	0.2299	0.2529
23	Union Parkway Belt	Dawn Export	6.15853	0.01054	0.2130	0.2343
24	Union Parkway Belt	Kirkwall	2.37697	0.00178	0.0799	0.0879
25	Union Parkway Belt	Niagara Falls	4.27106	0.00617	0.1466	0.1613
26	Union Parkway Belt	Chippawa	4.31896	0.00628	0.1483	0.1631
27	Union Parkway Belt	Iroquois	10.16778	0.01983	0.3541	0.3895
28	Union Parkway Belt	Cornwall	11.01681	0.02180	0.3840	0.4224
29	Union Parkway Belt	Napierville	14.09626	0.02894	0.4923	0.5415
30	Union Parkway Belt	Philipsburg	14.44621	0.02975	0.5047	0.5552
31	Union Parkway Belt	East Hereford	18.15642	0.03835	0.6353	0.6988
32	Union Parkway Belt	Welwyn	46.28071	0.10354	1.6251	1.7876
33	Union NCDA	Empress	56.87397	0.12803	1.9978	2.1976
34	Union NCDA	Transgas SSDA	48.16057	0.10875	1.6922	1.8614
35	Union NCDA	Centram SSDA	44.61612	0.09962	1.5664	1.7230
36	Union NCDA	Centram MDA	39.26096	0.08782	1.3786	1.5165
37	Union NCDA	Centrat MDA	36.78642	0.08147	1.2909	1.4200
38	Union NCDA	Union WDA	27.47814	0.05979	0.9632	1.0595
39	Union NCDA	Nipigon WDA	23.68595	0.05110	0.8298	0.9128
40	Union NCDA	Union NDA	8.61984	0.01685	0.3003	0.3303
41	Union NCDA	Calstock NDA	17.05665	0.03574	0.5965	0.6562
42	Union NCDA	Tunis NDA	11.83738	0.02364	0.4128	0.4541
43	Union NCDA	GMIT NDA	8.00632	0.01458	0.2778	0.3056
44	Union NCDA	Union SSMDA	22.04140	0.04742	0.7720	0.8492
45	Union NCDA	Union NCDA	1.61112	0.00000	0.0530	0.0583
46	Union NCDA	Union CDA	5.75646	0.00915	0.1985	0.2184
47	Union NCDA	Enbridge CDA	5.20928	0.00836	0.1797	0.1977
48	Union NCDA	Union EDA	9.89018	0.01945	0.3447	0.3792
49	Union NCDA	Enbridge EDA	11.86043	0.02382	0.4137	0.4551
50	Union NCDA	GMIT EDA	15.84503	0.03319	0.5541	0.6095
51	Union NCDA	KPUC EDA	9.52199	0.01840	0.3315	0.3647
52	Union NCDA	North Bay Junction	5.12991	0.00809	0.1768	0.1945
53	Union NCDA	Enbridge SWDA	9.84488	0.01915	0.3429	0.3772
54	Union NCDA	Union SWDA	10.05213	0.01940	0.3499	0.3849
55	Union NCDA	Spruce	36.78642	0.08147	1.2909	1.4200
56	Union NCDA	Emerson 1	39.62795	0.08806	1.3909	1.5300
57	Union NCDA	Emerson 2	39.62795	0.08806	1.3909	1.5300
58	Union NCDA	St. Clair	10.32252	0.02026	0.3597	0.3957
59	Union NCDA	Dawn Export	9.84488	0.01915	0.3429	0.3772
60	Union NCDA	Kirkwall	6.06332	0.01039	0.2097	0.2307
61	Union NCDA	Niagara Falls	7.95741	0.01478	0.2764	0.3040
62	Union NCDA	Chippawa	8.00531	0.01489	0.2781	0.3059
63	Union NCDA	Iroquois	11.79008	0.02368	0.4113	0.4524
64	Union NCDA	Cornwall	12.59522	0.02554	0.4396	0.4836
65	Union NCDA	Napierville	15.67466	0.03268	0.5480	0.6028
66	Union NCDA	Philipsburg	16.02462	0.03349	0.5603	0.6163
67	Union NCDA	East Hereford	19.73483	0.04209	0.6909	0.7600
68	Union NCDA	Welwyn	44.61612	0.09962	1.5664	1.7230
69	Union SSMDA	Empress	45.07892	0.10076	1.5828	1.7411
70	Union SSMDA	Transgas SSDA	36.36551	0.08147	1.2771	1.4048
71	Union SSMDA	Centram SSDA	32.82107	0.07234	1.1513	1.2664
72	Union SSMDA	Centram MDA	27.43845	0.06048	0.9626	1.0589
73	Union SSMDA	Centrat MDA	27.41259	0.05981	0.9610	1.0571
74	Union SSMDA	Union WDA	37.50337	0.08335	1.3164	1.4480
75	Union SSMDA	Nipigon WDA	40.51306	0.09017	1.4221	1.5643
76	Union SSMDA	Union NDA	29.05013	0.06427	1.0194	1.1213
77	Union SSMDA	Calstock NDA	37.48693	0.08316	1.3156	1.4472
78	Union SSMDA	Tunis NDA	32.26767	0.07106	1.1320	1.2452

TRANSCANADA FUEL RATIOS

November 2011

Pressure Point	Pressure (%)
Chippawa	0.83
Emerson 1	0.13
Emerson 2	0.13
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**1.02**	0.33

December 2011

Pressure Point	Pressure (%)
Chippawa	0.83
Emerson 1	0.13
Emerson 2	0.13
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**1.09**	0.40

January 2012

Pressure Point	Pressure (%)
Chippawa	0.83
Emerson 1	0.13
Emerson 2	0.13
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**1.36**	0.67

February 2012

Pressure Point	Pressure (%)
Chippawa	0.83
Emerson 1	0.13
Emerson 2	0.13
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**1.30**	0.61

March 2012

Pressure Point	Pressure (%)
Chippawa	0.83
Emerson 1	0.13
Emerson 2	0.13
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**1.00**	0.31

April 2012

Pressure Point	Pressure (%)
Chippawa	0.83
Emerson 1	0.13
Emerson 2	0.13
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Parkway Belt	Iroquois	**0.3895**	**0.88**	0.19

Ln	Description	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Peak Strip Average
1	**ENERGY NORTH NATURAL GAS, INC.**								
2									
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**								
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**								
5									Peak
6	For Month of:	Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Strip Average
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**								
9	Opening Prices (15 day average)		3.1057	3.3715	3.5012	3.5151	3.4954	3.4754	$ 3.4107
10	NYMEX	ln 201	3.1057	3.3715	3.5012	3.5151	3.4954	3.4754	$ 3.4107
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	400,000	480,000	480,000	520,000	650,000	400,000	2,930,000
24	Market Priced Volumes (Dth)		646,969	536,554	641,967	528,432	335,754	617,632	3,307,308
25	Total Volumes (Dth)	Sch 6, lns 63 - 68 / 10	1,046,969	1,016,554	1,121,967	1,048,432	985,754	1,017,632	6,237,308
26									
27									Weighted Average
28	Hedge Price	ln 170	$ 3.9599	$ 4.0771	$ 4.1587	$ 4.1362	$ 4.1431	$ 3.9796	$ 4.0863
29	NYMEX Price	ln 10	$ 3.1057	$ 3.3715	$ 3.5012	$ 3.5151	$ 3.4954	$ 3.4754	$ 3.4236
30									
31	Hedged Volumes at Hedged Price	ln 23 * ln 28	$ 1,583,950	$ 1,957,010	$ 1,996,170	$ 2,150,836	$ 2,692,993	$ 1,591,834	$ 11,972,792
32	Less Hedged Volumes at NYMEX	ln 24 * ln 29	1,242,267	1,618,304	1,680,576	1,827,835	2,272,010	1,390,160	10,031,151
33									
34	Hedge Contract (Savings)/Loss	ln 31 - ln 32	$ 341,683	$ 338,706	$ 315,594	$ 323,001	$ 420,983	$ 201,674	$ 1,941,641
35									
36	Total Financial Hedge	ln 23	4,000,000	4,800,000	4,800,000	5,200,000	6,500,000	4,000,000	29,300,000
37	Total Underground Storage	Sch 6, Ln 77	1,223,530	4,811,730	5,793,480	4,971,120	3,670,590	52,360	20,522,810
38	Sub Total		5,223,530	9,611,730	10,593,480	10,171,120	10,170,590	4,052,360	49,822,810
39	Total Throughput	Sch 6, ln 92	9,922,220	15,075,830	17,807,020	15,547,840	13,617,450	8,018,010	79,988,370
40	Hedge Percentage	ln 38 / ln 39	53%	64%	59%	65%	75%	51%	62%

Line						Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Peak Strip Average
1	**ENERGY NORTH NATURAL GAS, INC.**											
2												
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**											
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**											
5												
6	For Month of:				Reference							
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41												
42	Hedged Volumes (Dth)											
43	Hedge #	1	Trade Date	10-Jun-11	Swaps	[redacted]						
44	Hedge #	2	Trade Date	24-Jun-11	Swaps							
45	Hedge #	3	Trade Date	08-Jul-11	Swaps							
46	Hedge #	4	Trade Date	22-Jul-11	Swaps							
47	Hedge #	5	Trade Date	05-Aug-11	Swaps							
48	Hedge #	6	Trade Date	18-Aug-11	Swaps							
49	Hedge #	7	Trade Date	09-Sep-11	Swaps							
50	Hedge #	8	Trade Date	23-Sep-11	Swaps							
51	Hedge #	9	Trade Date	05-Dec-11	Swaps							
52	Hedge #	10	Trade Date	16-Dec-11	Swaps							
53	Hedge #	11	Trade Date	06-Jan-12	Swaps							
54	Hedge #	12	Trade Date	27-Jan-12	Swaps							
55	Hedge #	13	Trade Date	10-Feb-12	Swaps							
56	Hedge #	14	Trade Date	24-Feb-12	Swaps							
57	Hedge #	15	Trade Date	08-Jun-12	Swaps							
58	Hedge #	16	Trade Date	21-Jun-12	Swaps							
59	Hedge #	17	Trade Date	05-Jul-12	Swaps							
60	Hedge #	18	Trade Date	20-Jul-12	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	Trade Date		Swaps							
67	Hedge #	25	Trade Date		Swaps							
68	Hedge #	26	Trade Date		Swaps							
69	Hedge #	27	Trade Date		Swaps							
70	Hedge #	28	Trade Date		Swaps							
71	Hedge #	29	Trade Date		Swaps							
72	Hedge #	30	Trade Date		Swaps							
73												
74												
75												
76												
77												
78												
79												
80	Subtotal Hedge Volumes					280,000	320,000	330,000	360,000	430,000	290,000	2,010,000
81	Remaining					120,000	160,000	150,000	160,000	220,000	110,000	920,000
82	Total Volumes					400,000	480,000	480,000	520,000	650,000	400,000	2,930,000
83												
84												

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Line						Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Strip Average
1	**ENERGY NORTH NATURAL GAS, INC.**											
2												
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**											
4	**NYMEX Futures @ Henry Hub and Hedged Contracts**											
5												Peak
6	For Month of:				Reference	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Strip Average
7			(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
85	Strike Price											Weighted Average
86	Hedge #	1	Trade Date	10-Jun-11	Swaps	[redacted]						
87	Hedge #	2	Trade Date	24-Jun-11	Swaps							
88	Hedge #	3	Trade Date	08-Jul-11	Swaps							
89	Hedge #	4	Trade Date	22-Jul-11	Swaps							
90	Hedge #	5	Trade Date	05-Aug-11	Swaps							
91	Hedge #	6	Trade Date	18-Aug-11	Swaps							
92	Hedge #	7	Trade Date	09-Sep-11	Swaps							
93	Hedge #	8	Trade Date	23-Sep-11	Swaps							
94	Hedge #	9	Trade Date	05-Dec-11	Swaps							
95	Hedge #	10	Trade Date	16-Dec-11	Swaps							
96	Hedge #	11	Trade Date	06-Jan-12	Swaps							
97	Hedge #	12	Trade Date	27-Jan-12	Swaps							
98	Hedge #	13	Trade Date	10-Feb-12	Swaps							
99	Hedge #	14	Trade Date	24-Feb-12	Swaps							
100	Hedge #	15	Trade Date	08-Jun-12	Swaps							
101	Hedge #	16	Trade Date	21-Jun-12	Swaps							
102	Hedge #	17	Trade Date	05-Jul-12	Swaps							
103	Hedge #	18	Trade Date	20-Jul-12	Swaps							
104	Hedge #	19	Trade Date	00-Jan-00	Swaps							
105	Hedge #	20	Trade Date	00-Jan-00	Swaps							
106	Hedge #	21	Trade Date	00-Jan-00	Swaps							
107	Hedge #	22	Trade Date	00-Jan-00	Swaps							
108	Hedge #	23	Trade Date	00-Jan-00	Swaps							
109	Hedge #	24	Trade Date	00-Jan-00	Swaps							
110	Hedge #	25	Trade Date	00-Jan-00	Swaps							
111	Hedge #	26	Trade Date		Swaps							
112	Hedge #	27	Trade Date		Swaps							
113	Hedge #	28	Trade Date		Swaps							
114	Hedge #	29	Trade Date		Swaps							
115	Hedge #	30	Trade Date		Swaps							
116												
117												
118												
119												
120												
121												
122												
123	Subtotal Weigthed Average Hedge Prices					$4.3260	$4.4299	$4.4575	$4.4123	$4.4744	$4.1708	4.3890
124	NYMEX					$3.1057	$3.3715	$3.5012	$3.5151	$3.4954	$3.4754	3.4250
125												
126												

1 **ENERGY NORTH NATURAL GAS, INC.**
2
3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**
5

Line	For Month of:		(a)		Reference (b)	Nov-12 (c)	Dec-12 (d)	Jan-13 (e)	Feb-13 (f)	Mar-13 (g)	Apr-13 (h)	Peak Strip Average (i)
127	Hedge Dollars											
128	Hedge #	1	Trade Date	10-Jun-11	Swaps	[redacted]						
129	Hedge #	2	Trade Date	24-Jun-11	Swaps	[redacted]						
130	Hedge #	3	Trade Date	08-Jul-11	Swaps	[redacted]						
131	Hedge #	4	Trade Date	22-Jul-11	Swaps	[redacted]						
132	Hedge #	5	Trade Date	05-Aug-11	Swaps	[redacted]						
133	Hedge #	6	Trade Date	18-Aug-11	Swaps	[redacted]						
134	Hedge #	7	Trade Date	09-Sep-11	Swaps	[redacted]						
135	Hedge #	8	Trade Date	23-Sep-11	Swaps	[redacted]						
136	Hedge #	9	Trade Date	05-Dec-11	Swaps	[redacted]						
137	Hedge #	10	Trade Date	16-Dec-11	Swaps	[redacted]						
138	Hedge #	11	Trade Date	06-Jan-12	Swaps	[redacted]						
139	Hedge #	12	Trade Date	27-Jan-12	Swaps	[redacted]						
140	Hedge #	13	Trade Date	10-Feb-12	Swaps	[redacted]						
141	Hedge #	14	Trade Date	24-Feb-12	Swaps	[redacted]						
142	Hedge #	15	Trade Date	08-Jun-12	Swaps	[redacted]						
143	Hedge #	16	Trade Date	21-Jun-12	Swaps	[redacted]						
144	Hedge #	17	Trade Date	05-Jul-12	Swaps	[redacted]						
145	Hedge #	18	Trade Date	20-Jul-12	Swaps	[redacted]						
146	Hedge #	19	Trade Date	00-Jan-00	Swaps	[redacted]						
147	Hedge #	20	Trade Date	00-Jan-00	Swaps	[redacted]						
148	Hedge #	21	Trade Date	00-Jan-00	Swaps	[redacted]						
149	Hedge #	22	Trade Date	00-Jan-00	Swaps	[redacted]						
150	Hedge #	23	Trade Date	00-Jan-00	Swaps	[redacted]						
151	Hedge #	24	Trade Date	00-Jan-00	Swaps	[redacted]						
152	Hedge #	25	Trade Date	00-Jan-00	Swaps	[redacted]						
153	Hedge #	26	Trade Date	00-Jan-00	Swaps	[redacted]						
154	Hedge #	27	Trade Date	00-Jan-00	Swaps	[redacted]						
155	Hedge #	28	Trade Date	00-Jan-00	Swaps	[redacted]						
156	Hedge #	29	Trade Date	00-Jan-00	Swaps	[redacted]						
157	Hedge #	30	Trade Date	00-Jan-00	Swaps	[redacted]						
158												
159												
160												
161												
162												
163												
164												
165	Subtotal Hedge Dollars					$1,211,270	$1,417,575	$1,470,990	$1,588,425	$1,924,005	$1,209,540	$8,821,805
166	Remaining					372,680	539,435	525,180	562,411	768,988	382,294	3,150,987
167												
168			Target Hedged Dollars			$1,583,950	$1,957,010	$1,996,170	$2,150,836	$2,692,993	$1,591,834	$11,972,792
169												
170			Weighted Average Hedged Cost per Unit			$3.9599	$4.0771	$4.1587	$4.1362	$4.1431	$3.9796	$4.0863
171												
172												

REDACTED

1 **ENERGY NORTH NATURAL GAS, INC.**
2
3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub and Hedged Contracts**
5

										Peak
6	For Month of:	Reference		Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
173	NYMEX Settlement - 15 Day Average									
174		Days	Date							
175		1	30-Jul	3.3700	3.6020	3.7140	3.7270	3.6970	3.6650	
176		2	31-Jul	3.3480	3.5790	3.6900	3.7020	3.6730	3.6400	
177		3	01-Aug	3.2970	3.5400	3.6530	3.6640	3.6370	3.6070	
178		4	02-Aug	3.0660	3.3230	3.4510	3.4660	3.4420	3.4200	
179		5	03-Aug	3.0220	3.2770	3.4090	3.4230	3.4010	3.3820	
180			04-Aug							
181			05-Aug							
182		6	06-Aug	3.0630	3.3230	3.4540	3.4680	3.4470	3.4300	
183		7	07-Aug	3.1500	3.4090	3.5370	3.5510	3.5320	3.5100	
184		8	08-Aug	3.1570	3.4250	3.5560	3.5710	3.5570	3.5410	
185		9	09-Aug	3.1560	3.4200	3.5570	3.5700	3.5530	3.5340	
186		10	10-Aug	3.0270	3.3110	3.4530	3.4690	3.4560	3.4390	
187			11-Aug							
188			12-Aug							
189		11	13-Aug	2.9880	3.2760	3.4140	3.4280	3.4140	3.3970	
190		12	14-Aug	3.0660	3.3430	3.4730	3.4850	3.4690	3.4520	
191		13	15-Aug	2.9810	3.2720	3.4090	3.4230	3.4080	3.3940	
192		14	16-Aug	2.9490	3.2370	3.3730	3.3870	3.3710	3.3590	
193		15	17-Aug	2.9450	3.2350	3.3750	3.3920	3.3740	3.3610	
194			18-Aug							
195			19-Aug							
196			20-Aug							
197			21-Aug							
198			22-Aug							
199			23-Aug							
200										
201			15 Day Average	3.1057	3.3715	3.5012	3.5151	3.4954	3.4754	

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ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Residential Heating Rate R-3

November 1, 2012 - April 30, 2013 / **May 1, 2012 - October 31, 2012**
Residential Heating (R3)

			Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Winter Nov-Apr	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
	07/01/2012	07/01/2011															
Winter:																	
Cust. Chg	$17.31	$17.33	$17.31	$17.31	$17.31	$17.31	$17.31	$17.31	$103.86								
Headblock	$0.2739	$0.2741	$27.39	$27.39	$27.39	$27.39	$27.39	$27.39	$164.34								
Tailblock	$0.2263	$0.2265	$2.04	$11.32	$19.69	$19.91	$14.94	$7.24	$75.13								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$17.31	$17.33								$17.33	$17.33	$17.31	$17.31	$17.31	$17.31	$103.90	$207.76
Headblock	$0.2739	$0.2741								$5.48	$5.48	$5.48	$5.48	$5.48	$5.48	$32.88	$197.22
Tailblock	$0.2263	$0.2265								$15.86	$7.93	$2.26	$2.26	$4.98	$11.54	$44.83	$119.96
HB Threshold	20	20															
Total Base Rate Amount			$46.74	$56.02	$64.39	$64.61	$59.64	$51.94	$343.33	$38.67	$30.74	$25.05	$25.05	$27.77	$34.33	$181.60	$524.94
CGA Rate - (Seasonal)			$0.6719	$0.6719	$0.6719	$0.6719	$0.6719	$0.6719	$0.6719	$0.5118	$0.4741	$0.4695	$0.5210	$0.5403	$0.5403	$0.5123	$0.6313
CGA amount			$73.24	$100.79	$125.65	$126.32	$111.54	$88.69	$626.21	$46.06	$26.08	$14.09	$15.63	$22.69	$38.36	$162.91	$789.12
LDAC			$0.0258	$0.0258	$0.0258	$0.0258	$0.0258	$0.0258	0.0258	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0369
LDAC amount			$2.81	$3.87	$4.82	$4.85	$4.28	$3.41	$24.05	$6.24	$3.81	$2.08	$2.08	$2.91	$4.92	$22.05	$46.10
Total Bill			**$122.79**	**$160.67**	**$194.86**	**$195.78**	**$175.45**	**$144.04**	**$993.59**	**$90.97**	**$60.63**	**$41.22**	**$42.76**	**$53.37**	**$77.61**	**$366.56**	**$1,360.15**

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
Residential Heating (R3)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter:	07/01/2011	04/01/2011															
Cust. Chg	$17.33	$17.16	$17.33	$17.33	$17.33	$17.33	$17.33	$17.33	$103.98								
Headblock	$0.2741	$0.2714	27.41	27.41	27.41	27.41	27.41	27.41	$164.46								
Tailblock	$0.2265	$0.2243	$2.04	$11.33	$19.71	$19.93	$14.95	$7.25	$75.20								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$17.33	$17.16								$17.16	$17.16	$17.33	$17.33	$17.33	$17.33	$103.64	$207.62
Headblock	$0.2741	$0.2714								$5.43	$5.43	$5.48	$5.48	$5.48	$5.48	$32.78	$197.24
Tailblock	$0.2265	$0.2243								$15.70	$7.85	$2.27	$2.27	$4.98	$11.55	$44.62	$119.81
HB Threshold	20	20															
Total Base Rate Amount			$46.78	$56.07	$64.45	$64.67	$59.69	$51.99	$343.64	$38.29	$30.44	$25.08	$25.08	$27.80	$34.36	$181.04	$524.68
CGA Rate - (Seasonal)			$0.7926	$0.7366	$0.7201	$0.7070	$0.7122	$0.7460	$0.7309	$0.7326	$0.7429	$0.7612	$0.7884	$0.7581	$0.7585	$0.7515	$0.7361
CGA amount			$86.39	$110.49	$134.67	$132.92	$118.23	$98.47	$681.17	$65.93	$40.86	$22.84	$23.65	$31.84	$53.85	$238.98	$920.14
LDAC			$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693	$0.0693
LDAC amount			$7.56	$10.40	$12.97	$13.04	$11.51	$9.15	$64.63	$6.24	$3.81	$2.08	$2.08	$2.91	$4.92	$22.04	$86.67
Total Bill			**$140.73**	**$176.95**	**$212.08**	**$210.63**	**$189.43**	**$159.61**	**$1,089.44**	**$110.46**	**$75.11**	**$49.99**	**$50.81**	**$62.55**	**$93.14**	**$442.05**	**$1,531.49**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($17.94)**	**($16.28)**	**($17.22)**	**($14.85)**	**($13.98)**	**($15.58)**	**($95.85)**	**($19.49)**	**($14.48)**	**($8.78)**	**($8.05)**	**($9.17)**	**($15.52)**	**($75.49)**	**($171.34)**
% Change	**-12.75%**	**-9.20%**	**-8.12%**	**-7.05%**	**-7.38%**	**-9.76%**	**-8.80%**	**-17.64%**	**-19.28%**	**-17.55%**	**-15.84%**	**-14.67%**	**-16.67%**	**-17.08%**	**-11.19%**
Base Rate	($0.04)	($0.05)	($0.06)	($0.06)	($0.05)	($0.05)	($0.31)	$0.38	$0.30	($0.03)	($0.03)	($0.03)	($0.03)	$0.56	$0.26
% Change	-0.09%	-0.09%	-0.09%	-0.09%	-0.09%	-0.09%	-0.09%	0.99%	0.99%	-0.10%	-0.10%	-0.10%	-0.10%	0.31%	0.05%
CGA & LDAC	($17.90)	($16.23)	($17.16)	($14.79)	($13.92)	($15.53)	($95.54)	($19.87)	($14.78)	($8.75)	($8.02)	($9.15)	($15.49)	($76.05)	($171.60)
% Change	-20.72%	-14.69%	-12.75%	-11.13%	-11.78%	-15.77%	-14.03%	-30.13%	-36.18%	-38.31%	-33.91%	-28.72%	-28.76%	-31.83%	-18.65%

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Commercial Rate G-41

November 1, 2012 - April 30, 2013 / **May 1, 2012 - October 31, 2012**
Commercial Rate (G-41)

			Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Winter Nov-Apr	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	07/01/2012	07/01/2011															
Cust. Chg	$40.74	$40.77	$40.74	$40.74	$40.74	$40.74	$40.74	$40.74	$244.44								
Headblock	$0.3251	$0.3254	$32.51	$32.51	$32.51	$32.51	$32.51	$32.51	$195.06								
Tailblock	$0.2114	$0.2116	$19.66	$35.73	$41.86	$34.25	$28.33	$15.01	$174.83								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$40.74	$40.77								$40.77	$40.77	$40.74	$40.74	$40.74	$40.74	$244.50	$488.94
Headblock	$0.3251	$0.3254								$6.51	$6.51	$6.50	$6.50	$6.50	$6.50	$39.02	$234.08
Tailblock	$0.2114	$0.2116								$20.53	$12.91	$10.99	$10.99	$14.59	$25.79	$95.80	$270.62
HB Threshold	20	20															
Total Base Rate Amount			$92.91	$108.98	$115.11	$107.50	$101.58	$88.26	$614.33	$67.80	$60.19	$58.23	$58.23	$61.83	$73.03	$379.32	$993.65
CGA Rate - (Seasonal)			$0.6736	$0.6736	$0.6736	$0.6736	$0.6736	$0.6736	$0.6736	$0.5126	$0.4749	$0.4703	$0.5218	$0.5411	$0.5411	$0.5146	$0.6280
CGA amount			$130.00	$181.20	$200.73	$176.48	$157.62	$115.19	$961.23	$59.97	$38.47	$33.86	$37.57	$48.16	$76.84	$294.87	$1,256.09
LDAC			$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	0.0187	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0275
LDAC amount			$3.61	$5.03	$5.57	$4.90	$4.38	$3.20	$26.68	$5.77	$4.00	$3.55	$3.55	$4.39	$7.01	$28.28	$54.96
Total Bill			**$226.52**	**$295.21**	**$321.41**	**$288.88**	**$263.58**	**$206.64**	**$1,602.24**	**$133.55**	**$102.65**	**$95.65**	**$99.36**	**$114.38**	**$156.88**	**$702.46**	**$2,304.70**

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
Commercial Rate (G-41)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			193	269	298	262	234	171	1,427	117	81	72	72	89	142	573	2,000
Winter:	07/01/2011	04/01/2011															
Cust. Chg	$40.77	$40.37	$40.77	$40.77	$40.77	$40.77	$40.77	$40.77	$244.62								
Headblock	$0.3254	$0.3222	32.54	32.54	32.54	32.54	32.54	32.54	$195.24								
Tailblock	$0.2116	$0.2095	$19.68	$35.76	$41.90	$34.28	$28.35	$15.02	$174.99								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$40.77	$40.37								$40.37	$40.37	$40.77	$40.77	$40.77	$40.77	$243.82	$488.44
Headblock	$0.3254	$0.3222								$6.44	$6.44	$6.51	$6.51	$6.51	$6.51	$38.92	$234.16
Tailblock	$0.2116	$0.2095								$20.32	$12.78	$11.00	$11.00	$14.60	$25.82	$95.52	$270.52
HB Threshold	20	20															
Total Base Rate Amount			$92.99	$109.07	$115.21	$107.59	$101.66	$88.33	$614.85	$67.14	$59.59	$58.28	$58.28	$61.88	$73.09	$378.26	$993.12
CGA Rate - (Seasonal)			$0.7929	$0.7369	$0.7204	$0.7073	$0.7125	$0.7463	$0.7327	$0.7365	$0.7468	$0.7651	$0.7923	$0.7620	$0.7624	$0.7589	$0.7402
CGA amount			$153.03	$198.22	$214.69	$185.32	$166.73	$127.62	$1,045.61	$86.17	$60.49	$55.09	$57.05	$67.82	$108.26	$434.87	$1,480.48
LDAC			$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	0.0493	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0488
LDAC amount			$9.52	$13.27	$14.71	$12.93	$11.55	$8.44	$70.42	$5.55	$3.84	$3.41	$3.41	$4.22	$6.73	$27.16	$97.58
Total Bill			**$255.54**	**$320.57**	**$344.60**	**$305.84**	**$279.94**	**$224.39**	**$1,730.88**	**$158.85**	**$123.92**	**$116.78**	**$118.74**	**$133.92**	**$188.08**	**$840.30**	**$2,571.18**

DIFFERENCE:

Total Bill	**($29.02)**	**($25.36)**	**($23.19)**	**($16.96)**	**($16.37)**	**($17.75)**	**($128.64)**	**($25.30)**	**($21.27)**	**($21.13)**	**($19.38)**	**($19.54)**	**($31.21)**	**($137.83)**	**($266.48)**
% Change	**-11.36%**	**-7.91%**	**-6.73%**	**-5.54%**	**-5.85%**	**-7.91%**	**-7.43%**	**-15.93%**	**-17.17%**	**-18.10%**	**-16.32%**	**-14.59%**	**-16.59%**	**-16.40%**	**-10.36%**
Base Rate	($0.08)	($0.09)	($0.10)	($0.09)	($0.09)	($0.07)	($0.53)	$0.67	$0.59	($0.05)	($0.05)	($0.05)	($0.06)	$1.06	$0.53
% Change	-0.08%	-0.09%	-0.09%	-0.09%	-0.09%	-0.08%	-0.09%	0.99%	0.99%	-0.08%	-0.08%	-0.08%	-0.08%	0.28%	0.05%
CGA & LDAC	($28.94)	($25.27)	($23.09)	($16.87)	($16.28)	($17.67)	($128.12)	($25.97)	($21.87)	($21.09)	($19.34)	($19.49)	($31.15)	($138.89)	($267.01)
% Change	-18.91%	-12.75%	-10.76%	-9.10%	-9.76%	-13.85%	-12.25%	-30.14%	-36.15%	-38.28%	-33.90%	-28.73%	-28.77%	-31.94%	-18.04%

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ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Commercial Rate G-42

November 1, 2012 - April 30, 2013 / **May 1, 2012 - October 31, 2012**
C&I High Winter Use Medium G-42

			Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Winter Nov-Apr	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
	07/01/2012	07/01/2011															
Winter:																	
Cust. Chg	$122.22	$122.32	$122.22	$122.22	$122.22	$122.22	$122.22	$122.22	$733.32								
Headblock	$0.3038	$0.3041	$303.80	$303.80	$303.80	$303.80	$303.80	$303.80	$1,822.80								
Tailblock	$0.2007	$0.2009	$110.99	$316.70	$454.59	$622.77	$482.08	$295.63	$2,282.76								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.22	$122.32								$122.32	$122.32	$122.22	$122.22	$122.22	$122.22	$733.52	$1,466.84
Headblock	$0.3038	$0.3041								$121.64	$121.64	$121.52	$64.71	$110.58	$121.52	$661.61	$2,484.41
Tailblock	$0.2007	$0.2009								$172.37	$60.47	$2.81	$0.00	$0.00	$60.01	$295.66	$2,578.42
HB Threshold	400	400															
Total Base Rate Amount			$537.01	$742.72	$880.61	$1,048.79	$908.10	$721.65	$4,838.88	$416.33	$304.43	$246.55	$186.93	$232.80	$303.75	$1,690.79	$6,529.68
CGA Rate - (Seasonal)			$0.6736	$0.6736	$0.6736	$0.6736	$0.6736	$0.6736	$0.6736	$0.5126	$0.4749	$0.4703	$0.5218	$0.5411	$0.5411	$0.5094	$0.6451
CGA amount			$1,046.10	$1,736.54	$2,199.30	$2,763.78	$2,291.59	$1,665.81	$11,703.13	$644.85	$332.90	$194.70	$111.14	$196.96	$378.23	$1,858.79	$13,561.92
LDAC			$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	0.0187	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0240
LDAC amount			$29.04	$48.21	$61.06	$76.73	$63.62	$46.25	$324.89	$62.08	$34.59	$20.43	$10.51	$17.96	$34.49	$180.07	$504.96
Total Bill			**$1,612.15**	**$2,527.47**	**$3,140.97**	**$3,889.30**	**$3,263.31**	**$2,433.71**	**$16,866.90**	**$1,123.26**	**$671.93**	**$461.68**	**$308.58**	**$447.73**	**$716.47**	**$3,729.65**	**$20,596.56**

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
C&I High Winter Use Medium G-42

