

1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Summary**

Summary
Page 1

	Reference	PK 10-11 Nov - Apr (c)
(a)	(b)	
9 Anticipated Direct Cost of Gas		
Purchased Gas:		
Demand Costs:	Sch. 5A, col (j), In 43	\$ 8,314,931
Supply Costs	Sch. 6, col (i), In 44	39,083,750
Storage Gas:		
Demand, Capacity:	Sch. 5A, col (j), In 58	\$ 1,055,525
Commodity Costs:	Sch. 6, col (i), In 47	7,649,468
Produced Gas:	Sch. 6, col (i), In 53	\$ 1,255,498
Hedge Contract (Savings)/Loss	Sch. 7, col (i), In 34	\$ 5,704,479
Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), In 199	\$ 563,657
Total Unadjusted Cost of Gas		\$ 63,627,308
Adjustments		
Prior Period (Over)/Under Recovery)	Sch. 3, col (c) In 28	\$ 2,985,736
Interest 10/31/10 - 04/30/11	Sch. 3, col (q) In 193	101,158
Prior Period Adjustments	Sch. 4, In 26 col (b)	-
Refunds from Suppliers	Sch. 4, In 26 col (c)	-
Broker Revenues	Sch. 4, In 26 col (d)	(754,779)
Fuel Financing	Sch. 4, In 26 col (e)	130,835
Transportation CGA Revenues	Sch. 4, In 26 col (f)	(31,147)
Interruptible Sales Margin	Sch. 4, In 26 col (g)	-
Capacity Release and Off System Sales Margins	Sch. 4, In 26 col (h) + col (i)	(730,714)
Hedging Costs	Sch. 4, In 26 col (j)	-
FPO Premium - Collection		
Fixed Price Option Administrative Costs	Sch. 4, In 26 col (k)	40,691
Total Adjustments		\$ 1,741,780
Total Anticipated Direct Costs	Ins 23 + 40	\$ 65,369,088
Anticipated Indirect Cost of Gas		
Working Capital		
Total Anticipated Direct Cost of Gas	Ln 23	\$ 63,627,308
Lead Lag Days		10.18
Prime Rate		3.25%
Working Capital Percentage	per GTC 16(f)	0.091%
Working Capital	In 46 * In 49	57,674
Plus: Working Capital Reconciliation	Sch. 3, col (c), In 78	(481,137)
Total Working Capital Allowance	Ins 50 + 51	\$ (423,463)
Bad Debt		
Total Anticipated Direct Cost of Gas	In 46	\$ 63,627,308
Less Refunds	In 30	-
Plus Working Capital	In 53	(423,463)
Plus Prior Period (Over) Under Recovery	In 27	2,985,736
Subtotal		\$ 66,189,582
Bad Debt Percentage	per GTC 16(f)	2.40%
Bad Debt Allowance	In 60 * In 61	\$ 1,588,550
Prior Period Bad Debt Allowance	Sch. 3, col (c), In 162	(20,082)
Total Bad Debt Allowance	Ins 63 + 64	\$ 1,568,468
Production and Storage Capacity	per GTC16(f)	\$ 1,749,387
Miscellaneous Overhead	per GTC 16(f)	\$ 25,381
Sales Volume	Sch. 10B, In 23/1000	83,088
Divided by Total Sales	Sch. 10B, In 23/1000	104,919
Ratio		79.19%
Miscellaneous Overhead	Ins 70 * 73	\$ 20,100
Total Anticipated Indirect Cost of Gas	Ins 53 + 66 + 68 + 75	\$ 2,914,492
Total Cost of Gas	Ins 42 + 77	\$ 68,283,580
Projected Forecast Sales (Therms)	Sch. 3, col (q), In 52	83,071,582

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4 **Summary of Supply and Demand Forecast**
5

7 For Month of:		Peak Costs May 10 - Oct 10 (c)	Nov-10 (d)	Dec-10 (e)	Jan-11 (f)	Feb-11 (g)	Mar-11 (h)	Apr-11 (i)	May-11 (j)	Peak Period Nov - Apr (k)
8 (a) (b)										
9 I. Gas Volumes (Therms)										
10										
11 A. Firm Demand Volumes										
12 Firm Gas Sales	Sch. 10B, ln 23	-	3,782,386	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	3,474,534	83,071,582
13 Lost Gas (Unaccounted for)		-	249,857	370,008	415,832	357,166	309,553	173,832		1,876,249
14 Company Use		-	129,348	191,549	215,271	184,900	160,252	89,991		971,312
15 Unbilled Therms		-	7,280,123	5,620,265	(1,864,776)	(2,701,537)	(1,821,518)	(3,038,023)	(3,474,534)	0
16										
17 Total Firm Volumes	Sch. 6, ln 92	-	11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316		85,919,143
18										
19 B. Supply Volumes (Therms)										
20 <u>Pipeline Gas:</u>										
21 Dawn Supply	Sch. 6, ln 63	-	992,558	985,941	1,025,643	870,970	1,025,643	992,558		5,893,314
22 Niagara Supply	Sch. 6, ln 64	-	66,998	675,767	728,703	624,485	800,664	31,431		2,928,047
23 TGP Supply (Direct)	Sch. 6, ln 65	-	5,300,261	5,472,304	5,524,413	4,910,681	5,537,647	4,063,699		30,809,005
24 Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	5,590,584	5,590,584	5,049,640	-	-		16,230,807
25 Dracut Supply 2 - Swing	Sch. 6, ln 67	-	5,541,783	367,247	308,520	348,222	6,430,123	6,676,608		19,672,503
26 City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-	-		-
27 LNG Truck	Sch. 6, ln 69	-	23,160	23,987	535,154	196,030	47,974	-		826,305
28 Propane Truck	Sch. 6, ln 70	-	-	-	-	-	-	-		-
29 PNGTS	Sch. 6, ln 71	-	65,343	80,232	86,022	75,269	72,788	55,418		435,071
30 Granite Ridge	Sch. 6, ln 72	-	-	-	-	-	-	-		-
31 Subtotal Pipeline Volumes		-	11,990,103	13,196,061	13,799,040	12,075,297	13,914,838	11,819,713		76,795,052
32										
33 <u>Storage Gas:</u>										
34 TGP Storage	Sch. 6, ln 77	-	96,774	3,785,782	4,762,625	4,143,103	284,533	-		13,072,818
35										
36 <u>Produced Gas:</u>										
37 LNG Vapor	Sch. 6, ln 80	-	23,160	23,987	588,918	196,030	23,987	23,160		879,241
38 Propane	Sch. 6, ln 81	-	-	-	426,800	137,304	-	-		564,104
39 Subtotal Produced Gas		-	23,160	23,987	1,015,718	333,334	23,987	23,160		1,443,345
40										
41 <u>Less - Gas Refill:</u>										
42 LNG Truck	Sch. 6, ln 86	-	(23,160)	(23,987)	(535,154)	(196,030)	(47,974)	-		(826,305)
43 Propane	Sch. 6, ln 87	-	-	-	-	-	-	-		-
44 TGP Storage Refill	Sch. 6, ln 88	-	(645,163)	(38,048)	-	-	-	(3,882,557)		(4,565,768)
45 Subtotal Refills		-	(668,322)	(62,035)	(535,154)	(196,030)	(47,974)	(3,882,557)		(5,392,072)
46										
47 Total Firm Sendout Volumes		-	11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316		85,919,143
48										

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4 Summary of Supply and Demand Forecast

		Peak Costs								Peak Period
		May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Nov - Apr
7 For Month of:										
49 II. Gas Costs										
50										
51 A. Demand Costs										
52 Supply										
53	Niagra Supply	Sch.5A, In 12								
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, In 16								
60	Tenn Gas Pipeline 33371	Sch.5A, In 17								
61	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, In 18								
62	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, In 19								
63	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, In 20								
64	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, In 21								
65	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, In 22								
66	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, In 23								
67	Portland Natural Gas Trans Service	Sch.5A, In 24								
68	ANE (TransCanada via Union to Iroquois)	Sch.5A, In 25								
69	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, In 26								
70	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, In 27								
71	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, In 28								
72	National Fuel FST 2358	Sch.5A, In 29								
73	Subtotal Pipeline Demand		\$ 970,611	\$ 793,419	\$ 793,419	\$ 793,419	\$ 793,419	\$ 793,419	\$ 793,419	\$ 5,731,125
74	Less Capacity Credit		(193,845)	(137,157)	(137,157)	(137,157)	(137,157)	(137,157)	(137,157)	(1,016,786)
75	Net Pipeline Demand Costs		\$ 776,766	\$ 656,262	\$ 656,262	\$ 656,262	\$ 656,262	\$ 656,262	\$ 656,262	\$ 4,714,339
76										
77 Peaking Supply:										
78	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, In 34								
79	Granite Ridge Demand	Sch.5A, In 35								
80	DOMAC Demand FLS-160	Sch.5A, In 36								
81	Subtotal Peaking Demand		\$ 2,022,281	\$ 410,725	\$ 410,725	\$ 410,725	\$ 410,725	\$ 410,725	\$ 337,047	\$ 4,412,953
82	Less Capacity Credit		(403,879)	(71,001)	(71,001)	(71,001)	(71,001)	(71,001)	(58,265)	(817,150)
83	Net Peaking Supply Demand Costs		\$ 1,618,403	\$ 339,724	\$ 339,724	\$ 339,724	\$ 339,724	\$ 339,724	\$ 278,782	\$ 3,595,803
84										
85 Storage:										
86	Dominion - Demand	Sch.5A, In 46								
87	Dominion - Storage	Sch.5A, In 47								
88	Honeoye - Demand	Sch.5A, In 48								
89	National Fuel - Demand	Sch.5A, In 49								
90	National Fuel - Capacity	Sch.5A, In 50								
91	Tenn Gas Pipeline - Demand	Sch.5A, In 51								
92	Tenn Gas Pipeline - Capacity	Sch.5A, In 52								
93	Subtotal Storage Demand		\$ 648,589	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 1,297,178
94	Less Capacity Credit		(129,533)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)	(241,653)
95	Net Storage Demand Costs		\$ 519,057	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 1,055,525
96										
97	Total Demand Charges	Ins 54 + 73 + 81 + 93	\$ 3,641,481	\$ 1,313,202	\$ 1,313,234	\$ 1,313,234	\$ 1,313,138	\$ 1,313,234	\$ 1,239,524	\$ 11,447,046
98	Total Capacity Credit	Ins 55 + 74 + 82 + 94	(727,256)	(227,011)	(227,016)	(227,016)	(227,000)	(227,016)	(214,274)	(2,076,590)
99	Net Demand Charges		\$ 2,914,225	\$ 1,086,191	\$ 1,086,218	\$ 1,086,218	\$ 1,086,138	\$ 1,086,218	\$ 1,025,250	\$ 9,370,456

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4 **Summary of Supply and Demand Forecast**
5
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		Peak Costs								Peak Period
		May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Nov - Apr
7 For Month of:										
102	B. Commodity Costs									
103	<u>Pipeline:</u>									
104	Dawn Supply									
105	Niagara Supply									
106	TGP Supply (Direct)									
107	Dracut Supply 1 - Baseload									
108	Dracut Supply 2 - Swing									
109	City Gate Delivered Supply									
110	LNG Truck									
111	Propane Truck									
112	PNGTS									
113	Granite Ridge									
114	Subtotal Pipeline Commodity Costs	\$ -	\$ 5,602,107	\$ 6,701,736	\$ 7,654,721	\$ 6,663,481	\$ 6,960,911	\$ 5,712,047		\$ 39,295,003
115										
116	<u>Storage:</u>									
117	TGP Storage - Withdrawals	\$ -	\$ 56,636	\$ 2,215,221	\$ 2,786,813	\$ 2,424,305	\$ 166,492	\$ -		\$ 7,649,468
118										
119	<u>Produced Gas Costs:</u>									
120	LNG Vapor									
121	Propane									
122	Subtotal Produced Gas Costs	\$ -	\$ 12,010	\$ 12,177	\$ 912,545	\$ 296,084	\$ 11,540	\$ 11,142		\$ 1,255,498
123										
124	<u>Less Storage Refills:</u>									
125	LNG Truck									
126	Propane									
127	TGP Storage Refill									
128	Storage Refill (Trans.)									
129	Subtotal Storage Refill	\$ -	\$ (332,808)	\$ (31,481)	\$ (261,284)	\$ (95,386)	\$ (22,967)	\$ (1,997,728)		\$ (2,741,654)
130										
131	Total Supply Commodity Costs	\$ -	\$ 5,337,945	\$ 8,897,653	\$ 11,092,796	\$ 9,288,485	\$ 7,115,976	\$ 3,725,460		\$ 45,458,315
132										
133	C. Supply Volumetric Transportation Costs									
134	Dawn Supply									
135	Niagara Supply									
136	TGP Supply (Direct)									
137	Dracut Supply 1 - Baseload									
138	Dracut Supply 2 - Swing									
139	Subtotal Pipeline Volumetric Trans. Costs	\$ -	\$ 356,345	\$ 399,544	\$ 413,999	\$ 368,374	\$ 412,099	\$ 289,200		\$ 2,239,562
140										
141	TGP Storage - Withdrawals	\$ -	\$ 2,153	\$ 84,225	\$ 105,957	\$ 92,174	\$ 6,330	\$ -		\$ 290,839
142										
143	Total Supply Volumetric Trans. Costs	\$ -	\$ 358,499	\$ 483,769	\$ 519,956	\$ 460,549	\$ 418,429	\$ 289,200		\$ 2,530,401
144										
145	Total Commodity Gas & Trans. Costs	\$ -	\$ 5,696,443	\$ 9,381,422	\$ 11,612,752	\$ 9,749,033	\$ 7,534,405	\$ 4,014,660		\$ 47,988,716

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Summary of Supply and Demand Forecast