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,553	2,578	3,265	4,103	3,402	2,473	17,374	1,258	701	414	213	364	699	3,649	21,023
	07/01/2011	04/01/2011															
Winter:																	
Cust. Chg	$122.32	$121.11	$122.32	$122.32	$122.32	$122.32	$122.32	$122.32	$733.92								
Headblock	$0.3041	$0.3011	304.10	304.10	304.10	304.10	304.10	304.10	$1,824.60								
Tailblock	$0.2009	$0.1989	$111.10	$317.02	$455.04	$623.39	$482.56	$295.93	$2,285.04								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.32	$121.11								$121.11	$121.11	$122.32	$122.32	$122.32	$122.32	$731.50	$1,465.42
Headblock	$0.3041	$0.3011								$120.44	$120.44	$121.64	$64.77	$110.69	$121.64	$659.63	$2,484.23
Tailblock	$0.2009	$0.1989								$170.66	$59.87	$2.81	$0.00	$0.00	$60.07	$293.41	$2,578.44
HB Threshold	400	400															
Total Base Rate Amount			$537.52	$743.44	$881.46	$1,049.81	$908.98	$722.35	$4,843.56	$412.21	$301.42	$246.77	$187.09	$233.01	$304.03	$1,684.53	$6,528.09
CGA Rate - (Seasonal)			$0.7929	$0.7369	$0.7204	$0.7073	$0.7125	$0.7463	$0.7284	$0.7365	$0.7468	$0.7651	$0.7923	$0.7620	$0.7624	$0.7525	$0.7326
CGA amount			$1,231.37	$1,899.68	$2,352.25	$2,902.16	$2,424.01	$1,845.60	$12,655.07	$926.52	$523.51	$316.75	$168.76	$277.37	$532.92	$2,745.82	$15,400.89
LDAC			$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	0.0493	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0490
LDAC amount			$76.64	$127.22	$161.12	$202.47	$167.88	$122.03	$857.35	$59.63	$33.23	$19.62	$10.10	$17.25	$33.13	$172.96	$1,030.31
Total Bill			**$1,845.53**	**$2,770.33**	**$3,394.82**	**$4,154.44**	**$3,500.87**	**$2,689.98**	**$18,355.98**	**$1,398.35**	**$858.15**	**$583.15**	**$365.95**	**$527.63**	**$870.08**	**$4,603.32**	**$22,959.29**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($233.38)**	**($242.86)**	**($253.86)**	**($265.14)**	**($237.57)**	**($256.27)**	**($1,489.08)**	**($275.09)**	**($186.23)**	**($121.46)**	**($57.37)**	**($79.91)**	**($153.61)**	**($873.66)**	**($2,362.74)**
% Change	**-12.65%**	**-8.77%**	**-7.48%**	**-6.38%**	**-6.79%**	**-9.53%**	**-8.11%**	**-19.67%**	**-21.70%**	**-20.83%**	**-15.68%**	**-15.14%**	**-17.65%**	**-18.98%**	**-10.29%**
Base Rate	($0.51)	($0.72)	($0.85)	($1.02)	($0.88)	($0.69)	($4.67)	$4.13	$3.01	($0.22)	($0.16)	($0.21)	($0.28)	$6.26	$1.59
% Change	-0.09%	-0.10%	-0.10%	-0.10%	-0.10%	-0.10%	-0.10%	1.00%	1.00%	-0.09%	-0.09%	-0.09%	-0.09%	0.37%	0.02%
CGA & LDAC	($232.87)	($242.15)	($253.01)	($264.12)	($236.69)	($255.58)	($1,484.40)	($279.22)	($189.24)	($121.24)	($57.20)	($79.70)	($153.33)	($879.92)	($2,364.33)
% Change	-18.91%	-12.75%	-10.76%	-9.10%	-9.76%	-13.85%	-11.73%	-30.14%	-36.15%	-38.28%	-33.90%	-28.73%	-28.77%	-32.05%	-15.35%

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Commercial Rate G-52

November 1, 2012 - April 30, 2013 / **May 1, 2012 - October 31, 2012**
Commercial Rate (G-52)

			Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Winter Nov-Apr	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter:	07/01/2012	07/01/2011															
Cust. Chg	$122.22	$122.32	$122.22	$122.22	$122.22	$122.22	$122.22	$122.22	$733.32								
Headblock	$0.1683	$0.1684	$168.30	$168.30	$168.30	$168.30	$168.30	$168.30	$1,009.80								
Tailblock	$0.1142	$0.1143	$82.45	$124.02	$151.89	$152.23	$147.43	$99.58	$757.60								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.22	$122.32								$122.32	$122.32	$122.22	$122.22	$122.22	$122.22	$733.52	$1,466.84
Headblock	$0.1236	$0.1237								$123.70	$123.70	$123.60	$123.60	$123.60	$123.60	$741.80	$1,751.60
Tailblock	$0.0712	$0.0713								$36.36	$26.67	$17.59	$13.53	$14.95	$23.07	$132.16	$889.77
HB Threshold	1,000	1,000															
Total Base Rate Amount			$372.97	$414.54	$442.41	$442.75	$437.95	$390.10	$2,500.72	$282.38	$272.69	$263.41	$259.35	$260.77	$268.89	$1,607.48	$4,108.21
CGA Rate - (Seasonal)			$0.6671	$0.6671	$0.6671	$0.6671	$0.6671	$0.6671	$0.6671	$0.5103	$0.4726	$0.4680	$0.5195	$0.5388	$0.5388	$0.5076	$0.6059
CGA amount			$1,148.75	$1,391.57	$1,554.34	$1,556.34	$1,528.33	$1,248.81	$8,428.14	$770.55	$649.35	$583.60	$618.21	$651.95	$713.37	$3,987.03	$12,415.17
LDAC			$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	$0.0187	0.0187	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0304
LDAC amount			$32.20	$39.01	$43.57	$43.63	$42.84	$35.01	$236.26	$74.51	$67.80	$61.54	$58.72	$59.71	$65.33	$387.62	$623.87
Total Bill			**$1,553.92**	**$1,845.12**	**$2,040.32**	**$2,042.72**	**$2,009.12**	**$1,673.92**	**$11,165.12**	**$1,127.45**	**$989.84**	**$908.54**	**$936.28**	**$972.43**	**$1,047.59**	**$5,982.13**	**$17,147.25**

November 1, 2011 - April 30, 2012 / **May 1, 2011 - October 31, 2011**
Commercial Rate (G-52)

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Winter Nov-Apr	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			1,722	2,086	2,330	2,333	2,291	1,872	12,634	1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
Winter:	07/01/2011	04/01/2011															
Cust. Chg	$122.32	$121.11	$122.32	$122.32	$122.32	$122.32	$122.32	$122.32	$733.92								
Headblock	$0.1684	$0.1667	168.40	168.40	168.40	168.40	168.40	168.40	$1,010.40								
Tailblock	$0.1143	$0.1131	$82.52	$124.13	$152.02	$152.36	$147.56	$99.67	$758.27								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$122.32	$121.11								$121.11	$121.11	$122.32	$122.32	$122.32	$122.32	$731.50	$1,465.42
Headblock	$0.1237	$0.1225								$122.50	$122.50	$123.70	$123.70	$123.70	$123.70	$739.80	$1,750.20
Tailblock	$0.0713	$0.0705								$35.96	$26.37	$17.61	$13.55	$14.97	$23.10	$131.55	$889.82
HB Threshold	1,000	1,000															
Total Base Rate Amount			$373.24	$414.85	$442.74	$443.08	$438.28	$390.39	$2,502.59	$279.57	$269.98	$263.63	$259.57	$260.99	$269.12	$1,602.85	$4,105.44
CGA Rate - (Seasonal)			$0.7911	$0.7351	$0.7186	$0.7055	$0.7107	$0.7445	$0.7312	$0.7256	$0.7359	$0.7542	$0.7814	$0.7511	$0.7515	$0.7487	$0.7379
CGA amount			$1,362.27	$1,533.38	$1,674.44	$1,645.99	$1,628.27	$1,393.70	$9,238.06	$1,095.66	$1,011.13	$940.49	$929.87	$908.83	$994.99	$5,880.95	$15,119.01
LDAC			$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	$0.0493	0.0493	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0474	$0.0486
LDAC amount			$84.97	$102.94	$114.98	$115.13	$113.05	$92.38	$623.45	$71.57	$65.13	$59.11	$56.41	$57.35	$62.76	$372.33	$995.77
Total Bill			**$1,820.49**	**$2,051.17**	**$2,232.16**	**$2,204.20**	**$2,179.61**	**$1,876.47**	**$12,364.09**	**$1,446.80**	**$1,346.23**	**$1,263.23**	**$1,245.84**	**$1,227.18**	**$1,326.86**	**$7,856.13**	**$20,220.23**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**($266.57)**	**($206.05)**	**($191.84)**	**($161.48)**	**($170.49)**	**($202.55)**	**($1,198.97)**	**($319.35)**	**($356.39)**	**($354.69)**	**($309.56)**	**($254.75)**	**($279.27)**	**($1,874.01)**	**($3,072.98)**
% Change	**-14.64%**	**-10.05%**	**-8.59%**	**-7.33%**	**-7.82%**	**-10.79%**	**-9.70%**	**-22.07%**	**-26.47%**	**-28.08%**	**-24.85%**	**-20.76%**	**-21.05%**	**-23.85%**	**-15.20%**
Base Rate	($0.27)	($0.31)	($0.33)	($0.33)	($0.33)	($0.29)	($1.86)	$2.82	$2.71	($0.22)	($0.22)	($0.22)	($0.23)	$4.63	$2.77
% Change	-0.07%	-0.07%	-0.08%	-0.08%	-0.08%	-0.07%	-0.07%	1.01%	1.00%	-0.09%	-0.08%	-0.08%	-0.09%	0.29%	0.07%
CGA & LDAC	($266.30)	($205.74)	($191.50)	($161.15)	($170.16)	($202.26)	($1,197.11)	($322.16)	($359.10)	($354.46)	($309.34)	($254.53)	($279.04)	($1,878.64)	($3,075.75)
% Change	-19.55%	-13.42%	-11.44%	-9.79%	-10.45%	-14.51%	-12.96%	-29.40%	-35.51%	-37.69%	-33.27%	-28.01%	-28.04%	-31.94%	-20.34%

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ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing

Residential Heating

	Winter 2011-12	Winter 2012-13
Customer Charge	$17.33	$17.31
First 100 Therms	$0.2741	$0.2739
Excess 100 Therms	$0.2265	$0.2263
LDAC	$0.0693	$0.0258
CGA	$0.7309	$0.6719
Total Adjust	$0.8002	$0.6977

		Winter 2011-12 CGA @	Winter 2012-13 CGA @	Total		Base Rate		CGA		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$0.8002	$0.6977	($0.10)	-13%						
Cooking alone	5	$22.70	$22.17	($0.53)	-2%	-$0.02	0%	-$0.29	-1%	-$0.22	-1%
	10	$28.07	$27.03	($1.05)	-4%	-$0.02	0%	-$0.59	-2%	-$0.44	-2%
	20	$38.82	$36.74	($2.07)	-5%	-$0.02	0%	-$1.18	-3%	-$0.87	-2%
Water Heating alone	30	$49.56	$46.46	($3.10)	-6%	-$0.03	0%	-$1.77	-4%	-$1.31	-3%
	45	$65.67	$61.03	($4.64)	-7%	-$0.03	0%	-$2.65	-4%	-$1.96	-3%
	50	$71.05	$65.89	($5.16)	-7%	-$0.03	0%	-$2.95	-4%	-$2.18	-3%
Heating Alone	80	$97.90	$90.18	($7.72)	-8%	-$0.04	0%	-$4.42	-5%	-$3.27	-3%
	125	$158.64	$144.96	($13.68)	-9%	-$0.05	0%	-$7.84	-5%	-$5.79	-4%
	150	$176.10	$160.67	($15.43)	-9%	-$0.05	0%	-$8.85	-6%	-$6.53	-4%
	200	$227.43	$206.87	($20.56)	-9%	-$0.06	0%	-$11.79	-6%	-$8.71	-4%

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Variance Analysis of the Components of the Winter 2011-12 Actual Results vs Proposed Winter 2012-13 Cost of Gas Rate

	WINTER SALES ACTUAL RESULTS (6 months actual)			WINTER 2011-12 (6 months Proposed)		
Therm Sales	65,771,915			77,755,617		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
Demand Charges		$ 9,753,327	$ 0.1483		$ 10,538,954	$ 0.1355
Purchased Gas	61,918,285	25,445,436	0.3869	58,646,280	26,630,667	0.3425
Storage Gas	5,321,960	2,554,402	0.0388	20,522,810	9,121,704	0.1173
Produced Gas	869,735	317,581	0.0048	819,280	291,366	0.0037
Hedging (Gain)/Loss		6,802,122	0.1034		1,941,641	0.0250
Total Volumes and Cost	68,109,980	$ 44,872,868	$ 0.6822	79,988,370	$ 48,524,333	$ 0.6241
Direct Costs						
Prior Period Balance		$ 3,735,297	$ 0.0568		1,606,569	$ 0.0207
Interest		138,331	0.0021		73,865	0.0009
Prior Period Adjustment		(43,023)	(0.0007)		-	-
Broker Revenues		(1,015,743)	(0.0154)		(396,197)	(0.0051)
Refunds from Suppliers		-	-		-	-
Fuel Financing		144,515	0.0022		109,724	0.0014
Transportation CGA Revenues		-	-		(8,224)	(0.0001)
280 Day Margin		-	-		-	-
Interruptible Sales Margin		-	-		-	-
Capacity Release and Off System Sales Margins		(770,313)	(0.0117)		(1,130,619)	(0.0145)
Hedging Costs		-	-		-	-
FPO Admin Costs		-	-		40,691	0.0005
Indirect Costs						
Misc Overhead		10,337	0.0002		10,735	0.0001
Occupant Disallowance/Credits		-				
Production & Storage		1,980,428	0.0301		1,980,428	0.0255
Other Indirect Gas Costs		1,422,499	0.0216		1,429,276	0.0184
Total Adjusted Cost		$ 50,475,195	**$ 0.7674**		$ 52,240,580	**$ 0.6719**

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Capacity Assignment Calculations 2012-2013
Derivation of Class Assignments and Weightings

Basic assumptions:

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

		Column A	Column B	Column C	Column D	Column E	Column F
		Design Day Demand. Dktherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg	710	693	0.5%		132	561
2	RATE R-3-Resi Htg	66,635	64,807	47.0%		3,712	61,095
3	RATE G-41 (T)	24,355	23,672	17.2%		841	22,831
4	RATE G-51 (S)	2,663	2,604	1.9%		636	1,968
5	RATE G-42 (V)	35,322	34,345	24.9%		1,721	32,624
6	RATE G-52	4,184	4,099	3.0%		1,263	2,836
7	RATE G-43	4,276	4,163	3.0%		401	3,762
8	RATE G-53	1,804	1,759	1.3%		257	1,502
9	RATE G-54	1,912	1,859	1.3%		98	1,761
10							
11	Total	141,860	138,001	100.0%		9,060	128,941
12							-
13	Residential Total	67,345	65,500	**47.463%**		3,844	61,656
14	LLF Total	63,953	62,180	**45.058%**		2,962	59,218
15	HLF Total	10,562	10,321	**7.479%**		2,254	8,067
16	Total	141,860	138,001	100.0%		9,060	128,941
17							
18	C&I Breakdown						
19	LLF Total					2,962	59,218
20	HLF Total					2,254	8,067
21	Total					5,216	67,285
22							
23	C&I Breakdown Percentage						
24	LLF Total					56.791%	88.010%
25	HLF Total					43.209%	11.990%
26	Total					**100.0%**	**100.0%**

27						
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.
29	Pipeline			$5,792,874	53,718	$8.9866
30	Storage			$5,573,306	28,115	$16.5194
31						
32	Peaking			$6,945,969		
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)			$2,462,292		
34	Subtotal Peaking Costs			$9,408,262	56,167	$13.9588
35	Total			$20,774,441	138,000	$12.5450
36						
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.
38	Pipeline - Baseload			977,044	9,060	$8.9866
39	Pipeline - Remaining			4,815,830	44,658	$8.9865
40	Storage			5,573,306	28,115	$16.5194
41	Peaking			9,408,262	56,167	$13.9588
42	Total			20,774,441	138,000	$12.5450
43						
44						
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.
46	Pipeline - Base	Line 38 * Line 13 Col C	**47.463%**	463,734	4,300	$8.9866
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**47.463%**	2,285,728	21,196	$8.9865
48	Storage	Line 40 * Line 13 Col C	**47.463%**	2,645,262	13,344	$16.5194
49	Peaking	Line 41 * Line 13 Col C	**47.463%**	4,465,532	26,659	$13.9588
50	Total		**47.464%**	9,860,280	65,499	$12.5450

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Capacity Assignment Calculations 2012-2013
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		513,310	4,760	$8.9866	
55	Pipeline - Remaining	Line 39 - Line 47		2,530,103	23,462	$8.9866	
56	Storage	Line 40 - Line 48		2,928,043	14,771	$16.5193	
57	Peaking	Line 41 - Line 49		4,942,730	29,508	$13.9587	
58	Total		**52.537%**	10,914,185	72,501	$12.5449	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		291,516	2,703	$8.9874	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		2,226,755	20,649	$8.9865	
64	Storage	Line 56 * Line 24 Col F		2,576,985	13,000	$16.5191	
65	Peaking	Line 57 * Line 24 Col F		4,350,120	25,970	$13.9588	
66	Total		**45.4663%**	9,445,376	62,322	$12.6298	**1.0068**
67			56.791%	87%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		221,794	2,057	$8.9853	
71	Pipeline - Remaining	Line 55 - Line 63		303,348	2,813	$8.9865	
72	Storage	Line 56 - Line 64		351,058	1,771	$16.5188	
73	Peaking	Line 57 - Line 65		592,610	3,538	$13.9582	
74	Total		**7.0703%**	1,468,810	10,179	$12.0248	**0.9585**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 8.9866	$ 8.9866	$ 8.9866	
80	Storage			$ 16.5194	$ 16.5194	$ 16.5194	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 12.5450	$ 12.6298	$ 12.0248	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			38.93%	**37.47%**	**47.84%**	
88	Storage			20.37%	**20.86%**	**17.40%**	
89	Peaking			40.70%	**41.67%**	**34.76%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			47.46%	43.47%	9.07%	100.00%
96	Storage			47.46%	46.24%	6.30%	100.00%
97	Peaking			47.46%	46.24%	6.30%	100.00%

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Correction Factor Calculation

Data Source: Schedule 10B

	Nov	Dec	Jan	Feb	Mar	Apr	Total Sales
G-41	793,973	1,753,113	2,931,550	3,164,977	2,685,436	1,726,896	13,055,944
G-42	977,234	1,816,915	2,718,933	2,940,752	2,590,088	1,730,163	12,774,086
G-43	111,415	167,717	229,066	238,181	206,197	139,916	1,092,492
High Winter Use	1,882,621	3,737,744	5,879,550	6,343,911	5,481,721	3,596,975	26,922,523
G-51	187,448	274,514	359,907	385,766	332,045	241,900	1,781,580
G-52	223,378	294,954	368,393	347,643	326,431	252,589	1,813,388
G-53	30,712	35,448	45,707	46,192	43,680	34,154	235,893
G-54	641	739	929	919	3,772	4,964	11,964
Low Winter Use	442,179	605,654	774,936	780,520	705,929	533,607	3,842,824
Gross Total	2,324,800	4,343,398	6,654,486	7,124,430	6,187,650	4,130,582	30,765,347

Total Sales	30,765,347	
Low Winter Use	3,842,824	
Winter Ratio for Low Winter Use =	**0.95850**	Schedule 10A p 2, ln 74
High Winter Use	26,922,523	
Winter Ratio for High Winter Use =	**1.00680**	Schedule 10A p 2, ln 66

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

Correction Factor = $\boxed{\textbf{99.9234\%}}$

Allocation Calculation for Miscellaneous Overhead

Projected Winter Sales Volume	(11/1/12 - 4/30/13)	77,826,455	Sch.10B
Projected Annual Sales Volume	(11/1/12 - 10/31/13)	95,484,050	Sch.10B
Percentage of Winter to Annual Sales		81.51%	

1 **ENERGY NORTH NATURAL GAS, INC.**
2
3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **2012 - 2013 Winter Cost of Gas Filing**
5
6 **Dry Therms**

								Subtotal							Subtotal	
7	**Firm Sales**															
8		**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**PK 12-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**OP 13**	**Total**
9	R-1	64,166	88,417	111,208	113,714	102,801	83,421	563,726	67,153	54,234	47,099	38,571	41,431	48,833	297,320	861,046
10	R-3	3,469,410	6,479,481	9,405,373	10,057,648	8,632,848	5,809,694	43,854,454	3,075,847	1,809,921	1,139,367	964,835	1,045,881	1,566,338	9,602,189	53,456,643
11	R-4	244,831	378,321	542,475	583,409	533,298	360,593	2,642,927	206,634	120,743	66,195	53,269	55,801	78,362	581,004	3,223,932
12	Total Residential.	3,778,407	6,946,220	10,059,056	10,754,770	9,268,947	6,253,708	47,061,107	3,349,634	1,984,898	1,252,661	1,056,675	1,143,113	1,693,533	10,480,513	57,541,620
13																
14	G-41	793,973	1,753,113	2,931,550	3,164,977	2,685,436	1,726,896	13,055,944	763,239	448,943	206,222	188,227	195,440	281,384	2,083,454	15,139,399
15	G-42	977,234	1,816,915	2,718,933	2,940,752	2,590,088	1,730,163	12,774,086	933,331	528,863	303,894	266,225	299,407	451,670	2,783,390	15,557,477
16	G-43	111,415	167,717	229,066	238,181	206,197	139,916	1,092,492	88,052	63,990	45,226	36,726	39,261	65,735	338,990	1,431,482
17	G-51	187,448	274,514	359,907	385,766	332,045	241,900	1,781,580	177,591	155,232	132,622	120,514	128,357	140,827	855,143	2,636,723
18	G-52	223,378	294,954	368,393	347,643	326,431	252,589	1,813,388	202,975	176,177	151,541	138,768	144,675	156,904	971,040	2,784,427
19	G-53	30,712	35,448	45,707	46,192	43,680	34,154	235,893	26,372	23,411	21,897	20,782	25,323	24,061	141,846	377,739
20	G-54	641	739	929	919	3,772	4,964	11,964	1,280	488	298	134	368	650	3,219	15,183
21	Total C/I	2,324,800	4,343,398	6,654,486	7,124,430	6,187,650	4,130,582	30,765,347	2,192,840	1,397,104	861,700	771,376	832,832	1,121,232	7,177,083	37,942,430
22																
23	**Sales Volume**	**6,103,208**	**11,289,618**	**16,713,541**	**17,879,201**	**15,456,597**	**10,384,290**	**77,826,455**	**5,542,473**	**3,382,001**	**2,114,361**	**1,828,051**	**1,975,945**	**2,814,765**	**17,657,596**	**95,484,050**
24																
25	Transportation Sales															
26																
27	G-41	346,902	592,251	849,034	903,931	829,780	592,146	4,114,045	366,071	205,723	141,425	130,531	140,154	204,951	1,188,854	5,302,899
28	G-42	1,193,548	1,968,036	2,806,411	2,952,958	2,636,879	1,847,163	13,404,996	1,046,516	570,803	361,868	331,417	385,148	615,204	3,310,956	16,715,952
29	G-43	656,809	950,554	1,194,487	1,188,478	1,099,782	809,158	5,899,268	498,423	317,562	203,367	222,072	250,160	394,162	1,885,746	7,785,014
30	G-51	89,621	120,528	161,913	159,738	157,832	137,921	827,553	102,824	94,744	82,396	68,419	79,037	88,078	515,497	1,343,050
31	G-52	352,948	450,286	535,915	576,318	510,139	388,529	2,814,135	349,729	328,175	294,883	286,867	295,232	329,890	1,884,776	4,698,911
32	G-53	809,112	957,322	1,206,036	1,217,486	1,072,407	913,794	6,176,157	738,809	708,856	687,341	678,305	737,266	784,433	4,335,008	10,511,165
33	G-54	1,284,272	1,357,661	1,327,986	1,571,589	1,205,775	1,137,421	7,884,703	1,242,152	1,469,596	1,375,774	1,362,581	1,436,585	1,449,915	8,336,604	16,221,307
34																
35	Total Trans. Sales	**4,733,213**	**6,396,638**	**8,081,781**	**8,570,497**	**7,512,596**	**5,826,133**	**41,120,858**	**4,344,524**	**3,695,459**	**3,147,054**	**3,080,191**	**3,323,582**	**3,866,633**	**21,457,441**	**62,578,299**
36																
37	Total All Sales	**10,836,421**	**17,686,256**	**24,795,322**	**26,449,698**	**22,969,193**	**16,210,423**	**118,947,312**	**9,886,997**	**7,077,460**	**5,261,414**	**4,908,241**	**5,299,526**	**6,681,398**	**39,115,037**	**158,062,349**

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing

Normal and Design Year Volumes **Schedule 11A**

Volumes (Therms) **Normal Year**

For the Months of November 12 - April 13

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Peak Nov - Apr
Pipeline Gas:							
Dawn Supply	924,000	926,310	954,800	862,400	954,800	820,050	5,442,360
Niagara Supply	721,490	745,360	745,360	672,980	745,360	721,490	4,352,040
TGP Supply (Direct)	5,292,980	5,155,150	5,155,150	4,656,190	5,155,150	5,272,190	30,686,810
Dracut Supply 1 - Baseload	-	2,380,840	2,380,840	2,150,610	-	-	6,912,290
Dracut Supply 2 - Swing	3,531,220	957,880	1,983,520	2,142,140	3,002,230	3,362,590	14,979,580
City Gate Delivered Supply	-	-	-	-	-	-	0
LNG Truck	21,560	22,330	680,680	-	44,660	-	769,230
Propane Truck	-	-	-	-	-	-	0
PNGTS	58,520	76,230	83,160	71,610	66,990	46,970	403,480
Granite Ridge	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	10,549,770	10,264,100	11,983,510	10,555,930	9,969,190	10,223,290	63,545,790
Storage Gas:							
TGP Storage	1,223,530	4,811,730	5,793,480	4,971,120	3,670,590	52,360	20,522,810
Produced Gas:							
LNG Vapor	21,560	22,330	710,710	20,790	22,330	21,560	819,280
Propane	-	-	-	-	-	-	0
Subtotal Produced Gas	21,560	22,330	710,710	20,790	22,330	21,560	819,280
Less - Gas Refills:							
LNG Truck	(21,560)	(22,330)	(680,680)	-	(44,660)	-	(769,230)
Propane	-	-	-	-	-	-	-
TGP Storage Refill	(1,851,080)	-	-	-	-	(2,279,200)	(4,130,280)
Subtotal Refills	(1,872,640)	(22,330)	(680,680)	-	(44,660)	(2,279,200)	(4,899,510)
Total Sendout Volumes	9,922,220	15,075,830	17,807,020	15,547,840	13,617,450	8,018,010	79,988,370

1	**ENERGY NORTH NATURAL GAS, INC.**							
2								
3	**Peak 2012 - 2013 Winter Cost of Gas Filing**							
42	**Normal and Design Year Volumes**							**Schedule 11B**
43								
44								
45	**Volumes (Therms)**	**Design Year**						
46								
47	**For the Months of November 12 - April 13**							
48								
49								**Peak**
50		**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**Nov - Apr**
51	Pipeline Gas:							
52	Dawn Supply	940,381	971,727	971,727	877,689	971,727	867,501	5,600,751
53	Niagara Supply	734,281	758,574	758,574	684,911	758,574	734,281	4,429,193
54	TGP Supply (Direct)	5,386,031	5,246,541	5,246,541	4,738,736	5,246,541	5,368,791	31,233,180
55	Dracut Supply 1 - Baseload	-	2,423,048	2,423,048	2,188,736	-	-	7,034,832
56	Dracut Supply 2 - Swing	4,528,717	1,728,733	3,176,136	3,423,770	5,390,733	4,056,176	22,304,265
57	City Gate Delivered Supply	-	-	-	-	-	-	0
58	LNG Truck	21,942	22,726	611,248	82,283	45,452	-	783,651
59	Propane Truck	-	-	146,543	25,077	-	-	171,619
60	PNGTS	59,557	77,581	84,634	72,880	68,178	47,803	410,633
61	Granite Ridge	-	-	-	-	-	-	-
62	Other Purchased Resources	-	-	-	-	-	-	-
63	Subtotal Pipeline Volumes	11,670,909	11,228,930	13,418,450	12,094,081	12,481,204	11,074,551	71,968,125
64								
65	Storage Gas:							
66	TGP Storage	1,169,990	5,518,468	6,297,417	5,123,508	2,677,734	56,423	20,843,540
67								
68	Produced Gas:							
69	LNG Vapor	21,942	22,726	611,248	133,221	22,726	21,942	833,804
70	Propane	-	-	297,004	25,077	-	-	322,080
71	Subtotal Produced Gas	21,942	22,726	908,251	158,297	22,726	21,942	1,155,885
72								
73	Less - Gas Refills:							
74	LNG Truck	(21,942)	(22,726)	(611,248)	(82,283)	(45,452)	-	(783,651)
75	Propane	-	-	(146,543)	(25,077)	-	-	(171,619)
76	TGP Storage Refill	(1,807,098)	-	-	-	-	(2,264,750)	(4,071,849)
77	Subtotal Refills	(1,829,041)	(22,726)	(757,790)	(107,360)	(45,452)	(2,264,750)	(5,027,119)
78								
79	Total Sendout Volumes	11,033,801	16,747,398	19,866,328	17,268,526	15,136,212	8,888,166	88,940,431

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 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	5,442,360	4,000	7,240,000	75%	5,600,751	4,000	7,240,000	77%
Niagara Supply	4,352,040	3,122	5,650,820	77%	4,429,193	3,122	5,650,820	78%
TGP Supply (Direct)	30,686,810	21,596	39,088,760	79%	31,233,180	21,596	39,088,760	80%
Dracut Supply 1 & 2	21,891,870	50,000	90,500,000	24%	29,339,097	50,000	90,500,000	32%
LNG Truck	769,230	-	-	-	783,651	-	-	-
Propane Truck	-	-	-	-	171,619	-	-	-
PNGTS	403,480	1,000	1,810,000	22%	410,633	1,000	1,810,000	23%
Granite Ridge	-	-	-	-	-	-	-	-
Other Purchased Resources	-	-	-	-	-	-	-	-
Subtotal Pipeline Volumes	63,545,790				71,968,125			
Storage Gas:								
TGP Storage	20,522,810		25,801,310	80%	20,843,540		25,801,310	81%
Produced Gas:								
LNG Vapor	819,280				833,804			
Propane	-				322,080			
Subtotal Produced Gas	819,280				1,155,885			
Less - Gas Refills:								
LNG Truck	(769,230)				(783,651)			
Propane	-				(171,619)			
TGP Storage Refill	(4,130,280)				(4,071,849)			
Subtotal Refills	(4,899,510)				(5,027,119)			
Total Sendout Volumes	79,988,370				88,940,431			

ENERGY NORTH NATURAL GAS, INC. **Schedule 11D**

Peak 2012 - 2013 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2012 / 13 Heating Season
(Therms)

EnergyNorth Natural Gas, Inc.
d/b/a National Grid New Hampshire

72 HDD at Manchester, N.H.

Requirements

Firm Sales	1,133,557
Interruptible Sales	0
Firm Transportation	246,443
Interruptible Transportation	0
Total Requirements	1,380,000

Resources

Purchased Pipeline Gas	643,600
Underground Storage Gas	281,100
Propane Air Production	350,000
LNG Produced Gas	105,300
Third-Party Supply	0
Total Resources	1,380,000

Please refer to the ENGI 2010 IRP filing (DG 10-041) for a complete description of the methodology and assumptions used in the derivation of this data.

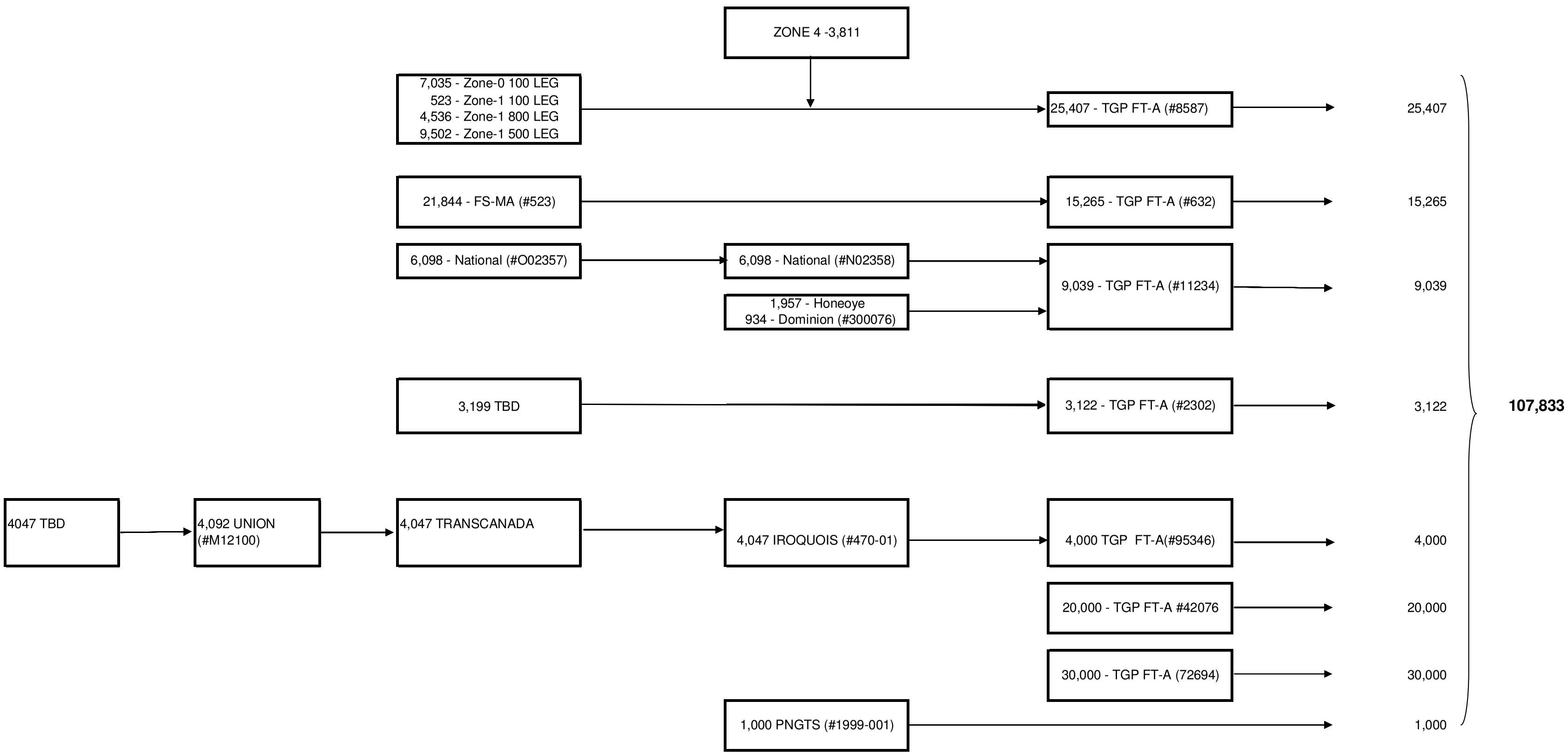
Preparation of this report was supervised by:

Theodore Poe, Jr.
Manager, Energy Planning

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

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
Granite Ridge Energy, LLC EXPIRES (Formerly AES Londonderry, L.L.C.)	-	-	Supply	15,000	450,000	09/30/2012	N/a	Mutually agreed upon.
Montly Purchase - TBD No Off-Peak	-	-	Supply	3,199	1,167,635	03/31/2012	N/a	Terminates
TBD - No Off-Peak Sent RFP	-	-	Supply	4,047	611,097	Peak Only	N/a	Terminates
Distrigas of Massachusetts Corp. Renew Need to negotiate	FLS	FLS183	Liquid Refill	Up to 3 trucks	100,000 National Grid Total	03/31/2012 Peak Only	-	Terminates
Repsol AMA	-	-	Supply	April 2012 = 10,000 / day	4,491,000	04/30/2012	-	Terminates
Montly Purchase - TBD	-	-	Supply	21,596	3,908,876	04/30/2012	N/a	Terminates
Eastern Propane Gas Need to negotiate (Trucking Contract and Maybe Supply)			Trucking	28,500 Gallons	900,000 Gallons	03/31/2012	N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	03/31/2016	03/31/2013	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	04/01/2013	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	03/31/2013	03/31/2013	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	03/31/2013	03/31/2013	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	11/01/2017	10/31/2012	Evergreen Provision
Portland Natural Gas Transmission System	FT 1999-01	1999-001	Transportation	1,000	365,000	10/31/2019	10/31/2018	Evergreen Provision
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2015	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2012	10/31/2012	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2015	10/31/2012	Evergreen Provision
TransCanada Pipeline	FT		Transportation	4,047	1,477,155	10/31/2017	04/30/2016	Evergreen Provision
Union Gas Limited	M12	M12100	Transportation	4,092	1,493,580	10/31/2017	10/31/2015	Evergreen Provision

* MAQ is calculated on a 365 day calendar year.

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

May 2011 - Apr 2012 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	14,331,712	38.37%	77.36%
G-42	15,403,573	41.24%	50.97%
G-43	1,251,018	3.35%	15.24%
G-51	2,764,675	7.40%	73.97%
G-52	3,190,891	8.54%	45.77%
G-53	392,113	1.05%	4.21%
G-54	15,437	0.04%	0.09%
Total C/I	37,349,418	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	4,194,419	7.49%	22.64%
G-42	14,816,927	26.46%	49.03%
G-43	6,955,718	12.42%	84.76%
G-51	972,759	1.74%	26.03%
G-52	3,780,622	6.75%	54.23%
G-53	8,921,064	15.93%	95.79%
G-54	16,358,087	29.21%	99.91%
Total C/I	55,999,596	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	18,526,131	19.85%	100.00%
G-42	30,220,501	32.37%	100.00%
G-43	8,206,736	8.79%	100.00%
G-51	3,737,433	4.00%	100.00%
G-52	6,971,513	7.47%	100.00%
G-53	9,313,176	9.98%	100.00%
G-54	16,373,523	17.54%	100.00%
Total C/I	93,349,014	100.00%	

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak May 11 - Oct 11 (Therms)	Peak Nov 11-Apr 12 (Therms)	Total May 11 - Apr 12 (Therms)	Ratio
Pipeline Deliveries	16,235,690	62,165,410	78,401,100	
All Others	495,940	5,944,570	6,440,510	
	16,731,630	68,109,980	84,841,610	
Total Winter Supplies				68,109,980
Total Pipeline Deliveries				78,401,100
Ratio Winter Supplies to Pipeline Supplies				0.869

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 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-11	Aug-11	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	203,496	154,227	357,723	14,331,712	2.50%
G-42	341,785	272,667	614,452	15,403,573	3.99%
G-43	33,989	35,316	69,305	1,251,018	5.54%
G-51	154,920	134,687	289,607	2,764,675	10.48%
G-52	204,251	186,110	390,361	3,190,891	12.23%
G-53	23,759	20,389	44,148	392,113	11.26%
G-54	881	861	1,742	15,437	11.28%
Total C/I	963,081	804,257	1,767,338	37,349,418	4.73%

1 **ENERGY NORTH NATURAL GAS, INC.**

3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**

6 **Underground Storage Gas**

Ln	Description	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
8			(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		1,895,479	1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	2,297,475	2,360,230	1,879,057	1,299,709	802,597	435,538	1,895,479
11	Injections (MMBtu)	Sch 11A ln 37 /10	11,436	27,746	-	-	184,117	184,117	185,108	-	-	-	-	227,920	820,444
13	Subtotal		1,906,915	1,929,391	1,929,241	1,929,241	2,113,358	2,297,475	2,482,583	2,360,230	1,879,057	1,299,709	802,597	663,458	
15	Storage Sale		-					-							
17	Withdrawals (MMBtu)	Sch 11A ln 27 /10	(5,270)	(150)	-	-	-	-	(122,353)	(481,173)	(579,348)	(497,112)	(367,059)	(5,236)	(2,057,701)
19	Ending Balance (MMBTu)		1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	2,297,475	2,360,230	1,879,057	1,299,709	802,597	435,538	658,222	658,222
22	Beginning Balance		$ 9,092,272	$ 9,085,950	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,773,400	$ 10,386,322	$ 10,491,583	$ 8,352,695	$ 5,777,405	$ 3,567,666	$ 1,936,033	9,092,272
24	Injections	ln 11 * ln 36	18,859	78,943	-	-	608,506	612,922	649,138	-	-	-	-	886,634	2,855,003
26	Subtotal		$ 9,111,130	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,773,400	$ 10,386,322	$ 11,035,460	$ 10,491,583	$ 8,352,695	$ 5,777,405	$ 3,567,666	$ 2,822,667	
28	Storage Sale		$ -					$ -							
30	Withdrawals	ln 17 * ln 34	$ (25,180)	$ -	$ -	$ -	$ -	$ -	$ (543,878)	$ (2,138,887)	$ (2,575,290)	$ (2,209,739)	$ (1,631,633)	$ (22,276)	(9,146,884)
32	Ending Balance		$ 9,085,950	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,773,400	$ 10,386,322	$ 10,491,583	$ 8,352,695	$ 5,777,405	$ 3,567,666	$ 1,936,033	$ 2,800,391	$ 2,800,391
34	Average Rate For Withdrawals	ln 22 /ln 9	$4.7779	$4.7501	$4.7505	$4.7505	$4.6246	$4.5208	$4.4452	$4.4452	$4.4452	$4.4452	$4.4452	$4.2545	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$1.6490	$2.8452	$0.0000	$0.0000	$3.3050	$3.3290	$3.5068	$3.7824	$3.9169	$3.9312	$3.9108	$3.8901	
38	For Informational Purposes								Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
39	Summer Hedge Contracts - Vols Dth								-	-	-	-	-	-	-
40	Average Hedge Price								$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
41	NYMEX								$3.1057	$3.3715	$3.5012	$3.5151	$3.4954	$3.4754	
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				$ 9,164,894	$ 9,469,147	$ 10,079,861	$ 10,438,952	$ 9,422,139	$ 7,065,050	$ 4,672,536	$ 2,751,850	$ 2,368,212	
49	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.80%	1.29%	1.37%	1.35%	1.40%	1.51%	1.61%	1.62%	1.56%	
51	Inventory Finance Charge	ln 47 * ln 49				$ 6,099	$ 10,209	$ 11,528	$ 11,780	$ 11,004	$ 8,870	$ 6,263	$ 3,718	$ 3,088	
52	Financial Expenses					500	500	500	500	500	500	500	500	500	
53	Total Inventory Finance Charges					$ 6,599	$ 10,709	$ 12,028	$ 12,280	$ 11,504	$ 9,370	$ 6,763	$ 4,218	$ 3,588	

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1 **ENERGY NORTH NATURAL GAS, INC.**

2

3 **Peak 2012 - 2013 Winter Cost of Gas Filing**

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

5

39

40 **Liquid Propane Gas (LPG)**

Ln	Description	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
41															
42			(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
43	Beginning Balance		93,824	93,828	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	93,824
44															
45	Injections	Sch 11A ln 36 /10	72	1,016	-	-	-	-	-	-	-	-	-	-	1,088
46															
47	Subtotal		93,896	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	
48															
49	Withdrawals	Sch 11A ln 31 /10	(68)	-	-	-	-	-	-	-	-	-	-	-	(68)
50															
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		93,828	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844	94,844
54															
55															
56	Beginning Balance		$ 1,382,938	$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,382,938
57															
58	Injections	ln 45 * ln 68	1,061	13,101	-	-	-	-	-	-	-	-	-	-	14,162
59															
60	Subtotal		$ 1,384,000	$ 1,396,098	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	
61															
62	Withdrawals	ln 51 * ln 66	(1,002)	-	10,676	-	-	-	-	-	-	-	-	-	9,674
63															
64	Ending Balance		$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774
65															
66	Average Rate For Withdrawals		$14.7397	$14.7199	$14.7199	$14.8325	$14.8325	$14.8325	$14.8325	$14.8325	$14.8325	$14.8325	$14.8325	$14.8325	
67															
68	Propane Rate for Injections	Actual or Sch. 6, ln 151 * 10	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
69															
70															
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	
72															
73	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.80%	1.29%	1.37%	1.35%	1.40%	1.51%	1.61%	1.62%	1.56%	
74															
75	Inventory Finance Charge	ln 71 * ln 73				$ 936	$ 1,517	$ 1,609	$ 1,588	$ 1,643	$ 1,766	$ 1,886	$ 1,901	$ 1,834	
76															
77															
78															
70															

1 **ENERGY NORTH NATURAL GAS, INC.**

3 **Peak 2012 - 2013 Winter Cost of Gas Filing**
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**

Line	Item	Reference	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	Total
72	**Liquid Natural Gas (LNG)**														
73			(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
74	Beginning Balance		7,885	5,928	10,583	10,583	10,583	10,583	10,583	10,583	10,583	7,580	5,501	7,734	7,885
76	Injections	Sch 11A ln 35 /10	797	6,395	-	-	-	-	2,156	2,233	68,068	-	4,466	-	84,115
78	Subtotal		8,682	12,323	10,583	10,583	10,583	10,583	12,739	12,816	78,651	7,580	9,967	7,734	
80	Withdrawals	Sch 11A ln 30 /10	(2,754)	(1,740)	-	-	-	-	(2,156)	(2,233)	(71,071)	(2,079)	(2,233)	(2,156)	(86,422)
82	Ending Balance		5,928	10,583	10,583	10,583	10,583	10,583	10,583	10,583	7,580	5,501	7,734	5,578	5,578
85	Beginning Balance		$ 34,430	$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 41,161	$ 40,206	$ 26,843	$ 19,481	$ 27,229	$ 34,430
87	Injections	ln 76 * ln 97	3,480	24,011	-	-	-	-	6,696	7,528	238,320	-	15,610	-	295,645
89	Subtotal		$ 37,910	$ 49,896	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 49,546	$ 48,689	$ 278,526	$ 26,843	$ 35,091	$ 27,229	
91	Withdrawals	ln 80 * ln 95	(12,025)	(7,045)	-	-	-	-	(8,385)	(8,483)	(251,683)	(7,362)	(7,862)	(7,591)	(310,437)
93	Ending Balance		$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 41,161	$ 40,206	$ 26,843	$ 19,481	$ 27,229	$ 19,639	$ 19,639
95	Average Rate For Withdrawals		$4.3665	$4.0490	$4.0490	$4.0490	$4.0490	$4.0490	$3.8893	$3.7991	$3.5413	$3.5413	$3.5207	$3.5207	
97	LNG Rate for Injections	Actual or Sch. 6, ln 150 * 10	$4.3665	$3.7546	$3.5012	$3.5151	$3.4954	$3.4754	$3.1057	$3.3715	$3.5012	$3.5151	$3.4954	$3.4754	
100	Month Dollar Average	ln (85 + ln 93) /2				$ 42,850	$ 42,850	$ 42,850	$ 42,006	$ 40,683	$ 33,524	$ 23,162	$ 23,355	$ 23,434	
102	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.80%	1.29%	1.37%	1.35%	1.40%	1.51%	1.61%	1.62%	1.56%	
104	Inventory Finance Charge	ln 100 * ln 102				$ 29	$ 46	$ 49	$ 47	$ 48	$ 42	$ 31	$ 32	$ 31	
107	Total Fuel Financing	lns 53 + 75 + 104				$ 7,564	$ 12,272	$ 13,686	$ 13,915	$ 13,194	$ 11,178	$ 8,679	$ 6,151	$ 5,453	

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 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-12	4,733,213	$0.0002	$ 947
Dec-12	6,396,638	0.0002	1,279
Jan-13	8,081,781	0.0002	1,616
Feb-13	8,570,497	0.0002	1,714
Mar-13	7,512,596	0.0002	1,503
Apr-13	5,826,133	0.0002	1,165
Total	**41,120,858**		**$ 8,224**

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

Liberty Utilities

ChristiAne Mason
Director/Head
Regulatory, Government & Community
C: 603-856-4231
E: ChristiAne.Mason@libertyutilities.com

July 27, 2012

Via Electronic Mail and U.S. Mail

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

Re: DG 11-192
EnergyNorth Natural Gas, Inc.
2011-12 Winter Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Enclosed are seven copies of the redacted version of the 2011-12 Winter Period Cost of Gas reconciliation filing for EnergyNorth Natural Gas, Inc. ("the Company"). This filing is being submitted under protective order and confidential treatment granted by the Commission in Order No. 25,286 dated October 31, 2011 in Docket DG 11-192. This report has been filed electronically with the New Hampshire Public Utilities Commission in accordance with Order Number 24,223 issued on October 24, 2003, in which the Commission found that the filing requirement would be satisfied by filing one electronic copy and one paper copy with the Commission. The Company has also filed separately a confidential version with the Commission.

The filing shows an under collection for the 2011-12 Winter Period of $1,606,569 summarized as follows:

Winter Period Beginning Balance	$3,735,297
Less: Cost of Gas Revenue Billed	($47,440,335)
Add: Cost of Gas Allowable (5/1/11 -10/31/11)	$1,890,001
Add: Cost of Gas Allowable (11/1/11 -4/30/12)	$43,421,606
Winter Period Ending Balance	$1,606,569

This filing consists of a six-page summary and nine supporting schedules. Page 1 of the Summary compares the actual deferred gas costs to the projections submitted in the Company's filing including the beginning balance, interest and other allowable adjustments to gas costs, gas costs and gas cost revenue. The result is a net under collection of $1,606,569. Page 2 of the Summary compares the actual allowed Bad Debt and Working Capital costs to the filed projections submitted in the Company's filing resulting in an under collection of $113,348 and an over collection of $541, respectively, for a net under collection for all the gas accounts of $1,719,376. Page 3 of the Summary compares actual demand charges of $9,753,327 to the $12,917,335 in demand charges estimated in the filing. Page 4 shows a similar comparison for commodity costs. The actual commodity costs were $35,119,541 compared to $46,765,731 in the filing. The $11,646,190 decrease in commodity costs was caused mainly by lower prices than originally forecasted. The results show that the actual demand and commodity costs were $14,810,198 lower than filed. Page 5 of the Summary provides a variance analysis that explains how much of the difference between actual costs and forecasted costs is due to weather ($3,447,242) changes in demand ($7,743,150) and changes in gas prices ($3,619,807). Page 6 of the Summary shows the calculation of the actual Transportation Cost of Gas Revenue compared to the filing.

The attached Schedule 1 provides a monthly summary of the deferred gas cost account balances including beginning balances, actual gas cost allowable, gas cost collections, and interest applied. Schedule 1A provides the same information for bad debt associated with the cost of gas. Schedule 2 provides the details of gas cost by source. Schedule 3 provides the detailed calculation of winter gas cost revenue billed by rate class. Schedule 4 provides a monthly summary of the non-firm margin and capacity release credits to the winter cost of gas account. Schedule 5 provides the monthly summary of the deferred gas cost balances associated with gas working capital. It shows the monthly beginning account balances, working capital allowable, the working capital collections and the interest applied to derive the monthly ending balances. Schedule 6 shows the bad debt and working capital calculation that determines the amount of expense booked for those items. Schedule 7 provides the backup calculations for the revenue billed to recover working capital and bad debt by rate class. Schedule 8 provides a summary of the monthly commodity costs and related volumes. Schedule 9 provides a summary of the monthly prime interest rates used to calculate the interest on the deferred balances.

Please return one copy of this filing to me bearing the Commission's receipt stamp in the envelope that has been provided for your convenience.

Please do not hesitate to contact me with questions regarding this filing.

Sincerely,

ChristiAne G. Mason

Enclosure

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2330 2012-07-27 Cost of Gas Reconciliation Report Peak Cover letter REDACTED

ENERGY NORTH NATURAL GAS, INC

WINTER 2011-2012 COST OF GAS RESULTS
DG 11-192
NOVEMBER 2011 THROUGH APRIL 2012

	Original Filing 1/	Actual		Difference
Peak Gas cost Account 175.20				
Balance 05/01/11 - (Over) / Under	$3,735,297	$3,735,297	2/	($0)
Peak Gas Costs 5/1/11 - 10/31/11	$3,557,973	$3,307,565	3/	(250,408)
Fuel Financing 5/1/11 - 10/31/11	80,980	37,301	3/	(43,679)
Prior Period Adjustment 5/1/10-10/31/10	-	(43,023)	3/	(43,023)
Broker Revenue 5/1/11 - 10/31/11	(987,254)	(764,952)	3/	222,302
280 Day Margins 5/1/11 - 10/31/11	-	-	4/	-
IT Sales Margins 5/1/11 - 10/31/11	-	-	4/	-
Off System Sales Margin 5/1/11 - 10/31/11	(44,872)	(67,043)	4/	(22,171)
Capacity Release 5/1/11 - 10/31/11	(311,822)	(653,025)	4/	(341,203)
Interest 5/1/11 - 10/31/11	78,435	73,178	3/	(5,257)
Sum 5/1/11 - 10/31/11 costs	$2,373,440	$1,890,001		($483,439)
Beginning Balance 10/31/11 (Over)/Under	$6,108,737	$5,625,298		($483,439)
Interest 11/1/11 - 4/30/12	42,152	59,360		17,208
Prior Period Adjustments	-	-		0
Interruptible Sales Margin 11/1/11 - 4/30/12	-	-		-
280-Day Margin 11/1/11 - 4/30/12	-	-		-
Off System Sales Margin 11/1/10 -4/30/11	(95,170)	(9,497)		85,673
Capacity Release Credits 11/1/11 - 4/30/12	(19,280)	(40,749)		(21,469)
Other Transportation Related Margins	0	0		0
Fixed Price Option Admin Costs	40,691	0		(40,691)
Broker Revenues 11/1/11 - 4/30/12	(430,318)	(250,791)		179,527
Production & Storage	1,980,428	1,980,428		0
Misc Overhead	10,337	10,337		0
Fuel Financing 11/1/11 - 4/30/12	101,995	107,214		5,219
Transportation Cost of Gas Revenue	-	-		-
Total Adjustment to Costs	$1,630,835	$1,856,303		$225,468
Gas Costs 11/1/11 - 4/30/12	$56,125,094	$41,565,303		($14,559,791)
Total Gas Costs and Adjustments 11/11 - 04/12	$57,755,929	$43,421,606		($14,334,323)
Gas Cost Billed	($63,864,666)	(47,440,335)		$16,424,331
Total (Over) / Under 04/30/12	$0	$1,606,569		$1,606,569

Prepared By: Kevin Baxter
Reviewed By: Robert Campbell

ENERGY NORTH NATURAL GAS, INC

WINTER 2011-2012 COST OF GAS RESULTS
DG 11-192
NOVEMBER 2011 THROUGH APRIL 2012

	Original Filing 1/	Actual		Difference
Bad Debts Account 175.52	$36,020	$36,020		$0
	84,431	64,770	5/	(19,661)
Beginning Balance	1,281	(279)	5/	(1,560)
BD Costs 5/1/11 - 10/31/11 Interest 5/1/11 - 10/31/11	$121,732	$228,246		($21,221)
Beginning Balance 10/31/11 (Over)/Under	1,420,593	1,132,153		(288,440)
Bad Debt Costs 11/1/11 - 4/30/12	(1,543,183)	(1,249,713)		293,470
Bad Debt CGA Billed	-	-		0
Adjustment	858	2,662		1,804
Interest	$0	$113,348		$113,348
Total (Over) / Under 04/30/12				
Working Capital Account 142.20	$8,916	$8,916		($0)
	4,522	3,288	6/	(1,234)
Beginning Balance	179	168	6/	(11)
WC Costs 5/1/11 - 10/31/11 Interest 5/1/11 - 10/31/11	$13,617	$12,372		($1,245)
Beginning Balance 10/31/11 (Over)/Under	71,328	52,761		(18,567)
Working Capital Costs 11/1/11 - 4/30/12	(85,065)	(65,772)		19,293
Working Capital CGA Billed	-	-		0
Adjustment	120	98		(22)
Interest	$0	($541)		($541)
Total (Over) / Under 04/30/12	$0	$1,719,376		$1,719,376
Total 175.20, 175.52, 142.20				

1/ As filed 09-01-11 in the Winter 2011-2012 Cost of Gas DG 11-192.
2/ The beginning balance is the sum of the actual April 30, 2011 balance $4,200,751 less the May 2011 Billings of $3,570,466, plus reverse of prior month unbilled $3,105,012.
3/ The 5/1/11 - 10/31/11 costs are per Schedule 1, page 1, of the Summer 2011 Reconciliation filed on January 31, 2012 in DG 11-046.
4/ The 5/1/11 - 10/31/11 costs are per Schedule 4, of the Summer 2011Reconciliation filed on January 31, 2012 in DG 11-046.
5/ The 5/1/11 - 10/31/11 costs are per Schedule 1, page 3, of the Summer 2011 Reconciliation filed on January 31, 2012 in DG 11-046.
6/ The 5/1/11 - 10/31/11 costs are per Schedule 5, of the Summer 2011 Reconciliation filed on January 31, 2012 in DG 11-046.

ENERGY NORTH NATURAL GAS, INC

WINTER 2011-2012 COST OF GAS RESULTS
DG 11-192
SUMMARY OF DEMAND CHARGES FOR PERIOD
NOVEMBER 2011 THROUGH APRIL 2012

	Filing (a)	1/ Actual May 11 - Oct 11 (b)	Actual Nov 11 - Apr 12 (c)	Actual Total Peak Demand (d)=(b)+(c)	Difference (e)=(d)-(a)
Supplies:					
BP/Nexen	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ICE					
Subtotal Supply Demand Charges	$6,404	$0	$11,147	$11,147	$4,743
Pipelines:					
Iroquois Gas Trans	$160,191	$0	$134,544	$134,544	($25,647)
TGP NET 33371	259,015	-	149,172	149,172	($109,843)
TGP FTA Z5-Z6 2302	202,161	-	115,760	115,760	($86,401)
TGP FTA Z0 - Z6 8587	4,249,377	-	2,602,387	2,602,387	($1,646,990)
TGP Dracut FTA Z6 - Z6 42076	893,304	-	500,563	500,563	($392,741)
TGP (Concord Lateral) Z6-Z6	4,089,120	1,790,646	2,141,433	3,932,079	($157,041)
Portland Natual Gas Pipeline	241,474	-	177,081	177,081	($64,393)
ANE (Uniongas and TransCanada)	350,302	-	357,957	357,957	$7,655
TGP FTA 632	2,133,117	778,427	659,227	1,437,655	($695,462)
TGP FTA 11234	1,231,606	478,177	401,589	879,766	($351,840)
National Fuel	245,959	104,360	104,655	209,015	($36,944)
Subtotal Pipeline Demand Charges	$14,055,626	$3,151,610	$7,344,370	$10,495,980	($3,559,646)
Peaking Supply					
Granite Ridge	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NJR / BG Energy					
DOMAC					
Repsol					
JP Morgan					
Subtotal Peaking Supply	$520,367	($475,061)	$554,283	$79,223	($441,145)
Propane					
Energy North Propane	$0	$0	$0	$0	$0
Storage:					
Demand & Capacity Charges	$1,567,467	$743,679	$534,334	$1,278,013	($289,454)
Other:					
Capacity Managed	($3,232,529)	(112,664)	($1,118,790)	($1,231,454)	$2,001,075
Pipeline Refunds	$0	$0	($879,582)	($879,582)	($879,582)
Total Demand Charges (Forward to Page 4)	$12,917,335	$3,307,565	$6,445,762	$9,753,327	($3,164,008)

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2011 Cost of Gas Reconciliation, DG 11-046 filed January 31, 2012.

ENERGY NORTH NATURAL GAS, INC

WINTER 2011-2012 COST OF GAS RESULTS
DG 11-192
SUMMARY OF COMMODITY COSTS FOR PERIOD
NOVEMBER 2011 THROUGH APRIL 2012

	Filing	Average Cost per Therm	Actual	Average Cost per Therm	Difference	
Demand Charges (Brought from Page 3):	**$12,917,335**		**$9,753,327**		**($3,164,008)**	
TGP Gulf Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Dracut Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
PNGTS Comodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
TGP/Iroquois Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
TGP/Niagara Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
City Gate Delivered Supply						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Storage Gas - Commodity Withdrawn						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Propane P/S Plant Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Propane Tank Farm Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
LNG P/S Plant Commodity						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Hedging (Gains) Losses	[redacted]		[redacted]		[redacted]	
Other- Cashout, Broker Penalty, Canadian Managed, Non-Firm costs						
Therms	[redacted]		[redacted]		[redacted]	
Cost						
Prior period Adj	[redacted]		[redacted]		[redacted]	
Subtotal:						
Volumes (net of fuel retention)	85,279,058		68,109,980		(17,169,078)	
Cost	$ 46,765,731	0.5484	$ 35,119,541	0.5156	$ (11,646,190)	(0.0328)
Total Demand and Commodity Costs	$ 59,683,066		$ 44,872,868		$ (14,810,198)	
Demand (therms):	85,279,058		68,109,980		(17,169,078)	
Firm Gas Sales	82,632,661		65,771,915		(16,860,746)	
Lost Gas (Unaccounted For)	1,652,632		2,104,598		451,966	
Unbilled Therms	14,672		(604,340)		(619,012)	
Fuel Retention	-		-		-	
Company Use	979,095		837,807		(141,288)	
Total Demand	85,279,060		68,109,980		(17,169,080)	
						-

ENERGY NORTH NATURAL GAS, INC

WINTER 2011-2012 COST OF GAS RESULTS
DG 11-192

Weather Variance - Volume Impact	(A) Actual Volume	(B) Normal Volume	(C) Actual Rate		(A-B)*C Difference
TGP Gulf TGP/Iroquios TGP/Niagra PNGTS Dracut City Gate Delivered Supply DOMAC Storage gas - commodity withdrawn Propane LNG	[redacted]				
Total Volume Weather Varaince	68,109,980	77,928,952		$	(3,447,242)

Demand Variance - Commodity Costs	(A) Forecast Volume	(B) Actual Volume	(C) Forecast Rate		(B-A)*C Difference
TGP Gulf TGP/Iroquios TGP/Niagra PNGTS Comodity City Gate Delivered Supply Dracut Storage Gas - Commodity Withdrawn Propane P/S Plant Commodity LNG P/S Plant Commodity	[redacted]				
Total Demand Variance (Less: Fuel Retention)	85,279,058	68,109,980		$	(11,190,391)
Demand Variance Net of Weather Variance					(7,743,150)

Rate Variance - Commodity Costs	(A) Actual Volume	(B) Forecast Rate	(C) Actual Rate		(C-B)*A Difference
TGP Gulf TGP/Iroquios TGP/Niagra PNGTS Comodity Dracut DOMAC Storage Gas - Commodity Withdrawn Propane P/S Plant Commodity LNG P/S Plant Commodity	[redacted]				
Total Commodity Cost Rate Variance	68,109,980			$	(5,147,155)
Demand Charge Variance (from page 3)					(3,164,008)
Other Rate Variance (from page 4)					
Hedging (Gains)/Losses					4,710,205
Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments					(18,848)
Total Rate Variance				$	(3,619,807)
Due to Weather Variance					(3,447,242)
Due to Demand Variance (from above)					(7,743,150)
Total Gas Cost Variance				$	(14,810,198)

ENERGY NORTH NATURAL GAS, INC

WINTER 2011-2012 COST OF GAS RESULTS
DG 11-192

	FILING	ACTUAL
Cost of Propane	$ -	$ 19,541
Cost of LNG	381,653	244,922
Total Costs	381,653	264,463
Percentage of Supplies Used For Pressure Support Purposes	9.9%	9.9%
Cost of Supplies Used For Pressure Support Purposes	37,784	26,182
Firm Therms Sold	82,647,332	65,771,915
Firm Therms Transported	36,930,101	34,162,155
Total Therms	119,577,433	99,934,070
Actual Liquid Cost/Therm	0.0003	0.0003
Firm Therms Transported	36,930,101	34,162,155
Liquid Costs Allocated to Transported Therms	11,669	8,950
Prior (Over) or under Collection	(10,838)	(10,838)
Total	831	(1,888)
Costs Recovered:		
Therms Transported	36,930,101	34,162,155
Recovery Rate	0.0000	-
Costs Recovered	0	-
(Over) / Under Collection For Period	831	(1,888)

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.20

	FOR THE MONTH OF: DAYS IN MONTH	Nov-11 30	Dec-11 31	Jan-12 31	Feb-12 29	Mar-12 31	Apr-12 30	May-12	Total
1	BEGINNING BALANCE	$ 5,625,298	$ 4,412,942	$ 4,356,536	$ 3,405,366	$ 3,058,426	$ 2,900,816	$ 2,076,323	**$ 5,625,298**
2									
3	Add: Actual Costs	4,969,709	8,992,035	10,290,854	8,044,444	5,848,215	3,420,047		**41,565,303**
4									
5	Add. FPO Admin Costs	-	-	-	-	-	-		**-**
6	Add: MISC OH	1,723	1,723	1,723	1,723	1,723	1,723		**10,337**
7	Add: Production and Storage	330,071	330,071	330,071	330,071	330,071	330,071		**1,980,428**
8	Add: Fuel Financing	7,461	20,451	13,012	17,177	32,756	16,357		**107,214**
9	Reverse Fuel Finance Estimate		-			-			**-**
10	Add new Fuel Finance Estimate		-			-			**-**
11									
12	Less: CUSTOMER BILLINGS	(1,561,988)	(7,054,008)	(10,548,793)	(10,446,693)	(9,300,630)	(5,703,419)	(2,824,803)	**(47,440,335)**
13	Estimated Unbilled	(4,911,161)	(7,215,127)	(8,224,110)	(6,469,273)	(3,531,311)	(2,355,050)		**(32,706,032)**
14	Reverse Prior Month Unbilled		4,911,161	7,215,127	8,224,110	6,469,273	3,531,311	2,355,050	**32,706,032**
15	Sub-Total Accrued Customer Billings	(6,473,149)	(9,357,975)	(11,557,775)	(8,691,857)	(6,362,668)	(4,527,157)	(469,754)	**(47,440,335)**
16									
17	Less: REFUND	-	-	-	-	-	-		**-**
18									
19	Less: Broker Revenues	(59,962)	(52,719)	(37,893)	(51,607)	(10,518)	(38,091)	-	**(250,791)**
20									
21	NON FIRM MARGIN AND CREDITS	(1,598)	(2,077)	(1,860)	(5,227)	(5,402)	(34,082)	-	**(50,245)**
22									
23	ENDING BALANCE PRE INTEREST	**$ 4,399,553**	**$ 4,344,450**	**$ 3,394,668**	**$ 3,050,091**	**$ 2,892,603**	**$ 2,069,684**	**$ 1,606,569**	**$ 1,547,209**
24									
25	MONTH'S AVERAGE BALANCE	5,012,425	4,378,696	3,875,602	3,227,729	2,975,514	2,485,250		
26									
27	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
28									
29	INTEREST APPLIED	13,389	12,086	10,698	8,335	8,213	6,639		**59,360**
30									
31	ENDING BALANCE	**$ 4,412,942**	**$ 4,356,535.92**	**$ 3,405,366**	**$ 3,058,426**	**$ 2,900,816**	**$ 2,076,323**	**$ 1,606,569**	**$ 1,606,569**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
OFF PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.40