7 For Month of:		Peak Costs								Peak Period
		May 10 - Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Nov - Apr
48	D. Supply and Demand Costs by Source									
49										
50	<u>Purchased Gas Demand Costs</u>									
51	Pipeline Gas Demand Costs	Ins 54 + 73	\$ 970,611	\$ 794,379	\$ 794,411	\$ 794,411	\$ 794,315	\$ 794,411	\$ 794,379	\$ 5,736,915
52	Peaking Gas Demand Costs	In 81	2,022,281	410,725	410,725	410,725	410,725	410,725	337,047	4,412,953
53	Subtotal Purchased Gas Demand Costs		\$ 2,992,892	\$ 1,205,104	\$ 1,205,136	\$ 1,205,136	\$ 1,205,040	\$ 1,205,136	\$ 1,131,426	\$ 10,149,868
54	Less Capacity Credit	Ins 55 + 74 + 82	(597,723)	(208,324)	(208,330)	(208,330)	(208,313)	(208,330)	(195,588)	(1,834,937)
55	Net Purchased Gas Demand Costs		\$ 2,395,168	\$ 996,780	\$ 996,806	\$ 996,806	\$ 996,727	\$ 996,806	\$ 935,838	\$ 8,314,931
56										
57	<u>Storage Gas Demand Costs</u>									
58	Storage Demand	In 93	\$ 648,589	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 1,297,178
59	Less Capacity Credit	In 94	(129,533)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)	(18,687)	(241,653)
60	Net Storage Demand Costs		\$ 519,057	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 1,055,525
61										
62	Total Demand Costs	Ins 155 + 160	\$ 2,914,225	\$ 1,086,191	\$ 1,086,218	\$ 1,086,218	\$ 1,086,138	\$ 1,086,218	\$ 1,025,250	\$ 9,370,456
63										
64	<u>Purchased Gas Supply</u>									
65	Commodity Costs	In 114	\$ -	\$ 5,602,107	\$ 6,701,736	\$ 7,654,721	\$ 6,663,481	\$ 6,960,911	\$ 5,712,047	\$ 39,295,003
66	Less Storage Inj.(TGP Storage)	In 127								
67	Less Storage Transportation	In 128								
68	Less LNG Truck	In 125								
69	Less Propane Truck	In 126								
70	Plus Transportation Costs	In 139								
71	Subtotal Purchased Gas Supply		\$ -	\$ 5,625,644	\$ 7,069,800	\$ 7,807,436	\$ 6,936,470	\$ 7,350,043	\$ 4,003,518	\$ 38,792,911
72										
73	<u>Storage Commodity Costs</u>									
74	Commodity Costs	In 117	\$ -	\$ 56,636	\$ 2,215,221	\$ 2,786,813	\$ 2,424,305	\$ 166,492	\$ -	\$ 7,649,468
75	Transportation Costs	In 141	-	2,153	84,225	105,957	92,174	6,330	-	290,839
76	Subtotal Storage Commodity Costs		\$ -	\$ 58,789	\$ 2,299,446	\$ 2,892,770	\$ 2,516,479	\$ 172,823	\$ -	\$ 7,940,307
77										
78	<u>Produced Gas Commodity Costs</u>	In 122	\$ -	\$ 12,010	\$ 12,177	\$ 912,545	\$ 296,084	\$ 11,540	\$ 11,142	\$ 1,255,498
79										
80	SubTotal Commodity Costs	Ins 171 + 176 + 178	\$ -	\$ 5,696,443	\$ 9,381,422	\$ 11,612,752	\$ 9,749,033	\$ 7,534,405	\$ 4,014,660	\$ 47,988,716
81										
82	Hedge Contract (Savings)/Loss	Sch 7, In 34	\$ -	\$ 499,143	\$ 1,220,185	\$ 1,444,724	\$ 1,366,799	\$ 847,092	\$ 326,536	\$ 5,704,479
83										
84	Total Commodity Costs	Ins 180 + 182	\$ -	\$ 6,195,586	\$ 10,601,607	\$ 13,057,476	\$ 11,115,833	\$ 8,381,497	\$ 4,341,196	\$ 53,693,195
85										
86	Total Demand Costs	In 99	\$ 2,914,225	\$ 1,086,191	\$ 1,086,218	\$ 1,086,218	\$ 1,086,138	\$ 1,086,218	\$ 1,025,250	\$ 9,370,456
87	Total Supply Costs	In 184	-	6,195,586	10,601,607	13,057,476	11,115,833	8,381,497	4,341,196	53,693,195
88										
89	Total Direct Gas Costs	Ins 186 + 187	\$ 2,914,225	\$ 7,281,777	\$ 11,687,824	\$ 14,143,693	\$ 12,201,971	\$ 9,467,715	\$ 5,366,446	\$ 63,063,651

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

2 **d/b/a National Grid NH**

3 **Peak 2010 - 2011 Winter Cost of Gas Filing**

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

				Contract	Unit Dth	Peak Period
	Supplier	Contract	Contract Type	Unit	(MDQ/ACQ)	Cost per
	(a)	(b)	(c)	(d)	(e)	Unit Dth
						(f)
9	Demand Costs					
10	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
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	Niagara Supply		Supply	MDQ	3,199	
14	Tenn Gas Pipeline - Demand	FS-MA	Storage	MDQ	21,844	
15	Granite Ridge Demand		Peaking	MDQ	15,000	
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	
17	National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
18	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
19	National Fuel	FST 2358	Transportation	MDQ	6,098	
20	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
21	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
22	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
23	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
24	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
25	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
26	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
27	Tenn Gas Pipeline	33371	Transportation	MDQ	4,000	
28	ANE (TransCanada via Union to Iroquois)	Union Dawn to Iroquois	Transportation	MDQ	4,047	
29	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	72694 Z6-Z6	Transportation	MDQ	30,000	
30	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
31	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
32	DOMAC Liquid Demand Charge	FLS-160	Peaking	MDQ	2,843	
33	Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
34						
35	Supply Costs - Commodity					
36	City Gate Delivered Supply		Pipeline	Dkt	-	
37	LNG Truck		Pipeline	Dkt	82,630	
38	TGP Supply (Direct)		Pipeline	Dkt	3,080,901	
39	LNG Vapor (Storage)		Produced	Dkt	87,924	
40	Dawn Supply		Pipeline	Dkt	589,331	
41	Niagara Supply		Pipeline	Dkt	292,805	
42	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,623,081	
43	Dracut Supply 2 - Swing		Pipeline	Dkt	1,967,250	
44	Granite Ridge		Pipeline	Dkt	-	
45	TGP Storage		Storage	Dkt	1,307,282	
46	PNGTS		Pipeline	Dkt	43,507	
47	Propane		Produced	Dkt	56,410	
48	Propane Truck		Pipeline	Dkt	-	
49						
50	Supply Costs - Volumetric Transportation					
51	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,623,081	
52	Dracut Supply 2 - Swing		Pipeline	Dkt	1,967,250	
53	Niagara Supply		Pipeline	Dkt	292,805	
54	TGP Storage - Withdrawals		Pipeline	Dkt	1,307,282	
55	Dawn Supply		Pipeline	Dkt	589,331	
56	TGP Supply (Direct)		Pipeline	Dkt	3,080,901	

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1 ENERGY NORTH NATURAL GAS, INC.

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

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

		Prior Period Balance															
		Apr-10															
		Ending Bal															
		Plus May Billings															
(a)	Days in Month	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	Peak Period
10 Account 175.20 COG (Over)/Under Balance - Interest Calculation																	
12	Beginning Balance	Account 175.20 1/	\$ 3,011,016	\$ 2,985,736	\$ 3,505,456	\$ 4,034,687	\$ 4,141,048	\$ 4,641,129	\$ 5,202,219	\$ 5,758,777	\$ 4,343,921	\$ 3,031,815	\$ 2,520,380	\$ 2,159,401	\$ 779,836	\$ 111,657	\$ 3,011,016
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		590,989	600,930	552,767	547,882	593,537	591,777	7,281,777	11,687,824	14,143,693	12,201,971	9,467,715	5,366,446	-	63,627,308
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	294,915	294,915	294,915	294,915	294,915	294,915	-	1,769,487
15	Projected Revenues w/o Int.	In 52 * 59		-	-	-	-	-	-	(3,052,386)	(8,684,912)	(16,362,651)	(14,941,746)	(12,530,368)	(8,662,754)	(2,803,949)	(67,038,767)
16	Projected Unbilled Revenue									(5,875,059)	(10,410,613)	(8,905,739)	(6,725,598)	(5,255,633)	(2,803,949)	-	(39,976,591)
17	Reverse Prior Month Unbilled									-	5,875,059	10,410,613	8,905,739	6,725,598	5,255,633	2,803,949	39,976,591
18	Prior Period Adjustment-Unbilled																-
19	Add Net Adjustments	Schedule 4		(80,251)	(81,757)	(457,673)	(59,905)	(45,576)	(50,327)	(77,578)	(84,544)	(99,918)	(102,086)	(85,843)	(119,658)	-	(1,345,114)
20	Gas Cost Billed	Account 175.20 2/	(25,280)														(25,280)
21	Monthly (Over)/Under Recovery		\$ 2,985,736	\$ 3,496,475	\$ 4,024,629	\$ 4,129,780	\$ 4,629,025	\$ 5,189,090	\$ 5,743,670	\$ 4,330,446	\$ 3,021,650	\$ 2,512,728	\$ 2,153,574	\$ 775,785	\$ 110,468	\$ 111,657	\$ (1,349)
22	Average Monthly Balance	(In 12 + 21)/2		\$ 3,253,745	\$ 3,765,043	\$ 4,082,233	\$ 4,385,037	\$ 4,915,109	\$ 5,472,945	\$ 5,044,611	\$ 3,682,786	\$ 2,772,272	\$ 2,336,977	\$ 1,467,593	\$ 445,152	\$ 111,657	
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	In 22 * In 24 / 365 * Days of Month		\$ 8,981	\$ 10,057	\$ 11,268	\$ 12,104	\$ 13,129	\$ 15,107	\$ 13,475	\$ 10,165	\$ 7,652	\$ 5,826	\$ 4,051	\$ 1,189	\$ -	\$ 113,006
27																	
28	(Over)/Under Balance	In 21 + In 26	\$ 2,985,736	\$ 3,505,456	\$ 4,034,687	\$ 4,141,048	\$ 4,641,129	\$ 5,202,219	\$ 5,758,777	\$ 4,343,921	\$ 3,031,815	\$ 2,520,380	\$ 2,159,401	\$ 779,836	\$ 111,657	\$ 111,657	111,657
29																	
30																	
31	Calculation of COG with Interest																
32																	
33	Beginning Balance	In 12	\$ 3,011,016	\$ 2,985,736	\$ 3,505,456	\$ 4,034,687	\$ 4,141,048	\$ 4,641,129	\$ 5,202,219	\$ 5,758,777	\$ 4,329,539	\$ 2,996,081	\$ 2,460,590	\$ 2,078,885	\$ 681,262	\$ 2,803	\$ 3,011,016
34	Fcst Direct Gas Costs(Inc U/G Hedges)	In 13		590,989	600,930	552,767	547,882	593,537	591,777	7,281,777	11,687,824	14,143,693	12,201,971	9,467,715	5,366,446	-	63,627,308
35	Prod Storage & Misc Overhead	In 14		-	-	-	-	-	-	294,915	294,915	294,915	294,915	294,915	294,915	-	1,769,487
36	Projected Revenues with int.	In 52 * In 61		-	-	-	-	-	-	(3,057,303)	(8,698,903)	(16,389,010)	(14,965,816)	(12,550,553)	(8,676,709)	(2,808,466)	(67,146,760)
37	Projected Unbilled Revenue									(5,884,523)	(10,427,383)	(8,920,085)	(6,736,433)	(5,264,100)	(2,808,466)	-	(40,040,989)
38	Reverse Prior Month Unbilled									5,884,523	10,427,383	8,920,085	6,736,433	5,264,100	2,808,466	-	40,040,989
39	Add Net Adjustments	In 19		(80,251)	(81,757)	(457,673)	(59,905)	(45,576)	(50,327)	(77,578)	(84,544)	(99,918)	(102,086)	(85,843)	(119,658)	-	(1,345,114)
40	Gas Cost Billed	In 20	(25,280)														(25,280)
41	Add Interest	In 26		-	-	-	-	-	-	13,475	10,165	7,652	5,826	4,051	1,189	-	42,360
42	(Over)/Under Balance		\$ 2,985,736	\$ 3,496,475	\$ 4,024,629	\$ 4,129,780	\$ 4,629,025	\$ 5,189,090	\$ 5,743,670	\$ 4,329,540	\$ 2,996,136	\$ 2,460,711	\$ 2,079,053	\$ 681,503	\$ 3,078	\$ 2,803	\$ (66,983)
43																	
44	Average Monthly Balance			\$ 3,253,745	\$ 3,765,043	\$ 4,082,233	\$ 4,385,037	\$ 4,915,109	\$ 5,472,945	\$ 5,044,158	\$ 3,662,837	\$ 2,728,396	\$ 2,269,822	\$ 1,380,194	\$ 342,170	\$ 2,803	
45																	
46	Interest Applied	In 24 * In 44 / 365 * Days of Month		8,981	10,057	11,268	12,104	13,129	15,107	13,474	10,110	7,531	5,659	3,810	914	-	112,145
47																	
48	(Over)/Under Balance	-In 41 +In 42 + In 46	\$ 2,985,736	\$ 3,505,456	\$ 4,034,687	\$ 4,141,048	\$ 4,641,129	\$ 5,202,219	\$ 5,758,777	\$ 4,329,539	\$ 2,996,081	\$ 2,460,590	\$ 2,078,885	\$ 681,262	\$ 2,803	\$ 2,803	2,803
49																	
50																	
51	Forecast Sendout Therms	Sch 1								11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316		85,919,143
52	Less Forecast Billing Therm Sales	Sch. 10B, In 23 Nov - May								3,782,386	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	3,474,534	83,071,582
53	Less Forecast Unaccounted For	Sch 1								249,857	370,008	415,832	357,166	309,553	173,832		1,876,249
54	Less Forecast Company Use	Sch 1								129,348	191,549	215,271	184,900	160,252	89,991		971,312
55	Unbilled Volumes									7,280,123	5,620,265	-1,864,776	-2,701,537	-1,821,518	-3,038,023	-3,474,534	0
56	Gross Unbilled									7,280,123	12,900,387	11,035,612	8,334,075	6,512,557	3,474,534	0	
57																	
58																	
59	COB w/o Interest	Sch. 3, pg. 4, In 211 col. (c)								\$0.8070	\$0.8070	\$0.8070	\$0.8070	\$0.8070	\$0.8070	\$0.8070	
60																	
61	COG With Interest	Sch. 3, pg. 4, In 211 col. (d)								\$0.8083	\$0.8083	\$0.8083	\$0.8083	\$0.8083	\$0.8083	\$0.8083	
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																	
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70																	

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1 ENERGY NORTH NATURAL GAS, INC.