	FOR THE MONTH OF: DAYS IN MONTH	Nov-11 30	Dec-11 31	Jan-12 31	Feb-12 29	Mar-12 31	Apr-12 30	May-12	Total
1	BEGINNING BALANCE	$ 680,336	$ (408,621)	$ (409,749)	$ (410,880)	$ (411,941)	$ (1,162,743)	$ (1,165,849)	**680,336**
2									
3	Add:ACTUAL COST	-	-	-	-	(748,632)	-		**$ (748,632)**
4									
5	Add: MISC OH & PROD and STOR	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(2,970,287)	-	-	-	-	-	-	**(2,970,287)**
8	Estimated Unbilled		-	-	-	-	-		-
9	Reverse Prior Month Unbilled	1,880,968	-	-	-	-	-	-	**1,880,968**
10	Sub-Total Accrued Customer Billings	(1,089,319)	-	-	-	-	-	-	(1,089,319)
11									
12	Add: ADJUSTMENTS	-	-	-	-	-	-	-	-
13									
14	ENDING BALANCE PRE INTEREST	**$ (408,983)**	**$ (408,621)**	**$ (409,749)**	**$ (410,880)**	**$ (1,160,573)**	**$ (1,162,743)**	**$ (1,165,849)**	**$ (1,157,615)**
15									
16	MONTH'S AVERAGE BALANCE	135,676	(408,621)	(409,749)	(410,880)	(786,257)	(1,162,743)		
17									
18	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
19									
20	INTEREST APPLIED	362	(1,128)	(1,131)	(1,061)	(2,170)	(3,106)		**(8,234)**
21									
22	ENDING BALANCE	**$ (408,621)**	**$ (409,749)**	**$ (410,880)**	**$ (411,941)**	**$ (1,162,743)**	**$ (1,165,849)**	**$ (1,165,849)**	**$ (1,165,849)**

ENERGY NORTH NATURAL GAS, INC

MAY 2011 THROUGH OCTOBER 2011
PEAK BAD DEBT
SCHEDULE 1A
ACCOUNTS 175.52 and 175.54

	FOR THE MONTH OF: DAYS IN MONTH	May-11 31	Jun-11 30	Jul-11 31	Aug-11 31	Sep-11 30	Oct-11 31		Total
1	BEGINNING BALANCE	$ 60,123	$ 142,670	$ 162,766	$ 177,963	$ 203,556	$ 219,853		**60,123**
2									
3	Add: COST ALLOW	68,670	61,711	45,459	61,250	53,929	90,434		**$ 381,454**
4									
5	Adjustment	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(28,212)	(58,324)	(42,110)	(34,219)	(36,398)	(46,190)		**(245,454)**
8	Estimated Unbilled	(32,928)	(16,626)	(5,249)	(7,212)	(9,012)	(45,481)		**(116,508)**
9	Reverse Prior Month Unbilled	74,739	32,928	16,626	5,249	7,212	9,012		**145,766**
10	Sub-Total Accrued Customer Billings	13,598	(42,022)	(30,733)	(36,183)	(38,197)	(82,659)		(216,196)
11									
12	ENDING BALANCE PRE INTEREST	**$ 142,391**	**$ 162,359**	**$ 177,493**	**$ 203,030**	**$ 219,288**	**$ 227,628**		**$ 225,381**
13									
14	MONTH'S AVERAGE BALANCE	101,257	152,515	170,130	190,497	211,422	223,741		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17									
18	INTEREST APPLIED	279	407	470	526	565	618		**$ 2,865**
19									
20	ENDING BALANCE	**$ 142,670**	**$ 162,766**	**$ 177,963**	**$ 203,556**	**$ 219,853**	**$ 228,246**		**$ 228,246**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
PEAK BAD DEBT
SCHEDULE 1A
ACCOUNTS 175.52 and 175.54

	FOR THE MONTH OF: DAYS IN MONTH	Nov-11 30	Dec-11 31	Jan-12 31	Feb-12 29	Mar-12 31	Apr-12 30	May-12	Total
1	BEGINNING BALANCE	$ 228,246	$ 186,855	$ 185,908	$ 156,234	$ 142,525	$ 138,176	$ 124,588	**228,246**
2									
3	Add: COST ALLOW	139,872	240,508	273,013	216,718	161,759	100,283		**$ 1,132,153**
4									
5	Adjustment	-	-	-	-	-	-	-	-
6									
7	Less: CUSTOMER BILLINGS	(109,125)	(172,971)	(271,959)	(274,134)	(246,709)	(148,752)	(71,543)	**(1,295,194)**
8	Estimated Unbilled	(118,173)	(187,171)	(218,370)	(175,049)	(94,835)	(60,303)		**(853,900)**
9	Reverse Prior Month Unbilled	45,481	118,173	187,171	218,370	175,049	94,835	60,303	**899,381**
10	Sub-Total Accrued Customer Billings	(181,817)	(241,969)	(303,159)	(230,813)	(166,495)	(114,220)	(11,241)	(1,249,713)
11									
12	ENDING BALANCE PRE INTEREST	**$ 186,301**	**$ 185,394**	**$ 155,762**	**$ 142,140**	**$ 137,789**	**$ 124,238**	**$ 113,348**	**$ 110,686**
13									
14	MONTH'S AVERAGE BALANCE	207,274	186,125	170,835	149,187	140,157	131,207		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17									
18	INTEREST APPLIED	554	514	472	385	387	350		**$ 2,662**
19									
20	ENDING BALANCE	**$ 186,855**	**$ 185,908**	**$ 156,234**	**$ 142,525**	**$ 138,176**	**$ 124,588**	**$ 113,348**	**$ 113,348**

REDACTED

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
GAS COSTS BY SOURCE
SCHEDULE 2A

	FOR THE MONTH OF:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
1	**DEMAND**							
2								
3	ALBERTA NORTHEAST	[redacted]						
4	BP/NORTHEAST GAS MARKETS							
5	CANADIAN CAPACITY MANAGED							
6	TOTAL CANADIAN DEMAND	$ (170,917.40)	$ (171,937.08)	$ (175,089.68)	$ (204,311.82)	$ (187,064.88)	$ (192,669.54)	**$ (1,101,990.40)**
7								
8	PEAKING SUPPLY	9,631.02	9,130.42	9,130.42	9,130.42	9,130.42	9,130.42	**55,283.12**
9								
10	TRANSPORT CAPACITY	1,239,958.44	1,201,003.95	1,206,062.34	1,208,296.49	1,202,380.37	1,233,141.43	**7,290,843.02**
11	CAPACITY RELEASE ADJUSTMENT	1,007.50	2,077.00	1,860.00	1,542.75	1,472.50	32,788.75	**40,748.50**
12	TOTAL TRANSPORT	$ 1,240,965.94	$ 1,203,080.95	$ 1,207,922.34	$ 1,209,839.24	$ 1,203,852.87	$ 1,265,930.18	**$ 7,331,591.52**
13								
14	STORAGE FIXED COSTS	36,220.00	93,532.33	102,729.95	100,720.81	105,483.13	95,647.34	**534,333.56**
15								
16	LNG	-	124,750.00	124,750.00	124,750.00	124,750.00	-	**499,000.00**
17								
18	PROPANE	-	-	-	-	-	-	-
19								
20	PIPELINE REFUNDS	-	(288,376.35)	-	-	(1,051,461.38)	(288,376.34)	**(1,628,214.07)**
21								
22	OTHER	543.13	1,086.26	1,086.26	1,303.50	1,803.50	1,303.50	**7,126.15**
23								
24								
25								
26	**TOTAL DEMAND**	**$ 1,116,442.69**	**$ 971,266.53**	**$ 1,270,529.29**	**$ 1,241,432.15**	**$ 206,493.66**	**$ 890,965.56**	**$ 5,697,129.88**
27								
28	**COMMODITY**							
29								
30	ALBERTA NORTHEAST / BP	[redacted]						
31	ALBERTA NORTHEAST / Emera							
32	SHELL CANADA							
33	TOTAL CANADIAN COMMODITY	**$ 797,711.16**	**$ 841,013.66**	**$ 771,324.51**	**$ 707,836.61**	**$ 605,583.52**	**$ 44,716.17**	**$ 3,768,185.63**
34								
35	PIPELINE TRANSPORT	[redacted]						
36	DRACUT SUPPLY							
37	PNGTS							
38								
39	GAS SUPPLY	[redacted]						
40								
41	STORAGE	[redacted]						
42								
43	LNG	[redacted]						
44								
45	PROPANE	[redacted]						
46								
47	**OTHER COST ADJUSTMENTS**							
48	CANDIAN CAPACITY MANAGED	[redacted]						
49	SUPPLIER CASHOUT							
50	NET OTHER COST ADJUSTMENTS							
51								
52	**SUBTOTAL COMMODITY COST**	**$ 3,905,345.61**	**$ 8,020,768.17**	**$ 9,020,324.75**	**$ 6,846,403.18**	**$ 4,908,034.51**	**$ 2,534,588.43**	**$ 35,235,464.65**
53								
54	OFF SYSTEM SALES COST	[redacted]						
55	OFF SYSTEM SALES COST - PPA							
56	NON-FIRM COST							
57								
58	**TOTAL COMMODITY COST**	**$ 3,853,266.01**	**$ 8,020,768.17**	**$ 9,020,324.75**	**$ 6,803,011.93**	**$ 4,893,089.04**	**$ 2,529,081.38**	**$ 35,119,541.28**
59								
60	**ENERGY NORTH NATURAL GAS, INC**							
61								
62	**NOVEMBER 2011 THROUGH APRIL 2012**							
63	**GAS COSTS SUMMARY**							
64	**SCHEDULE 2A**							
65								
66	**FOR THE MONTH OF:**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**Total**
67								
68	**Total Peak Demand**	**$ 1,116,442.69**	**$ 971,266.53**	**$ 1,270,529.29**	**$ 1,241,432.15**	**$ 955,125.81**	**$ 890,965.56**	**$ 6,445,762.03**
69	**Off-Peak Demand**	-	-	-	-	**(748,632.15)**	-	**(748,632.15)**
70	**Total Demand**	**$ 1,116,442.69**	**$ 971,266.53**	**$ 1,270,529.29**	**$ 1,241,432.15**	**$ 206,493.66**	**$ 890,965.56**	**$ 5,697,129.88**
71								
72	**Total Peak Commodity**	**$ 3,853,266.01**	**$ 8,020,768.17**	**$ 9,020,324.75**	**$ 6,803,011.93**	**$ 4,893,089.04**	**$ 2,529,081.38**	**$ 35,119,541.28**
73	**Off-Peak Commodity**	-	-	-	-	-	-	-
74	**Total Commodity**	**$ 3,853,266.01**	**$ 8,020,768.17**	**$ 9,020,324.75**	**$ 6,803,011.93**	**$ 4,893,089.04**	**$ 2,529,081.38**	**$ 35,119,541.28**
75								
76	**Firm Sendout Costs**	**$ 4,969,708.70**	**$ 8,992,034.70**	**$ 10,290,854.04**	**$ 8,044,444.08**	**$ 5,099,582.70**	**$ 3,420,046.94**	**$ 40,816,671.16**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

	FOR THE MONTH OF:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
1	**DEMAND**							
2	**Supply**							
3	Alberta Northeast	[redacted]						
4	Northeast Gas Markets/BP							
5	**Subtotal Canadian Supply**	**$ 1,336.46**	**$ 5,002.61**	**$ 2,835.74**	**$ 2,684.93**	**$ 2,785.21**	**$ 2,154.31**	**$ 16,799.26**
6	**Peaking Suppy**							
7	Repsol	[redacted]						
8	Granite Ridge							
9	NRJ/BG Energy							
10	JP Morgan							
11	**Subtotal Peaking Supply**	**$ 9,631.02**	**$ 9,130.42**	**$ 9,130.42**	**$ 9,130.42**	**$ 9,130.42**	**$ 9,130.42**	**$ 55,283.12**
12								
13	**Transport Capacity**							
14	Iroquois 470-01-RTS	$ 22,987.18	$ 22,357.56	$ 22,819.74	$ 22,166.25	$ 22,166.25	$ 22,047.51	**$ 134,544.49**
15	National Fuel N02358	17,935.67	17,327.38	17,290.18	17,186.04	17,185.81	17,729.86	**104,654.94**
16	PNGTS FT-1999-001	39,238.10	22,070.36	14,238.24	22,196.48	18,288.21	51,732.00	**167,763.39**
17	Transcanada	47,383.67	44,790.93	48,964.93	47,369.12	48,856.09	48,229.06	**285,593.80**
18	TGP 632 FTA	138,248.07	81,581.62	109,956.93	109,210.56	108,675.36	108,089.58	**655,762.12**
19	TGP 2302 FTA Zone 5-6	12,278.43	26,600.94	19,365.28	19,246.24	19,119.78	19,149.53	**115,760.20**
20	TGP 8587 FTA	431,650.54	442,541.48	434,769.04	431,906.36	431,906.61	429,613.08	**2,602,387.11**
21	TGP 11234 FTA	78,186.23	52,917.93	65,301.92	64,988.09	64,987.51	64,707.66	**391,089.34**
22	TGP 33371 NET	15,832.50	34,040.70	25,439.87	26,022.39	23,285.96	24,550.68	**149,172.10**
23	TGP 72694 NET	357,469.41	357,226.01	356,495.81	356,860.91	356,800.06	356,581.00	**2,141,433.20**
24	TGP 42076 FTA	69,024.39	89,783.93	81,572.81	81,050.16	81,050.16	80,615.44	**483,096.89**
25	Union Gas	9,724.25	9,765.11	9,847.59	10,093.89	10,058.57	10,096.03	**59,585.44**
26	**Subtotal Transport Capacity**	**$ 1,239,958.44**	**$ 1,201,003.95**	**$ 1,206,062.34**	**$ 1,208,296.49**	**$ 1,202,380.37**	**$ 1,233,141.43**	**$ 7,290,843.02**
27								
28	**Storage Fixed**							
29	Sempra	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
30	Dominion 300076-Storage	2,676.08	2,758.98	2,730.42	2,716.08	2,944.99	2,476.28	**16,302.83**
31	NFG Deliverability FSS 2357	36,682.63	35,345.52	35,515.03	35,686.72	35,649.40	33,765.26	**212,644.56**
32	Tenn Reservation FSMA 523	(11,883.10)	46,683.44	55,740.11	53,573.62	58,144.35	50,661.41	**252,919.83**
33	Honeoye Storage SS-NY	8,744.39	8,744.39	8,744.39	8,744.39	8,744.39	8,744.39	**52,466.34**
34	**Subtotal Storage**	**$ 36,220.00**	**$ 93,532.33**	**$ 102,729.95**	**$ 100,720.81**	**$ 105,483.13**	**$ 95,647.34**	**$ 534,333.56**
35								
36	**LNG / DISTRIGAS**	[redacted]						
37	**LNG/ DISTRIGAS FLS160**							
38	**Transgas Trucking**							
39	**Subtotal Distrigas**	$ -	$ 124,750.00	$ 124,750.00	$ 124,750.00	$ 124,750.00	$ -	**$ 499,000.00**
40								
41	**Propane**							
42	**En Propane**	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
43								
44	**Intercontinental Exchange**	$ 543	$ 1,086	$ 1,086	$ 1,304	$ 1,804	$ 1,304	**7,126.15**
45								
46	**Capacity Managed - Canadian**	[redacted]						
47								
48	**PNGTS Refund per RP02-13**	[redacted]						
49	**TGP Pipeline Refund** PK	$ -	$ (288,376.35)	$ -	$ -	$ (302,829.23)	$ (288,376.34)	**(879,581.92)**
50	**TGP Pipeline Refund** OP	$ -	$ -	$ -	$ -	$ (748,632.15)	$ -	**(748,632.15)**
51	**Demand Subtotal**	**$ 1,115,435.19**	**$ 969,189.53**	**$ 1,268,669.29**	**$ 1,239,889.40**	**$ 205,021.16**	**$ 858,176.81**	**$ 5,656,381.38**
52								
53	**Capacity Release Adjustment**							
54	ALBERTA NORTHEAST	[redacted]						
55	TGP - FT-A 95346							
56	TGP - FT-A 42076							
57	TGP - FT-A 2302							
58	PNGTS - FT							
59	**Total Capacity Release Adjustment**							
60								
61	**TOTAL DEMAND**	**$ 1,116,442.69**	**$ 971,266.53**	**$ 1,270,529.29**	**$ 1,241,432.15**	**$ 206,493.66**	**$ 890,965.56**	**$ 5,697,129.88**

REDACTED

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

62	**FOR THE MONTH OF:**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**Total**
63								
64	**COMMODITY**							
65								
66	**Canadian Supply**							
67	BP	[redacted]						
68	ANE Union/Dawn/Iroquois (BG)							
69	Shell Canada							
70	**Subtotal Canadian Commodity**							
71								
72	**Pipeline Transport**							
73	ANE Union/Dawn	[redacted]						
74								
75	Dominion							
76	El Paso							
77	Iroquois							
78	National Fuel							
79	PNGTS							
80	**Subtotal TGP Transportation**							
81	**Total Transportation**							
82								
83	**City Gate Delivery**							
84	VPEM	[redacted]						
85								
86	**Dracut Supply (Repsol)**							
87								
88	**PNGTS Supply**							
89	Emera							
90	Shell							
91								
92	**Subtotal PNGTS**							
93								
94	**Gas Supply**							
95	Andarko	[redacted]						
96	J Aron							
97	BG LNG							
98	Barclay							
99	BP Energy							
100	Chevron							
101	Cheniere							
102	Conoco							
103	EServices							
104	StatOil							
105	EnCan							
106	Gavilon							
107	JP Morgan							
108	Hess							
109	L. Dreyfus							
110	Macquarie							
111	Merrill							
112	NJR Energy							
113	Repsol							
114	South Jersey							
115	Shell US							
116	Spark							
117	Tenaska							
118	Total Gas & Power							
119	VPEM							
120	United							
121	**Total Other TGP Supply**							
122								
123	**Peaking Supply**							
124	Granite Ridge (formerly AES)	[redacted]						
125								
126	NYMEX Hedging (Gains) Losses							
127								
128	**STORAGE WITHDRAWALS**							
129								
130	**STORAGE INJECTIONS**							
131								
132	DISTRIGAS (FLS187)							
133	LNG VAPOR							
134	LNG BOIL OFF							
135	**Subtotal LNG**							
136	**PROPANE**							
137	Country Gas							
138	Propane Storage Withdrawal							
139	Energy North Propane							
140	**Subtotal Propane**							
141								
142	Broker Cashout							
143	Other Taxes W. Virginia							
144	**Subtotal Cashouts**							
145								
146	Capacity Managed - Canadian							
147	Broker Inventory							
148	**Subtotal Capacity Managed**							
149								
150	**TOTAL COMMODITY**							
151								
152	Off System Gas Sales Cost							
153	Off System Sales Costs - PPA							
154	NON-FIRM COST							
155								
156	**NET COMMODITY COST**	**$ 3,853,266.01**	**$ 8,020,768.17**	**$ 9,020,324.75**	**$ 6,803,011.93**	**$ 4,893,089.04**	**$ 2,529,081.38**	**$ 35,119,541.28**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

			Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
157	**FOR THE MONTH OF:**								
158									
159	Peak Demand 175.20		$ 1,116,442.69	$ 971,266.53	$ 1,270,529.29	$ 1,241,432.15	$ 955,125.81	$ 890,965.56	$ 6,445,762.03
160	Peak Commodity 175.20		3,853,266.01	8,020,768.17	9,020,324.75	6,803,011.93	4,893,089.04	2,529,081.38	35,119,541.28
161	Total Peak Gas Costs		**$ 4,969,708.70**	**$ 8,992,034.70**	**$ 10,290,854.04**	**$ 8,044,444.08**	**$ 5,848,214.85**	**$ 3,420,046.94**	**$ 41,565,303.31**
162									
163	Off-Peak Demand 175.40	OP	-	-	-	-	(748,632.15)	-	(748,632.15)
164	Off-Peak Comm 175.40	OP	-	-	-	-	-	-	-
165	Total Off-Peak Gas Costs		$ -	$ -	$ -	$ -	$ (748,632.15)	$ -	$ (748,632.15)
166									
167	Firm Sendout Costs		**$ 4,969,708.70**	**$ 8,992,034.70**	**$ 10,290,854.04**	**$ 8,044,444.08**	**$ 5,099,582.70**	**$ 3,420,046.94**	**$ 40,816,671.16**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
SCHEDULE 3
WINTER CGAC GAS REVENUES BILLED

	FOR MONTH OF:	Nov-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Total	Total
		OffPeak	Peak						Peak	Peak	OffPeak
1	**VOLUMES**										
2	**RESIDENTIAL**										
3	R-1	47,895	14,708	77,909	102,345	102,236	94,088	69,436	48,003	**508,725**	**47,895**
4	R-1 FPO	3,158	1,669	8,023	10,158	9,996	9,706	6,833	4,028	**50,413**	**3,158**
5	R-3	2,068,685	1,057,279	4,686,326	6,824,203	6,953,795	6,272,017	3,676,027	1,646,587	**31,116,234**	**2,068,685**
6	R-3 FPO	274,247	173,844	810,726	1,116,575	1,142,461	1,034,094	615,412	287,402	**5,180,514**	**274,247**
7	R-4	42,182	4,393	22,780	620,250	511,494	584,265	448,041	276,855	**2,468,078**	**42,182**
8	R-4 FPO	1,939	1,054	6,411	139,308	103,704	112,036	73,081	41,201	**476,795**	**1,939**
9	Total Residential	2,438,106	1,252,947	5,612,175	8,812,839	8,823,686	8,106,206	4,888,830	2,304,076		
10	**COMMERCIAL/INDUSTRIAL**										
11	G41 - G43	1,166,134	557,358	2,837,938	4,654,629	4,774,127	4,175,738	2,400,833	1,122,655	**20,523,278**	**1,166,134**
12	G41 - G43 (FPO)	69,442	48,182	260,350	416,864	417,406	325,587	209,339	100,784	**1,778,512**	**69,442**
13	Total G41- G43	1,235,576	605,540	3,098,288	5,071,493	5,191,533	4,501,325	2,610,172	1,223,439		
14	G51 - G63	323,545	134,003	529,541	674,613	652,853	591,829	448,790	288,774	**3,320,403**	**323,545**
15	G51 - G63 (FPO)	15,965	12,272	59,528	62,499	70,330	64,571	49,628	30,135	**348,963**	**15,965**
16	Total G51-G63	339,510	146,275	589,069	737,112	723,183	656,400	498,418	318,909		
17	Total Sales Volumes	4,013,192	2,004,762	9,299,532	14,621,444	14,738,402	13,263,931	7,997,420	3,846,424	**65,771,915**	**4,013,192**
18	**TRANSPORTATION**										
19	G41 - G43	1,321,701	403,760	2,577,400	3,708,448	3,933,688	3,663,258	2,517,136	1,387,976	**18,191,666**	**1,321,701**
20	G51 - G63	2,361,903	89,955	2,592,439	2,824,294	2,812,250	2,815,446	2,513,878	2,322,227	**15,970,489**	**2,361,903**
21	Total Transportation Volumes	3,683,604	493,715	5,169,839	6,532,742	6,745,938	6,478,704	5,031,014	3,710,203	**34,162,155**	**3,683,604**
22	**Total Volumes**	**7,696,796**	**2,498,477**	**14,469,371**	**21,154,186**	**21,484,340**	**19,742,635**	**13,028,434**	**7,556,627**	**99,934,070**	**7,696,796**
23											
24	**RATES**										
25	Residential	0.74030	0.77300	0.75530	0.71150	0.69710	0.68890	0.70220	0.72640		
26	Residential (FPO)	0.74030	0.7930	0.79300	0.79300	0.79300	0.79300	0.79300	0.79300		
27	C/I Sales G41 to G43	0.74420	0.77330	0.75670	0.71200	0.69770	0.68910	0.70150	0.72670		
28	C/I Sales G41 to G43 (FPO)	0.74420	0.7933	0.79330	0.79330	0.79330	0.79330	0.79330	0.79330		
29	C/I Transport G41 to G43	0.00000	0.0000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		
30	C/I Sales G51 to G63	0.73330	0.77150	0.75420	0.71020	0.69570	0.68740	0.70070	0.72490		
31	C/I Sales G51 to G63 (FPO)	0.73330	0.7915	0.79150	0.79150	0.79150	0.79150	0.79150	0.79150		
32	C/I Transport G51 to G63	0.00000	0.0000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		
33											
34	**REVENUES**										
35	Residential	$ 1,598,132	$ 832,042	$ 3,615,632	$ 5,369,547	$ 5,275,322	$ 4,788,110	$ 2,944,679	$ 1,432,058	**$ 24,257,389**	**$ 1,598,132**
36	Residential (FPO)	$ 206,798	$ 140,018	$ 654,352	$ 1,003,971	$ 996,136	$ 916,578	$ 551,394	$ 263,776	**$ 4,526,224**	**$ 206,798**
37	C/I Sales G41 to G43	$ 867,837	$ 431,005	$ 2,147,468	$ 3,314,096	$ 3,330,908	$ 2,877,501	$ 1,684,184	$ 815,833	**$ 14,600,996**	**$ 867,837**
38	C/I Sales G41 to G43 (FPO)	$ 51,679	$ 38,223	$ 206,536	$ 330,698	$ 331,128	$ 258,288	$ 166,069	$ 79,952	**$ 1,410,894**	**$ 51,679**
39	C/I Transport G41 to G43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	**$ -**
40	C/I Sales G51 to G63	$ 237,256	$ 103,383	$ 399,380	$ 479,110	$ 454,190	$ 406,823	$ 314,467	$ 209,332	**$ 2,366,686**	**$ 237,256**
41	C/I Sales G51 to G63 (FPO)	$ 11,707	$ 9,713	$ 47,116	$ 49,468	$ 55,666	$ 51,108	$ 39,281	$ 23,852	**$ 276,204**	**$ 11,707**
42	C/I Transport G51 to G63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	**$ -**
43	**Winter Gas Cost Rev filed**	**$ 2,973,408**	**$ 1,554,384**	**$ 7,070,484**	**$ 10,546,889**	**$ 10,443,350**	**$ 9,298,408**	**$ 5,700,073**	**$ 2,824,803**	**$ 47,438,391**	**$ 2,973,408**
44											
45	Winter Proration	$ -	$ 7,604	$ (15,761)	$ 2,955	$ 5,018	$ 3,084	$ 3,901	$ -	**6,801**	**-**
46											
47	Less Occupant Billing	$ 3,121	$ -	$ 714	$ 1,052	$ 1,675	$ 862	$ 555	$ -	**4,858**	**3,121**
48	Total	$ 2,970,287	$ 1,561,988	$ 7,054,008	$ 10,548,793	$ 10,446,693	$ 9,300,630	$ 5,703,419	$ 2,824,803	$ 47,440,335	$ 2,970,287
49											
50	**Summer Gas Cost Billed (Acct 175.40)**	**$ 2,970,287**									**$ 2,973,408**
51											
52	Winter Gas Costs Billed (Acct 175.20)		**$ 1,561,988**	**$ 7,054,008**	**$ 10,548,793**	**$ 10,446,693**	**$ 9,300,630**	**$ 5,703,419**	**$ 2,824,803**	**$ 47,440,335**	
53	Winter Transportation Gas Costs Billed (Acct 175.20)	-	-	-	-	-	-	-	-	**$ -**	**$ -**
54	**Total Winter Gas Cost Billed (Acct 175.20)**	**$ -**	**$ 1,561,988**	**$ 7,054,008**	**$ 10,548,793**	**$ 10,446,693**	**$ 9,300,630**	**$ 5,703,419**	**$ 2,824,803**	**$ 47,440,335**	**$ 2,973,408**
55											
56											
57	Total Sales CGA Billed	**$ 2,970,287**	**$ 1,561,988**	**$ 7,054,008**	**$ 10,548,793**	**$ 10,446,693**	**$ 9,300,630**	**$ 5,703,419**	**$ 2,824,803**	**$ 47,440,335**	**$ 2,970,287**
58											
59	Plus: Working Capital Gas Cost Billed	1,204	2,005	9,300	14,621	14,738	13,264	7,997	3,846	**65,772**	**1,204**
60	Plus: Bad Debt Cost Billed	71,836	37,289	172,971	271,959	274,134	246,709	148,752	71,543	**1,223,358**	**71,836**
61	Plus: Broker Revenues	-	59,962	52,719	37,893	51,607	10,518	38,091	-	**250,791**	**-**
62											
63	**Total Winter Gas Costs Billed**	**$ 3,043,327**	**$ 1,661,244**	**$ 7,288,998**	**$ 10,873,266**	**$ 10,787,173**	**$ 9,571,121**	**$ 5,898,260**	**$ 2,900,193**	**$ 48,980,256**	**$ 3,043,327**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
SCHEDULE 3A- CALCULATION OF UNBILLED GAS COSTS (ACCRUED COG)

	FOR MONTH OF:	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
1	Firm Gas Purchases		8,732,260	13,558,770	17,034,720	12,969,750	9,381,320	6,433,160	68,109,980
2	Firm Sales		2,004,762	9,299,532	14,621,444	14,738,402	13,263,931	7,997,420	61,925,491
3	Company Use		104,294	130,710	209,500	159,704	140,097	93,502	837,807
4	Unaccounted For %		3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	
5	Unaccounted For Gas		269,827	418,966	526,373	400,765	289,883	198,785	2,104,598
6	COG Factor- Gas Cost Only		$0.7730	$0.7170	$0.7005	$0.6874	$0.6926	$0.7264	
7	COG Factor- Bad Debt Factor		$0.0186	$0.0186	$0.0186	$0.0186	$0.0186	$0.0186	
8	COG Factor- Working Capital Factor		$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	
9									
10	Unbilled Volume								
11	Beginning Bal		-	6,353,377	10,062,939	11,740,342	9,411,221	5,098,630	
12	Incremental Unbilled		6,353,377	3,709,562	1,677,403	(2,329,121)	(4,312,591)	(1,856,547)	
13	Ending Balance	-	6,353,377	10,062,939	11,740,342	9,411,221	5,098,630	3,242,084	
14									
15	COG Factor- Gas Cost Only		$0.7730	$0.7170	$0.7005	$0.6874	$0.6926	$0.7264	
16	Gross Unbilled Gas Cost	$1,880,968	$4,911,161	$7,215,127	$8,224,110	$6,469,273	$3,531,311	$2,355,050	
17									
18	Monthly Incremental Gas Cost		$3,030,192	$2,303,967	$1,008,982	($1,754,836)	($2,937,962)	($1,176,262)	
19									
20	COG Factor- Bad Debt Only		$0.0186	$0.0186	$0.0186	$0.0186	$0.0186	$0.0186	
21	Gross Unbilled Bad Debt Cost	$45,481	$118,173	$187,171	$218,370	$175,049	$94,835	$60,303	
22									
23	Monthly Incremental Bad Debt Cost		$72,692	$68,998	$31,200	($43,322)	($80,214)	($34,532)	
24									
25	COG Factor- Working Capital Only		$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	
26	Gross Unbilled Working Capital Cost	$762	$6,353	$10,063	$11,740	$9,411	$5,099	$3,242	
27									
28	Monthly Incremental Working Capital Cost		$5,591	$3,710	$1,677	($2,329)	($4,313)	($1,857)	

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
SCHEDULE 4 - NONFIRM MARGIN

	FOR THE MONTH OF:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
1	INTERRUPTIBLE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2								
3	280 DAY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4								
5	OFF SYSTEM GAS SALES MARGIN	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	PROPANE OFF SYSTEM SALES MARGIN	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7								
8	CAPACITY RELEASE CREDIT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9								
10	TOTAL NON FIRM MARGIN AND CREDITS	$ (1,598)	$ (2,077)	$ (1,860)	$ (5,227)	$ (5,402)	$ (34,082)	$ (50,245)

REDACTED

00000161

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
PEAK PERIOD WORKING CAPITAL
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	Nov-11 30	Dec-11 31	Jan-12 31	Feb-12 29	Mar-12 31	Apr-12 30	May-12	Total
1	BEGINNING BALANCE	**$ 12,372**	$ 10,358	$ 8,800	$ 5,597	$ 3,417	$ 1,898	$ 64	**$ 12,372**
2									
3	Add: COST ALLOW	6,314	11,425	13,076	10,217	7,426	4,303		**52,761**
4									
5	Less: CUSTOMER BILLINGS	(2,005)	(9,300)	(14,621)	(14,738)	(13,264)	(7,997)	(3,846)	**(65,772)**
6	Estimated Unbilled	(6,353)	(10,063)	(11,740)	(9,411)	(5,099)	(3,242)		**(45,909)**
7	Reverse Prior Month Unbilled	-	6,353	10,063	11,740	9,411	5,099	3,242	**45,909**
8	Subtotal: Accrued Customer Billings	(8,358)	(13,009)	(16,299)	(12,409)	(8,951)	(6,141)	(604)	**(65,772)**
9									
10	Adjustment	-	-	-	-	-	-	-	**-**
11									
12	ENDING BALANCE PRE INTEREST	**10,328**	**8,774**	**5,577**	**3,405**	**1,891**	**61**	**(541)**	**(639)**
13									
14	MONTH'S AVERAGE BALANCE	11,350	9,566	7,189	4,501	2,654	979		
15									
16	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
17	INTEREST APPLIED	30	26	20	12	7	3		**98**
18	ENDING BALANCE	**$ 10,358**	**$ 8,800**	**$ 5,597**	**$ 3,417**	**$ 1,898**	**$ 64**	**$ (541)**	**$ (541)**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
OFF PEAK WORKING CAPITAL
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Total
	DAYS IN MONTH	30	31	31	29	31	30		
1	BEGINNING BALANCE	$ (614)	$ (1,057)	$ (1,060)	$ (1,063)	$ (1,066)	$ (2,022)	$ (2,027)	(614)
2									
3	Add:ACTUAL COST	-	-	-	-	(951)	-		$ (951)
4									0
5	Less: CUSTOMER BILLINGS	(1,204)	-	-	-	-	-	-	(1,204)
6	Estimated Unbilled	-	-	-	-	-	-		-
7	Reverse Prior Month Unbilled	762	-	-	-	-	-	-	762
8	Subtotal: Accrued Customer Billings	(442)	-	-	-	-	-	-	(442)
9									
10	ENDING BALANCE PRE INTEREST	(1,055)	(1,057)	(1,060)	(1,063)	(2,018)	(2,022)	(2,027)	(2,007)
11									
12	MONTH'S AVERAGE BALANCE	(834)	(1,057)	(1,060)	(1,063)	(1,542)	(2,022)		
13									
14	INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
15	INTEREST APPLIED	(2)	(3)	(3)	(3)	(4)	(5)		(20)
16	ENDING BALANCE	$ (1,057)	$ (1,060)	$ (1,063)	$ (1,066)	$ (2,022)	$ (2,027)	$ (2,027)	$ (2,027)