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

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

			Prior Period Balance															
		Days in Month	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Peak Period	
(a)	(b)		Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total	
			Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
Account 142.20 Working Capital (Over)/Under Balance - Interest Calculation																		
Beginning Balance	Account 142.20 1/		\$ (481,136)	\$ (481,137)	\$ (481,918)	\$ (482,650)	\$ (483,470)	\$ (484,297)	\$ (485,042)	\$ (485,833)	\$ (424,018)	\$ (330,904)	\$ (224,943)	\$ (133,669)	\$ (55,439)	\$ (11,402)	\$ (481,136)	
Days Lag				10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18		
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%	3.25%		
Forecast Working Capital	In 34 * 0.091%			536	545	501	497	538	536	6,600	10,594	12,820	11,060	8,582	4,864	-	57,674	
Projected Revenues w/o Int.	In 121 * In 125			-	-	-	-	-	-	19,290	54,886	103,407	94,427	79,188	54,746	17,720	423,665	
Projected Unbilled Revenue										37,129	65,792	56,282	42,504	33,214	17,720		252,640	
Reverse Prior Month Unbilled											(37,129)	(65,792)	(56,282)	(42,504)	(33,214)	(17,720)	(252,640)	
Add Net Adjustments				-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Working Capital Billed	Account 142.20 2/	(1)															(1)	
Monthly (Over)/Under Recovery			\$ (481,137)	\$ (480,591)	\$ (481,363)	\$ (482,139)	\$ (482,963)	\$ (483,749)	\$ (484,495)	\$ (422,804)	\$ (329,864)	\$ (224,177)	\$ (133,223)	\$ (55,179)	\$ (11,313)	\$ (11,402)	\$ 202	
Average Monthly Balance	(In 78 + In 92)/2		\$	\$ (480,864)	\$ (481,641)	\$ (482,394)	\$ (483,217)	\$ (484,023)	\$ (484,769)	\$ (454,319)	\$ (376,941)	\$ (277,540)	\$ (179,083)	\$ (94,424)	\$ (33,376)	\$ (11,402)		
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%	3.25%		
Interest Applied	In 94 * In 96 / 365 * Days of Month		\$	\$ (1,327)	\$ (1,287)	\$ (1,332)	\$ (1,334)	\$ (1,293)	\$ (1,338)	\$ (1,214)	\$ (1,040)	\$ (766)	\$ (446)	\$ (261)	\$ (89)	\$ -	\$ (11,727)	
(Over)/Under Balance	In 92 + In 98		\$	\$ (481,137)	\$ (481,918)	\$ (482,650)	\$ (483,470)	\$ (484,297)	\$ (485,042)	\$ (485,833)	\$ (424,018)	\$ (330,904)	\$ (224,943)	\$ (133,669)	\$ (55,439)	\$ (11,402)	\$ (11,524)	
Calculation of Working Capital with Interest																		
Beginning Balance	In 78		\$ (481,136)	\$ (481,137)	\$ (481,929)	\$ (482,671)	\$ (483,501)	\$ (484,338)	\$ (485,093)	\$ (485,895)	\$ (422,984)	\$ (328,239)	\$ (220,438)	\$ (127,580)	\$ (47,972)	\$ (3,154)	\$ (481,136)	
Forecast Working Capital	In 82			536	545	501	497	538	536	6,600	10,594	12,820	11,060	8,582	4,864	-	57,674	
Projected Rev. with interest	In 121 * In 127			-	-	-	-	-	-	19,668	55,962	105,435	96,279	80,741	55,819	18,068	431,972	
Projected Unbilled Revenue										37,857	67,082	57,385	43,337	33,865	18,068		257,594	
Reverse Prior Month Unbilled											(37,857)	(67,082)	(57,385)	(43,337)	(33,865)	(18,068)	(257,594)	
Add Net Adjustments	In 88		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Working Capital Billed	In 90	(1)		-	-	-	-	-	-								(1)	
Add Interest	In 98			-	-	-	-	-	-	(1,214)	(1,040)	(766)	(446)	(261)	(89)	-	(3,816)	
Monthly (Over)/Under Recovery			\$ (481,137)	\$ (480,601)	\$ (481,384)	\$ (482,169)	\$ (483,004)	\$ (483,800)	\$ (484,557)	\$ (422,983)	\$ (328,242)	\$ (220,446)	\$ (127,593)	\$ (47,990)	\$ (3,175)	\$ (3,154)	\$ 4,693	
Average Monthly Balance			\$	\$ (480,869)	\$ (481,656)	\$ (482,420)	\$ (483,253)	\$ (484,069)	\$ (484,825)	\$ (454,439)	\$ (375,613)	\$ (274,342)	\$ (174,015)	\$ (87,785)	\$ (25,573)	\$ (3,154)		
Interest Applied	In 96 * In 115 / 365 * Days of Month			(1,327)	(1,287)	(1,332)	(1,334)	(1,293)	(1,338)	(1,214)	(1,037)	(757)	(434)	(242)	(68)	-	(11,663)	
(Over)/Under Balance	-In 112 +In 113 + In 117		\$	\$ (481,137)	\$ (481,929)	\$ (482,671)	\$ (483,501)	\$ (484,338)	\$ (485,093)	\$ (485,895)	\$ (422,984)	\$ (328,239)	\$ (220,438)	\$ (127,580)	\$ (47,972)	\$ (3,154)	\$ (3,154)	
Forecast Therm Sales	In 52									3,782,386	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	3,474,534	83,071,582	
Unbilled Therm	In 55									7,280,123	5,620,265	(1,864,776)	(2,701,537)	(1,821,518)	(3,038,023)			
Gross Unbilled										7,280,123	12,900,387	11,035,612	8,334,075	6,512,557	3,474,534			
Working Cap. Rate w/out Int.	Sch. 3, pg. 4, In 228 col. (c)									-\$0.0051	-\$0.0051	-\$0.0051	-\$0.0051	-\$0.0051	-\$0.0051	-\$0.0051		
Working Capital Rate w/ Int.	Sch. 3, pg. 4, In 228 col. (d)									-\$0.0052	-\$0.0052	-\$0.0052	-\$0.0052	-\$0.0052	-\$0.0052	-\$0.0052		
Beginning Balance for Acct 142.20. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.																		
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.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

			Prior Period Balance																													
		Days in Month	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	DemandPeriod															
	(a)	(b)	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total															
			Plus May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)															
Account 175.52 Bad Debt (Over)/Under Balance - Interest Calculation																																
Forecast Direct Gas Costs	In 34		\$	590,989	\$	600,930	\$	552,767	\$	547,882	\$	593,537	\$	591,777	\$	7,281,777	\$	11,687,824	\$	14,143,693	\$	12,201,971	\$	9,467,715	\$	5,366,446	\$	-	63,627,308			
Forecast Working Capital	In 106			536		545		501		497		538		536		(474,536)		10,594		12,820		11,060		8,582		4,864			(423,463)			
Prior Period Balance	In 42									497,623		497,623		497,623		497,623		497,623		497,623		497,623		497,623		497,623			2,985,736			
Total Forecast Direct Gas Costs & Working Capital				591,525		601,475		553,268		548,378		594,075		592,314		7,304,864		12,196,041		14,654,136		12,710,654		9,973,919		5,868,933		-	63,203,845			
Beginning Balance	Account 175.52 1/		\$	(19,924)	\$	(20,082)	\$	(5,921)	\$	8,518	\$	21,838	\$	35,078	\$	49,448	\$	63,820	\$	30,181	\$	13,321	\$	17,092	\$	23,320	\$	3,696	(909)	\$	(19,924)	
Forecast Bad Debt	In 140 * 0.024			14,197		14,435		13,278		13,161		14,258		14,216		175,317		292,705		351,699		305,056		239,374		140,854				1,588,550		
Projected Revenues w/o int	In 183 * In 187			-		-		-		-		-		-		(71,487)		(203,401)		(383,215)		(349,937)		(293,462)		(202,882)		(65,669)		(1,570,053)		
Projected Unbilled Revenue																(137,594)		(243,817)		(208,573)		(157,514)		(123,087)		(65,669)			(936,255)			
Reverse Prior Month Unbilled																137,594		243,817		208,573		157,514		123,087		65,669			936,255			
Bad Debt Billed	Account 175.52 2/		(158)			-		-		-		-		-		-		-		-		-		-		-		-	(158)			
Add Net Adjustments			-		-		-		-		-		-		-		-		-		-		-		-		-		-	-		
Monthly (Over)/Under Recovery			\$	(20,082)	\$	(5,885)	\$	8,514	\$	21,796	\$	34,999	\$	49,335	\$	63,664	\$	30,055	\$	13,261	\$	17,050	\$	23,270	\$	3,659	\$	(913)	(909)	\$	(1,585)	
Average Monthly Balance	(In 142 + In 154)/2		\$	(12,905)	\$	1,297	\$	15,157	\$	28,419	\$	42,207	\$	56,556	\$	46,937	\$	21,721	\$	15,186	\$	20,181	\$	13,490	\$	1,392	\$	(909)				
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%						
Interest Applied	In 156 * In 158 / 365 * Days of Month		\$	(36)	\$	3	\$	42	\$	78	\$	113	\$	156	\$	125	\$	60	\$	42	\$	50	\$	37	\$	4			\$	675		
(Over)/Under Balance	In 154 + In 160		\$	(20,082)	\$	(5,921)	\$	8,518	\$	21,838	\$	35,078	\$	49,448	\$	63,820	\$	30,181	\$	13,321	\$	17,092	\$	23,320	\$	3,696	\$	(909)	(909)	\$	(909)	
Calculation of Bad Debt with Interest																																
Beginning Balance	In 142		\$	(19,924)	\$	(20,082)	\$	(5,921)	\$	8,518	\$	21,838	\$	35,078	\$	49,448	\$	63,820	\$	30,181	\$	13,321	\$	17,092	\$	23,321	\$	3,696	(909)	\$	(19,924)	
Forecast Bad Debt	In 144			14,197		14,435		13,278		13,161		14,258		14,216		175,317		292,705		351,699		305,056		239,374		140,854		-		1,588,550		
Projected Revenues with int.	In 183 * In 189			-		-		-		-		-		-		(71,487)		(203,401)		(383,215)		(349,937)		(293,462)		(202,882)		(65,669)		(1,570,053)		
Projected Unbilled Revenue																(137,594)		(243,817)		(208,573)		(157,514)		(123,087)		(65,669)			(936,255)			
Reverse Prior Month Unbilled																137,594		243,817		208,573		157,514		123,087		65,669			936,255			
Bad Debt Billed	In 150		(158)			-		-		-		-		-		-		-		-		-		-		-		-	(158)			
Add Interest	In 160			-		-		-		-		-		-		125		60		42		50		37		4		-	319			
Add Net Adjustments	In 152		-			-		-		-		-		-		-		-		-		-		-		-		-	0			
Monthly (Over)/Under Recovery			\$	(20,082)	\$	(5,885)	\$	8,514	\$	21,796	\$	34,999	\$	49,335	\$	63,664	\$	30,181	\$	13,321	\$	17,092	\$	23,321	\$	3,696	\$	(909)	(909)	\$	(1,266)	
Average Monthly Balance			\$	(12,905)	\$	1,297	\$	15,157	\$	28,419	\$	42,207	\$	56,556	\$	47,000	\$	21,751	\$	15,207	\$	20,206	\$	13,509	\$	1,394	\$	(909)				
Interest Applied	In 158 * In 177 / 365 * Days of Month			(36)		3		42		78		113		156		126		60		42		50		37		4		-	\$	676		
(Over)/Under Balance	-In 173 +In 175 + In 179		\$	(20,082)	\$	(5,921)	\$	8,518	\$	21,838	\$	35,078	\$	49,448	\$	63,820	\$	30,181	\$	13,321	\$	17,092	\$	23,321	\$	3,696	\$	(909)	(909)	\$	(909)	
Forecast Term Sales	In 52															3,782,386		10,761,973		20,275,900		18,515,175		15,527,097		10,734,516		3,474,534		83,071,582		
Unbilled Therm	In 55															7,280,123		5,620,265		(1,864,776)		(2,701,537)		(1,821,518)		(3,038,023)						
Gross Unbilled																7,280,123		12,900,387		11,035,612		8,334,075		6,512,557		3,474,534						
COG Rate Without Interest	Sch. 3, pg. 4, In 245 col. (c)															\$0.0189		\$0.0189		\$0.0189		\$0.0189		\$0.0189		\$0.0189		\$0.0189				
COG With Interest	Sch. 3, pg. 4, In 245 col. (d)															\$0.0189		\$0.0189		\$0.0189		\$0.0189		\$0.0189		\$0.0189		\$0.0189				
Beginning Balance for Acct 175.52. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.																																
Bad Debt Billed Acct 175.52. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.																																
Total Interest	Ins 46 + 117 + 179		\$	-	\$	7,618	\$	8,774	\$	9,978	\$	10,848	\$	11,949	\$	13,925	\$	12,386	\$	9,134	\$	6,816	\$	5,275	\$	3,605	\$	849	\$	-	\$	101,158

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

194					
195	Calculation of COG		<u>COG Rate</u>	<u>COG Rate With</u>	
196	(a)	(b)	<u>Without Interest</u>	<u>Interest</u>	
197	(Over)Under Recovery Balance	In 12, col. (q)	(c)	(d)	
198			\$ 3,011,016	\$ 3,011,016	
199	Unadjusted Forecast of Gas Costs	In 13, col. (q)	63,627,308	63,627,308	
200					
201	Production & Storage and Misc Overhead	In 14, col. (q)	1,769,487	1,769,487	
202					
203	Adjustments	In 19, col. (q)	(1,370,394)	(1,370,394)	
204					
205	Interest Nov -Apr	In 46, col. (q)	-	\$ 112,145	
206					
207	Total Gas To Be Recovered		\$ 67,037,417	\$ 67,149,562	
208					
209	Forecast Gas Sales (Nov - Apr)	In 52, col. (q)	83,071,582	83,071,582	
210					
211	Preliminary COG Rate	In 207 / In. 209	<u>\$0.8070</u>	<u>\$0.8083</u>	
212					
213					
214	Calculation of Working Capital Rate		<u>Working Capital</u>	<u>Working</u>	
215	(a)	(b)	<u>Rate without</u>	<u>Capital Rate</u>	
216	(Over)Under Recovery Balance	In 78, col. (q)	<u>interest</u>	<u>with interest</u>	
217			(c)	(d)	
218	Unadjusted Working Capital Forecast	In 82, col. (q)	\$ (481,136)	\$ (481,136)	
219					
220	Adjustments without interest	In 88, col. (q)	57,674	57,674	
221			(1)	(1)	
222	Interest Nov -Apr	In 117, col. (q)	-	\$ (11,663)	
223					
224	Total Gas To Be Recovered		\$ (423,463)	\$ (435,126)	
225					
226	Forecast Gas Sales (Nov - Apr)	In 52, col. (q)	83,071,582	83,071,582	
227					
228	Preliminary Working Capital COG Rate		<u>-\$0.0051</u>	<u>-\$0.0052</u>	
229					
230					
231	Calculation of Bad Debt Rate		<u>Bad Debt Rate</u>	<u>Bad Debt Rate</u>	
232	(a)	(b)	<u>without interest</u>	<u>with interest</u>	
233	(Over)Under Recovery Balance	In 142, col. (q)	(c)		
234			\$ (19,924)	\$ (19,924)	
235	Unadjusted Bad Debt Forecast	In 144, col. (q)	1,588,550	1,588,550	
236					
237	Adjustments without interest	In 152, col. (q)	(158)	(158)	
238					
239	Interest Nov -Apr	In 179, col. (q)	-	\$ 676	
240					
241	Total Gas To Be Recovered		\$ 1,568,468	\$ 1,569,144	
242					
243	Forecast Gas Sales (Nov - Apr)	In 52, col. (q)	83,071,582	83,071,582	
244					
245	Preliminary Bad Debt COG Rate		<u>\$0.0189</u>	<u>\$0.0189</u>	

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Adjustments to Gas Costs**
5

[illegible]

1/ Estimate is based on prior years actual. Exception: Transportation Revenue is calculated on Schedule 17 and Inventory Finance Charges for Nov 10 - Apr 11 calculated on Schedule 16.
2/ Credit from JP Morgan of contract is from 11/01/2020 through 04/30/2011, included in Column I.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Demand Costs**

				Peak Costs							Peak
				May 10 -Oct 10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May -Apr
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	Total
11	Supply										
12	Niagra Supply		Sch 5B, In 9 * Sch 5C In 9 x days								
13	Subtotal Supply Demand & Reservation Charges										
14											
15	Pipeline										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, In 12 * Sch 5C In 12 x days								
17	Tenn Gas Pipeline 33371		Sch 5B, In 13 * Sch 5C In 16 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, In 14 * Sch 5C In 18 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, In 15 * Sch 5C In 20 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, In 16 * Sch 5C In 22 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, In 17 * Sch 5C In 24 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, In 18 * Sch 5C In 26 x days								
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, In 19 * Sch 5C In 28 x days								
24	Portland Natural Gas Trans Service		Sch 5B, In 20 * Sch 5C In 30 x days								
25	ANE (TransCanada via Union to Iroquois)		Sch 5B, In 21 * Sch 5C In 46 x days								
26	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, In 22 * Sch 5C In 32 x days								
27	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, In 23 * Sch 5C In 34 x days								
28	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, In 24 * Sch 5C In 36 x days								
29	National Fuel FST 2358	peak	Sch 5B, In 25 * Sch 5C In 38 x days								
30											
31	Subtotal Pipeline Demand Charges			\$ 970,611	\$ 793,419	\$ 793,419	\$ 793,419	\$ 793,419	\$ 793,419	\$ 793,419	\$ 5,731,125
32											
33	Peaking Supply										
34	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, In 28 * Sch 5C In 28 x days								
35	Granite Ridge Demand	peak	Sch 5B, In 29 * Sch 5C In 49 x days								
36	DOMAC Demand FLS-160	peak	Per Contract								
37	Subtotal Peaking Demand Chargs			\$ 2,022,281	\$ 410,725	\$ 410,725	\$ 410,725	\$ 410,725	\$ 410,725	\$ 337,047	\$ 4,412,953
38											
39	Subtotal Supply, Pipeline & Peaking		In 13 + In 31 + In 37	\$ 2,992,892	\$ 1,205,104	\$ 1,205,136	\$ 1,205,136	\$ 1,205,040	\$ 1,205,136	\$ 1,131,426	\$ 10,149,868
40											
41	Less Transportation Capacity Credit			\$ (597,723)	\$ (208,324)	\$ (208,330)	\$ (208,330)	\$ (208,313)	\$ (208,330)	\$ (195,588)	\$ (1,834,937)
42											
43	Total Supply, Pipeline & Peaking Demand			\$ 2,395,168	\$ 996,780	\$ 996,806	\$ 996,806	\$ 996,727	\$ 996,806	\$ 935,838	\$ 8,314,931
44											
45	Storage										
46	Dominion - Demand	peak	Sch 5B, In 33 * Sch 5C In 53 x days	\$ 10,520	\$ 1,753	\$ 1,753	\$ 1,753	\$ 1,753	\$ 1,753	\$ 1,753	\$ 21,041
47	Dominion - Storage	peak	Sch 5B, In 34 * Sch 5C In 54 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
48	Honeoye - Demand	peak	Sch 5B, In 35 * Sch 5C In 57 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, In 37 * Sch 5C In 59 x days	78,869	13,145	13,145	13,145	13,145	13,145	13,145	157,738
50	National Fuel - Capacity	peak	Sch 5B, In 38 * Sch 5C In 60 x days	173,871	28,979	28,979	28,979	28,979	28,979	28,979	347,743
51	Tenn Gas Pipeline - Demand	peak	Sch 5B, In 39 * Sch 5C In 63 x days	150,724	25,121	25,121	25,121	25,121	25,121	25,121	301,447
52	Tenn Gas Pipeline - Capacity	peak	Sch 5B, In 40 * Sch 5C In 64 x days	173,203	28,867	28,867	28,867	28,867	28,867	28,867	346,407
53											
54	Subtotal Storage Demand Costs			\$ 648,589	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 108,098	\$ 1,297,178
55											
56	Less Transportation Capacity Credit			\$ (129,533)	\$ (18,687)	\$ (18,687)	\$ (18,687)	\$ (18,687)	\$ (18,687)	\$ (18,687)	\$ (241,653)
57											
58	Total Storage Demand Costs		In 54 + In 56	\$ 519,057	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 89,411	\$ 1,055,525
59											
60	Total Demand Charges		In 39 + In 54	\$ 3,641,481	\$ 1,313,202	\$ 1,313,234	\$ 1,313,234	\$ 1,313,138	\$ 1,313,234	\$ 1,239,524	\$ 11,447,046
61											
62	Total Transportation Capacity Credit			\$ (727,256)	\$ (227,011)	\$ (227,016)	\$ (227,016)	\$ (227,000)	\$ (227,016)	\$ (214,274)	\$ (2,076,590)
63											
64	Total Demand Charges less Cap. Cr.		In 60 + In 62	\$ 2,914,225	\$ 1,086,191	\$ 1,086,218	\$ 1,086,218	\$ 1,086,138	\$ 1,086,218	\$ 1,025,250	\$ 9,370,456

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Demand Volumes

	(a)	Peak (b)	Reference (c)	Nov-10 (d)	Dec-10 (e)	Jan-11 (f)	Feb-11 (g)	Mar-11 (h)	Apr-11 (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		33371	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 Dawn 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		15,000	15,000	15,000	15,000	15,000	15,000
	DOMAC Liquid Demand Charge	peak	FLS-160	2,843	2,843	2,843	2,843	2,843	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	GSS-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

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Demand Rates

					Nov-10 30	Dec-10 31	Jan-11 31	Feb-11 28	Mar-11 31	Apr-11 30	Nov - Apr 181
					Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
6	Tariff Rates										
7											
8	Supply										
9	Niagra Supply										
10											
11	Pipeline										
12	Iroquois Gas Trans Service	RTS 470-01	\$6 5971	31st Rev Sheet No. 4	\$0.2199	\$0 2128	\$0.2128	\$0.2356	\$0.2128	\$0 2199	\$0.2190
13											
14	Tenn Gas Pipeline	33371 Segment 3	\$5 0700	1st Rev Sheet No. 30	\$0.1690	\$0.1635	\$0.1635	\$0.1811	\$0.1635	\$0.1690	\$0.1683
15	Tenn Gas Pipeline	33371 Segment 4	\$5 5400	1st Rev Sheet No. 30	\$0.1847	\$0.1787	\$0.1787	\$0.1979	\$0.1787	\$0.1847	\$0.1839
16			\$10 6100		\$0.3537	\$0 3423	\$0.3423	\$0.3789	\$0.3423	\$0 3537	\$0.3522
17											
18	Tenn Gas Pipeline	2302 Z5-Z6	\$4 9300	1st Rev Sheet No. 23	\$0.1643	\$0.1590	\$0.1590	\$0.1761	\$0.1590	\$0.1643	\$0.1636
19											
20	Tenn Gas Pipeline	8587 Z0-Z6	\$16 5900	1st Rev Sheet No. 23	\$0.5530	\$0 5352	\$0.5352	\$0.5925	\$0.5352	\$0 5530	\$0.5507
21											
22	Tenn Gas Pipeline	8587 Z1-Z6	\$15.1500	1st Rev Sheet No. 23	\$0.5050	\$0.4887	\$0.4887	\$0.5411	\$0.4887	\$0 5050	\$0.5029
23											
24	Tenn Gas Pipeline	8587 Z4-Z6	\$5 8900	1st Rev Sheet No. 23	\$0.1963	\$0.1900	\$0.1900	\$0.2104	\$0.1900	\$0.1963	\$0.1955
25											
26	TGP Dracut	42076 FTA Z6-Z6	\$3.1600	1st Rev Sheet No. 23	\$0.1053	\$0.1019	\$0.1019	\$0.1129	\$0.1019	\$0.1053	\$0.1049
27											
28	TGP Concord Lateral	72694 Z6-Z6	\$12.1700	per contract	\$0.4057	\$0 3926	\$0.3926	\$0.4346	\$0.3926	\$0.4057	\$0.4040
29											
30	Portland Natural Gas	FT-1999-001	\$27.4017	7th Rev Sheet No. 100	\$0.9134	\$0 8839	\$0.8839	\$0.9786	\$0.8839	\$0 9134	\$0.9095
31											
32	Tenn Gas Pipeline	632 Z4-Z6 (stg)	\$5 8900	1st Rev Sheet No. 23	\$0.1963	\$0.1900	\$0.1900	\$0.2104	\$0.1900	\$0.1963	\$0.1955
33											
34	Tenn Gas Pipeline	11234 Z4-Z6(stg)	\$5 8900	1st Rev Sheet No. 23	\$0.1963	\$0.1900	\$0.1900	\$0.2104	\$0.1900	\$0.1963	\$0.1955
35											
36	Tenn Gas Pipeline	11234 Z5-Z6(stg)	\$4 9300	1st Rev Sheet No. 23	\$0.1643	\$0.1590	\$0.1590	\$0.1761	\$0.1590	\$0.1643	\$0.1636
37											
38	National Fuel	FST 2358	\$3 3612	136th Rev Sheet No. 9	\$0.1120	\$0.1084	\$0.1084	\$0.1200	\$0.1084	\$0.1120	\$0.1116
39											
40											
41	ANE	TransCanada PipeLines Limited	\$10 8267	Union Dawn to Iroquois							
42		Delivery Pressure Demand Charge	0.7857	Union Dawn to Iroquois							
43		Sub Total Demand Charges	11 6124								
44		Conversion rate GJ to MMBTU	1 0551								
45		Conversion rate to US\$	0 9697	08/17/2010							
46		Demand Rate/US\$	\$11 8810		\$0.3960	\$0 3833	\$0.3833	\$0.4243	\$0.3833	\$0 3960	\$0.3944
47											
48	Peaking										
49	Granite Ridge Demand			per contract							
50	DOMAC Demand FLS-160			per contract							
51											
52	Storage										
53	Dominion - Demand	GSS 300076	\$1 8773	36th Rev Sheet No. 35	\$0.0626	\$0 0606	\$0.0606	\$0.0670	\$0.0606	\$0 0626	\$0.0623
54	Dominion - Capacity	GSS 300076	\$0 0145	36th Rev Sheet No. 35	\$0.0005	\$0 0005	\$0.0005	\$0.0005	\$0.0005	\$0 0005	\$0.0005
55			\$1 8918		\$0.0631	\$0 0610	\$0.0610	\$0.0676	\$0.0610	\$0 0631	\$0.0627
56											
57	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
58											
59	National Fuel - Demand	FSS-1 2357	\$2.1556	17th Rev. Sheet No. 10	\$0.0719	\$0 0695	\$0.0695	\$0.0770	\$0.0695	\$0 0719	\$0.0715
60	National Fuel - Capacity	FSS-1 2357	\$0 0432	17th Rev. Sheet No. 10	\$0.0014	\$0 0014	\$0.0014	\$0.0015	\$0.0014	\$0 0014	\$0.0014
61			\$2.1988		\$0.0733	\$0 0709	\$0.0709	\$0.0785	\$0.0709	\$0 0733	\$0.0729
62											
63	Tenn Gas Pipeline	FS-MA	\$1.1500	1st Rev Sheet No. 61	\$0.0383	\$0 0371	\$0.0371	\$0.0411	\$0.0371	\$0 0383	\$0.0381
64	Tenn Gas Pipeline - Space	FS-MA	\$0 0185	1st Rev Sheet No. 61	\$0.0006	\$0 0006	\$0.0006	\$0.0007	\$0.0006	\$0 0006	\$0.0006
65			\$1.1685		\$0.0390	\$0 0377	\$0.0377	\$0.0417	\$0.0377	\$0 0390	\$0.0388