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
1	Demand	$ 1,114,845	$ 969,190	$ 1,268,669	$ 1,236,206	$ 949,724	$ 856,884	$ 6,395,517
2	Commodity	3,853,266	8,020,768	9,020,325	6,803,012	4,893,089	2,529,081	35,119,541
3	Total Gas Costs	$ 4,968,111	$ 8,989,958	$ 10,288,994	$ 8,039,218	$ 5,842,813	$ 3,385,965	$ 41,515,058
4								
5	Lead Lag Days	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	
6	Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7								
8	Working Capital Rate 1/	0.00127	0.00127	0.00127	0.00127	0.00127	0.00127	
9								
10	Total Working Capital Costs	$ 6,314	$ 11,425	$ 13,076	$ 10,217	$ 7,426	$ 4,303	$ 52,761
11								
12	Prior Period Undercollection	622,550	622,550	622,550	622,550	622,550	622,550	3,735,297
13								
14	Subtotal Gas Costs, Working Capital & Under Collection	5,596,974	9,623,932	10,924,620	8,671,984	6,472,788	4,012,818	45,303,116
15								
16	Bad Debt Rate 1/	0.0250	0.0250	0.0250	0.0250	0.0250	0.0250	
17								
18	Total Bad Debt Cost	$ 139,872	$ 240,508	$ 273,013	$ 216,718	$ 161,759	$ 100,283	$ 1,132,153

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
1	**Demand**	$ 793,934	$ 1,426,490	$ 1,044,501	$ 1,519,111	$ 1,208,407	$ 1,406,848	**$ 7,399,291**
2	**Commodity**	2,025,962	1,115,424	848,156	1,004,390	1,022,616	2,282,537	**8,299,085**
3	**Total Gas Costs**	**$ 2,819,896**	**$ 2,541,913**	**$ 1,892,657**	**$ 2,523,501**	**$ 2,231,023**	**$ 3,689,385**	**$ 15,698,376**
4								
5	**Lead Lag Days**	**0.0391**	**0.0391**	**0.0391**	**0.0391**	**0.0391**	**0.0391**	
6	**Prime Rate**	**3.25%**	**3.25%**	**3.25%**	**3.25%**	**3.25%**	**3.25%**	
7								
8	**Working Capital Rate 1/**	**0.00127**	**0.00127**	**0.00127**	**0.00127**	**0.00127**	**0.00127**	
9								
10	**Total Working Capital Costs**	**$ 3,584**	**$ 3,230**	**$ 2,405**	**$ 3,207**	**$ 2,835**	**$ 4,689**	**$ 19,951**
11								
12	**Prior Period Undercollection**	**(76,695)**	**(76,695)**	**(76,695)**	**(76,695)**	**(76,695)**	**(76,695)**	**(460,169)**
13								
14	**Subtotal Gas Costs, Working Capital & Under Collection**	2,746,785	2,468,449	1,818,368	2,450,013	2,157,164	3,617,379	**15,258,158**
15								
16	**Bad Debt Rate 1/**	**0.0250**	**0.0250**	**0.0250**	**0.0250**	**0.0250**	**0.0250**	
17								
18	**Total Bad Debt Cost**	**$ 68,670**	**$ 61,711**	**$ 45,459**	**$ 61,250**	**$ 53,929**	**$ 90,434**	**$ 381,454**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

	FOR MONTH OF:	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	
1	**Monthly Revenue**	$ 9,173,856	$ 5,610,374	$ 4,708,239	$ 4,187,160	$ 4,390,419	$ 4,933,311	
2	**Charge Off**	160,502	260,084	439,473	504,172	495,202	263,825	

	FOR MONTH OF:	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
3	**Monthly Revenue**	$ 8,992,721	$ 13,217,665	$ 18,544,566	$ 18,409,026	$ 16,903,722	$ 11,304,944	**120,376,003**
4	**Charge Off**	230,381	202,159	125,780	94,415	121,089	111,188	**3,008,270**
5								
6								
7	**Bad Debt Rate**							**0.0250**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
SCHEDULE 7
WORKING CAPITAL & BAD DEBT COLLECTED

	FOR MONTH OF:	OffPeak Nov-11	Peak Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Peak May-12	Total Peak
1	**VOLUMES**									
2	**RESIDENTIAL**									
3	R-1, R-3 and R-4	2,158,762	1,076,380	4,787,015	7,546,798	7,567,525	6,950,370	4,193,504	1,971,445	**34,093,037**
4	R-1, R-3 and R-4 (FPO)	279,344	176,567	825,160	1,266,041	1,256,161	1,155,836	695,326	332,631	**5,707,722**
5										
6	**COMMERCIAL/INDUSTRIAL**									
7	G41 - G43	1,166,134	557,358	2,837,938	4,654,629	4,774,127	4,175,738	2,400,833	1,122,655	**20,523,278**
8	G41 - G43 (FPO)	69,442	48,182	260,350	416,864	417,406	325,587	209,339	100,784	**1,778,512**
9	G51 - G63	323,545	134,003	529,541	674,613	652,853	591,829	448,790	288,774	**3,320,403**
10	G51 - G63 (FPO)	15,965	12,272	59,528	62,499	70,330	64,571	49,628	30,135	**348,963**
11										
12	**TRANSPORTATION**									
13	G41 - G43	1,321,701	403,760	2,577,400	3,708,448	3,933,688	3,663,258	2,517,136	1,387,976	**18,191,666**
14	G51 - G63	2,361,903	89,955	2,592,439	2,824,294	2,812,250	2,815,446	2,513,878	2,322,227	**15,970,489**
15										
16	**TOTAL VOLUME**	**7,696,796**	**2,498,477**	**14,469,371**	**21,154,186**	**21,484,340**	**19,742,635**	**13,028,434**	**7,556,627**	**99,934,070**
17										
18	**WORKING CAPITAL RATES**									
19	Residential R1, R3 & R4	**$0.0003**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	
20	Residential R1, R-3 & R4 (FPO)	**$0.0003**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	
21	C/I Sales G41 to G43	**$0.0003**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	
22	C/I Sales G41 to G43 (FPO)	**$0.0003**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	
23	C/I Sales G51 to G63	**$0.0003**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	
24	C/I Sales G51 to G63 (FPO)	**$0.0003**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	**$0.0010**	
25										
26	**WORKING CAPITAL COSTS COLLECTED**									
27	Residential	$ 648	$ 1,076	$ 4,787	$ 7,547	$ 7,568	$ 6,950	$ 4,194	$ 1,971	**$ 34,093**
28	Residential (FPO)	84	177	825	1,266	1,256	1,156	695	333	**5,708**
29	C/I Sales G41 to G43	350	557	2,838	4,655	4,774	4,176	2,401	1,123	**20,523**
30	C/I Sales G41 to G43 (FPO)	21	48	260	417	417	326	209	101	**1,779**
31	C/I Sales G51 to G63	97	134	530	675	653	592	449	289	**3,320**
32	C/I Sales G51 to G63 (FPO)	5	12	60	62	70	65	50	30	**349**
33										
34	**SUMMER GAS COST WORKING CAPITAL COLLEC**	**$ 1,204**	**$ 2,005**	**$ 9,300**	**$ 14,621**	**$ 14,738**	**$ 13,264**	**$ 7,997**	**$ 3,846**	**$ 65,772**
35										
36	**BAD DEBT RATES**									
37	Residential R1, R3 & R4	**$0.0179**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	
38	Residential R1 & R3 (FPO)	**$0.0179**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	
39	C/I Sales G41 to G43	**$0.0179**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	
40	C/I Sales G41 to G43 (FPO)	**$0.0179**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	
41	C/I Sales G51 to G63	**$0.0179**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	
42	C/I Sales G51 to G63 (FPO)	**$0.0179**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	**$0.0186**	
43										
44	**BAD DEBTS COLLECTED**									
45	Residential R1, R3 & R4	$ 38,642	$ 20,021	$ 89,038	$ 140,370	$ 140,756	$ 129,277	$ 77,999	$ 36,669	**$ 634,130**
46	Residential R1, R-3 & R4 (FPO)	5,000	3,284	15,347.98	23,548.36	23,364.59	21,498.55	12,933.06	6,186.94	**106,164**
47	C/I Sales G41 to G43	20,874	10,367	52,785.65	86,576.10	88,798.76	77,668.73	44,655.49	20,881.38	**381,733**
48	C/I Sales G41 to G43 (FPO)	1,243	896	4,842.51	7,753.67	7,763.75	6,055.92	3,893.71	1,874.58	**33,080**
49	C/I Sales G51 to G63	5,791	2,492	9,849.46	12,547.80	12,143.07	11,008.02	8,347.49	5,371.20	**61,759**
50	C/I Sales G51 to G63 (FPO)	286	228	1,107.22	1,162.48	1,308.14	1,201.02	923.08	560.51	**6,491**
51										
52	**SUMMER BAD DEBTS COLLECTED**	**$ 71,836**	**$ 37,289**	**$ 172,971**	**$ 271,959**	**$ 274,134**	**$ 246,709**	**$ 148,752**	**$ 71,543**	**$ 1,223,358**

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
COMMODITY AND RELATED VOLUMES
SCHEDULE 8

	FOR THE MONTH OF:	Nov-11		Dec-11		Jan-12		Feb-12		Mar-12		Apr-12		Total	
		Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	Dollar	Volume Dkt	**Dollar**	**Volume Dkt**
	TENNESEE COMMODITY														
1	Gas Supply	[redacted]													
2	Off System Sales Gas Costs														
3	Pipeline Transport														
4	Storage Injections														
5	TOTAL TENNESSEE														
6															
7															
8															
9	City Gate Supply	[redacted]													
10															
11	Dracut Supply	[redacted]													
12															
13															
14	**CANADIAN COMMODITY**														
15	PNGTS Supply	[redacted]													
16	TOTAL PNGTS														
17															
18	BP/Northeast Gas Market	[redacted]													
19	SHELL CANADIAN														
20	NEXEN														
21	TOTAL TGP/Niagara														
22															
23	ANE Dawn-Iroquois	[redacted]													
24	ANE Union/Transgas Transporation														
25	TOTAL TGP/Iroquois Commodity														
26															
27															
28	**LNG**														
29	Distrigas (FCS 064)	[redacted]													
30															
31	LNG Vapor - P/S Plant	[redacted]													
32	LNG Injections														
33	Subtotal LNG														
34															
35															
36	**Propane**														
37	Off System Sales	[redacted]													
38	Propane Sendout - P/S Plant														
39	EN Propane - Tank Farm														
40	Total Propane														
41															
42															
43	Storage Withdrawals	[redacted]													
44															
45															
46	Hedging (Gains) Loses	[redacted]													
47															
48	Supplier Cashouts	[redacted]													
49															
50	Capacity Managed - Canadian	[redacted]													
51															
52	Taxes	[redacted]													
53															
54	Non-Firm Costs	[redacted]													
55															
56															
57	**NET COMMODITY COST**	**$ 3,853,266**	**873,226**	**$ 8,020,768**	**1,355,877**	**$ 9,020,325**	**1,703,472**	**$ 6,803,012**	**1,296,975**	**$ 4,893,089**	**938,132**	**$ 2,529,081**	**643,316**	**$ 35,119,541**	**6,810,998**

REDACTED

00000168

ENERGY NORTH NATURAL GAS, INC

NOVEMBER 2011 THROUGH APRIL 2012
MONTHLY PRIME RATES
SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
Nov-11	11/01 - 11/30	**3.25%**	30	3.2500%
Dec-11	12/01 - 012/31	**3.25%**	31	3.2500%
Jan-12	01/01 - 01/31	**3.25%**	31	3.2500%
Feb-12	02/01 - 02/29	**3.25%**	29	3.2500%
Mar-12	03/01 - 03/31	**3.25%**	31	3.2500%
Apr-12	04/01 - 04/30	**3.25%**	30	3.2500%

Local Distribution Adjustment Charge Calculation

		Sales Customers	Transporatation Customers		Reference
Residential Non Heating Rates - R-1					
Energy Efficiency Charge	$0.0147				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				
Conservation Charge (CCx)		$0.0147			
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0011				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0011			
Cost Allowance Adjustment Factor		0.0000			Cost Allowance Factor
Rate Case Expense Factor (RCEF)		0.0027			Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0073			RILAP Page 1
LDAC		**$0.0258**		**per therm**	
Residential Heating Rates - R-3, R-4					
Energy Efficiency Charge	$0.0147				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0147			
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0011				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0011			
Cost Allowance Adjustmern Factor		0.0000			Cost Allowance Factor
Rate Case Expense Factor (RCEF)		0.0027			Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0073			RILAP Page 1
LDAC		**$0.0258**		**per therm**	
Commercial/Industrial Low Annual Use Rates - G-41, G-51					
Energy Efficiency Charge	$0.0076				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0076	$0.0076		
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0011				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0011	0.0011		
Cost Allowance Adjustmern Factor		0.0000	0.0000		Cost Allowance Factor
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000		
Rate Case Expense Factor (RCEF)		0.0027	0.0027		Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0073	0.0073		RILAP Page 1
LDAC		**$0.0187**	**$0.0187**	**per therm**	
Commercial/Industrial Medium Annual Use Rates - G-42, G-52					
Energy Efficiency Charge	$0.0076				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0076	$0.0076		
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0011				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0011	0.0011		
Cost Allowance Adjustmern Factor		0.0000	0.0000		Cost Allowance Factor
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000		
Rate Case Expense Factor (RCEF)		0.0027	0.0027		Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0073	0.0073		RILAP Page 1
LDAC		**$0.0187**	**$0.0187**	**per therm**	
Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54					
Energy Efficiency Charge	$0.0076				Energy Efficiency Page 1
Demand Side Management Charge	0.0000				Conservation Charge
Conservation Charge (CCx)		$0.0076	$0.0076		
Relief Holder and pond at Gas Street, Concord, NH	0.0000				
Manufactured Gas Plants	0.0011				Proposed First Revised Page 91
Environmental Surcharge (ES)		0.0011	0.0011		
Cost Allowance Adjustmern Factor		0.0000	0.0000		Cost Allowance Factor
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000		
Rate Case Expense Factor (RCEF)		0.0027	0.0027		Rate Case Expense Calculation
Residential Low Income Assistance Program (RLIAP)		0.0073	0.0073		RILAP Page 1
LDAC		**$0.0187**	**$0.0187**	**per therm**	

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

Rate Case Expense Factors for Resdential Customers

Rate Case Expense (Balance 07/31/12)	$	623,004
Temporary Rate Reconciliation - DG 10-017		-
Sipulation per Settlement Argument - DG 10-017		-
Reconciliation DG 08-009 and Merger Incentive DG 06-707		-
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	$	623,004
OffPeak 2012 Rate Case Expense Factor	$	0.0116
OffPeak 2012 Projected Volumes (Aug-Oct)		16,967,216
OffPeak 2012 Rate Case Expense Projected Collection (Aug-Oct)		197,035
OffPeak 2012 Rate Case Expense Projected Interest (Aug-Oct)		4,804
Total Net Rate Case Expense/Temporary Rate Reconciliation Recoverable		430,773
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		57,541,620
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		100,520,729
Total Volumes		158,062,349
Rate Case Expense Factor	$	0.0027

DG 06-107 Merger Settlement - Emergency Response Incentive

Emergency Response Merger Incentive

Merger Incentive - Emergency Response	$	-
Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)		58,353,540
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)		92,474,643
Total Volumes		150,828,182
Rate Case Expense Factor	$	-

ENERGY NORTH NATURAL GAS, INC.

Residential Low Income Assistance Program (RLIAP)

Ln		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 17.3100	$ 0.2739	$ 0.2263		
3	R-4 Rate at 40% of R-3	$ 6.9200	$ 0.1096	$ 0.0905		
4	Program Subsidy	$ 10.3900	$ 0.1643	$ 0.1358		
5	Average Annual Therms		572	203	775	
6						
7	Peak Period RLIAP Subsidy	$ 62.34	$ 94.01	$ 27.55	$ 183.90	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 17.3100	$ 0.2739	$ 0.2263		
11	R-4 Rate at 40% of R-3	$ 6.9200	$ 0.1096	$ 0.0905		
12	Program Subsidy	$ 10.3900	$ 0.1643	$ 0.1358		
13	Average Annual Therms		118	52	170	
14						
15	Off Peak Period RLIAP Subsidy	$ 62.34	$ 19.42	$ 7.07	$ 88.83	
16						
17	Estimated Annual Subsidy	$ 124.68	$ 113.43	$ 34.62	$ 272.74	
18						
19	Number of Estimated 2012/13 Participants				5,485	1/
20						
21	Annual Subsidy times Number of Particpants (Ln 17 * Ln 19)				$ 1,495,954	
22	Prior Year Ending Balance - RLIAP Page 2				(347,982)	
23	Estimated Annual Administrative Costs				8,600	
24	Total Program Costs				$ 1,156,572	
25						
26	Estimated weather normalized firm therms billed for the					
27	twelve months ended 10/31/13 sales and transportation				158,062,349	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0073**	

1/ Estimated number of participants for 2012-13 is based on the actual number participants as of June 2012, as provided in the RLIAP Quarterly Report as revised and filed on July 27, 2012.

ENERGY NORTH NATURAL GAS, INC.

NOVEMBER 2011 THROUGH OCTOBER 2012
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

										(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ (339,001)	$ (432,258)	$ (558,608)	$ (535,648)	$ (580,681)	$ (584,556)	$ (550,971)	$ (510,885)	$ (492,685)	$ (457,636)	$ (418,857)	$ (383,571)	$ (339,001)
4														
5	Add: Actual Costs	20,040	8,134	219,086	154,062	179,363	154,962	129,488	79,615	90,563	88,581	88,833	98,794	1,311,522
6														
7	Less: Collected Revenue	(112,269)	(133,118)	(194,619)	(197,656)	(181,632)	(119,862)	(87,939)	(60,076)	(54,204)	(48,593)	(52,477)	(62,196)	(1,304,642)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ (431,230)	$ (557,242)	$ (534,140)	$ (579,242)	$ (582,950)	$ (549,456)	$ (509,421)	$ (491,346)	$ (456,326)	$ (417,649)	$ (382,501)	$ (346,974)	**$ (332,121)**
12														
13	Month's Average Balance	$ (385,115)	$ (494,750)	$ (546,374)	$ (557,445)	$ (581,816)	$ (567,006)	$ (530,196)	$ (501,115)	$ (474,505)	$ (437,642)	$ (400,679)	$ (365,272)	
14														
15	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16														
17	Interest Applied	$ (1,029)	$ (1,366)	$ (1,508)	$ (1,439)	$ (1,606)	$ (1,515)	$ (1,463)	$ (1,339)	$ (1,310)	$ (1,208)	$ (1,070)	$ (1,008)	**(15,861)**
18														
19	Ending Balance	**$ (432,258)**	**$ (558,608)**	**$ (535,648)**	**$ (580,681)**	**$ (584,556)**	**$ (550,971)**	**$ (510,885)**	**$ (492,685)**	**$ (457,636)**	**$ (418,857)**	**$ (383,571)**	**$ (347,982)**	**$ (347,982)**

EnergyNorth Natural Gas, Inc.
Energy Efficiency Programs
For Residential Non Heating and Heating Classes
November 1, 2012 - October 31, 2013
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	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 12	Actual	(2,461,879)	($0.0498)	(160,729)	235,382	186,477	0	(2,436,131)	(2,449,005)	**3.25%**	(6,760)	(2,442,891)	4,471,593	3,230,081	31
June 12	Actual	(2,442,891)	($0.0498)	(90,552)	235,382	75,628	71,156	(2,386,658)	(2,414,775)	3.25%	(6,450)	(2,393,109)	2,482,396	1,819,769	30
July 12	Forecast	(2,393,109)	($0.0498)	(77,901)	314,458	0	0	(2,156,552)	(2,274,830)	3.25%	(6,279)	(2,162,831)	1,565,536	0	31
August 12	Forecast	(2,162,831)	($0.0498)	(63,201)	314,458	0	0	(1,911,574)	(2,037,203)	3.25%	(5,623)	(1,917,198)	1,270,112	0	31
September 12	Forecast	(1,917,198)	($0.0498)	(68,074)	314,458	0	0	(1,670,814)	(1,794,006)	3.25%	(4,792)	(1,675,606)	1,368,039	0	30
October 12	Forecast	(1,675,606)	($0.0498)	(94,782)	314,458	0	0	(1,455,930)	(1,565,768)	3.25%	(4,322)	(1,460,252)	1,904,776	0	31
November 12	Forecast	(1,460,252)	($0.0147)	(55,505)	314,458	0	0	(1,201,299)	(1,330,775)	3.25%	(3,555)	(1,204,854)	3,778,407	0	30
December 12	Forecast	(1,204,854)	($0.0147)	(102,040)	314,458	0	0	(992,436)	(1,098,645)	3.25%	(3,033)	(995,469)	6,946,220	0	31
January 13	Forecast	(995,469)	($0.0147)	(147,768)	170,065	0	0	(973,171)	(984,320)	3.25%	(2,717)	(975,888)	10,059,056	0	31
February 13	Forecast	(975,888)	($0.0147)	(157,988)	170,065	0	0	(963,811)	(969,850)	3.25%	(2,418)	(966,229)	10,754,770	0	28
March 13	Forecast	(966,229)	($0.0147)	(136,161)	170,065	0	0	(932,325)	(949,277)	3.25%	(2,620)	(934,946)	9,268,947	0	31
April 13	Forecast	(934,946)	($0.0147)	(91,867)	170,065	0	0	(856,748)	(895,847)	3.25%	(2,393)	(859,141)	6,253,708	0	30
May 13	Forecast	(859,141)	($0.0147)	(49,206)	170,065	0	0	(738,282)	(798,712)	3.25%	(2,205)	(740,487)	3,349,634	0	31
June 13	Forecast	(740,487)	($0.0147)	(29,158)	170,065	0	0	(599,581)	(670,034)	3.25%	(1,790)	(601,370)	1,984,898	0	30
July 13	Forecast	(601,370)	($0.0147)	(18,402)	170,065	0	0	(449,707)	(525,539)	3.25%	(1,451)	(451,158)	1,252,661	0	31
August 13	Forecast	(451,158)	($0.0147)	(15,523)	170,065	0	0	(296,616)	(373,887)	3.25%	(1,032)	(297,648)	1,056,675	0	31
September 13	Forecast	(297,648)	($0.0147)	(16,792)	170,065	0	0	(144,375)	(221,012)	3.25%	(590)	(144,966)	1,143,113	0	30
October 13	Forecast	(144,966)	($0.0147)	(24,878)	170,065	0	0	221	(72,373)	3.25%	(200)	21	1,693,533	0	31
November 13	Forecast	21	($0.0147)	(55,505)	170,065	0	0	114,581	57,301	3.25%	153	114,734	3,778,407	0	30
December 13	Forecast	114,734	($0.0147)	(102,040)	170,065	0	0	182,759	148,746	3.25%	411	183,169	6,946,220	0	31

Estimated Residential Nonheating Conservation Charge Effective November 1, 2012 - October 31, 2013		
Beginning Balance	$	(1,460,252)
Program Budget Nov 12-Oct 13		2,329,562
Projected Interest		(24,003)
Projected Budget with Interest	$	845,307
Total Charges	**$**	**845,307**
Projected Therm Sales		**57,541,620**
Residential Rate		**$0.0147**
Total Charges with Interest	**$**	**845,307**
Projected Therm Sales		**57,541,620**
Residential Rate		**$0.0147**

		Year One Budget 1/01/12 - 12/31/12		Year Two Budget 1/01/13 - 12/31/13	
Residential Non Heating Therm Sales	1%		**1,000,804**	**861,046**	1%
Residential Heating Therm Sales	37%		**60,975,253**	**56,680,574**	36%
C&I Therm Sales	62%		**101,612,535**	**100,520,729**	64%
Total Therms	100%		**163,588,592**	**158,062,349**	100%
Low-Income Program Budget		**$**	**1,123,016**	**$ 750,000**	
Other Refund			-	-	
Total Shared Budget		**$**	**1,123,016**	**$ 750,000**	
Residential Program Budget		**$**	**2,181,559**	**$ 1,620,000**	
Residential Program Incentive			**$217,565**	**$147,743**	
Total Residential Program Budget		**$**	**2,399,124**	**$ 1,767,743**	
Commercial/Industrial Program Budget		**$**	**2,500,000**	**$ 2,310,000**	
Commercial/Industrial Program Incentive			**$95,559**	**$79,168**	
Total Commercial/Industrial Program Budget		**$**	**2,595,559**	**$ 2,389,168**	
Total Program Budget		**$**	**6,117,699**	**$ 4,906,911**	
Shared Expenses Allocation to Residential		$	425,458	$ 273,033	
Shared Expenses Allocation to C&I			697,558	476,967	
Total Allocated Shared Expenses		**$**	**1,123,016**	**$ 750,000**	
Total Residential (including allocation of Shared Budget)		$	2,824,582	$ 2,040,776	
Total C&I (including allocation of Shared Budget)			3,293,117	2,866,135	
Total Budget		**$**	**6,117,699**	**$ 4,906,911**	

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EnergyNorth Natural Gas, Inc.
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2012 - October 31, 2013
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Com-Ind	Actual DSM Expenditures Low-Income	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	Commercial/ Industrial Therm Sales	# of Days
May 12	Actual	(3,296,907)	($0.0298)	(188,588)	274,426	259,978	0	(3,225,517)	(3,261,212)	**3.25%**	(9,002)	(3,234,519)	7,675,149	6,328,457	31
June 12	Actual	(3,234,519)	($0.0298)	(140,366)	274,426	373,499	94,323	(2,907,063)	(3,070,791)	3.25%	(8,203)	(2,915,266)	5,618,481	4,710,280	30
July 12	Forecast	(2,915,266)	($0.0298)	(129,853)	313,860	0	0	(2,731,259)	(2,823,262)	3.25%	(7,793)	(2,739,052)	4,357,483	0	31
August 12	Forecast	(2,739,052)	($0.0298)	(120,386)	313,860	0	0	(2,545,578)	(2,642,315)	3.25%	(7,294)	(2,552,871)	4,039,787	0	31
September 12	Forecast	(2,552,871)	($0.0298)	(130,115)	313,860	0	0	(2,369,126)	(2,460,998)	3.25%	(6,574)	(2,375,700)	4,366,259	0	30
October 12	Forecast	(2,375,700)	($0.0298)	(145,768)	313,860	0	0	(2,207,608)	(2,291,654)	3.25%	(6,326)	(2,213,933)	4,891,547	0	31
November 12	Forecast	(2,213,933)	($0.0076)	(53,641)	313,860	0	0	(1,953,714)	(2,083,824)	3.25%	(5,566)	(1,959,280)	7,058,014	0	30
December 12	Forecast	(1,959,280)	($0.0076)	(81,624)	313,860	0	0	(1,727,044)	(1,843,162)	3.25%	(5,088)	(1,732,132)	10,740,036	0	31
January 13	Forecast	(1,732,132)	($0.0076)	(111,996)	238,845	0	0	(1,605,283)	(1,668,707)	3.25%	(4,606)	(1,609,889)	14,736,267	0	31
February 13	Forecast	(1,609,889)	($0.0076)	(119,281)	238,845	0	0	(1,490,326)	(1,550,107)	3.25%	(3,865)	(1,494,190)	15,694,927	0	28
March 13	Forecast	(1,494,190)	($0.0076)	(104,122)	238,845	0	0	(1,359,468)	(1,426,829)	3.25%	(3,938)	(1,363,406)	13,700,246	0	31
April 13	Forecast	(1,363,406)	($0.0076)	(75,671)	238,845	0	0	(1,200,233)	(1,281,819)	3.25%	(3,424)	(1,203,657)	9,956,715	0	30
May 13	Forecast	(1,203,657)	($0.0076)	(49,684)	238,845	0	0	(1,014,496)	(1,109,076)	3.25%	(3,061)	(1,017,557)	6,537,363	0	31
June 13	Forecast	(1,017,557)	($0.0076)	(38,703)	238,845	0	0	(817,416)	(917,487)	3.25%	(2,451)	(819,867)	5,092,563	0	30
July 13	Forecast	(819,867)	($0.0076)	(30,467)	238,845	0	0	(611,489)	(715,678)	3.25%	(1,975)	(613,465)	4,008,754	0	31
August 13	Forecast	(613,465)	($0.0076)	(29,272)	238,845	0	0	(403,892)	(508,678)	3.25%	(1,404)	(405,296)	3,851,567	0	31
September 13	Forecast	(405,296)	($0.0076)	(31,589)	238,845	0	0	(198,041)	(301,668)	3.25%	(806)	(198,846)	4,156,413	0	30
October 13	Forecast	(198,846)	($0.0076)	(37,908)	238,845	0	0	2,090	(98,378)	3.25%	(272)	1,819	4,987,864	0	31
November 13	Forecast	1,819	($0.0076)	(53,641)	238,845	0	0	187,022	94,420	3.25%	252	187,274	7,058,014	0	30
December 13	Forecast	187,274	($0.0076)	(81,624)	238,845	0	0	344,495	265,885	3.25%	734	345,229	10,740,036	0	31

Estimated C & I Conservation Charge Effective November 1, 2012 - October 31, 2013	
Beginning Balance	($2,213,933)
Program Budget	3,016,166
Projected Interest	(36,456)
Program Budget with Interest	$765,777
Total Charges	**$765,777**
Projected Therm Sales	**100,520,729**
C&I Rate	$0.0076
Total Charges with Interest	**$765,777**
Projected Therm Sales	**100,520,729**
Com/Ind Rate	**$0.0076**
Com/Ind Rate from Prior Programs (1)	**$0.0000**
Combined Com/Ind Rate	**$0.0076**

EnergyNorth Natural Gas, Inc.
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2012 - October 31, 2013
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures: Residential	Com-Ind	Low-Income	Total	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	Therm Sales	# of Days
May 12	Actual	(5,758,786)	n/a	(349,317)	509,808	186,477	259,978	0	446,455	(5,661,648)	(5,710,217)	**3.25%**	(15,762)	(5,677,409)	12,146,742	9,558,538	31
June 12	Actual	(5,677,409)	n/a	(230,918)	509,808	75,628	373,499	165,479	614,606	(5,293,722)	(5,485,565)	3.25%	(14,653)	(5,308,375)	8,100,878	6,530,049	30
July 12	Forecast	(5,308,375)	n/a	(207,754)	628,318	0	0	0	0	(4,887,811)	(5,098,093)	3.25%	(14,072)	(4,901,883)	5,923,019	0	31
August 12	Forecast	(4,901,883)	n/a	(183,587)	628,318	0	0	0	0	(4,457,152)	(4,679,518)	3.25%	(12,917)	(4,470,069)	5,309,899	0	31
September 12	Forecast	(4,470,069)	n/a	(198,189)	628,318	0	0	0	0	(4,039,939)	(4,255,004)	3.25%	(11,366)	(4,051,306)	5,734,298	0	30
October 12	Forecast	(4,051,306)	n/a	(240,550)	628,318	0	0	0	0	(3,663,537)	(3,857,421)	3.25%	(10,648)	(3,674,185)	6,796,324	0	31
November 12	Forecast	(3,674,185)	n/a	(109,146)	628,318	0	0	0	0	(3,155,013)	(3,414,599)	3.25%	(9,121)	(3,164,134)	10,836,421	0	30
December 12	Forecast	(3,164,134)	n/a	(183,664)	628,318	0	0	0	0	(2,719,480)	(2,941,807)	3.25%	(8,120)	(2,727,600)	17,686,256	0	31
January 13	Forecast	(2,727,600)	n/a	(259,764)	408,909	0	0	0	0	(2,578,455)	(2,653,027)	3.25%	(7,323)	(2,585,778)	24,795,322	0	31
February 13	Forecast	(2,585,778)	n/a	(277,269)	408,909	0	0	0	0	(2,454,137)	(2,519,957)	3.25%	(6,283)	(2,460,420)	26,449,698	0	28
March 13	Forecast	(2,460,420)	n/a	(240,283)	408,909	0	0	0	0	(2,291,793)	(2,376,106)	3.25%	(6,559)	(2,298,352)	22,969,193	0	31
April 13	Forecast	(2,298,352)	n/a	(167,538)	408,909	0	0	0	0	(2,056,981)	(2,177,666)	3.25%	(5,817)	(2,062,798)	16,210,423	0	30
May 13	Forecast	(2,062,798)	n/a	(98,890)	408,909	0	0	0	0	(1,752,779)	(1,907,788)	3.25%	(5,266)	(1,758,045)	9,886,997	0	31
June 13	Forecast	(1,758,045)	n/a	(67,861)	408,909	0	0	0	0	(1,416,997)	(1,587,521)	3.25%	(4,241)	(1,421,237)	7,077,460	0	30
July 13	Forecast	(1,421,237)	n/a	(48,869)	408,909	0	0	0	0	(1,061,196)	(1,241,217)	3.25%	(3,426)	(1,064,623)	5,261,414	0	31
August 13	Forecast	(1,064,623)	n/a	(44,795)	408,909	0	0	0	0	(700,508)	(882,565)	3.25%	(2,436)	(702,944)	4,908,241	0	31
September 13	Forecast	(702,944)	n/a	(48,381)	408,909	0	0	0	0	(342,416)	(522,680)	3.25%	(1,396)	(343,812)	5,299,526	0	30
October 13	Forecast	(343,812)	n/a	(62,786)	408,909	0	0	0	0	2,311	(170,751)	3.25%	(471)	1,840	6,681,398	0	31
November 13	Forecast	1,840	n/a	(109,146)	408,909	0	0	0	0	301,603	151,721	3.25%	405	302,008	10,836,421	0	30
December 13	Forecast	302,008	n/a	(183,664)	408,909	0	0	0	0	527,254	414,631	3.25%	1,144	528,398	17,686,256	0	31

Residential (R-1 & R-3) and C & I Conservation Charge Effective November 1, 2012 - October 31, 2013	
Beginning Balance	$ (3,674,184.88)
Program Budget	5,345,728.11
Projected Interest	(60,459.25)
Program Budget with Interest	$1,611,084
Total Charges	**$1,611,084**