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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 SHEET 35A)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	FERC ACA	Current Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
===	Storage Demand	\$1.7984	\$0.0664	\$0.0219	(\$0.0118)	\$0.0024	-	\$1.8773
	Storage Capacity	\$0.0145	-	-	-	-	-	\$0.0145
	Injection Charge	\$0.0154	-	\$0.0066	\$0.0001	(\$0.0011)	-	\$0.0210
	Withdrawal Charge	\$0.0154	-	-	\$0.0001	(\$0.0011)	\$0.0019	\$0.0163
	GSS-TE Surcharge [3]	-	\$0.0046	-	\$0.0005	-	-	\$0.0051
	Demand Charge Adjustment	\$21.5808	\$0.7968	\$0.2628	(\$0.1416)	\$0.0288	-	\$22.5276
	From Customers Balance	\$0.6163	\$0.0147	\$0.0048	(\$0.0025)	(\$0.0006)	\$0.0019	\$0.6346
GSS-E [2], [4]								
===	Storage Demand	\$2.2113	\$0.0664	\$0.0219	(\$0.0118)	\$0.0024	-	\$2.2902
	Storage Capacity	\$0.0369	-	-	-	-	-	\$0.0369
	Injection Charge	\$0.0154	-	\$0.0066	\$0.0001	(\$0.0011)	-	\$0.0210
	Withdrawal Charge	\$0.0154	-	-	\$0.0001	(\$0.0011)	\$0.0019	\$0.0163
	Authorized Overruns	\$1.0657	\$0.0147	\$0.0048	(\$0.0025)	(\$0.0006)	\$0.0019	\$1.0840
ISS [2]								
=====	ISS Capacity	\$0.0736	\$0.0022	\$0.0007	(\$0.0004)	\$0.0001	-	\$0.0762
	Injection Charge	\$0.0154	-	\$0.0066	\$0.0001	(\$0.0011)	-	\$0.0210
	Withdrawal Charge	\$0.0154	-	-	\$0.0001	(\$0.0011)	\$0.0019	\$0.0163
	Authorized Overrun/from Cust. Bal	\$0.6163	\$0.0147	\$0.0048	(\$0.0025)	(\$0.0006)	\$0.0019	\$0.6346
	Excess Injection Charge	\$0.2245	-	\$0.0066	\$0.0001	(\$0.0011)	-	\$0.2301

- [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 \$0.6183.
 Daily Capacity Release Rate for GSS-E per Dt is \$1.0677.
 [5] 858 over/under from previous TCRA period.
 [6] Electric over/under from previous EPCA period.

Issued by: Machelie Grim, Director - Regulation & FERC Compliance
 Issued on: September 30, 2009 Effective on: November 1, 2009

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

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

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

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

3. RATE

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

4. MINIMUM BILL

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

5. COMPRESSOR FUEL ALLOWANCE

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

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

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

		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

- 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.

(Footnotes continued on Sheet 4.01)

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Jan 26, 2009

Effective: Jan 27, 2009

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National Fuel Gas Supply Corporation
 FERC Gas Tariff
 Fourth Revised Volume No. 1

136th Revised Sheet No. 9
 Superseding
 135th Revised Sheet No. 9

Rate Sch. (1)	Rate Component (2)		Base Rate (3)	FERC ACA (4)	Current Rate 1/ (5)
IT	Commodity	(Max)	\$0.1168	0.0019	\$0.1187
		(Min)	0.0000	0.0019	\$0.0019
	Overrun	(Max)	0.1168	0.0019	\$0.1187
		(Min)	0.0000	0.0019	\$0.0019
IG	Commodity	(Max)	0.3400	-	\$0.3400
		(Min)	0.0069	-	\$0.0069
FG	Reservation	(Max)	0.0000	-	\$0.0000
		(Min)	0.0000	-	\$0.0000
	Commodity	(Max)	0.0069	0.0019	\$0.0088
		(Min)	0.0069	0.0019	\$0.0088
	Overrun	(Max)	0.3400	0.0019	\$0.3419
		(Min)	0.3400	0.0019	\$0.3419
X-58 Conversion Surcharge	Reservation	(Max)	0.1221	-	\$0.1221
		(Min)	-	-	-
	Commodity	(Max)	-	-	-
		(Min)	-	-	-
W-1	Commodity	(Max)	0.0252	0.0019	\$0.0271
		(Min)	0.0000	-	\$0.0000
	Overrun	(Max)	0.0252	0.0019	\$0.0271
		(Min)	0.0000	-	\$0.0000
	Fly-By Rate	(Max)	0.0100	-	\$0.0100
		(Min)	0.0000	-	\$0.0000
IR-1	First Day	(Max)	0.0532	0.0019	\$0.0551
		(Min)	0.0000	-	\$0.0000
	Each Subsequent Day	(Max)	0.0028	-	\$0.0028
		(Min)	0.0000	-	\$0.0000
IR-2	First Day	(Max)	0.0028	-	\$0.0028
		(Min)	0.0000	-	\$0.0000
	Each Subsequent Day	(Max)	0.0028	-	\$0.0028
		(Min)	0.0000	-	\$0.0000
FST	Reservation	(Max)	3.3612	-	\$3.3612
		(Min)	0.0000	-	\$0.0000
	Commodity	(Max)	0.0063	0.0019	\$0.0082
		(Min)	0.0063	0.0019	\$0.0082
	Overrun	(Max)	0.1168	0.0019	\$0.1187
		(Min)	0.0063	0.0019	\$0.0082
	Maximum Volumetric Rate		0.1168	0.0019	\$0.1187
1/ 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%. 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 Transportation LAUF retention of 0.25%.					

Issued by: J.R. Pustulka, Senior Vice President
 Issued on: May 28, 2010

Effective on: June 1, 2010

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National Fuel Gas Supply Corporation
 FERC Gas Tariff
 Fourth Revised Volume No. 1

Seventeenth Revised Sheet No. 10
 Superseding
 Sixteenth Revised Sheet No. 10

Rate Sch. (1)	Rate Component (2)		Base Rate (3)	FERC ACA (4)	Current Rate 2/ (5)
ESS	Demand	(Max)	\$2.1345	-	\$2.1345
		(Min)	0.0000	-	\$0.0000
	Capacity	(Max)	0.0432	-	\$0.0432
		(Min)	0.0000	-	\$0.0000
	Injection/ Withdrawal	(Max)	0.0139	0.0019	\$0.0158
		(Min)	0.0000	-	\$0.0000
	Max. Volumetric Dem. Rate 3/		0.0702	0.0019	\$0.0721
	Max. Volumetric Cap. Rate 4/		0.0014	-	\$0.0014
	Storage Balance Transfer	(Max) 5/	3.8600	-	\$3.8600
		(Min) 5/	0.0000	-	\$0.0000
ISS	Injection	(Max)	1.0635	0.0019	\$1.0654
		(Min)	0.0000	-	\$0.0000
	Storage Balance Transfer	(Max) 5/	3.8600	-	\$3.8600
		(Min) 5/	0.0000	-	\$0.0000
IAS	Usage	(Max) 1/	0.0028	-	\$0.0028
		(Min) 1/	0.0000	-	\$0.0000
	Advance/Return	(Max)	0.0139	0.0019	\$0.0158
		(Min)	0.0000	-	\$0.0000
FSS	Demand	(Max)	2.1556	-	\$2.1556
		(Min)	0.0000	-	\$0.0000
	Capacity	(Max)	0.0432	-	\$0.0432
		(Min)	0.0000	-	\$0.0000
	Injection/ Withdrawal	(Max)	0.0139	0.0019	\$0.0158
		(Min)	0.0000	-	\$0.0000
	Max. Volumetric Dem. Rate 3/		0.0709	0.0019	\$0.0728
	Max. Volumetric Cap. Rate 4/		0.0014	-	\$0.0014
	Storage Balance Transfer	(Max) 5/	3.8600	-	\$3.8600
		(Min) 5/	0.0000	-	\$0.0000
P-1	First Day	(Max)	0.0575	0.0019	\$0.0594
		(Min)	0.0000	-	\$0.0000
	Each Subsequent Day	(Max)	0.0071	-	\$0.0071
		(Min)	0.0000	-	\$0.0000
P-2	First Day	(Max)	0.0071	-	\$0.0071
		(Min)	0.0000	-	\$0.0000
	Each Subsequent Day	(Max)	0.0071	-	\$0.0071
		(Min)	0.0000	-	\$0.0000

1/

Unit Dth Rates per day.

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%.

3/

Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.

4/

Assessed per dekatherm per day on storage balance.

5/

Rate per nomination.

Issued by: J.R. Pustulka, Senior Vice President
 Issued on: August 31, 2009

Effective on: October 1, 2009

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Portland Natural Gas Transmission System
FERC Gas Tariff
Second Revised Volume No. 1

Seventh Revised Sheet No. 100 : Effective
Supercedes Sixth Revised Sheet No. 100

Statement of Transportation Rates

(Rates per DTH)

Rate Rate Base ACA Unit Current

Schedule Component Rate Charge 1/ Rate

FT Recourse Reservation Rate

-- Maximum \$27.4017 ----- \$27.4017

-- Minimum \$00.0000 ----- \$00.0000

Seasonal Recourse Reservation Rate

-- Maximum \$52.0632 ----- \$52.0632

-- Minimum \$00.0000 ----- \$00.0000

Recourse Usage Rate

-- Maximum \$00.0000 \$00.0019 \$00.0019

-- Minimum \$00.0000 \$00.0019 \$00.0019

FT-FLEX Recourse Reservation Rate

--Maximum \$18.3920 ----- \$18.3920

--Minimum \$00.0000 ----- \$00.0000

Recourse Usage Rate

--Maximum \$00.2962 \$00.0019 \$00.2981

--Minimum \$00.0000 \$00.0019 \$00.0019

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 17 of
the General Terms and Conditions at such time that initial and successive
ACA assessments are made.

Issued by:

Issue date: 10/01/09

Effective date: 10/01/09

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RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
 RATE SCHEDULE FT-G

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$3.10		\$6.45	\$9.06	\$10.53	\$12.22	\$14.09	\$16.59
L		\$2.71						
1	\$6.66		\$4.92	\$7.62	\$9.08	\$10.77	\$12.64	\$15.15
2	\$9.06		\$7.62	\$2.86	\$4.32	\$6.32	\$7.89	\$10.39
3	\$10.53		\$9.08	\$4.32	\$2.05	\$6.08	\$7.64	\$10.14
4	\$12.53		\$11.08	\$6.32	\$6.08	\$2.71	\$3.38	\$5.89
5	\$14.09		\$12.64	\$7.89	\$7.64	\$3.38	\$2.85	\$4.93
6	\$16.59		\$15.15	\$10.39	\$10.14	\$5.89	\$4.93	\$3.16

Surcharges

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
PCB Adjustment: 1/	0	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	L	\$0.00						
	1	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	2	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	3	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	4	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	5	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
	6	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$3.10		\$6.45	\$9.06	\$10.53	\$12.22	\$14.09	\$16.59
L		\$2.71						
1	\$6.66		\$4.92	\$7.62	\$9.08	\$10.77	\$12.64	\$15.15
2	\$9.06		\$7.62	\$2.86	\$4.32	\$6.32	\$7.89	\$10.39
3	\$10.53		\$9.08	\$4.32	\$2.05	\$6.08	\$7.64	\$10.14
4	\$12.53		\$11.08	\$6.32	\$6.08	\$2.71	\$3.38	\$5.89
5	\$14.09		\$12.64	\$7.89	\$7.64	\$3.38	\$2.85	\$4.93
6	\$16.59		\$15.15	\$10.39	\$10.14	\$5.89	\$4.93	\$3.16

Minimum Base Reservation Rates The minimum FT-G Reservation Rate is \$0.00 per Dth

Notes:

- 1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
- 2/ Maximum rates are inclusive of base rates and above surcharges.

RATES PER DEKATHERM

RATE SCHEDULE NET 284

=====						
Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS			Rate After Current Adjustments	Fuel and Use
		(ACA)	(PCB)	5/		

Demand Rate 1/, 5/						

Segment U	\$9.65		\$0.00		\$9.65	
Segment 1	\$1.33		\$0.00		\$1.33	
Segment 2	\$8.08		\$0.00		\$8.08	
Segment 3	\$5.07		\$0.00		\$5.07	
Segment 4	\$5.54		\$0.00		\$5.54	
Commodity Rate 2/, 3/						

Segments U, 1, 2, 3 & 4		\$0.0019			\$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/						

Segment U	\$0.3173				\$0.3173	5.52%
Segment 1	\$0.0437				\$0.0437	0.69%
Segment 2	\$0.2656				\$0.2656	0.59%
Segment 3	\$0.1667				\$0.1667	0.73%
Segment 4	\$0.1821				\$0.1821	0.36%

Notes:

- 1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.
- 2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.
- 3/ The Incremental Pressure Charge associated with service to MassPower shall be \$0.0334 plus an additional Incremental Fuel Charge of 5.83%.
- 4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.
- 5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
- 6/ The applicable fuel retention percentages are listed on Sheet No. 105.
- 7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
 RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	(PCB) 2/	Current Adjustment	Retention Percent 1/
=====					
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA					
=====					
Deliverability Rate	\$2.02		\$0.00	\$2.02	
Space Rate	\$0.0248		\$0.0000	\$0.0248	
Injection Rate	\$0.0053			\$0.0053	1.49%
Withdrawal Rate	\$0.0053			\$0.0053	
Overrun Rate	\$0.2427			\$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA					
=====					
Deliverability Rate	\$1.15		\$0.00	\$1.15	
Space Rate	\$0.0185		\$0.0000	\$0.0185	
Injection Rate	\$0.0102			\$0.0102	1.49%
Withdrawal Rate	\$0.0102			\$0.0102	
Overrun Rate	\$0.1380			\$0.1380	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

RATES PER DEKATHERM

INTERRUPTIBLE STORAGE SERVICE
 RATE SCHEDULE IS

=====						
Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA) (PCB) 2/		Current Adjustment	Retention Percent 1/	

INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA						
=====						
Space Rate	\$0.0848		\$0.0000	\$0.0848		
Injection Rate	\$0.0102			\$0.0102	1.49%	
Withdrawal Rate	\$0.0102			\$0.0102		
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA						
=====						
Space Rate	\$0.0993		\$0.0000	\$0.0993		
Injection Rate	\$0.0053			\$0.0053	1.49%	
Withdrawal Rate	\$0.0053			\$0.0053		

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll (\$/GJ/mo)	Commodity Toll (\$/GJ)
(a)		(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll (\$/GJ)
(a)		(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll (\$/GJ/mo)	Commodity Toll (\$/GJ)	Daily Equivalent *(1) (\$/GJ)
(a)		(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	0.78572	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	1.96558	0.03798	0.10260

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

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FT, STFT and Interruptible Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Line No.	Receipt Point	Delivery point	Demand Toll (\$/GJ/MO)	Commodity Toll (\$/GJ)	(1) (FT, STFT Minimum Tolls) (100% LF FT Tolls)	IT Bid Floor (110% FT Tolls)
					(\$/GJ)	(\$/GJ)
1	Union Dawn	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn	Iroquois	10.82669	0.01413	0.3700	0.4070
8	Union Dawn	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn	East Hereford	16.76744	0.02275	0.5741	0.6315
12	Union Dawn	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

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10-Year Currency Converter

Using rates for: 17 Aug 2010

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

Currency: U.S. dollar

Amount: 1.00

Convert: ☒ from \$Can ☐ to \$Can

Use the: ☒ Nominal rate [HELP](#)
☐ Cash rate (4%) [HELP](#)

Answer: 0.97 CONVERT

Exchange rate: 0.9697

Summary:

On 17 Aug 2010, 1.00 Canadian dollar(s) = 0.97 U.S. dollar(s), at an exchange rate of 0.9697 (using nominal rate.)

Effective 1 January 2009, the euro replaces the Slovak koruna.

SEE ALSO:
10-Year Currency Converter

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

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

6 For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak
7 (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
8								(i)
9 Supply and Commodity Costs								
10								
11 Pipeline Gas								
12 Dawn Supply	In 63 * In 102							
13 Niagara Supply	In 64 * In 107							
14 TGP Supply (Direct)	In 65 * In 123							
15 Dracut Supply 1 - Baseload	In 66 * In 112							
16 Dracut Supply 2 - Swing	In 67 * In 117							
17 City Gate Delivered Supply	In 68 * In 129							
18 LNG Truck	In 69 * In 131							
19 Propane Truck	In 70 * In 133							
20 PNGTS	In 71 * In 138							
21 Granite Ridge	In 72 * In 143							
22								
23 Subtotal Pipeline Gas Costs		\$ 5,602,107	\$ 6,701,736	\$ 7,654,721	\$ 6,663,481	\$ 6,960,911	\$ 5,712,047	\$ 39,295,003
24								
25 Volumetric Transportation Costs								
26 Dawn Supply	In 63 * In 190							
27 Niagara Supply	In 64 * In 201							
28 TGP Supply (Direct)	In 65 * In 228							
29 Dracut Supply 1 - Baseload	In 66 * In 249							
30 Dracut Supply 2 - Swing	In 67 * In 249							
31 City Gate Delivered Supply	In 68 * In 249							
32 TGP Storage - Withdrawals	In 77 * In 165							
33								
34 Total Volumetric Transportation Costs		\$ 358,499	\$ 483,769	\$ 519,956	\$ 460,549	\$ 418,429	\$ 289,200	\$ 2,530,401
35								
36 Less - Gas Refill								
37 LNG Truck	In 86 * In 150							
38 Propane	In 87 * In 151							
39 TGP Storage Refill	In 88 * In 121							
40 Storage Refill (Trans.)	In 88 * In 228							
41								
42 Subtotal Refills		\$ (332,808)	\$ (31,481)	\$ (261,284)	\$ (95,386)	\$ (22,967)	\$ (1,997,728)	\$ (2,741,654)
43								
44 Total Supply & Pipeline Commodity Costs	In 23 + In 34 + In 42	\$ 5,627,797	\$ 7,154,024	\$ 7,913,393	\$ 7,028,644	\$ 7,356,373	\$ 4,003,518	\$ 39,083,750
45								
46 Storage Gas								
47 TGP Storage - Withdrawals	In 77 * In 157	\$ 56,636	\$ 2,215,221	\$ 2,786,813	\$ 2,424,305	\$ 166,492	\$ -	\$ 7,649,468
48								
49 Produced Gas								
50 LNG Vapor	In 80 * In 145							
51 Propane	In 81 * In 147							
52								
53 Total Produced Gas	In 50 + In 51	\$ 12,010	\$ 12,177	\$ 912,545	\$ 296,084	\$ 11,540	\$ 11,142	\$ 1,255,498
54								
55								
56 Total Commodity Gas & Trans. Costs	In 44 + In 47 + In 53	\$ 5,696,443	\$ 9,381,422	\$ 11,612,752	\$ 9,749,033	\$ 7,534,405	\$ 4,014,660	\$ 47,988,716
57								
58								

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

6 For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak
7 (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
								(i)
59								
60 Volumes (Therms)								
61								
62 Pipeline Gas	See Schedule 11A							
63 Dawn Supply		992,558	985,941	1,025,643	870,970	1,025,643	992,558	5,893,314
64 Niagara Supply		66,998	675,767	728,703	624,485	800,664	31,431	2,928,047
65 TGP Supply (Direct)		5,300,261	5,472,304	5,524,413	4,910,681	5,537,647	4,063,699	30,809,005
66 Dracut Supply 1 - Baseload		-	5,590,584	5,590,584	5,049,640	-	-	16,230,807
67 Dracut Supply 2 - Swing		5,541,783	367,247	308,520	348,222	6,430,123	6,676,608	19,672,503
68 City Gate Delivered Supply		-	-	-	-	-	-	-
69 LNG Truck		23,160	23,987	535,154	196,030	47,974	-	826,305
70 Propane Truck		-	-	-	-	-	-	-
71 PNGTS		65,343	80,232	86,022	75,269	72,788	55,418	435,071
72 Granite Ridge		-	-	-	-	-	-	-
73								
74 Subtotal Pipeline Volumes		11,990,103	13,196,061	13,799,040	12,075,297	13,914,838	11,819,713	76,795,052
75								
76 Storage Gas								
77 TGP Storage		96,774	3,785,782	4,762,625	4,143,103	284,533	-	13,072,818
78								
79 Produced Gas								
80 LNG Vapor		23,160	23,987	588,918	196,030	23,987	23,160	879,241
81 Propane		-	-	426,800	137,304	-	-	564,104
82								
83 Subtotal Produced Gas		23,160	23,987	1,015,718	333,334	23,987	23,160	1,443,345
84								
85 Less - Gas Refill								
86 LNG Truck		(23,160)	(23,987)	(535,154)	(196,030)	(47,974)	-	(826,305)
87 Propane		-	-	-	-	-	-	-
88 TGP Storage Refill		(645,163)	(38,048)	-	-	-	(3,882,557)	(4,565,768)
89								
90 Subtotal Refills		(668,322)	(62,035)	(535,154)	(196,030)	(47,974)	(3,882,557)	(5,392,072)
91								
92 Total Sendout Volumes		11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316	85,919,143
93								
94								
95								

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

6 For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak
7 (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	Nov- Apr
96	Gas Costs and Volumetric Transportation Rates							Average Rate
97								
98	Pipeline Gas							
99	Dawn Supply							
100	NYMEX Price	Sch 7, In 10/10						
101	Basis Differential							
102	Net Commodity Costs							
103								
104	Niagara Supply							
105	NYMEX Price	Sch 7, In 10/10						
106	Basis Differential							
107	Net Commodity Costs							
108								
109	Dracut Supply 1 - Baseload							
110	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10						
111	Basis Differential							
112	Net Commodity Costs							
113								
114	Dracut Supply 2 - Swing							
115	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10						
116	Basis Differential							
117	Net Commodity Costs							
118								
119								
120	TGP Supply (Direct)							
121	NYMEX Price	Sch 7, In 10/10						
122	Basis Differential							
123	Net Commodity Costs							
124								
125								
126	City Gate Delivered Supply							
127	NYMEX Price	Sch 7, In 10/10						
128	Basis Differential							
129	Net Commodity Costs							
130								
131	LNG Truck	Sch 7, In 10/10	\$0.4479	\$0.4743	\$0.4882	\$0.4866	\$0.4787	\$0.4667
132								\$0.4738
133	Propane Truck	NYMEX - Propane	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
134								
135	PNGTS							
136	NYMEX Price	Sch 7, In 10/10						
137	Additional Cost							
138	Net Commodity Cost							
139								
140	Granite Ridge							
141	NYMEX Price	Sch 7, In 10/10						
142	Additional Cost							
143	Net Commodity Cost							
144								
145	LNG Vapor (Storage)	Sch 16, In 122 /10	\$0.5186	\$0.5076	\$0.4906	\$0.4869	\$0.4811	\$0.4811
146								\$0.4943
147	Propane	Sch 16, In 84 /10	\$1.4612	\$1.4612	\$1.4612	\$1.4612	\$1.4612	\$1.4612
148								
149	Storage Refill							
150	LNG Truck	In 131	\$0.4479	\$0.4743	\$0.4882	\$0.4866	\$0.4787	\$0.4667
151	Propane	In 133	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.4943
152								\$1.4612
153								

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Supply and Commodity Costs, Volumes and Rates

5	6 For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
154									
155									Average Rate
156	TGP Storage								
157	Commodity Costs - Storage withdrawal	Sch 16, ln 34 /10	\$0.5852	\$0.5851	\$0 5851	\$0.5851	\$0.5851	\$0.5851	\$0.5852
158									
159	TGP - Max Commodity - Z 4-6	Original Sheet No. 24	\$0 00834	\$0.00834	\$0.00834	\$0.00834	\$0.00834	\$0 00834	\$0.00834
160	TGP - Max Comm. ACA Rate - Z 4-6	Original Sheet No. 24	\$0 00019	\$0.00019	\$0.00019	\$0.00019	\$0.00019	\$0 00019	\$0.00019
161	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		\$0 00853	\$0.00853	\$0.00853	\$0.00853	\$0.00853	\$0 00853	\$0.00853
162	TGP - Fuel Charge % - Z 4-6	Original Sheet No. 32	2.17%	2.17%	2.17%	2.17%	2.17%	1.92%	2.13%
163	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		\$0 01270	\$0.01270	\$0.01270	\$0.01270	\$0.01270	\$0 01123	\$0.01245
164	TGP - Withdrawal Charge	1st Rev Sheet No. 61	\$0 00102	\$0.00102	\$0.00102	\$0.00102	\$0.00102	\$0 00102	\$0.00102
165	Total Volumetric Transportation Rate - TGP (Storage)		\$0 02225	\$0.02225	\$0.02225	\$0.02225	\$0.02225	\$0 02078	\$0.02200
166									
167	Total TGP - Comm. & Vol. Trans. Rate	ln 157 + ln 165	\$0.60748	\$0.60739	\$0.60739	\$0.60739	\$0.60739	\$0.60593	\$0.60716
168									
169									
170	Per Unit Volumetric Transportation Rates								
171	Dawn Supply Volumetric Transportation Charge								
172	Commodity Costs	ln 102	\$0.4889	\$0.5073	\$0.5102	\$0.5136	\$0.5047	\$0.4967	\$0.5036
173									
174	TransCanada - Commodity Rate/GJ	Union Dawn to Iroquois	\$0 00141	\$0.00141	\$0.00141	\$0.00141	\$0.00141	\$0 00141	\$0.00141
175	Conversion Rate GL to MMBTU		1.0551	1.0551	1 0551	1 0551	1.0551	1.0551	1.0551
176	Conversion Rate to US\$	08/17/2010	0.9697	0.9697	0.9697	0 9697	0.9697	0.9697	0.9697
177	Commodity Rate/US\$	ln 174 x ln 175 x ln 176	\$0 00145	\$0.00145	\$0.00145	\$0.00145	\$0.00145	\$0 00145	\$0.00145
178	TransCanada Fuel %	Union Dawn to Iroquois	1.00%	1.63%	1.41%	1.62%	1.60%	1.47%	1.46%
179	TransCanada Fuel * Percentage	ln 172 x ln 178	\$0 00489	\$0.00827	\$0.00719	\$0.00832	\$0.00808	\$0 00730	\$0.00734
180	Subtotal TransCanada		\$0.00633	\$0.00972	\$0.00864	\$0.00977	\$0.00952	\$0.00875	\$0.00879
181	IGTS - Z1 RTS Commodity	31st Rev Sheet No. 4	\$0 00030	\$0.00030	\$0.00030	\$0.00030	\$0.00030	\$0 00030	\$0.00030
182	IGTS - Z1 RTS ACA Rate Commodity	24th Rev Sheet 4A	\$0 00019	\$0.00019	\$0.00019	\$0.00019	\$0.00019	\$0 00019	\$0.00019
183	IGTS - Z1 RTS Deferred Asset Surcharge	24th Rev Sheet 4A	\$0 00003	\$0.00003	\$0.00003	\$0.00003	\$0.00003	\$0 00003	\$0.00003
184	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		\$0.00052	\$0.00052	\$0.00052	\$0.00052	\$0.00052	\$0.00052	\$0.00052
185	TGP NET-NE - Comm. Segments 3 & 4	1st Rev Sheet No. 30	\$0 00019	\$0.00019	\$0.00019	\$0.00019	\$0.00019	\$0 00019	\$0.00019
186	IGTS -Fuel Use Factor - Percentage	24th Rev Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1 00%	1.00%
187	IGTS -Fuel Use Factor - Fuel * Percentage	ln 172 x ln 186	\$0.00489	\$0.00507	\$0.00510	\$0.00514	\$0.00505	\$0.00497	\$0.00504
188	TGP NET-284 - Fuel Charge % Z 4-6	Original Sheet No. 105	1.54%	1.54%	1.54%	1.54%	1.54%	1.54%	1.54%
189	TGP NET-284 -Fuel Use Factor - Fuel * %	ln 172 x ln 188	\$0.00753	\$0.00781	\$0.00786	\$0.00791	\$0.00777	\$0.00765	\$0.00776
190	Total Volumetric Transportation Charge - Dawn Supply		\$0.01946	\$0.02331	\$0.02231	\$0.02352	\$0.02305	\$0.02207	\$0.02229
191									
192									
193	Niagara Supply Volumetric Transportation Charge								
194	Commodity Costs	ln 107							
195									
196	TGP FTA - FTA Z 5-6 Comm. Rate	Original Sheet No. 24							
197	TGP FTA - FTA Z 5-6 - ACA Rate	Original Sheet No. 24							
198	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate								
199	TGP FTA Fuel Charge % Z 5-6	Original Sheet No. 32							
200	TGP FTA Fuel * Percentage	ln 194 x ln 199							
201	Total Volumetric Transportation Rate - Niagra Supply								
202									
203									
204									