00000177

New Hampshire Program Year TWO (January 1, 2012 - December 31, 2012)

Program	Internal Admin	External Admin	Rebates/ Services	Internal Impl	Marketing	Evaluation	Budget Total	Participant Goal	Lifetime MMBTU Savings
Residential									
Low Income	$ 55,000	$ 291,159	$ 420,937		$ 5,966	$ -	$ 1,123,016	275	75,048
Residential High-Efficiency Heating, Water-Heating, Controls Program	$ 25,767	$ 178,054	$ 503,406		$ 51,087	$ 1,425		2,137	328,375
New Home Construction with Energy Star	$ 824	$ 32,445	$ 51,000		$ 5,500	$ -		34	23,120
Res Building Practices and Demo	$ 1,556	$ 4,523	$ 15,000		$ 3,750	$ 500		10	0
Energy Audit with Home Performance and Weatherization	$ 34,295	$ 149,166	$ 1,440,692		$ 37,623	$ 13,631	$ 2,181,559	1,400	394,800
Residential Total	**$ 117,441**	**$ 655,347**	**$ 2,431,035**	**$ -**	**$ 103,926**	**$ 15,556**	**$ 3,304,575**	**3,856**	**821,343**
Commercial & Industrial									
Large C & I Retrofit Program	$ 176,000	$ 165,000	$ 1,567,500		$ 64,488	$ 68,936		270	769,785
New Equipment and Construction Program	$ 104,500	$ 110,000	$ 841,500		$ 38,363	$ 41,008		371	314,735
Small Business Energy Solutions Program	$ 32,240	$ 48,360	$ 253,125		$ 10,284	$ 12,493		29	141,071
Commercial Total	**$ 312,740**	**$ 323,360**	**$ 2,662,125**	**$ -**	**$ 113,134**	**$ 122,437**	**$ 2,500,000**	**670**	**1,225,591**
GRAND TOTAL	**$ 430,181**	**$ 978,707**	**$ 5,093,160**	**$ -**	**$ 217,060**	**$ 137,993**	**$ 5,804,575**	**4,526**	**2,046,934**

New Hampshire Program Year TWO (January 1, 2013 - December 31, 2013)

Program	Internal Admin	External Admin	Rebates/ Services	Internal Impl	Marketing	Evaluation	Budget Total	Participant Goal	Lifetime MMBTU Savings
Residential									
Low Income	$ -	$ -	$ -		$ -	$ -	$ 750,000	0	0
High-Efficiency Heating, Water-Heating, Controls Program	$ -	$ -	$ -		$ -	$ -	$ 730,000	0	0
New Home Construction with Energy Star	$ -	$ -	$ -		$ -	$ -	$ 90,000	0	0
Building Practices and Demo	$ -	$ -	$ -		$ -	$ -	$ 70,000	0	0
Home Performance w/Energy Star	$ -	$ -	$ -		$ -	$ -	$ 730,000	0	0
Residential Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,370,000**	**0**	**0**
Commercial & Industrial									
Large Business	$ -	$ -	$ -		$ -	$ -	$ 950,000	0	0
New Equipment and Construction Program	$ -	$ -	$ -		$ -	$ -	$ -	0	0
Small Business	$ -	$ -	$ -		$ -	$ -	$ 1,360,000	0	0
Commercial Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,310,000**	**0**	**0**
GRAND TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,680,000**	**0**	**0**

Exhibit D - Shareholder Incentive Page 1 of 1

National Grid Gas Energy Efficiency

Shareholder Incentive Year TWO- January 1, 2010 - December 31, 2010

Commercial/Industrial Incentive

1. Target Benefit/Cost Ratio	2.01
Actual Benefit/Cost Ratio	1.99
2. Threshold Benefit/Cost Ratio	1.00
3. Target lifetime MMBTU	1,236,404
Actual lifetime MMBTU	678,145
4. Threshold MMBTU	803,663
5. Budget	$2,411,290
6. CE Percentage	4.00%
7. Lifetime MMBTU Percentage	4.00%
8. Target C/I Incentive	**$192,903**
Actual C/I Incentive	**$95,559**
9. Cap	**$289,355**

Residential Incentive

10. Target Benefit/Cost Ratio	2.15
Actual Benefit/Cost Ratio	2.54
11. Threshold Benefit/Cost Ratio	1.00
12. Target lifetime MMBTU	885,455
Actual Lifetime MMBTU	821,512
13. Threshold MMBTU	575,546
14. Budget	$2,575,126
15. CE Percentage	4.00%
16. Lifetime MMBTU Percentage	4.00%
17. Target Residential Incentive	**$206,010**
Actual Residential Incentive	**$217,565**
18. Cap	**$309,015**
19. TOTAL TARGET INCENTIVE	**$313,124**

Exhibit B - Shareholder Incentive Page 1 of 2

National Grid NH Energy Efficiency

Target Shareholder Incentive Year ONE- January 1, 2011 - December 31, 2011

Commercial/Industrial Incentive	**Planned**	**Actual**
1. Benefit/Cost Ratio	1.47	2.35
2. Threshold Benefit / Cost Ratio [1]	1.00	
3. Lifetime MMBTU Savings	1,091,292	702,108
4. Threshold Lifetime MMBTU Savings (65%) [2]	709,340	
5. Budget / Actual Spend	$3,174,772	$1,242,485
6. Benefit / Cost Percentage of Budget	4.00%	
7. Lifetime MMBTU Percentage of Budget	4.00%	
8. C/I Incentive	**$253,982**	**$79,168**
9. Cap	**$380,973**	
Residential Incentive		
10. Benefit / Cost Ratio	1.96	1.68
11. Threshold Benefit / Cost Ratio [1]	1.00	
12. Lifetime MMBTU Savings	736,594	555,567
13. Threshold Lifetime MMBTU Savings (65%) [2]	478,786	
14. Budget / Actual Spend	$3,090,674	$2,286,081
15. Benefit / Cost Percentage of Budget	4.00%	
16. Lifetime MMBTU Percentage of Budget	4.00%	
17. Residential Incentive	**$247,254**	**$147,743**
18. Cap	**$370,881**	
19. TOTAL INCENTIVE	**$501,236**	**$226,911**

NHPUC NO. 7 - GAS
LIBERTY UTILITIES

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual Environmental increase	$256,547	
DG 10-17 Base Rate Revision Collections	($78,892)	
Environmental Subtotal	$177,655	
Overall Annual Net Increase to Rates	$177,655	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/13 - sales and transportation	158,062,349	therms
Surcharge per therm	$0.0011	per therm
Total Environmental Surcharge	$0.0011	

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

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

Concord Pond

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

	(thru 3/98) pool #1	(4/98 - 9/98) pool #2	(10/98 - 9/15/99) pool #3	(9/99 - 9/00) pool #4	(9/03 - 9/04) pool #5	(9/04 - 9/05) pool #6	(9/05 - 9/06) pool #7	(9/06 - 9/07) pool #8	(9/07 - 9/08) pool #9	(9/08 - 9/09) pool #10	(9/09 - 9/10) pool #11	(9/10 - 9/11) pool #11	(9/11 - 9/12) pool #12	subtotal
1 Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,448	86,412	6,586,270
Remediation costs (i.o. 500005)	-	-	-	-										-
A Subtotal - remediation costs	1,422,811	1,843,806	2,154,235	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,448	86,412	6,586,270
														-
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(2,131,966)
Cash recoveries (i.o. 500004)	(445,985)	-	-	-										(445,985)
Recovery costs (i.o. 500004)	623,784	-	-	-				-	-	-	-	-	-	623,784
Transfer Credit from Gas Restructuring														-
B Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(1,954,167)
														-
A-B Total net expenses to recover	520,030	1,409,330	1,654,552	95,798	60,293	21,613	81,979	142,350	95,374	115,579	136,936	217,032	81,238	4,632,103
														-
														-
Surcharge revenue:														-
Act June 1998 - October 1998	(54,889)	-	-	-										(54,889)
Act November 1998 - October 1999	(287,010)	(251,133)	-	-										(538,143)
Act November 1999 - October 2000	(178,131)	(266,400)	(316,340)	-										(760,871)
Act November 2000 - October 2001	-	(292,420)	(334,194)	(13,925)										(640,539)
Act November 2001 - October 2002	-	(281,914)	(318,686)	(24,514)										(625,114)
Act November 2002 - October 2003	-	(258,347)	(334,331)	(15,197)										(607,874)
Act November 2003 - October 2004	-	(14,567)	(276,773)	(14,567)										(305,907)
Act November 2004- October 2005	-	-	(56,719)	(14,180)	(14,180)									(85,078)
Act November 2005- October 2006	-	-	-	(6,875)	(6,875)									(13,750)
Act November 2006- October 2007	-	-	-	-	-	-	(14,091)							(14,091)
Act November 2007- October 2008														-
Act Nov 2009-Oct 2010 Base Rate Rev												($4,416)		(4,416)
Act Nov 2010-Oct 2011 Base Rate Rev												($32,261)		(32,261)
Act Nov 2011-Oct 2012 Base Rate Rev												($28,308)		(28,308)
AES collections					(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,429)	(134,711)
Gas Street overcollection	-	(23,511)												(23,511)
Prior Period Pool under/overcollection		-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	-	-	-	-	
														0
														-
C Surcharge Subtotal	(520,030)	(1,388,292)	(1,616,004)	(50,710)	(9,559)	39,108	34,729	104,437	234,166	(12,904)	(13,145)	(78,205)	(13,429)	(3,869,461)
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	138,826	67,810	762,642
E Allocation of Litigated Recovery					-		-		(329,540)	(102,675)	(123,791)	(67,710)	-	(623,716)
Surcharge calculation 2007/2008														
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	-	71,116	67,810	138,926
remaining life	-	-	-	-	24	36	48	60	72	84	84	72	84	
one year	-	-	-	-	12	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-		-	-	-	11,853	9,687	21,540
Required annual increase in rates 2007/2008:														
smaller of D or F	-	-	-	-	-	-	-		-	-	-	11,853	9,687	21,540
forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$0.0001

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

00000183

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

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

Laconia & Liberty Hill

	i.o. no. 500005 (through 9/15/99) pool #1	(9/99 - 9/00) pool #2	(9/00 - 9/01) pool #3	(9/04 - 9/05) pool #4	(9/05 - 9/06) pool #5	(9/06 - 9/07) pool #6	(9/07 - 9/08) pool #7 Incl. Audit Corr	(9/08 - 9/09) pool #8 Incl. Audit Corr	(9/09 - 9/10) pool #9	(9/10 - 9/11) pool #10	(9/11 - 9/12) pool #11	subtotal
1 Remediation costs (i.o. 500061)	-	-		-								-
Remediation costs (i.o. 500005)	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	607,876	262,678	211,728	269,281	11,450,276
A Subtotal - remediation costs	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	607,876	262,678	211,728	269,281	11,450,276
Cash recoveries (i.o. 500061)	-	-	-	-	-	-	-	-				-
Cash recoveries (i.o. 500004)	-	-	-	-	-	-	-	-				-
Recovery costs (i.o. 500004)	-	-	-			11,643	21,729	-	-			33,372
Transfer Credit from Gas Restructuring						-	-	-				-
B Subtotal - net recoveries	-	-	-	-	-	11,643	21,729	-	-	-	-	33,372
A-B Total net expenses to recover	1,027,747	3,513,285	700,000	9,702	2,330,555	2,100,842	449,954	607,876	262,678	211,728	269,281	11,483,648
Surcharge revenue:												
Act June 1998 - October 1998	-	-	-	-	-		-	-	-	-	-	-
Act November 1998 - October 1999	-	-	-	-	-		-	-	-	-	-	-
Act November 1999 - October 2000	(151,933)	-	-	-	-		-	-	-	-	-	(151,933)
Act November 2000 - October 2001	(153,172)	(543,065)	-	-	-		-	-	-	-	-	(696,237)
Act November 2001 - October 2002	(159,343)	(527,057)	(110,314)	-	-		-	-	-	-	-	(796,714)
Act November 2002 - October 2003	(151,969)	(547,087)	(106,378)	-	-		-	-	-	-	-	(805,434)
Act November 2003 - October 2004	(131,103)	(466,143)	(101,969)									(699,215)
Act November 2004- October 2005	(127,617)	(439,570)	(85,078)									(652,264)
Act November 2005- October 2006	(141,176)	(453,736)	(96,247)	-	-		-	-	-	-	-	(691,159)
Act November 2006- October 2007	-	(549,539)	(98,635)	-	(309,996)							(958,171)
Act November 2007- October 2008												-
Act Nov 2009-Oct 2010 Base Rate Rev										($4,308)		(4,308)
Act Nov 2010-Oct 2011 Base Rate Rev										($31,472)		(31,472)
Act Nov 2011-Oct 2012 Base Rate Rev										($27,616)		(27,616)
AES collections												-
Gas Street overcollection												-
Prior Period Pool under/overcollection		11,434	(1,477)	99,902	109,604	2,130,162	4,231,004		-	-	(18,523)	
C Surcharge Subtotal	(1,016,313)	(3,514,762)	(600,098)	99,902	(200,393)	2,130,162	4,231,004	-	-	(63,396)	(18,523)	(5,514,523)
D Net balance to be recovered (A-B+C)	11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	4,680,958	607,876	262,678	148,331	250,758	5,969,125
E Allocation of Litigated Recovery							(4,680,958)	(607,876)	(262,678)	(166,854)	-	(5,718,366)
Surcharge calculation 2007/2008												
Unrecovered costs (D+E)	-	-	-	-			-	-	-	(18,523)	250,758	232,236
remaining life	-	-	-	36	48	60	72	84	84	72	84	
one year	-	-	-	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	-	-	35,823	35,823
Required annual increase in rates 2007/2												
smaller of D or F	-	-	-	-	-		-	-	-	-	35,823	35,823
forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349
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	$0.0002

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

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

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

Manchester

		(9/00 - 9/01) pool #1	(9/02 - 9/03) pool #2	(9/02 - 9/03) pool #3 (withdrawn 2/1/04)	(9/03 - 9/04) pool #4	(9/04 - 9/05) pool #5	(9/05 - 9/06) pool #6	(9/06 - 9/07) pool #7	(9/07 - 9/08) pool #8 Incl. Audit Corr	(9/08 - 9/09) pool #9	(9/09 - 9/10) pool #10	(9/10 - 9/11) pool #11	(9/11 - 9/12) pool #12	subtotal
1	1 Remediation costs (i.o. 500061)	-	-		335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,281	507,622	9,710,868
2	Remediation costs (i.o. 500005)	495,106	329,986											825,092
3	A Subtotal - remediation costs	495,106	329,986	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,281	507,622	10,535,960
4														
5	Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(2,233,660)
6	Cash recoveries (i.o. 500004)	-	-											-
7	Recovery costs (i.o. 500004)	-	-		1,242,326			2,546	-					1,244,872
8	Transfer Credit from Gas Restructuring							-	-					-
9	B Subtotal - net recoveries	-	-	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(234,648)	(65,324)	(988,788)
10														
11	A-B Total net expenses to recover	495,106	329,986	-	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	137,633	442,298	9,547,172
12														-
13														-
14	Surcharge revenue:													-
15	Act June 1998 - October 1998	-	-	-	-									-
16	Act November 1998 - October 1999	-	-	-	-									-
17	Act November 1999 - October 2000	-	-	-	-									-
18	Act November 2000 - October 2001	-	-	-	-									-
19	Act November 2001 - October 2002	(73,543)	-	-	-									(73,543)
20	Act November 2002 - October 2003	(75,984)	-	-	-									(75,984)
21	Act November 2003 - October 2004	(72,835)	(24,416)	(41,325)	-									(138,576)
22	Act November 2004- October 2005	(70,898)	(42,539)	-	(212,695)	-			-	-	-	-	-	(326,132)
23	Act November 2005- October 2006	(54,998)	(41,249)	-	(206,243)	(261,242)			-	-	-	-	-	(563,732)
24	Act November 2006- October 2007	(70,454)	(56,363)	-	(211,361)	(281,815)	(42,272)							(662,265)
25	Act November 2007- October 2008													-
26	Act Nov 2009-Oct 2010 Base Rate Rev											$0		-
27	Act Nov 2010-Oct 2011 Base Rate Rev											$0		-
28	Act Nov 2011-Oct 2012 Base Rate Rev											$0		-
29	AES collections													-
30	Gas Street overcollection													-
31	Prior Period Pool under/overcollection		76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	-	-	-		
32														
33														
34	C Surcharge Subtotal	(418,713)	(88,173)	200,488	(429,812)	604,796	2,552,371	2,882,534	3,225,936	-	-	-	-	(1,840,233)
35														
36														
37	D Net balance to be recovered (A-B+C)	76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	6,486,145	312,185	328,678	137,633	442,298	7,706,939
38														
39	E Allocation of Litigated Recovery			-	-	-			(6,486,145)	(312,185)	(328,678)	(135,468)	-	(7,262,476)
40														
41	Surcharge calculation 2007/2008													
42	Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-	2,166	442,298	444,463
43	remaining life	-	-	-	24	36	48	60	70	84	84	72	84	
44	one year	-	-	-	12	12	12	12	12	12	12	12	12	
45	F amortization 2007/2008	-	-	-	-	-	-	-	-	-	-	361	63,185	
46														
47	Required annual increase in rates 2007/2													
48	smaller of D or F	-	-	-	-	-	-		-	-	-	361	63,185	63,546
49														
50	forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349
51														
52	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0004	$0.0004

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

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
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EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
Tariff page 91

	Nashua												
	(9/00 - 9/01) pool #1	**(9/01 - 9/02) pool #2**	**(9/02 - 9/03) pool #3**	**(9/03 - 9/04) pool #4**	**(9/04 - 9/05) pool #5**	**(9/05 - 9/06) pool #6**	Corrected per 2/08 Audit **(9/06 - 9/07) pool #7**	**(9/07 - 9/08) pool #8**	**(9/08 - 9/09) pool #9**	**(9/09 - 9/10) pool #9**	**(9/10 - 9/11) pool #10**	**(9/11 - 9/12) pool #11**	**subtotal**
1 Remediation costs (i.o. 500061)	-	-	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,166	399,400	1,063,734
Remediation costs (i.o. 500005)	1,233,726	362,663	175,178										1,771,567
A Subtotal - remediation costs	1,233,726	362,663	175,178	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,166	399,400	2,835,300
													-
Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(193,902)
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)	(175,515)
													-
A-B Total net expenses to recover	1,233,726	362,663	175,178	10,841	206,367	10,223	18,524	97,191	16,289	98,975	33,399	396,411	2,659,786
Surcharge revenue:													
Act June 1998 - October 1998	-	-	-	-									-
Act November 1998 - October 1999	-	-	-	-									-
Act November 1999 - October 2000	-	-	-	-									-
Act November 2000 - October 2001	-	-	-	-									-
Act November 2001 - October 2002	(183,857)	-	-	-									(183,857)
Act November 2002 - October 2003	(182,362)	(60,787)	-	-									(243,150)
Act November 2003 - October 2004	(174,804)	(43,701)	(29,134)	-									(247,639)
Act November 2004- October 2005	(170,156)	(42,539)	(28,359)	-									(241,054)
Act November 2005- October 2006	(164,995)	(54,998)	(27,499)	-	(27,499)			-	-	-	-	-	(274,991)
Act November 2006- October 2007	(169,089)	(56,363)	(28,181)	-	(28,181)	-							(281,815)
Act November 2007- October 2008													-
Act Nov 2009-Oct 2010 Base Rate Rev											$0		-
Act Nov 2010-Oct 2011 Base Rate Rev											$0		-
Act Nov 2011-Oct 2012 Base Rate Rev											$0		-
AES collections													-
Gas Street overcollection													-
Prior Period Pool under/overcollection		188,463	292,737	354,741	365,582	516,269	526,492	545,015	-	-	-	(277)	
C Surcharge Subtotal	(1,045,263)	(69,925)	179,564	354,741	309,902	516,269	526,492	545,015	-	-	-	(277)	(1,472,506)
D Net balance to be recovered (A-B+C)	188,463	292,737	354,741	365,582	516,269	526,492	545,015	642,206	16,289	98,975	33,399	396,134	1,187,280
E Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	(16,289)	(98,975)	(33,676)	-	(791,146)
Surcharge calculation 2007/2008													
Unrecovered costs (D+E)	-	-	-	-	-	-		-	-	-		396,134	396,134
remaining life	-	-	12	24	36	48	60	72	84	84	72	84	
one year	-	12	12	12	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	-	-	-	56,591	
Required annual increase in rates 2007/2													
smaller of D or F	-	-	-	-	-	-		-	-	-	-	56,591	56,591
forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0004	$0.0004

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00000186

Filed under the following protective orders:
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Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132

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

	Dover									
	(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	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 Nov 2009-Oct 2010 Base Rate Rev										
Act Nov 2010-Oct 2011 Base Rate Rev										
Act Nov 2011-Oct 2012 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 2007/2008										
Unrecovered costs (D+E)	-	-	-		-	-	-	-	-	-
remaining life	24	36	48	60	72	84	84	84	84	
one year	12	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	-	
Required annual increase in rates 2007/2 smaller of D or F	-	-	-		-	-	-	-	-	-
forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

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

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

	Keene									
	(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	subtotal
1 Remediation costs (i.o. 500061)	-									-
Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	61,437
A Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	61,437
										-
Cash recoveries (i.o. 500061)	-									-
Cash recoveries (i.o. 500004)	-									-
Recovery costs (i.o. 500004)			18,831	823	-	-	-	-		19,655
Transfer Credit from Gas Restructuring				-	-	-				-
B Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	19,655
A-B Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	81,091
										-
										-
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 Nov 2009-Oct 2010 Base Rate Rev										
Act Nov 2010-Oct 2011 Base Rate Rev										
Act Nov 2011-Oct 2012 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	67,001
										-
E Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	(66,513)
										-
Surcharge calculation 2007/2008										-
Unrecovered costs (D+E)	-	-	-			-	-	-	488	488
remaining life	24	36	48	60	72	84	84	84	84	
one year	12	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	70	
Required annual increase in rates 2007/2										
smaller of D or F	-	-	-			-	-	-	70	70
forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

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

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

	Concord									
	(9/03 - 9/04) pool #1	**(9/04 - 9/05) pool #2**	Corrected per 1/24/07 Audit **(9/05 - 9/06) pool #3**	Corrected per 2/08 Audit **(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**	**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	180,032	289,103	1,000,717
A Subtotal - remediation costs	22,191	220,932	44,345	109,642	8,006	77,063	49,403	180,032	289,103	1,000,717
										-
Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(31,575)	(112,376)
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)	(111,950)
A-B Total net expenses to recover	22,191	220,932	22,106	61,665	(3,163)	92,679	46,190	168,638	257,528	888,766
										-
										-
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 Nov 2009-Oct 2010 Base Rate Rev								($1,886)		(1,886)
Act Nov 2010-Oct 2011 Base Rate Rev								($13,776)		(13,776)
Act Nov 2011-Oct 2012 Base Rate Rev								($12,088)		(12,088)
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	-	-	(27,750)	-	(83,431)
D Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	92,679	46,190	140,888	257,528	805,335
										-
E Allocation of Litigated Recovery	-	-	-	-	(268,051)	(92,679)	(46,190)	(9,392)	-	(416,311)
										-
Surcharge calculation 2007/2008										-
Unrecovered costs (D+E)	-	-	-		-	-	-	131,496	257,528	389,024
remaining life	36	48	60		72	84	84	72	84	
one year	12	12	12		12	12	12	12	12	
F amortization 2007/2008	-	-	-		-	-	-	21,916	36,790	
Required annual increase in rates 2007/2										
smaller of D or F	-	-	-		-	-	-	21,916	36,790	58,706
forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0002	$0.0004

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

		General														
		(9/02 - 9/03) pool #1	**(9/03 - 9/04) pool #2**	**(9/04 - 9/05) pool #3**	Corrected per 1/24/07 Audit **(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**	**subtotal**			**2012 MGP Remediation subtotal**
1	1 Remediation costs (i.o. 500061)	-										-			17,382,014
2	Remediation costs (i.o. 500005)	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	765,246			16,055,400
3	A Subtotal - remediation costs	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	765,246			33,437,414
4															
5	Cash recoveries (i.o. 500061)	-				-	-	-				-			(4,671,904)
6	Cash recoveries (i.o. 500004)	-										-			(445,985)
7	Recovery costs (i.o. 500004)				290,155	31,826	16,012	23,953	-	-	(14,068)	347,878			2,288,374
8	Transfer Credit from Gas Restructuring	(3,331)			-							(3,331)			(3,331)
9	B Subtotal - net recoveries	(3,331)	-	-	290,155	31,826	16,012	23,953	-	-	(14,068)	344,547			(2,832,846)
10															
11	A-B Total net expenses to recover	(123)	538,903	208,128	324,511	53,844	(164,988)	(2,931)	4,199	69,286	78,967	1,109,794			30,604,568
12															30,604,568
13															-
14	Surcharge revenue:														
15	Act June 1998 - October 1998	-	-									-			(54,889)
16	Act November 1998 - October 1999	-	-									-			(538,143)
17	Act November 1999 - October 2000	-	-									-			(912,804)
18	Act November 2000 - October 2001	-	-									-			(1,336,776)
19	Act November 2001 - October 2002	-	-									-			(1,679,228)
20	Act November 2002 - October 2003	-	-									-			(1,732,442)
21	Act November 2003 - October 2004	(8,265)	-									(8,265)			(1,428,735)
22	Act November 2004- October 2005		(70,898)									(70,898)			(1,403,787)
23	Act November 2005- October 2006		(68,748)	(27,499)			-	-	-	-	-	(96,247)			(1,694,877)
24	Act November 2006- October 2007		(77,499)	(28,181)	(49,318)							(154,998)			(2,141,793)
25	Act November 2007- October 2008											-			-
26	Act Nov 2009-Oct 2010 Base Rate Rev											-			(10,611)
27	Act Nov 2010-Oct 2011 Base Rate Rev											-			(77,509)
28	Act Nov 2011-Oct 2012 Base Rate Rev											-			(68,011)
29	AES collections		-									-			(134,711)
30	Gas Street overcollection											-			(23,511)
31	Prior Period Pool under/overcollection		(8,388)	313,370	465,817	741,010	794,853	-	-	-	-				
32															
33															
34	C Surcharge Subtotal	(8,265)	(225,533)	257,689	416,499	741,010	794,853	-	-	-	-	(330,408)		(13,237,827)	(13,237,827)
35															
36															
37	D Net balance to be recovered (A-B+C)	(8,388)	313,370	465,817	741,010	794,853	629,865	(2,931)	4,199	69,286	78,967	779,385	2,162,346	17,366,741	17,366,741
38													-		
39	E Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	2,931	(4,199)	(15,337)	-	(646,470)	(428,437)	(15,614,032)	(15,614,032)
40													-		1,752,709
41	Surcharge calculation 2007/2008												-		837,716
42	Unrecovered costs (D+E)	-	-	-	-		-	-	-	53,949	78,967	132,915	1,734,186	1,734,186	
43	remaining life		36	48	60	72	84	84	84	72	84				
44	one year		12	12	12	12	12	12	12	12	12				
45	F amortization 2007/2008		-	-	-	-	-	-	-	8,991	11,281				
46															
47	Required annual increase in rates 2007/2														
48	smaller of D or F	-	-	-	-		-	-	-	8,991	11,281	20,272	256,547	256,547	
49															
50	forecasted therm sales	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349	158,062,349			**158,062,349**
51															
52	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	$0.0001			**$0.0016**

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00000190

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

Cash Recoveries[1]

	(9/11 - 9/12) Concord Pond	(9/10 - 9/11) Concord Pond	(9/09 - 9/10) Concord Pond	(9/08 - 9/09) Concord Pond	(9/07 - 9/08) Concord Pond	(9/06 - 9/07) Concord Pond	(9/05 - 9/06) Concord Pond	(9/04- 9/05) Concord Pond	(9/03 - 9/04) Concord Pond	(9/11 - 9/12) Laconia	(9/10 - 9/11) Laconia	(9/09 - 9/10) Laconia	(9/08 - 9/09) Laconia	(9/07 - 9/08) Laconia	(9/06 - 9/07) Laconia
1 Remediation costs (i.o. 500061)	-	-	-	-	-		-	-	-	-	-	-	-	-	
Remediation costs (i.o. 500005)	-	-	-	-	-		-	-	-	-	-	-	-	-	
A Subtotal - remediation costs	-	-	-	-	-		-	-	-	-	-	-	-	-	
Cash recoveries (i.o. 500061)															
Cash recoveries (i.o. 500004)				-	568	-	-	-	(648,000)	-	-	-	-	-	-
Recovery costs (i.o. 500004)				-	-	-	73	-	658,508				-	-	45
Transfer Credit from Gas Restructuring				-	-	-	-	-	-						
B Subtotal - net recoveries	-	-	-	-	568	-	73	-	10,508	-	-	-	-	-	45
A-B Total net expenses to recover	-	-	-	-	568	-	73	-	10,508	-	-	-	-	-	45
Surcharge revenue:															
Act June 1998 - October 1998	-	-	-	-	-		-	-	-						
Act November 1998 - October 1999	-	-	-	-	-		-	-	-						
Act November 1999 - October 2000	-	-	-	-	-		-	-	-						
Act November 2000 - October 2001	-	-	-	-	-		-	-	-						
Act November 2001 - October 2002	-	-	-	-	-		-	-	-						
Act November 2002 - October 2003	-	-	-	-	-		-	-	-						
Act November 2003 - October 2004	-	-	-	-	-		-	-	-						
Act November 2004- October 2005															
Act November 2005- October 2006															
Act November 2006- October 2007															
Act November 2007- October 2008															
Act Nov 2009-Oct 2010 Base Rate Rev															
Act Nov 2010-Oct 2011 Base Rate Rev															
Act Nov 2011-Oct 2012 Base Rate Rev															
AES collections	-	-	-	-	-		-	-	-						
Gas Street overcollection	-	-	-	-	-		-	-	-						
Prior Period Pool under/overcollection															
C Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D Net balance to be recovered (A-B+C)	-	-	-	-	568	-	73	-	10,508	-	-	-	-	-	45
E Allocation of Litigated Recovery															
Surcharge calculation 2007/2008															
Unrecovered costs (D+E)															
remaining life															
one year															
F amortization 2007/2008															
Required annual increase in rates 2007/2															
smaller of D or F															
forecasted therm sales															
surcharge per therm															

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

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

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Order No.
Order No.
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Tariff page 91

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

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

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

Natural Gas, Inc.
l Remediation - MGPs

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

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00000193

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Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130
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EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
Tariff page 91

	(9/09 - 9/10) Keene	(9/08 - 9/09) Keene	(9/07 - 9/08) Keene	(9/06 - 9/07) Keene	(9/05 - 9/06) Keene	(9/04 - 9/05) Keene	(9/03 - 9/04) Keene	(9/06 - 9/07) General	2012 subtotal	MGP TOTAL
1 Remediation costs (i.o. 500061)					-	-			-	17,382,014
Remediation costs (i.o. 500005)					-	-			-	16,055,400
A Subtotal - remediation costs					-	-			-	33,437,414
										(27,910,297)
Cash recoveries (i.o. 500061)									-	(4,671,904)
Cash recoveries (i.o. 500004)	-	116			(700,000)	(211,213)	0	(10,760,900)	(22,792,408)	(23,238,393)
Recovery costs (i.o. 500004)			1,559	28,211	309,618	56,392	121,018		7,178,376	9,466,750
Transfer Credit from Gas Restructuring									-	(3,331)
B Subtotal - net recoveries	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	(18,446,878)
									-	-
A-B Total net expenses to recover	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	14,990,536
Surcharge revenue:										
Act June 1998 - October 1998									-	(54,889)
Act November 1998 - October 1999									-	(538,143)
Act November 1999 - October 2000									-	(912,804)
Act November 2000 - October 2001									-	(1,336,776)
Act November 2001 - October 2002									-	(1,679,228)
Act November 2002 - October 2003									-	(1,732,442)
Act November 2003 - October 2004									-	(1,428,735)
Act November 2004- October 2005									-	(1,403,787)
Act November 2005- October 2006										(1,694,877)
Act November 2006- October 2007										(2,141,793)
Act November 2007- October 2008										-
Act 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										(68,011)
AES collections									-	(134,711)
Gas Street overcollection									-	(23,511)
Prior Period Pool under/overcollection									-	
									-	
C Surcharge Subtotal				-	-	-	-		-	(13,237,827)
									-	(156,131)
									-	
D Net balance to be recovered (A-B+C)	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	1,752,709
E Allocation of Litigated Recovery									15,614,032	
									-	
Surcharge calculation 2007/2008										
Unrecovered costs (D+E)										
remaining life										
one year										
F amortization 2007/2008										
Required annual increase in rates 2007/2										
smaller of D or F										
forecasted therm sales										
surcharge per therm										

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

00000194

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

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

Expense and Collection Summary per Year

	(thru 3/98)	(4/98 - 9/98)	10/98 - 9/15/99	(9/99 - 9/00)	(9/00 - 9/01)	(9/01 - 9/02)	(9/02 - 9/03)	(9/03 - 9/04)	(9/04 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	(9/10 - 9/11)	(9/11 - 9/12)	Total
1 Remediation costs (i.o. 500061)	1,422,811	1,843,806	2,154,235	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	686,896	993,434	17,382,014
Remediation costs (i.o. 500005)	-	-	1,027,747	3,513,285	2,428,832	362,663	689,437	571,259	445,367	2,444,366	2,229,625	255,263	658,324	316,280	461,046	651,906	16,055,400
A Subtotal - remediation costs	1,422,811	1,843,806	3,181,982	3,642,287	2,428,832	362,663	689,437	977,731	2,682,050	3,442,003	2,956,367	4,845,887	1,177,231	991,045	1,147,942	1,645,340	33,437,414
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(105,062)	(4,671,904)
Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	(23,238,393)
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)	9,466,750
Transfer Credit from Gas Restructuring	-	-	-	-	-	-	(3,331)	-	-	-	-	-	-	-	-	-	(3,331)
B Subtotal - net recoveries	(902,781)	(434,476)	(499,684)	(33,204)	-	-	(3,331)	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(310,226)	(119,129)	(18,446,878)
A-B Total net expenses to recover	520,030	1,409,330	2,682,299	3,609,083	2,428,832	362,663	686,106	1,835,026	2,808,471	1,903,772	(8,887,756)	3,340,669	(949,571)	877,655	837,716	1,526,211	14,990,536
Surcharge revenue:																	
Act June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
Act November 1998 - October 1999	(287,010)	(251,133)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
Act November 1999 - October 2000	(178,131)	(266,400)	(468,273)	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
Act November 2000 - October 2001	-	(292,420)	(487,366)	(556,990)	-	-	-	-	-	-	-	-	-	-	-	-	(1,336,776)
Act November 2001 - October 2002	-	(281,914)	(478,029)	(551,571)	(367,714)	-	-	-	-	-	-	-	-	-	-	-	(1,679,228)
Act November 2002 - October 2003	-	(258,347)	(486,300)	(562,284)	(364,725)	(60,787)	-	-	-	-	-	-	-	-	-	-	(1,732,442)
Act November 2003 - October 2004	-	(14,567)	(407,875)	(480,710)	(349,608)	(43,701)	(132,274)	-	-	-	-	-	-	-	-	-	(1,428,735)
Act November 2004- October 2005	-	-	(184,336)	(453,749)	(326,132)	(42,539)	(99,258)	(297,773)	-	-	-	-	-	-	-	-	(1,403,787)
Act November 2005- October 2006	-	-	(141,176)	(460,610)	(316,240)	(54,998)	(96,247)	(281,866)	(343,739)	-	-	-	-	-	-	-	(1,694,877)
Act November 2006- October 2007	-	-	-	(549,539)	(338,178)	(56,363)	(112,726)	(288,860)	(366,359)	(429,768)	-	-	-	-	-	-	(2,141,793)
Act November 2007- October 2008															-		-
Act 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															(68,011)		(68,011)
AES collections	-	-	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,429)	(134,711)
Gas Street overcollection	-	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
Prior Period Pool under/overcollection																	
C Surcharge Subtotal	(520,030)	(1,388,292)	(2,653,355)	(3,615,454)	(2,062,596)	(258,389)	(440,504)	(902,092)	(721,725)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(169,352)	(13,429)	(13,237,827)
D Net balance to be recovered (A-B+C)	-	21,038	28,944	(6,371)	366,236	104,274	245,602	932,934	2,086,746	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	668,364	1,512,782	1,752,709

E Allocation of Litigated Recovery

Surcharge calculation 2007/2008
Unrecovered costs (D+E)
remaining life
one year
F amortization 2007/2008

Required annual increase in rates 2007/2
smaller of D or F

forecasted therm sales

surcharge per therm

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

00000195

ENERGYNORTH NATURAL GAS, INC.
d/b/a LIBERTY UTILITIES

CONCORD FORMER MGP

LINE
NO.

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

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

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

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

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. The investigation work was completed in July 2012.**

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. The City is currently evaluating the draft design plans, and has committed to following up with ENGI following their internal discussions.

LINE
NO.

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. A Site Investigation Addendum Report will be submitted for the river portion of the site in summer 2012; however, based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: 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 the last twelve months to discuss the proposed remedy and the required access. The most recent meeting with the City was on March 14, 2011, when the City stated that they would hold internal discussions and contact National Grid when they are ready to reconvene the group.

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

CONCORD FORMER MGP

LINE
NO.

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

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

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

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
KEYSPAN PROJECT DEF077

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	City of Concord	7714475	600.00			600.00
	Clean Harbors	SB1196856	472.14			472.14
	Clean Harbors	SB1184641	86,480.60			86,480.60
	Clean Harbors	NH1146942	517.11			517.11
	Clean Harbors	SB1201700	2,137.76			2,137.76
	Clean Harbors	SB1180654	2,550.00			2,550.00
	Clean Harbors	NH1225542	550.10			550.10
	Clean Harbors	NH1250083	648.90			648.90
	Clean Harbors	SB1263315	4,740.39			4,740.39
	GZA GeoEnvironmental, Inc.	0643831	22,685.97			22,685.97
	GZA GeoEnvironmental, Inc.	0647642	5,441.48			5,441.48
	GZA GeoEnvironmental, Inc.	0648605	50,187.75			50,187.75
	GZA GeoEnvironmental, Inc.	0651155	26,794.63			26,794.63
	GZA GeoEnvironmental, Inc.	0652443	6,795.64			6,795.64
	GZA GeoEnvironmental, Inc.	0653551	21,276.02			21,276.02
	GZA GeoEnvironmental, Inc.	0655554	13,359.98			13,359.98
	GZA GeoEnvironmental, Inc.	0656957	37,600.41			37,600.41
	McClane	2011100957	182.00			182.00
	McClane	2011080875	2,038.40			2,038.40
	McClane		1,201.20			1,201.20
	State of New Hampshire	7690221	1,504.80			1,504.80
	State of New Hampshire	7697095	298.27			298.27
	State of New Hampshire	7705810	826.61			826.61
	State of New Hampshire	7716409	213.06			213.06
	[redacted]					
	Total Pool Activity		**289,103.22**	**-**	**(31,574.76)**	**257,528.46**

REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD POND - REMEDIATION
KEYSPAN PROJECT DEF056

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	City of Concord		1,440.00			1,440.00
	Clean Harbors		1,015.39			1,015.39
	Clean Harbors		752.30			752.30
	Clean Harbors		846.11			846.11
	GEI Consultants	53335	4,951.05			4,951.05
	GEI Consultants	53488	15,286.27			15,286.27
	GEI Consultants		2,851.50			2,851.50
	GEI Consultants		2,663.98			2,663.98
	GEI Consultants		1,214.00			1,214.00
	GEI Consultants		20,509.29			20,509.29
	GEI Consultants		11,237.55			11,237.55
	GEI Consultants		7,168.97			7,168.97
	GEI Consultants		4,254.20			4,254.20
	GEI Consultants		3,704.75			3,704.75
	GEI Consultants		2,927.88			2,927.88
	GEI Consultants		3,828.10			3,828.10
	State of New Hampshire	7690222	1,760.28			1,760.28
	[redacted]					
	Total Pool Activity		**86,411.62**	**-**	**(5,173.17)**	**81,238.45**

REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD - LITIGATION
KEYSPAN PROJECT DEF051

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity										

NO ACTIVITY FOR THIS PERIOD

LINE
NO.

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

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

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

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

LINE
NO.

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

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

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

LINE
NO.

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modeling 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. A hearing on the matter was 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. The Hearing Officer will be determining a new hearing date.**

LINE
NO.

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: Please refer to Item 4.

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

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

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

Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003 the United States District Court certified a question to the New Hampshire Supreme Court asking what “trigger of coverage” should be applied to the insurance policies issued by Lloyds of London to ENGI’s predecessor, Gas Service, Inc. In May, 2004 the Supreme Court responded that

LINE
NO.

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.

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

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF086

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Blue Chip	01017	400.00			400.00
	Blue Chip Films	01021	237.50			237.50
	Blue Chip Films	01030	400.00			400.00
	Clean Harbors	NH1171067	481.53			481.53
	Clean Harbors	SB1291273	632.84			632.84
	GEI Consultants	53334	1,695.37			1,695.37
	GEI Consultants	53487	1,465.40			1,465.40
	GEI Consultants	53659	23,024.66			23,024.66
	GEI Consultants	053811	13,789.36			13,789.36
	GEI Consultants	53968	9,300.84			9,300.84
	GEI Consultants	54155	7,266.45			7,266.45
	GEI Consultants	54322	3,229.53			3,229.53
	GEI Consultants	54566	1,363.00			1,363.00
	GEI Consultants	54,723.00	18,423.10			18,423.10
	GEI Consultants	54,916.00	12,285.65			12,285.65
	GEI Consultants	050690	14,337.06			14,337.06
	GEI Consultants	55159	2,319.95			2,319.95
	GEI Consultants	55164	23,998.15			23,998.15
	GEI Consultants	55317	3,355.55			3,355.55
	GZA	0655625	12,029.82			12,029.82
	McLane	2011081708	728.00			728.00
	McLane	2011080874	791.70			791.70
	McLane	2011120429	23,778.00			23,778.00
	McLane	2012010761	13,463.50			13,463.50
	McLane	2012020790	8,394.30			8,394.30
	McLane	2012031622	11,767.35			11,767.35
	McLane	2012030856	9,257.20			9,257.20
	McLane	2012041412	6,153.76			6,153.76
	McLane	2012050953	17,157.88			17,157.88
	MCLANE GRAF RAULE	2012030856	8,432.65			8,432.65
	Ostrow & Partners	071101	479.50			479.50
	Ostrow & Partners	081101	479.50			479.50
	Ostrow & Partners	101101	323.00			323.00
	Ostrow & Partners	91101	557.75			557.75
	Ostrow & Partners	111101	1,262.00			1,262.00
	Ostrow & Partners	121101	2,598.25			2,598.25
	Ostrow & Partners	021201	870.75			870.75
	Ostrow & Partners	011201	1,496.75			1,496.75
	Ostrow & Partners	061101	557.75			557.75
	Ostrow & Partners		1,340.25			1,340.25
	Ostrow & Partners	051201	323.00			323.00
	Ostrow & Partners	061201	557.75			557.75
	Public Service of New Hampshire		11.52			11.52
	Public Service of New Hampshire		12.47			12.47
	Public Service of New Hampshire		11.54			11.54
	Public Service of New Hampshire		13.10			13.10
	Public Service of New Hampshire		11.54			11.54
	Public Service of New Hampshire		12.47			12.47
	Public Service of New Hampshire		11.54			11.54
	Public Service of New Hampshire		12.61			12.61
	Public Service of New Hampshire		11.66			11.66
	Public Service of New Hampshire		12.44			12.44
	Public Service of New Hampshire		11.66			11.66
	Public Service of New Hampshire		12.73			12.73
	Public Service of New Hampshire		11.77			11.77
	Public Service of New Hampshire		12.94			12.94
	Public Service of New Hampshire		23.20			23.20
	Public Service of New Hampshire		48.96			48.96
	Public Service of New Hampshire		11.54			11.54
	Public Service of New Hampshire		12.47			12.47
	Public Service of New Hampshire		11.54			11.54
	Public Service of New Hampshire		12.48			12.48
	State of New Hampshire	7690220	2,082.70			2,082.70
	State of New Hampshire		3,088.53			3,088.53
	State of New Hampshire		3,013.28			3,013.28
	Total Pool Activity		**269,281.04**	**-**	**-**	**269,281.04**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LACONIA - LITIGATION
KEYSPAN PROJECT DEF050

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABL E EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
Total Pool Activity											

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF087

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
Total Pool Activity											

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
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. 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.

LINE
NO.

- 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 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.**

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

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

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

MANCHESTER FORMER MGP

LINE
NO.

- **After meeting with the developer of the property located directly downgradient of the site regarding potential impact to the property in September/October 2011, access was obtained to conduct the approved pre-design 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 these results. A Remedial Design Report for the off-site property is currently being finalized.**

- **Additional on-site pre-design investigation activities were conducted in spring 2012 including additional groundwater monitoring, holder foundation test pit excavations, and storm drain analysis. Further investigation activities are planned for the summer 2012 in order to complete the on-site Remedial Design Report.**

4. 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 for the off-site impacts will be submitted in the coming months.**

5. 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.

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

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: In late 2000, ENGI filed suit against UGI Utilities, Inc. in the United States District Court for the District of New Hampshire, alleging that during much of the early part of the 20th century, a predecessor to that entity "operated" the Manchester Gas Plant, as

defined by the Comprehensive Environmental Response, Compensation and Liability Act (commonly referred to as “CERCLA” or “Superfund”). This claim was similar to a claim litigated and ultimately settled by the parties in the late 1990s, related to the former gas plant in Concord, NH. The case went to trial in June 2003 and was settled after 8 days of trial.

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

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.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
KEYSPAN PROJECT DEF057

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Clean Harbors	NH1102485	641.48			641.48
	Clean Harbors	NH1201702	245.23			245.23
	Clean Harbors	SB1226170	4,669.45			4,669.45
	Clean Harbors	NH1219468	200.79			200.79
	Clean Harbors	NH1218836R	9,685.66			9,685.66
	Clean Harbors	SB1278817	4,318.81			4,318.81
	Clean Harbors	NH1225529	3,750.42			3,750.42
	Clean Harbors	NH1275853	216.30			216.30
	Colliers International		4,800.00			4,800.00
	EECS	289	5,985.06			5,985.06
	EECS	292	1,524.26			1,524.26
	EECS	294	1,766.03			1,766.03
	EECS	296	2,378.51			2,378.51
	EECS	300	1,698.84			1,698.84
	EECS	298	3,476.50			3,476.50
	ESMI	1008279	566.40			566.40
	GZA Environmental	0643887	7,154.92			7,154.92
	GZA Environmental	0645113	4,833.37			4,833.37
	GZA Environmental	0647512	4,291.46			4,291.46
	GZA Environmental	0648849	38,814.18			38,814.18
	GZA Environmental	0649414	97,295.96			97,295.96
	GZA Environmental	0652413	20,940.35			20,940.35
	GZA Environmental	0653160	35,270.11			35,270.11
	GZA Environmental	0653708	25,320.94			25,320.94
	GZA Environmental	0655569	27,925.28			27,925.28
	GZA Environmental	0654301	41,160.06			41,160.06
	GZA Environmental	0657011	17,463.90			17,463.90
	McLane	2011081707	364.00			364.00
	McLane	2011090540	6,749.10			6,749.10
	McLane	2011100954	6,843.20			6,843.20
	McLane	2011080872	3,989.70			3,989.70
	McLane	2011070659	4,176.40			4,176.40
	McLane	2011120428	4,914.80			4,914.80
	McLane	2012010759	773.50			773.50
	McLane	2011110294	14,163.00			14,163.00
	McLane	2012031621	182.00			182.00
	McLane	2012020789	4,809.20			4,809.20
	McLane	2012041121	728.00			728.00
	McLane	2012050951	2,074.80			2,074.80
	McLane	2012060826	2,402.40			2,402.40
	State of New Hampshire	7690224	1,490.36			1,490.36
	State of New Hampshire	9890-1011	89.80			89.80
	State of New Hampshire	9890/1-20-12	229.64			229.64
	State of New Hampshire	9890/4-18-12	940.12			940.12
	T Ford Company, Inc.	4	24,141.23			24,141.23
	T Ford Company, Inc.	1380	2,837.53			2,837.53
	T Ford Company, Inc.	1454	59,328.94			59,328.94
	[redacted]					
	Total Pool Activity		**507,621.99**	**-**	**(65,324.13)**	**442,297.86**

REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - LITIGATION
KEYSPAN PROJECT DEF058

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
											-
	Total Pool Activity		-	-	-	-	-	-	-	-	-

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
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.

LINE
NO.

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

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

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

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

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

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

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

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

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

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

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

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

LINE
NO.

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

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

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

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

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

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June 2011.

- 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. **The system has recovered 198 gallons of DNAPL as of July 2012.**

- 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 is currently scheduled for August 2012. Pending concurrence of the GMZ findings by NHDES, a GMP is expected to be filed in 2013.**

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.

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

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

$387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

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

Numerous, confidential insurance settlements have been entered into. A jury trial commenced against the London Market Insurers and Century Indemnity on November 1, 2005. On November 14, 2005, the jury returned a verdict in favor of EnergyNorth finding that the defendants were obligated to indemnify EnergyNorth for response costs incurred at the site. The Court then awarded ENGI its reasonable costs and attorneys fees to be 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
NASHUA - REMEDIATION
KEYSPAN PROJECT DEF054

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
	Clean Harbors	SB1113870	3,090.76			3,090.76
	Clean Harbors	SB1194034R	7,254.81			7,254.81
	Clean Harbors	SB1287793	7,688.26			7,688.26
	Environmental Staff Project Time		9,640.35			9,640.35
	GZA Environmental	0648178	26,662.49			26,662.49
	GZA Environmental	0650594	8,053.45			8,053.45
	GZA Environmental	0652228	900.12			900.12
	GZA Environmental	0649755	25,729.49			25,729.49
	GZA Environmental	0656883	6,749.56			6,749.56
	Innovative Engineering	9508	2,570.41			2,570.41
	Innovative Engineering	9554	2,991.23			2,991.23
	Innovative Engineering	9580	4,792.00			4,792.00
	Innovative Engineering	9697	11,535.33			11,535.33
	Innovative Engineering	9777	25,278.30			25,278.30
	Innovative Engineering	9837	104,095.50			104,095.50
	Innovative Engineering	9930	27,332.14			27,332.14
	Innovative Engineering	10045	8,145.00			8,145.00
	Innovative Engineering	9986	52,610.63			52,610.63
	Innovative Engineering	10092	3,875.00			3,875.00
	Innovative Engineering	10183	2,815.00			2,815.00
	Innovative Engineering	10245	29,960.98			29,960.98
	McLane	2011050844	400.40			400.40
	McLane	2011070658	4,841.20			4,841.20
	McLane	2011081706	109.20			109.20
	McLane	2011060321	6,191.90			6,191.90
	McLane		2,256.80			2,256.80
	McLane	2011060321	6,042.40			6,042.40
	McLane	201108071	509.60			509.60
	McLane	2012030857	582.40			582.40
	McLane	2012031620	655.20			655.20
	McLane	2012041120	728.00			728.00
	McLane	2012050949	728.00			728.00
	McLane		1,929.20			1,929.20
	State of New Hampshire	7690223	439.56			439.56
	State of New Hampshire	8323/1-20-12	298.27			298.27
	State of New Hampshire	8323/4-18-12	1,917.40			1,917.40
	[redacted]					
	Total Pool Activity		**399,400.34**	**-**	**(2,989.64)**	**396,410.70**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - LITIGATION
KEYSPAN PROJECT DEF049

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	100 % RECOVERABL E EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
	Total Pool Activity		-	-	-	-	-	-	-	-	-

NO ACTIVITY FOR THIS PERIOD

00000228

ENERGYNORTH NATURAL GAS, INC.
d/b/a LIBERTY UTILITIES

DOVER FORMER MGP

LINE
NO.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DOVER FORMER MGP

LINE
NO.

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

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

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
SITE NAME: DOVER - REMEDIATION
KEYSPAN PROJECT DEF059

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	100 % RECOVERABL E EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED

NO ACTIVITY FOR THIS PERIOD

Total Pool Activity											

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
DOVER - LITIGATION
KEYSPAN PROJECT DEF060

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity		-	-	-	-	-	-	-	-	-

NO ACTIVITY FOR THIS PERIOD

ENERGYNORTH NATURAL GAS, INC.
d/b/a LIBERTY UTILITIES

KEENE FORMER MGP

LINE
NO.

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

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

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

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

LINE
NO.

Phase II RAP implementation is underway. According to NHDES files, remedial actions in the Mill Creek and Ashuelot River continued in late 2011/2012.

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

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

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Insurance recovery claims are underway, and confidential settlements have been entered into with all but one defendant. The case is currently stayed. Trial had been scheduled for October 2006 against the sole remaining insurance company defendant, Century Indemnity, however that trial was put off while awaiting a ruling on an issue of law in the Manchester MGP litigation by the New Hampshire Supreme Court. The Supreme Court has since ruled on the appropriate method of allocating indemnification obligations among multiple insurers and the applicability of the New Hampshire attorneys fees statute, RSA 491:22-a, which is relevant to the Keene case. In

LINE
NO.

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

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

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

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - REMEDIATION
KEYSPAN PROJECT DEF055

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Environmental Staff Project Time		487.69			487.69
	Total Pool Activity		**487.69**			**487.69**

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - LITIGATION
KEYSPAN PROJECT DEF071

LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Total Pool Activity										

NO ACTIVITY FOR THIS PERIOD

REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
KEYSPAN PROJECT DEF064

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	Curry Printing	197116	1,302.84			1,302.84
	EECS	294	1,217.00			1,217.00
	EECS	296	974.00			974.00
	EECS	298	3,531.00			3,531.00
	EECS	300	437.00			437.00
	Environmental Staff Time		76,173.48			76,173.48
	GZA	0647698	6,480.00			6,480.00
	McLane	2011100955	409.50			409.50
	McLane	2011031035	40.00			40.00
	McLane	2011060325	72.80			72.80
	McLane	2011050847	45.50			45.50
	McLane	2011020723	1,562.50			1,562.50
	Pro Unlimited (refer to spreadsheet)		71.25			71.25
	Pro Unlimited (refer to spreadsheet)		42.75			42.75
	Pro Unlimited (refer to spreadsheet)		57.72			57.72
	Pro Unlimited (refer to spreadsheet)		228.72			228.72
	Pro Unlimited (refer to spreadsheet)		72.15			72.15
	Pro Unlimited (refer to spreadsheet)		202.02			202.02
	Pro Unlimited (refer to spreadsheet)		114.00			114.00
	[redacted]					
	Total Pool Activity		**93,034.23**	**-**	**(14,067.63)**	**78,966.60**

III DELIVERY TERMS AND CONDITIONS

ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.19 per MMBtu of Daily Imbalance Volumes*	
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.	
III.	Peaking Demand Charge	$18.62 MMBTU of Peak MDQ.	
IV.	Company Allowance Calculation (per Schedule 25)		
		138,409,150	Total Sendout - Therms Jul-2011 - Jun-2012
		136,259,218	Total Throughput - Therms Jul-2011 - Jun-2012
		2,149,932	Variance (Sendout - Throughput)
	Company Allowance Percentage 2012-13	1.6%	Variance / Total Sendout

* The difference between the ATV and the recalculated ATV adjusted for actual degree days.

ENERGY NORTH NATURAL GAS, INC.

Calculation of Supplier Balancing Charge
2012-13

Rate: **$0.19 /MMBtu**

	Rate	Volume	Total	
Injection Cost	$0.0087	**540,530**	$4,703	
Withdrawal Cost	$0.0087	**385,530**	$3,354	
Delivery Rate	$0.0506	385,530	$19,519	
FTA Demand Charge	$0.2791	385,530	$107,605	
FTA Commodity Charge	$0.1091	385,530	$42,061	
		Total Cost	$177,243	
		Absolute Value of the Sendout Error	**926,061**	MMBtu
		Rate	$ 0.19	/MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in Tab 6

TGP FSMA Injection Charge	$0.0087	/ MMBtu
TGP FSMA Withdrawal Charge	$0.0087	/ MMBtu
TGP FSMA Deliverability Charge	$1.54	/ MMBtu per month
	$0.0506	/ MMBtu per day
TGP Z4-6 Demand Charge	$8.49	/ MMBtu per month
	$0.2791	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.1091	/ MMBtu

EnergyNorth Natural Gas Inc.

Calculation of Supplier Balancing Charge
2012-13

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	611	598	13	1,102,514	1,086,584	15,931	99,262	57,596	41,666
Dec	948	922	26	1,790,147	1,746,397	43,750	144,712	94,231	50,481
Jan	1,149	1,105	44	2,128,369	2,054,331	74,039	171,635	122,837	48,798
Feb	947	916	31	1,775,887	1,723,724	52,164	92,548	72,356	20,192
Mar	660	652	8	1,256,941	1,244,962	11,979	167,707	89,843	77,864
Apr	495	505	-10	922,785	936,802	-14,017	109,331	47,657	61,674
May	211	222	-11	477,671	486,721	-9,049	51,828	21,389	30,439
Jun	47	77	-30	315,837	321,740	-5,903	7,477	787	6,690
Jul	0	0	0	268,914	268,914	0	0	0	0
Aug	0	2	-2	282,306	283,281	-976	976	0	976
Sep	72	72	0	315,766	315,766	0	8,245	4,122	4,122
Oct	408	418	-10	681,695	694,613	-12,918	72,340	29,711	42,629
Total	**5,548**	**5,489**	**59**	**11,318,834**	**11,163,834**	**155,000**	**926,061**	**540,530**	**385,530**

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EnergyNorth Natural Gas Inc.

Calculation of Supplier Balancing Charge
2011-12
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, 11	29	28	1	48,281	46,879	1,402	1,402	1,402	0
Apr 2, 11	27	22	5	45,477	38,469	7,008	7,008	7,008	0
Apr 3, 11	26	23	3	44,075	39,870	4,205	4,205	4,205	0
Apr 4, 11	21	25	-4	37,067	42,674	-5,607	5,607	0	5,607
Apr 5, 11	23	25	-2	39,870	42,674	-2,803	2,803	0	2,803
Apr 6, 11	23	26	-3	39,870	44,075	-4,205	4,205	0	4,205
Apr 7, 11	21	23	-2	37,067	39,870	-2,803	2,803	0	2,803
Apr 8, 11	18	22	-4	32,862	38,469	-5,607	5,607	0	5,607
Apr 9, 11	11	13	-2	23,050	25,854	-2,803	2,803	0	2,803
Apr 10, 11	12	10	2	24,452	21,649	2,803	2,803	2,803	0
Apr 11, 11	5	0	5	14,640	7,632	7,008	7,008	7,008	0
Apr 12, 11	13	11	2	25,854	23,050	2,803	2,803	2,803	0
Apr 13, 11	23	22	1	39,870	38,469	1,402	1,402	1,402	0
Apr 14, 11	17	17	0	31,460	31,460	0	0	0	0
Apr 15, 11	22	25	-3	38,469	42,674	-4,205	4,205	0	4,205
Apr 16, 11	18	20	-2	32,862	35,665	-2,803	2,803	0	2,803
Apr 17, 11	14	17	-3	27,255	31,460	-4,205	4,205	0	4,205
Apr 18, 11	16	15	1	30,059	28,657	1,402	1,402	1,402	0
Apr 19, 11	20	21	-1	35,665	37,067	-1,402	1,402	0	1,402
Apr 20, 11	21	22	-1	37,067	38,469	-1,402	1,402	0	1,402
Apr 21, 11	24	23	1	41,272	39,870	1,402	1,402	1,402	0
Apr 22, 11	20	19	1	35,665	34,264	1,402	1,402	1,402	0
Apr 23, 11	16	22	-6	30,059	38,469	-8,410	8,410	0	8,410
Apr 24, 11	13	6	7	25,854	16,042	9,812	9,812	9,812	0
Apr 25, 11	13	14	-1	25,854	27,255	-1,402	1,402	0	1,402
Apr 26, 11	4	14	-10	13,238	27,255	-14,017	14,017	0	14,017
Apr 27, 11	0	0	0	7,632	7,632	0	0	0	0
Apr 28, 11	2	2	0	10,435	10,435	0	0	0	0
Apr 29, 11	10	6	4	21,649	16,042	5,607	5,607	5,607	0
Apr 30, 11	13	12	1	25,854	24,452	1,402	1,402	1,402	0
May 1, 11	12	13	-1	19,681	20,504	-823	823	0	823
May 2, 11	12	4	8	19,681	13,100	6,581	6,581	6,581	0
May 3, 11	6	2	4	14,745	11,455	3,291	3,291	3,291	0
May 4, 11	9	15	-6	17,213	22,149	-4,936	4,936	0	4,936
May 5, 11	17	17	0	23,795	23,795	0	0	0	0
May 6, 11	6	5	1	14,745	13,923	823	823	823	0
May 7, 11	8	8	0	16,391	16,391	0	0	0	0
May 8, 11	10	11	-1	18,036	18,859	-823	823	0	823
May 9, 11	9	4	5	17,213	13,100	4,113	4,113	4,113	0
May 10, 11	11	11	0	18,859	18,859	0	0	0	0
May 11, 11	10	9	1	18,036	17,213	823	823	823	0
May 12, 11	5	9	-4	13,923	17,213	-3,291	3,291	0	3,291
May 13, 11	7	8	-1	15,568	16,391	-823	823	0	823
May 14, 11	10	9	1	18,036	17,213	823	823	823	0
May 15, 11	10	13	-3	18,036	20,504	-2,468	2,468	0	2,468
May 16, 11	11	17	-6	18,859	23,795	-4,936	4,936	0	4,936
May 17, 11	11	15	-4	18,859	22,149	-3,291	3,291	0	3,291
May 18, 11	13	13	0	20,504	20,504	0	0	0	0
May 19, 11	10	7	3	18,036	15,568	2,468	2,468	2,468	0
May 20, 11	7	6	1	15,568	14,745	823	823	823	0
May 21, 11	5	7	-2	13,923	15,568	-1,645	1,645	0	1,645
May 22, 11	10	14	-4	18,036	21,327	-3,291	3,291	0	3,291
May 23, 11	0	5	-5	9,809	13,923	-4,113	4,113	0	4,113
May 24, 11	0	0	0	9,809	9,809	0	0	0	0
May 25, 11	2	0	2	11,455	9,809	1,645	1,645	1,645	0
May 26, 11	0	0	0	9,809	9,809	0	0	0	0
May 27, 11	0	0	0	9,809	9,809	0	0	0	0
May 28, 11	0	0	0	9,809	9,809	0	0	0	0
May 29, 11	0	0	0	9,809	9,809	0	0	0	0
May 30, 11	0	0	0	9,809	9,809	0	0	0	0
May 31, 11	0	0	0	9,809	9,809	0	0	0	0
Jun 1, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 2, 11	6	6	0	11,400	11,400	0	0	0	0
Jun 3, 11	4	6	-2	11,007	11,400	-394	394	0	394
Jun 4, 11	3	8	-5	10,810	11,794	-984	984	0	984
Jun 5, 11	3	2	1	10,810	10,613	197	197	197	0
Jun 6, 11	2	0	2	10,613	10,220	394	394	394	0
Jun 7, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 8, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 9, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 10, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 11, 11	5	12	-7	11,203	12,581	-1,377	1,377	0	1,377
Jun 12, 11	3	11	-8	10,810	12,384	-1,574	1,574	0	1,574
Jun 13, 11	3	6	-3	10,810	11,400	-590	590	0	590
Jun 14, 11	8	7	1	11,794	11,597	197	197	197	0
Jun 15, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 16, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 17, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 18, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 19, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 20, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 21, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 22, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 23, 11	3	6	-3	10,810	11,400	-590	590	0	590
Jun 24, 11	4	10	-6	11,007	12,187	-1,181	1,181	0	1,181
Jun 25, 11	3	3	0	10,810	10,810	0	0	0	0
Jun 26, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 27, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 28, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 29, 11	0	0	0	10,220	10,220	0	0	0	0
Jun 30, 11	0	0	0	10,220	10,220	0	0	0	0
Jul 1, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 2, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 3, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 4, 11	0	0	0	8,675	8,675	0	0	0	0

EnergyNorth Natural Gas Inc.

Calculation of Supplier Balancing Charge
2011-12
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jul 5, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 6, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 7, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 8, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 9, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 10, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 11, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 12, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 13, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 14, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 15, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 16, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 17, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 18, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 19, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 20, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 21, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 22, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 23, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 24, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 25, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 26, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 27, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 28, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 29, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 30, 11	0	0	0	8,675	8,675	0	0	0	0
Jul 31, 11	0	0	0	8,675	8,675	0	0	0	0
Aug 1, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 2, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 3, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 4, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 5, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 6, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 7, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 8, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 9, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 10, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 11, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 12, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 13, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 14, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 15, 11	0	2	-2	9,107	10,082	-976	976	0	976
Aug 16, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 17, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 18, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 19, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 20, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 21, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 22, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 23, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 24, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 25, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 26, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 27, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 28, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 29, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 30, 11	0	0	0	9,107	9,107	0	0	0	0
Aug 31, 11	0	0	0	9,107	9,107	0	0	0	0
Sep 1, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 2, 11	0	1	-1	9,626	10,001	-375	375	0	375
Sep 3, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 4, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 5, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 6, 11	3	2	1	10,750	10,376	375	375	375	0
Sep 7, 11	3	7	-4	10,750	12,249	-1,499	1,499	0	1,499
Sep 8, 11	1	0	1	10,001	9,626	375	375	375	0
Sep 9, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 10, 11	2	3	-1	10,376	10,750	-375	375	0	375
Sep 11, 11	1	1	0	10,001	10,001	0	0	0	0
Sep 12, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 13, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 14, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 15, 11	9	8	1	12,999	12,624	375	375	375	0
Sep 16, 11	15	13	2	15,247	14,498	750	750	750	0
Sep 17, 11	10	9	1	13,374	12,999	375	375	375	0
Sep 18, 11	10	11	-1	13,374	13,748	-375	375	0	375
Sep 19, 11	7	8	-1	12,249	12,624	-375	375	0	375
Sep 20, 11	5	7	-2	11,500	12,249	-750	750	0	750
Sep 21, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 22, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 23, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 24, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 25, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 26, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 27, 11	0	0	0	9,626	9,626	0	0	0	0
Sep 28, 11	3	0	3	10,750	9,626	1,124	1,124	1,124	0
Sep 29, 11	1	2	-1	10,001	10,376	-375	375	0	375
Sep 30, 11	2	0	2	10,376	9,626	750	750	750	0
Oct 1, 11	4	8	-4	10,156	15,323	-5,167	5,167	0	5,167
Oct 2, 11	11	6	5	19,198	12,739	6,459	6,459	6,459	0
Oct 3, 11	10	7	3	17,906	14,031	3,875	3,875	3,875	0
Oct 4, 11	9	9	0	16,615	16,615	0	0	0	0
Oct 5, 11	17	16	1	26,949	25,657	1,292	1,292	1,292	0
Oct 6, 11	20	17	3	30,824	26,949	3,875	3,875	3,875	0
Oct 7, 11	13	12	1	21,782	20,490	1,292	1,292	1,292	0
Oct 8, 11	0	2	-2	4,989	7,572	-2,584	2,584	0	2,584

EnergyNorth Natural Gas Inc.

Calculation of Supplier Balancing Charge
2011-12
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Oct 9, 11	0	0	0	4,989	4,989	0	0	0	0
Oct 10, 11	3	0	3	8,864	4,989	3,875	3,875	3,875	0
Oct 11, 11	7	9	-2	14,031	16,615	-2,584	2,584	0	2,584
Oct 12, 11	8	9	-1	15,323	16,615	-1,292	1,292	0	1,292
Oct 13, 11	3	7	-4	8,864	14,031	-5,167	5,167	0	5,167
Oct 14, 11	4	4	0	10,156	10,156	0	0	0	0
Oct 15, 11	12	9	3	20,490	16,615	3,875	3,875	3,875	0
Oct 16, 11	11	9	2	19,198	16,615	2,584	2,584	2,584	0
Oct 17, 11	12	13	-1	20,490	21,782	-1,292	1,292	0	1,292
Oct 18, 11	11	13	-2	19,198	21,782	-2,584	2,584	0	2,584
Oct 19, 11	8	12	-4	15,323	20,490	-5,167	5,167	0	5,167
Oct 20, 11	10	10	0	17,906	17,906	0	0	0	0
Oct 21, 11	13	11	2	21,782	19,198	2,584	2,584	2,584	0
Oct 22, 11	17	17	0	26,949	26,949	0	0	0	0
Oct 23, 11	16	21	-5	25,657	32,116	-6,459	6,459	0	6,459
Oct 24, 11	14	14	0	23,074	23,074	0	0	0	0
Oct 25, 11	17	17	0	26,949	26,949	0	0	0	0
Oct 26, 11	20	21	-1	30,824	32,116	-1,292	1,292	0	1,292
Oct 27, 11	27	29	-2	39,867	42,450	-2,584	2,584	0	2,584
Oct 28, 11	29	29	0	42,450	42,450	0	0	0	0
Oct 29, 11	28	30	-2	41,159	43,742	-2,584	2,584	0	2,584
Oct 30, 11	29	30	-1	42,450	43,742	-1,292	1,292	0	1,292
Oct 31, 11	25	27	-2	37,283	39,867	-2,584	2,584	0	2,584
Nov 1, 11	26	27	-1	43,654	44,879	-1,225	1,225	0	1,225
Nov 2, 11	22	25	-3	38,752	42,428	-3,676	3,676	0	3,676
Nov 3, 11	20	18	2	36,301	33,850	2,451	2,451	2,451	0
Nov 4, 11	27	27	0	44,879	44,879	0	0	0	0
Nov 5, 11	28	29	-1	46,105	47,330	-1,225	1,225	0	1,225
Nov 6, 11	22	23	-1	38,752	39,978	-1,225	1,225	0	1,225
Nov 7, 11	17	14	3	32,625	28,948	3,676	3,676	3,676	0
Nov 8, 11	14	13	1	28,948	27,723	1,225	1,225	1,225	0
Nov 9, 11	11	7	4	25,272	20,370	4,902	4,902	4,902	0
Nov 10, 11	14	13	1	28,948	27,723	1,225	1,225	1,225	0
Nov 11, 11	26	25	1	43,654	42,428	1,225	1,225	1,225	0
Nov 12, 11	23	23	0	39,978	39,978	0	0	0	0
Nov 13, 11	14	10	4	28,948	24,047	4,902	4,902	4,902	0
Nov 14, 11	13	4	9	27,723	16,694	11,029	11,029	11,029	0
Nov 15, 11	13	13	0	27,723	27,723	0	0	0	0
Nov 16, 11	18	13	5	33,850	27,723	6,127	6,127	6,127	0
Nov 17, 11	27	25	2	44,879	42,428	2,451	2,451	2,451	0
Nov 18, 11	26	27	-1	43,654	44,879	-1,225	1,225	0	1,225
Nov 19, 11	21	16	5	37,527	31,399	6,127	6,127	6,127	0
Nov 20, 11	17	27	-10	32,625	44,879	-12,255	12,255	0	12,255
Nov 21, 11	28	31	-3	46,105	49,781	-3,676	3,676	0	3,676
Nov 22, 11	23	27	-4	39,978	44,879	-4,902	4,902	0	4,902
Nov 23, 11	30	31	-1	48,556	49,781	-1,225	1,225	0	1,225
Nov 24, 11	27	30	-3	44,879	48,556	-3,676	3,676	0	3,676
Nov 25, 11	21	21	0	37,527	37,527	0	0	0	0
Nov 26, 11	20	19	1	36,301	35,076	1,225	1,225	1,225	0
Nov 27, 11	15	21	-6	30,174	37,527	-7,353	7,353	0	7,353
Nov 28, 11	19	11	8	35,076	25,272	9,804	9,804	9,804	0
Nov 29, 11	9	8	1	22,821	21,596	1,225	1,225	1,225	0
Nov 30, 11	20	20	0	36,301	36,301	0	0	0	0
Dec 1, 11	28	29	-1	53,404	55,087	-1,683	1,683	0	1,683
Dec 2, 11	28	26	2	53,404	50,039	3,365	3,365	3,365	0
Dec 3, 11	30	31	-1	56,770	58,452	-1,683	1,683	0	1,683
Dec 4, 11	20	22	-2	39,943	43,308	-3,365	3,365	0	3,365
Dec 5, 11	15	12	3	31,529	26,481	5,048	5,048	5,048	0
Dec 6, 11	21	9	12	41,625	21,433	20,192	20,192	20,192	0
Dec 7, 11	27	24	3	51,722	46,673	5,048	5,048	5,048	0
Dec 8, 11	33	30	3	61,818	56,770	5,048	5,048	5,048	0
Dec 9, 11	28	29	-1	53,404	55,087	-1,683	1,683	0	1,683
Dec 10, 11	35	35	0	65,183	65,183	0	0	0	0
Dec 11, 11	34	34	0	63,500	63,500	0	0	0	0
Dec 12, 11	31	32	-1	58,452	60,135	-1,683	1,683	0	1,683
Dec 13, 11	31	27	4	58,452	51,722	6,731	6,731	6,731	0
Dec 14, 11	29	28	1	55,087	53,404	1,683	1,683	1,683	0
Dec 15, 11	20	17	3	39,943	34,895	5,048	5,048	5,048	0
Dec 16, 11	31	26	5	58,452	50,039	8,413	8,413	8,413	0
Dec 17, 11	39	40	-1	71,914	73,597	-1,683	1,683	0	1,683
Dec 18, 11	41	47	-6	75,279	85,375	-10,096	10,096	0	10,096
Dec 19, 11	29	27	2	55,087	51,722	3,365	3,365	3,365	0
Dec 20, 11	37	36	1	68,549	66,866	1,683	1,683	1,683	0
Dec 21, 11	22	27	-5	43,308	51,722	-8,413	8,413	0	8,413
Dec 22, 11	25	22	3	48,356	43,308	5,048	5,048	5,048	0
Dec 23, 11	33	34	-1	61,818	63,500	-1,683	1,683	0	1,683
Dec 24, 11	42	45	-3	76,962	82,010	-5,048	5,048	0	5,048
Dec 25, 11	33	37	-4	61,818	68,549	-6,731	6,731	0	6,731
Dec 26, 11	35	36	-1	65,183	66,866	-1,683	1,683	0	1,683
Dec 27, 11	28	19	9	53,404	38,260	15,144	15,144	15,144	0
Dec 28, 11	39	36	3	71,914	66,866	5,048	5,048	5,048	0
Dec 29, 11	41	39	2	75,279	71,914	3,365	3,365	3,365	0
Dec 30, 11	31	34	-3	58,452	63,500	-5,048	5,048	0	5,048
Dec 31, 11	32	32	0	60,135	60,135	0	0	0	0
Jan 1, 12	27	21	6	51,722	41,625	10,096	10,096	10,096	0
Jan 2, 12	39	33	6	71,914	61,818	10,096	10,096	10,096	0
Jan 3, 12	56	52	4	100,520	93,789	6,731	6,731	6,731	0
Jan 4, 12	44	42	2	80,327	76,962	3,365	3,365	3,365	0
Jan 5, 12	39	37	2	71,914	68,549	3,365	3,365	3,365	0
Jan 6, 12	32	33	-1	60,135	61,818	-1,683	1,683	0	1,683
Jan 7, 12	31	24	7	58,452	46,673	11,779	11,779	11,779	0
Jan 8, 12	36	31	5	66,866	58,452	8,413	8,413	8,413	0
Jan 9, 12	36	33	3	66,866	61,818	5,048	5,048	5,048	0
Jan 10, 12	34	32	2	63,500	60,135	3,365	3,365	3,365	0
Jan 11, 12	35	32	3	65,183	60,135	5,048	5,048	5,048	0
Jan 12, 12	32	35	-3	60,135	65,183	-5,048	5,048	0	5,048

EnergyNorth Natural Gas Inc.

Calculation of Supplier Balancing Charge
2011-12
Estimated Daily Imbalances

Date	Forecasted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jan 13, 12	34	34	0	63,500	63,500	0	0	0	0
Jan 14, 12	53	51	2	95,472	92,106	3,365	3,365	3,365	0
Jan 15, 12	54	57	-3	97,154	102,202	-5,048	5,048	0	5,048
Jan 16, 12	37	37	0	68,549	68,549	0	0	0	0
Jan 17, 12	28	26	2	53,404	50,039	3,365	3,365	3,365	0
Jan 18, 12	45	44	1	82,010	80,327	1,683	1,683	1,683	0
Jan 19, 12	39	42	-3	71,914	76,962	-5,048	5,048	0	5,048
Jan 20, 12	45	45	0	82,010	82,010	0	0	0	0
Jan 21, 12	47	53	-6	85,375	95,472	-10,096	10,096	0	10,096
Jan 22, 12	37	40	-3	68,549	73,597	-5,048	5,048	0	5,048
Jan 23, 12	25	32	-7	48,356	60,135	-11,779	11,779	0	11,779
Jan 24, 12	30	24	6	56,770	46,673	10,096	10,096	10,096	0
Jan 25, 12	36	31	5	66,866	58,452	8,413	8,413	8,413	0
Jan 26, 12	32	30	2	60,135	56,770	3,365	3,365	3,365	0
Jan 27, 12	32	27	5	60,135	51,722	8,413	8,413	8,413	0
Jan 28, 12	31	27	4	58,452	51,722	6,731	6,731	6,731	0
Jan 29, 12	33	31	2	61,818	58,452	3,365	3,365	3,365	0
Jan 30, 12	40	36	4	73,597	66,866	6,731	6,731	6,731	0
Jan 31, 12	30	33	-3	56,770	61,818	-5,048	5,048	0	5,048
Feb 1, 12	26	23	3	50,039	44,991	5,048	5,048	5,048	0
Feb 2, 12	34	36	-2	63,500	66,866	-3,365	3,365	0	3,365
Feb 3, 12	36	34	2	66,866	63,500	3,365	3,365	3,365	0
Feb 4, 12	38	38	0	70,231	70,231	0	0	0	0
Feb 5, 12	36	36	0	66,866	66,866	0	0	0	0
Feb 6, 12	29	25	4	55,087	48,356	6,731	6,731	6,731	0
Feb 7, 12	36	36	0	66,866	66,866	0	0	0	0
Feb 8, 12	37	34	3	68,549	63,500	5,048	5,048	5,048	0
Feb 9, 12	33	33	0	61,818	61,818	0	0	0	0
Feb 10, 12	30	25	5	56,770	48,356	8,413	8,413	8,413	0
Feb 11, 12	41	39	2	75,279	71,914	3,365	3,365	3,365	0
Feb 12, 12	48	48	0	87,058	87,058	0	0	0	0
Feb 13, 12	39	35	4	71,914	65,183	6,731	6,731	6,731	0
Feb 14, 12	32	30	2	60,135	56,770	3,365	3,365	3,365	0
Feb 15, 12	27	31	-4	51,722	58,452	-6,731	6,731	0	6,731
Feb 16, 12	25	25	0	48,356	48,356	0	0	0	0
Feb 17, 12	28	26	2	53,404	50,039	3,365	3,365	3,365	0
Feb 18, 12	31	29	2	58,452	55,087	3,365	3,365	3,365	0
Feb 19, 12	36	33	3	66,866	61,818	5,048	5,048	5,048	0
Feb 20, 12	36	35	1	66,866	65,183	1,683	1,683	1,683	0
Feb 21, 12	29	29	0	55,087	55,087	0	0	0	0
Feb 22, 12	23	20	3	44,991	39,943	5,048	5,048	5,048	0
Feb 23, 12	25	26	-1	48,356	50,039	-1,683	1,683	0	1,683
Feb 24, 12	30	29	1	56,770	55,087	1,683	1,683	1,683	0
Feb 25, 12	35	34	1	65,183	63,500	1,683	1,683	1,683	0
Feb 26, 12	36	37	-1	66,866	68,549	-1,683	1,683	0	1,683
Feb 27, 12	28	25	3	53,404	48,356	5,048	5,048	5,048	0
Feb 28, 12	33	31	2	61,818	58,452	3,365	3,365	3,365	0
Feb 29, 12	30	34	-4	56,770	63,500	-6,731	6,731	0	6,731
Mar 1, 12	36	43	-7	62,573	73,054	-10,482	10,482	0	10,482
Mar 2, 12	31	36	-5	55,086	62,573	-7,487	7,487	0	7,487
Mar 3, 12	27	29	-2	49,096	52,091	-2,995	2,995	0	2,995
Mar 4, 12	35	33	2	61,075	58,080	2,995	2,995	2,995	0
Mar 5, 12	43	41	2	73,054	70,059	2,995	2,995	2,995	0
Mar 6, 12	37	35	2	64,070	61,075	2,995	2,995	2,995	0
Mar 7, 12	22	14	8	41,609	29,630	11,979	11,979	11,979	0
Mar 8, 12	16	11	5	32,625	25,138	7,487	7,487	7,487	0
Mar 9, 12	31	29	2	55,086	52,091	2,995	2,995	2,995	0
Mar 10, 12	33	32	1	58,080	56,583	1,497	1,497	1,497	0
Mar 11, 12	21	19	2	40,112	37,117	2,995	2,995	2,995	0
Mar 12, 12	15	7	8	31,127	19,148	11,979	11,979	11,979	0
Mar 13, 12	12	8	4	26,635	20,646	5,990	5,990	5,990	0
Mar 14, 12	20	25	-5	38,614	46,101	-7,487	7,487	0	7,487
Mar 15, 12	22	26	-4	41,609	47,599	-5,990	5,990	0	5,990
Mar 16, 12	19	24	-5	37,117	44,604	-7,487	7,487	0	7,487
Mar 17, 12	18	22	-4	35,620	41,609	-5,990	5,990	0	5,990
Mar 18, 12	7	5	2	19,148	16,154	2,995	2,995	2,995	0
Mar 19, 12	7	9	-2	19,148	22,143	-2,995	2,995	0	2,995
Mar 20, 12	6	0	6	17,651	8,667	8,984	8,984	8,984	0
Mar 21, 12	0	0	0	8,667	8,667	0	0	0	0
Mar 22, 12	0	0	0	8,667	8,667	0	0	0	0
Mar 23, 12	11	4	7	25,138	14,656	10,482	10,482	10,482	0
Mar 24, 12	14	17	-3	29,630	34,122	-4,492	4,492	0	4,492
Mar 25, 12	17	24	-7	34,122	44,604	-10,482	10,482	0	10,482
Mar 26, 12	27	33	-6	49,096	58,080	-8,984	8,984	0	8,984
Mar 27, 12	33	27	6	58,080	49,096	8,984	8,984	8,984	0
Mar 28, 12	22	22	0	41,609	41,609	0	0	0	0
Mar 29, 12	26	26	0	47,599	47,599	0	0	0	0
Mar 30, 12	27	24	3	49,096	44,604	4,492	4,492	4,492	0
Mar 31, 12	25	27	-2	46,101	49,096	-2,995	2,995	0	2,995
Apr	495	505	-10	922,785	936,802	-14,017	109,331	47,657	61,674
May	211	222	-11	477,671	486,721	-9,049	51,828	21,389	30,439
Jun	47	77	-30	315,837	321,740	-5,903	7,477	787	6,690
Jul	0	0	0	268,914	268,914	0	0	0	0
Aug	0	2	-2	282,306	283,281	-976	976	0	976
Sep	72	72	0	315,766	315,766	0	8,245	4,122	4,122
Oct	408	418	-10	681,695	694,613	-12,918	72,340	29,711	42,629
Nov	611	598	13	1,102,514	1,086,584	15,931	99,262	57,596	41,666
Dec	948	922	26	1,790,147	1,746,397	43,750	144,712	94,231	50,481
Jan	1,149	1,105	44	2,128,369	2,054,331	74,039	171,635	122,837	48,798
Feb	947	916	31	1,775,887	1,723,724	52,164	92,548	72,356	20,192
Mar	660	652	8	1,256,941	1,244,962	11,979	167,707	89,843	77,864
Total	5,548	5,489	59	11,318,834	11,163,834	155,000	926,061	540,530	385,530
Datacheck	0	0	0	0	0	0	0	0	0

ENERGYNORTH NATURAL GAS, INC.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

Line	Description		Amount	Unit	Source:
1	Peak Day		138,000	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	4,000		
10			53,718	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		56,167	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,296,040		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		$6,276,468		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$111.75		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$18.62**	**/Dekatherm**	Line 29 divided by 6 month

ENERGY NORTH NATURAL GAS, INC.

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	49.00%	38.00%
Storage	17.00%	21.00%
Peaking	34.00%	41.00%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2012:

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	ANE *	Supply at Waddington		4,000		$14.3482		10/31/2017	X
	Iroquois	RTS to Wright	470-01	4,047		$6.5971		11/01/2017	
	TGP	NET-NE	95346	4,000		$7.4396		11/30/2012	
	BP Canada Energy Co.**	Supply at Niagara		3,199		$0.0000		03/31/2012	X
	TGP	FT-A (Z5-Z6)	2302	3,122		$7.4396		10/31/2015	
	TGP	FT-A (Z0-Z6)	8587	7,035		$24.4547		10/31/2015	
	TGP	FT-A (Z1-Z6)	8587	14,561		$21.6916		10/31/2015	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4.8846		10/31/2015	
	TGP	FT-A (Z6-Z6)	72694	4,000		$12.1700		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523***	21,844	1,560,391	$1.5400	$0.0211	10/31/2015	
	TGP	FT-A (Z4-Z6)	632	15,265		$8.4896		10/31/2015	
	TGP	FT-A (Z4-Z6)	8587	3,811		$8.4896		10/31/2015	
	National Fuel	FSS-1 (Storage)	O02357***	6,098	670,800	$2.4826	$0.0381	03/31/2012	
	National Fuel	FST (Transport)	N02358	6,098		$3.7805		03/31/2012	
	TGP	FT-A (Z4-Z6)	11234	6,150		$8.4896		10/31/2012	
	Honeoye	SS-NY (Storage)	SS-NY***	1,957	245,280	$4.4683	$0.0000	04/01/2012	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$7.4396		10/31/2012	
	Dominion	GSS (Storage)	300076***	934	102,700	$1.8788	$0.0145	03/31/2012	
	TGP	FT-A (Z4-Z6)	11234	932		$8.4896		10/31/2012	
Peaking									
	Energy North	LNG/Propane****		30,167	-	$18.6200	$0.0000		X
	TGP	FT-A (Z6-Z6)	72694	26,000	-	$12.1700	$0.0000	10/31/2029	X

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

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

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

ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

			Volume	Rate	Monthly Cost	Months/Year	Annual Cost	
1	Granite Ridge - 30 days @ 15,000/dt		[redacted]					
2								
3								
4	Concord Lateral		[redacted]					
5	DOMAC *	FLS 160						
6								
7	Subtotal						**$4,296,040**	*
8								
9	**Total**						**$4,296,040**	
10								

* Contract currently being negotiated for an effective date of November 1, 2012.

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ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	38.0%	21.0%	41.0%	100.0%
G-51	Low Annual /Low Winter Use	49.0%	17.0%	34.0%	100.0%
G-42	Medium Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-52	High Annual / Low Winter Use	49.0%	17.0%	34.0%	100.0%
G-43	High Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-53	High Annual / Load Factor < 90%	49.0%	17.0%	34.0%	100.0%
G-54	High Annual / Load Factor < 90%	49.0%	17.0%	34.0%	100.0%

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	**Storage**	**Peaking**	**Total**
G-41	**LAHW**	Low Annual C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	49.0%	17.0%	34.0%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	49.0%	17.0%	34.0%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	38.0%	21.0%	41.0%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	49.0%	17.0%	34.0%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	49.0%	17.0%	34.0%	100.0%

HLF	High Load Factor	49%	17%	34%	100%
LLF	Low Load Factor	38%	21%	41%	100%
	Total	39%	20%	41%	100%

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD		72		
		Base load	Heat load	Total
HLF	R-1 RNSH	132	562	693
LLF	R-3 RSH	3,712	61,094	64,806
LLF	G-41 SL	841	22,831	23,672
HLF	G-51 SH	636	1,968	2,604
LLF	G-42 ML	1,721	32,624	34,345
HLF	G-52 MH	1,263	2,836	4,099
LLF	G-43 LL	401	3,762	4,163
HLF	G-53 LLL90	257	1,502	1,759
HLF	G-54 LLG90	98	1,761	1,859
	TOTAL	9,060	128,940	138,000

HLF	2,386	8,629	11,014
LLF	6,675	120,311	126,986
Total	9,060	128,940	138,000

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	132	194	326	122	245	693
R-3 RSH	3,712	21,160	24,872	13,321	26,613	64,806
G-41 SL	841	7,908	8,748	4,978	9,945	23,672
G-51 SH	636	682	1,318	429	857	2,604
G-42 ML	1,721	11,299	13,020	7,114	14,211	34,345
G-52 MH	1,263	982	2,245	618	1,235	4,099
G-43 LL	401	1,303	1,704	820	1,639	4,163
G-53 LLL90	257	520	777	328	654	1,759
G-54 LLG90	98	610	708	384	767	1,859
TOTAL	9,060	44,658	53,718	28,115	56,167	138,000

HLF	2,386	2,988	5,374	1,881	3,759	11,014
LLF	6,675	41,669	48,344	26,234	52,408	126,986
Total	9,060	44,658	53,718	28,115	56,167	138,000

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	47.1%	17.7%	35.3%	100.0%
R-3 RSH	38.4%	20.6%	41.1%	100.0%
G-41 SL	37.0%	21.0%	42.0%	100.0%
G-51 SH	50.6%	16.5%	32.9%	100.0%
G-42 ML	37.9%	20.7%	41.4%	100.0%
G-52 MH	54.8%	15.1%	30.1%	100.0%
G-43 LL	40.9%	19.7%	39.4%	100.0%
G-53 LLL90	44.2%	18.6%	37.2%	100.0%
G-54 LLG90	38.1%	20.7%	41.3%	100.0%
TOTAL	38.9%	20.4%	40.7%	100.0%

High Load Factor	49%	17%	34%	100%
Low Load Factor	38%	21%	41%	100%
Total	39%	20%	41%	100%

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Design DD 72

	Daily Baseload * 1000	March Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total
R-1 RNSH	132	8.032	578	710
R-3 RSH	3,712	873.932	62,923	66,635
G-41 SL	841	326.595	23,515	24,355
G-51 SH	636	28.148	2,027	2,663
G-42 ML	1,721	466.681	33,601	35,322
G-52 MH	1,263	40.568	2,921	4,184
G-43 LL	401	53.810	3,874	4,276
G-53 LLL90	257	21.492	1,547	1,804
G-54 LLG90	98	25.188	1,814	1,912
TOTAL	9,060	1,570.851	132,800	141,860

HLF	2,386	123	8,887	11,272
LLF	6,675	1,447	123,913	130,588
Total	9,060	1,571	132,800	141,860

Design Day from 2012-2013 Resource Plan	**138,000**
Design Day from Billing Calculation	141,860
Variance	(3,860)

	Baseload as % of Total Class Load	Heat Load as % of Total
R-1 RNSH	19%	0.435%
R-3 RSH	6%	47.382%
G-41 SL	3%	17.707%
G-51 SH	24%	1.526%
G-42 ML	5%	25.302%
G-52 MH	30%	2.199%
G-43 LL	9%	2.917%
G-53 LLL90	14%	1.165%
G-54 LLG90	5%	1.366%
TOTAL		100.000%

Allocate Design Day Sendout to Rate Classes

	Base Load	Heat Load	Total
R-1 RNSH	132	562	693
R-3 RSH	3,712	61,094	64,806
G-41 SL	841	22,831	23,672
G-51 SH	636	1,968	2,604
G-42 ML	1,721	32,624	34,345
G-52 MH	1,263	2,836	4,099
G-43 LL	401	3,762	4,163
G-53 LLL90	257	1,502	1,759
G-54 LLG90	98	1,761	1,859
TOTAL	9,060	128,940	138,000

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-11	Sep-11	Oct-11	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	7	9	11	11	10	8	7	5	4	4	4	5	85	4.082	0.132
LLF	R-3 RSH	362	553	870	871	800	481	316	177	123	107	114	145	4,919	115.079	3.712
LLF	G-41 SL	106	182	243	324	282	158	95	53	29	23	25	34	1,555	26.057	0.841
HLF	G-51 SH	28	36	33	45	42	32	29	23	21	18	19	22	347	19.718	0.636
LLF	G-42 ML	188	290	219	455	419	258	171	94	59	48	54	75	2,330	53.336	1.721
HLF	G-52 MH	51	61	32	74	71	57	51	45	40	39	39	42	603	39.144	1.263
LLF	G-43 LL	3	23	5	60	55	51	43	30	16	8	15	(5)	305	12.442	0.401
HLF	G-53 LLL90	9	8	(1)	23	25	24	15	15	14	2	11	(3)	142	7.965	0.257
HLF	G-54 LLL110	11	4	10	9	23	6	4	17	10	(4)	16	5	110	3.043	0.098
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	0	0.000	0.000
	TOTAL	767	1,165	1,421	1,872	1,727	1,076	731	459	317	245	298	319	10,397	280.866	9.060
	HLF	106	118	84	162	171	126	107	106	89	59	90	70	1,287	73.953	2.386
	LLF	660	1,048	1,337	1,710	1,556	949	625	353	228	186	208	249	9,109	206.913	6.675

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

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-11	Sep-11	Oct-11	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	4	4	4	4	4	4	4	4	4	4	4	4	48
LLF	R-3 RSH	111	115	115	104	115	111	115	111	123	107	111	115	1,355
LLF	G-41 SL	25	26	26	24	26	25	26	25	29	23	25	26	307
HLF	G-51 SH	19	20	20	18	20	19	20	19	21	18	19	20	232
LLF	G-42 ML	52	53	53	48	53	52	53	52	59	48	52	53	628
HLF	G-52 MH	38	39	32	35	39	38	39	38	40	39	38	39	461
LLF	G-43 LL	3	12	5	11	12	12	12	12	16	8	12	(5)	146
HLF	G-53 LLL90	8	8	(1)	7	8	8	8	8	14	2	8	(3)	94
HLF	G-54 LLL110	3	3	3	3	3	3	3	3	10	(4)	3	3	36
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	293	311	288	282	312	302	312	302	348	276	301	284	3,307
	HLF	72	74	57	67	74	72	74	72	89	59	71	63	871
	LLF	192	207	199	187	207	200	207	200	228	186	200	189	2,436

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EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Heating Volumes (= Actual Volumes - Baseload)

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-11	Sep-11	Oct-11	Total
HLF	R-1 RNSH	3	5	7	8	6	4	3	1	0	0	0	0	37
LLF	R-3 RSH	251	438	755	767	685	370	201	65	0	0	3	30	3,565
LLF	G-41 SL	81	156	217	300	256	133	69	28	0	0	0	8	1,248
HLF	G-51 SH	9	16	13	27	22	12	9	4	0	0	0	2	115
LLF	G-42 ML	137	236	166	407	366	207	118	42	0	0	3	21	1,702
HLF	G-52 MH	13	22	0	39	32	19	12	7	0	0	1	3	142
LLF	G-43 LL	0	11	0	49	42	39	30	18	0	0	3	0	158
HLF	G-53 LLL90	1	0	0	15	17	17	7	7	0	0	4	0	48
HLF	G-54 LLL110	8	1	6	6	20	3	1	14	0	0	13	2	75
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	473	854	1,133	1,590	1,415	774	420	157	(31)	(31)	(3)	35	7,090
	HLF	35	44	27	95	97	55	33	34	0	0	19	7	417
	LLF	469	841	1,137	1,523	1,349	749	418	153	0	0	8	59	6,673
	Actual BDD	500.0	752.0	1015.5	1012.5	784.0	542.5	293.5	116.0	39.0	1.0	36.5	244.5	5337.0

Heat Factors

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-11	Sep-11	Oct-11	Total
HLF	R-1 RNSH	0.0056	0.0060	0.0071	0.0074	0.0080	0.0068	0.0093	0.0125	0.0000	0.0000	0.0030	0.0019	
LLF	R-3 RSH	0.5020	0.5818	0.7434	0.7577	0.8739	0.6818	0.6852	0.5622	0.0000	0.0000	0.0733	0.1217	
LLF	G-41 SL	0.1618	0.2077	0.2132	0.2967	0.3266	0.2453	0.2334	0.2387	0.0000	0.0000	0.0010	0.0344	
HLF	G-51 SH	0.0174	0.0215	0.0130	0.0272	0.0281	0.0229	0.0323	0.0376	0.0000	0.0000	0.0000	0.0079	
LLF	G-42 ML	0.2737	0.3143	0.1632	0.4017	0.4667	0.3813	0.4020	0.3631	0.0000	0.0000	0.0741	0.0866	
HLF	G-52 MH	0.0266	0.0296	0.0000	0.0385	0.0406	0.0356	0.0417	0.0637	0.0000	0.0000	0.0404	0.0111	
LLF	G-43 LL	0.0000	0.0140	0.0000	0.0484	0.0538	0.0725	0.1033	0.1525	0.0000	0.0000	0.0735	0.0000	
HLF	G-53 LLL90	0.0030	0.0000	0.0000	0.0151	0.0215	0.0308	0.0247	0.0631	0.0000	0.0000	0.1037	0.0000	
HLF	G-54 LLL110	0.0168	0.0019	0.0064	0.0058	0.0252	0.0049	0.0032	0.1177	0.0000	0.0000	0.3664	0.0085	
HLF	G-63 LLG110	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
	TOTAL	0.9469	1.1357	1.1157	1.5709	1.8049	1.4266	1.4295	1.3525	-0.7949	-31.0000	-0.0865	0.1452	

EnergyNorth Natural Gas, Inc

Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	**500.0**	**752.0**	**1015.5**	**1012.5**	**784.0**	**542.5**	**293.5**	**116.0**	**39.0**	**1.0**	**36.5**	**244.5**	**5337.0**
Norm Billing DD	**566.1**	**884.1**	**1147.8**	**1143.1**	**976.2**	**709.1**	**380.6**	**148.5**	**28.9**	**8.4**	**61.7**	**268.3**	**6322.8**

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

		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-11	Sep-11	Oct-11	Total
HLF	R-1 RNSH	7	9	12	12	12	9	8	6	4	4	4	5	92
LLF	R-3 RSH	396	629	968	970	968	595	376	195	123	107	116	148	5,591
LLF	G-41 SL	117	210	271	363	345	199	115	61	29	23	25	35	1,792
HLF	G-51 SH	29	39	35	49	47	35	32	25	21	18	19	22	370
LLF	G-42 ML	207	331	241	507	509	322	206	106	59	48	56	77	2,668
HLF	G-52 MH	53	65	32	79	79	63	55	47	40	39	40	42	634
LLF	G-43 LL	3	25	5	67	65	63	52	35	16	8	17	(5)	351
HLF	G-53 LLL90	9	8	(1)	24	29	30	17	17	14	2	14	(3)	160
HLF	G-54 LLL110	12	5	10	9	28	6	4	20	10	(4)	26	5	133
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	829	1,315	1,568	2,077	2,074	1,313	856	503	325	16	296	323	11,496

HLF	111	126	87	174	194	143	116	115	89	59	103	71	1,389
LLF	722	1,195	1,485	1,907	1,887	1,179	749	396	228	186	214	255	10,402

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 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%				$0.3927	$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%				$0.4724	$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%				$0.6408	$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%				$0.5141	$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%	$0.0051	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%	$0.0219	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	30%	$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	30%	$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%	$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	16%	$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%	$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%	$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	13%	$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	12%	$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					$0.6919	$0.6719	$ 1,012.23	$ 993.59	$ 18.64	1.88%	$0.6936	$0.6736	$ 1,630.78	$ 1,602.24	$ 28.54	1.78%
16																	
17	Total									$ 549.79						$ 826.58	

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing
Short Term Debt Limitations

	For Purposes of Fuel Financing
Total Direct Gas Costs	$ 48,820,141
Total Indirect Gas Costs	3,420,439
Total Gas Costs	$ 52,240,580
% of Debt to Total Gas Costs	30%
Short Term Debt	$ 15,672,174

	For Purposes Other Than Fuel Financing
12/1/2012 Projected Net Plant	$ 229,685,196
% of Debt to Net Plant	20%
Short Term Debt	$ 45,937,039

ENERGY NORTH NATURAL GAS, INC.

Peak 2012 - 2013 Winter Cost of Gas Filing

EnergyNorth 2012-13 Company Allowance Calculation

	Jul-2011	Aug-2011	Sep-2011	Oct-2011	Nov-2011	Dec-2011	Jan-2012	Feb-2012	Mar-2012	Apr-2012	May-2012	Jun-2012	Total
Total Sendout- Therms	4,519,480	4,862,620	5,078,100	9,249,660	13,393,530	19,805,400	23,983,650	19,905,220	14,923,140	10,268,990	6,999,830	5,419,530	138,409,150
Total Throughput- Therms	5,225,388	4,475,390	4,900,963	5,494,651	10,195,273	14,469,371	21,154,186	21,484,340	19,742,635	13,028,434	9,558,538	6,530,049	136,259,218
Variance	(705,908)	387,230	177,137	3,755,009	3,198,257	5,336,029	2,829,464	(1,579,120)	(4,819,495)	(2,759,444)	(2,558,708)	(1,110,519)	2,149,932
Company Allowance													**1.6%**