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3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Supply and Commodity Costs, Volumes and Rates

6 For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Nov- Apr
7 (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
205								
206								
207 TGP Direct Volumetric Transportation Charge								Average Rate
208 Commodity Costs	Ln 121	\$0.4479	\$0.4743	\$0.4882	\$0.4866	\$0.4787	\$0.4667	\$0.4738
209								
210 TGP - Max Comm. Base Rate - Z 0-6	Original Sheet No. 24	\$0 01608	\$0.01608	\$0.01608	\$0.01608	\$0.01608	\$0 01608	\$0.01608
211 TGP - Max Commodity ACA Rate - Z 0-6	Original Sheet No. 24	\$0 00019	\$0.00019	\$0.00019	\$0.00019	\$0.00019	\$0 00019	\$0.00019
212 Subtotal TGP - Max Comm. Rate Z 0-6		\$0 01627	\$0.01627	\$0.01627	\$0.01627	\$0.01627	\$0 01627	\$0.01627
213 Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
214 Prorated TGP - Max Commodity Rate - Z 0-6		\$0.00530	\$0.00530	\$0.00530	\$0.00530	\$0.00530	\$0.00530	\$0.00530
215 TGP - Max Comm. Base Rate - Z 1-6	Original Sheet No. 24	\$0 01503	\$0.01503	\$0.01503	\$0.01503	\$0.01503	\$0 01503	\$0.01503
216 TGP - Max Commodity ACA Rate - Z 1-6	Original Sheet No. 24	\$0 00019	\$0.00019	\$0.00019	\$0.00019	\$0.00019	\$0 00019	\$0.00019
217 Subtotal TGP - Max Commodity Rate - Z 1-6		\$0 01522	\$0.01522	\$0.01522	\$0.01522	\$0.01522	\$0 01522	\$0.01522
218 Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
219 Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		\$0.01026	\$0.01026	\$0.01026	\$0.01026	\$0.01026	\$0.01026	\$0.01026
220 TGP - Fuel Charge % - Z 0 -6	Original Sheet No. 32	8.71%	8.71%	8.71%	8.71%	8.71%	7.42%	8.50%
221 Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
222 Prorated TGP Fuel Charge % - Z 0-6		2.84%	2.84%	2.84%	2.84%	2.84%	2.42%	2.77%
223 TGP - Fuel Charge % - Z 1 -6	Original Sheet No. 32	7.82%	7.82%	7.82%	7.82%	7.82%	6.67%	7.63%
224 Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
225 Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		5.27%	5.27%	5.27%	5.27%	5.27%	4.50%	5.14%
226 TGP - Fuel Charge % - Z 0-6	In 208 x In 222	\$0.01272	\$0.01347	\$0.01386	\$0.01382	\$0.01359	\$0.01129	\$0.01312
227 TGP - Fuel Charge % - Z 1-6	In 208 x In 225	\$0.02361	\$0.02500	\$0.02573	\$0.02565	\$0.02523	\$0.02098	\$0.02437
228 Total Volumetric Transportation Rate - TGP (Direct)		\$0.05189	\$0.05403	\$0.05516	\$0.05503	\$0.05439	\$0.04783	\$0.05305
229								
230 TGP (Zone 6 Purchase) Volumetric Transportation Charge								
231 Commodity Costs	Ln 121	\$0.4479	\$0.4743	\$0.4882	\$0.4866	\$0.4787	\$0.4667	\$0.4738
232								
233 TGP - Max Comm. Base Rate - Z 6-6	Original Sheet No. 24	\$0 00642	\$0.00642	\$0.00642	\$0.00642	\$0.00642	\$0 00642	\$0.00642
234 TGP - Max Commodity ACA Rate - Z 6-6	Original Sheet No. 24	\$0 00019	\$0.00019	\$0.00019	\$0.00019	\$0.00019	\$0 00019	\$0.00019
235 Subtotal TGP - Max Commodity Rate - Z 6-6		\$0.00661	\$0.00661	\$0.00661	\$0.00661	\$0.00661	\$0.00661	\$0.00661
236 TGP - Fuel Charge % - Z 6-6	Original Sheet No. 32	0.89%	0.89%	0.89%	0.89%	0.89%	0.85%	0.88%
237 TGP - Fuel Charge	In 231 x In 236	\$0.00399	\$0.00422	\$0.00435	\$0.00433	\$0.00426	\$0.00397	\$0.00419
238 Total Vol. Trans. Rate - TGP (Zone 6)		\$0.01060	\$0.01083	\$0.01096	\$0.01094	\$0.01087	\$0.01058	\$0.01080
239								
240								
241 TGP Dracut								
242 Commodity Costs - NYMEX Price	Ln 112							
243								
244 TGP - Trans Charge - Comm. - Z 6-6	Original Sheet No. 24							
245 TGP - Trans Charge - ACA Rate - Z6-6	Original Sheet No. 24							
246 Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6								
247 TGP - Fuel Charge % - Z 6-6	Original Sheet No. 32							
248 TGP - Fuel Charge	In 242 x In 247							
249 Total Volumetric Transportation Rate - TGP Dracut								
250								
251								

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----- 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

- 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.

(Footnotes continued on Sheet 4.01)

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Jan 26, 2009

Effective: Jan 27, 2009

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To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

Commodity	0.0019
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DEFERRED ASSET SURCHARGE:

Commodity

Zone 1	0.0003
--------	--------

Zone 2	0.0002
--------	--------

Inter-Zone	0.0005
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MEASUREMENT VARIANCE/FUEL USE FACTOR:

Minimum	0.00%
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Maximum (Non-Eastchester Shipper)	1.00%
-----------------------------------	-------

Maximum (Eastchester Shipper)	4.50%
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Maximum (Brookfield Shipper)	1.20%
------------------------------	-------

Issued by: Jeffrey A. Bruner, Vice Pres., Gen Counsel & Secretary

Issued on: Sep 30, 2009

Effective: Nov 01, 2009

RATES PER DEKATHERM

RATE SCHEDULE NET 284

=====						
Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS			Rate After Current Adjustments	Fuel and Use
		(ACA)	(PCB)	5/		

Demand Rate 1/, 5/						

Segment U	\$9.65		\$0.00		\$9.65	
Segment 1	\$1.33		\$0.00		\$1.33	
Segment 2	\$8.08		\$0.00		\$8.08	
Segment 3	\$5.07		\$0.00		\$5.07	
Segment 4	\$5.54		\$0.00		\$5.54	
Commodity Rate 2/, 3/						

Segments U, 1, 2, 3 & 4		\$0.0019			\$0.0019	6/
Extended Receipt and Delivery Rate 4/, 7/						

Segment U	\$0.3173				\$0.3173	5.52%
Segment 1	\$0.0437				\$0.0437	0.69%
Segment 2	\$0.2656				\$0.2656	0.59%
Segment 3	\$0.1667				\$0.1667	0.73%
Segment 4	\$0.1821				\$0.1821	0.36%

Notes:

- 1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.
- 2/ The applicable surcharge for ACA will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.
- 3/ The Incremental Pressure Charge associated with service to MassPower shall be \$0.0334 plus an additional Incremental Fuel Charge of 5.83%.
- 4/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET 284.
- 5/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
- 6/ The applicable fuel retention percentages are listed on Sheet No. 105.
- 7/ The Extended Receipt and Delivery Rates are additive for each segment outside of the segments under Shipper's base NET-284 contract.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
 RATE SCHEDULE FS

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA) (PCB) 2/	Current Adjustment	Retention Percent 1/
=====				
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
=====				
Deliverability Rate	\$2.02	\$0.00	\$2.02	
Space Rate	\$0.0248	\$0.0000	\$0.0248	
Injection Rate	\$0.0053		\$0.0053	1.49%
Withdrawal Rate	\$0.0053		\$0.0053	
Overrun Rate	\$0.2427		\$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA				
=====				
Deliverability Rate	\$1.15	\$0.00	\$1.15	
Space Rate	\$0.0185	\$0.0000	\$0.0185	
Injection Rate	\$0.0102		\$0.0102	1.49%
Withdrawal Rate	\$0.0102		\$0.0102	
Overrun Rate	\$0.1380		\$0.1380	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

RATES PER DEKATHERM

INTERRUPTIBLE STORAGE SERVICE
 RATE SCHEDULE IS

=====						
Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA) (PCB) 2/		Current Adjustment	Retention Percent	1/

INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA						
=====						
Space Rate	\$0.0848		\$0.0000	\$0.0848		
Injection Rate	\$0.0102			\$0.0102	1.49%	
Withdrawal Rate	\$0.0102			\$0.0102		
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA						
=====						
Space Rate	\$0.0993		\$0.0000	\$0.0993		
Injection Rate	\$0.0053			\$0.0053	1.49%	
Withdrawal Rate	\$0.0053			\$0.0053		

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2012 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\,3\

=====

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone							
	0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone							
	0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

- 1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.
- 2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.
- 3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G.

NET-284 RATE SCHEDULE (continued)

5. FUEL AND USE (continued)

Shipper	Transportation Quantity (Dth)	Segments					Fuel and Use
		U	1	2	3	4	
Bay State (from Granite)	3,706				*	*	1.26%
- Pleasant St.							
Bay State (from Granite)	6,068				*		0.96%
- Agawam							
Boston Gas d/b/a National Grid	35,000				*	*	1.31%
Boston Gas d/b/a National Grid	8,600				*	*	1.31%
Barclays Bank PLC	14,010				*	*	1.23%
EnergyNorth Natural Gas, Inc.	4,000				*	*	1.54%
d/b/a National Grid							
Essex Gas Company	2,000				*	*	1.44%
d/b/a National Grid							
Iroquois Gas Transmission	37,000				*		0.68%
(Connecticut Natural, Yankee Gas)							
Lockport Energy Associates	13,184	*	*				6.21%
New York State Electric & Gas Corp	14,816	*	*				6.21%
Northern Utilities	844				*	*	1.26%
(from Granite) Pleasant St.							
Northern Utilities	1,382				*		0.96%
(from Granite) Agawam							
The Narragansett Electric Company	1,000				*	*	1.25%
d/b/a National Grid							
Yankee Gas Services Company (Wright)	9,000				*		1.07%
Total	150,610						

RATES PER DEKATHERM

COMMODITY RATES
 RATE SCHEDULE FT-G

Base Commodity Rate

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.0439		\$0.0669	\$0.0880	\$0.0978	\$0.1118	\$0.1231	\$0.1608
L		\$0.0286						
1	\$0.0669		\$0.0572	\$0.0776	\$0.0874	\$0.1014	\$0.1126	\$0.1503
2	\$0.0880		\$0.0776	\$0.0433	\$0.0530	\$0.0681	\$0.0783	\$0.1159
3	\$0.0978		\$0.0874	\$0.0530	\$0.0366	\$0.0663	\$0.0765	\$0.1142
4	\$0.1129		\$0.1025	\$0.0681	\$0.0663	\$0.0401	\$0.0459	\$0.0834
5	\$0.1231		\$0.1126	\$0.0783	\$0.0765	\$0.0459	\$0.0427	\$0.0765
6	\$0.1608		\$0.1503	\$0.1159	\$0.1142	\$0.0834	\$0.0765	\$0.0642

Minimum
 Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.0026		\$0.0096	\$0.0161	\$0.0191	\$0.0233	\$0.0268	\$0.0326
L		\$0.0034						
1	\$0.0096		\$0.0067	\$0.0129	\$0.0159	\$0.0202	\$0.0236	\$0.0294
2	\$0.0161		\$0.0129	\$0.0024	\$0.0054	\$0.0100	\$0.0131	\$0.0189
3	\$0.0191		\$0.0159	\$0.0054	\$0.0004	\$0.0095	\$0.0126	\$0.0184
4	\$0.0237		\$0.0205	\$0.0100	\$0.0095	\$0.0015	\$0.0032	\$0.0090
5	\$0.0268		\$0.0236	\$0.0131	\$0.0126	\$0.0032	\$0.0022	\$0.0069
6	\$0.0326		\$0.0294	\$0.0189	\$0.0184	\$0.0090	\$0.0069	\$0.0031

Maximum
 Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.0458		\$0.0688	\$0.0889	\$0.0997	\$0.1137	\$0.1250	\$0.1627
L		\$0.0305						
1	\$0.0688		\$0.0591	\$0.0795	\$0.0893	\$0.1033	\$0.1145	\$0.1522
2	\$0.0899		\$0.0795	\$0.0452	\$0.0549	\$0.0700	\$0.0802	\$0.1178
3	\$0.0997		\$0.0893	\$0.0549	\$0.0385	\$0.0682	\$0.0784	\$0.1161
4	\$0.1148		\$0.1044	\$0.0700	\$0.0682	\$0.0420	\$0.0478	\$0.0853
5	\$0.1250		\$0.1145	\$0.0802	\$0.0784	\$0.0478	\$0.0446	\$0.0784
6	\$0.1627		\$0.1522	\$0.1178	\$0.1161	\$0.0853	\$0.0784	\$0.0661

Notes:

- 1/ The above maximum rates include a per Dth charge for:
 (ACA) Annual Charge Adjustment \$0.0019
- 2/ The applicable fuel retention percentages are listed on Sheet No. 32, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Refer to Schedule 5.2 for FT, STFT and Interruptible transportation tolls

Storage Transportation Service

Line No	Particulars	Demand Toll (\$/GJ/mo)	Commodity Toll (\$/GJ)
(a)		(b)	(c)
1	Centra Gas Manitoba - MDA	3.16583	0.00330
2	Union Gas - WDA	23.37333	0.03242
3	Union Gas - NDA	8.93667	0.01154
4	Union Gas - EDA	5.78250	0.00692
5	Kingston PUC	5.61583	0.00657
6	Gaz Metropolitain - EDA	10.42417	0.01357
7	Enbridge - CDA	1.17750	0.00012
8	Enbridge - EDA	3.52250	0.00363
9	Cornwall	8.03083	0.01007
10	Philipsburg	10.62833	0.01384

Enhanced Capacity Release

Line No	Particulars	Commodity Toll (\$/GJ)
(a)		(b)
11	ECR Surcharge	0.036

Delivery Pressure

Line No	Particulars	Demand Toll (\$/GJ/mo)	Commodity Toll (\$/GJ)	Daily Equivalent ^{*(1)} (\$/GJ)
(a)		(b)	(c)	(d)
12	Emerson - 1 (Viking)	0.11697	0.00000	0.00385
13	Emerson - 2 (Great Lakes)	0.12218	0.00000	0.00402
14	Dawn	0.06338	0.00000	0.00208
15	Niagara Falls	0.16857	0.00000	0.00554
16	Iroquois	0.78572	0.00000	0.02583
17	Chippawa	0.81314	0.00000	0.02673
18	East Hereford	1.96558	0.03798	0.10260

^{*(1)} The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

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FT, STFT and Interruptible Transportation Tolls
Approved Final Mainline Tolls effective January 1, 2010

Line No.	Receipt Point	Delivery point	Demand Toll (\$/GJ/MO)	Commodity Toll (\$/GJ)	(1) (FT, STFT Minimum Tolls) (100% LF FT Tolls)	IT Bid Floor (110% FT Tolls)
					(\$/GJ)	(\$/GJ)
1	Union Dawn	Emerson 2	24.78632	0.00000	0.8149	0.8964
2	Union Dawn	St. Clair	1.44127	0.00000	0.0474	0.0521
3	Union Dawn	Dawn Export	1.08608	0.00000	0.0357	0.0393
4	Union Dawn	Kirkwall	3.89830	0.00408	0.1323	0.1455
5	Union Dawn	Niagara Falls	5.56504	0.00650	0.1895	0.2085
6	Union Dawn	Chippawa	5.60066	0.00655	0.1907	0.2098
7	Union Dawn	Iroquois	10.82669	0.01413	0.3700	0.4070
8	Union Dawn	Cornwall	11.41501	0.01498	0.3903	0.4293
9	Union Dawn	Napierville	13.74832	0.01837	0.4704	0.5174
10	Union Dawn	Philipsburg	14.01051	0.01875	0.4794	0.5273
11	Union Dawn	East Hereford	16.76744	0.02275	0.5741	0.6315
12	Union Dawn	Welwyn	30.92367	0.00000	1.0167	1.1184
13	Enbridge CDA	Empress	44.96349	0.06366	1.5420	1.6962
14	Enbridge CDA	Transgas SSDA	38.53100	0.05386	1.3207	1.4528
15	Enbridge CDA	Centram SSDA	35.13836	0.04935	1.2046	1.3251
16	Enbridge CDA	Centram MDA	31.69563	0.04470	1.0867	1.1954
17	Enbridge CDA	Centrat MDA	29.89504	0.04180	1.0247	1.1272
18	Enbridge CDA	Union WDA	23.06458	0.03197	0.7903	0.8693
19	Enbridge CDA	Nipigon WDA	21.03519	0.02948	0.7211	0.7932
20	Enbridge CDA	Union NDA	8.85618	0.01144	0.3026	0.3329
21	Enbridge CDA	Calstock NDA	16.51673	0.02317	0.5662	0.6228
22	Enbridge CDA	Tunis NDA	12.95923	0.01820	0.4443	0.4887
23	Enbridge CDA	GMIT NDA	8.90462	0.01063	0.3034	0.3337
24	Enbridge CDA	Union SSMDA	14.53608	0.01946	0.4974	0.5471
25	Enbridge CDA	Union NCDA	3.73926	0.00389	0.1268	0.1395
26	Enbridge CDA	Union CDA	2.49167	0.00173	0.0836	0.0920
27	Enbridge CDA	Enbridge CDA	1.08608	0.00000	0.0357	0.0393
28	Enbridge CDA	Union EDA	5.46815	0.00644	0.1862	0.2048
29	Enbridge CDA	Enbridge EDA	7.90059	0.00994	0.2696	0.2966
30	Enbridge CDA	GMIT EDA	9.99004	0.01297	0.3414	0.3755
31	Enbridge CDA	KPUC EDA	5.18271	0.00597	0.1764	0.1940
32	Enbridge CDA	North Bay Junction	6.35205	0.00765	0.2165	0.2382
33	Enbridge CDA	Enbridge SWDA	5.46696	0.00630	0.1860	0.2046
34	Enbridge CDA	Union SWDA	5.69755	0.00672	0.1940	0.2134
35	Enbridge CDA	Spruce	29.80382	0.04168	1.0216	1.1238
36	Enbridge CDA	Emerson 1	29.16586	0.04068	0.9996	1.0996
37	Enbridge CDA	Emerson 2	29.16586	0.04068	0.9996	1.0996
38	Enbridge CDA	St. Clair	5.82216	0.00682	0.1982	0.2180
39	Enbridge CDA	Dawn Export	5.46696	0.00630	0.1860	0.2046
40	Enbridge CDA	Kirkwall	2.65473	0.00222	0.0895	0.0985
41	Enbridge CDA	Niagara Falls	3.67800	0.00372	0.1246	0.1371
42	Enbridge CDA	Chippawa	3.72391	0.00379	0.1262	0.1388
43	Enbridge CDA	Iroquois	7.01147	0.00862	0.2391	0.2630
44	Enbridge CDA	Cornwall	7.59949	0.00948	0.2593	0.2852
45	Enbridge CDA	Napierville	9.93325	0.01286	0.3395	0.3735
46	Enbridge CDA	Philipsburg	10.19544	0.01324	0.3484	0.3832
47	Enbridge CDA	East Hereford	12.95192	0.01724	0.4430	0.4873
48	Enbridge CDA	Welwyn	35.84726	0.05044	1.2289	1.3518
49	Enbridge EDA	Empress	45.84410	0.06496	1.5722	1.7294
50	Enbridge EDA	Transgas SSDA	39.59108	0.05552	1.3571	1.4928
51	Enbridge EDA	Centram SSDA	36.59835	0.05155	1.2548	1.3803
52	Enbridge EDA	Centram MDA	32.87570	0.04644	1.1272	1.2399
53	Enbridge EDA	Centrat MDA	36.85711	0.05199	1.2637	1.3901
54	Enbridge EDA	Union WDA	24.24450	0.03371	0.8308	0.9139
55	Enbridge EDA	Nipigon WDA	21.03310	0.02897	0.7205	0.7926
56	Enbridge EDA	Union NDA	10.03625	0.01317	0.3432	0.3775
57	Enbridge EDA	Calstock NDA	16.10325	0.02182	0.5512	0.6063
58	Enbridge EDA	Tunis NDA	12.22185	0.01619	0.4180	0.4598
59	Enbridge EDA	GMIT NDA	9.61741	0.01236	0.3286	0.3615
60	Enbridge EDA	Union SSMDA	20.53183	0.02825	0.7033	0.7736
61	Enbridge EDA	Union NCDA	9.39814	0.01213	0.3211	0.3532
62	Enbridge EDA	Union CDA	8.46521	0.01037	0.2887	0.3176
63	Enbridge EDA	Enbridge CDA	7.90059	0.00994	0.2696	0.2966
64	Enbridge EDA	Union EDA	3.67770	0.00377	0.1247	0.1372
65	Enbridge EDA	Enbridge EDA	1.08608	0.00000	0.0357	0.0393
66	Enbridge EDA	GMIT EDA	5.31969	0.00611	0.1810	0.1991
67	Enbridge EDA	KPUC EDA	3.88012	0.00405	0.1317	0.1449
68	Enbridge EDA	North Bay Junction	7.23267	0.00895	0.2468	0.2715
69	Enbridge EDA	Enbridge SWDA	11.46271	0.01509	0.3920	0.4312

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TransCanada Fuel Ratios

November 2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3010	1.00	0.31

December 2009

Pressure Point	Pressure (%)
Chippawa	1.24
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.3010	1.63	0.94

January 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.4070	1.41	0.72

February 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

* There is a backhaul toll charge which is the equivalent of the FT 100% LF demand toll in winter season. For backhaul tolls for specific paths, please refer to TransCanada Mainline's posted FT Tolls at

<http://www.transcanada.com/Mainline/>

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.4070	1.62	0.93

March 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

* There is a backhaul toll charge which is the equivalent of the FT 100% LF demand toll in winter season. For backhaul tolls for specific paths, please refer to TransCanada Mainline's posted FT Tolls at

<http://www.transcanada.com/Mainline/>

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.4070	1.60	0.91

April 2010

Pressure Point	Pressure (%)
Chippawa	0.91
Emerson 1	0.11
Emerson 2	0.11
Iroquois	0.69
Niagara Falls	0.00

* There is a backhaul toll charge which is the equivalent of the FT 100% LF demand toll in winter season. For backhaul tolls for specific paths, please refer to TransCanada Mainline's posted FT Tolls at

<http://www.transcanada.com/Mainline/>

Receipt	Delivery	Min IT Bid Toll	Fuel Ratio (%) (with pressure)	Fuel Ratio (%) (without pressure)
Union Dawn	Iroquois	0.4070	1.47	0.78

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4 NYMEX Futures @ Henry Hub and Hedged Contracts
5

			Peak						
6 For Month of:	Reference		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	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)			4.4789	4.7433	4.8824	4.8659	4.7875	4.6671	\$ 4.7375
10 NYMEX	In 273		4.4789	4.7433	4.8824	4.8659	4.7875	4.6671	\$ 4.7375
11 December Trigger									
12 January Trigger									
13 February Trigger									
14 March Trigger									
15 April Trigger									
16									
17									
18									
19									
20 II. Development of Hedging Costs and Savings									
21									
22 TGP (Direct) Volumes									
23 Hedged Volumes (Dth)	In 107		350,000	860,000	1,000,000	970,000	610,000	180,000	Total 3,970,000
24 Market Priced Volumes (Dth)			840,160	449,184	317,786	210,400	769,408	996,430	3,583,368
25 Total Volumes (Dth)	Sch 6, Ins 63 - 68 / 10		1,190,160	1,309,184	1,317,786	1,180,400	1,379,408	1,176,430	7,553,368
26									
27									Weighted Average
28 Hedge Price	In 242		\$ 5.9050	\$ 6.1622	\$ 6.3271	\$ 6.2749	\$ 6.1761	\$ 6.4812	\$ 6.2252
29 NYMEX Price	In 10		\$ 4.4789	\$ 4.7433	\$ 4.8824	\$ 4.8659	\$ 4.7875	\$ 4.6671	\$ 4.7883
30									
31 Hedged Volumes at Hedged Price	In 23 * In 28		\$ 2,066,746	\$ 5,299,451	\$ 6,327,124	\$ 6,086,690	\$ 3,767,446	\$ 1,166,608	\$ 24,714,066
32 Less Hedged Volumes at NYMEX	In 24 * In 29		1,567,603	4,079,267	4,882,400	4,719,891	2,920,355	840,072	19,009,587
33									
34 Hedge Contract (Savings)/Loss	In 31 - In 32		\$ 499,143	\$ 1,220,185	\$ 1,444,724	\$ 1,366,799	\$ 847,092	\$ 326,536	\$ 5,704,479
35									
36 Total Financial Hedge	In 23		3,500,000	8,600,000	10,000,000	9,700,000	6,100,000	1,800,000	39,700,000
37 Total Underground Storage	Sch 6, Ln 77		96,774	3,785,782	4,762,625	4,143,103	284,533	-	13,072,818
38 Sub Total			3,596,774	12,385,782	14,762,625	13,843,103	6,384,533	1,800,000	52,772,818
39 Total Throughput	Sch 6, In 92		11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316	85,919,143
40 Hedge Percentage	In 38 / In 39		31%	73%	78%	85%	45%	23%	61%

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Peak

6 For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Strip Average
7 (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41								
42 Hedged Volumes (Dth)								
43 Hedge # 1	Trade Date 15-May-09 Swaps							
44 Hedge # 2	Trade Date 15-May-09 Swaps							
45 Hedge # 3	Trade Date 29-May-09 Swaps							
46 Hedge # 4	Trade Date 29-May-09 Swaps							
47 Hedge # 5	Trade Date 12-Jun-09 Swaps							
48 Hedge # 6	Trade Date 12-Jun-09 Swaps							
49 Hedge # 7	Trade Date 25-Jun-09 Swaps							
50 Hedge # 8	Trade Date 25-Jun-09 Swaps							
51 Hedge # 9	Trade Date 10-Jul-09 Swaps							
52 Hedge # 10	Trade Date 10-Jul-09 Swaps							
53 Hedge # 11	Trade Date 27-Jul-09 Swaps							
54 Hedge # 12	Trade Date 27-Jul-09 Swaps							
55 Hedge # 13	Trade Date 07-Aug-09 Swaps							
56 Hedge # 14	Trade Date 07-Aug-09 Swaps							
57 Hedge # 15	Trade Date 21-Aug-09 Swaps							
58 Hedge # 16	Trade Date 21-Aug-09 Swaps							
59 Hedge # 17	Trade Date 11-Sep-09 Swaps							
60 Hedge # 18	Trade Date 11-Sep-09 Swaps							
61 Hedge # 19	Trade Date 25-Sep-09 Swaps							
62 Hedge # 20	Trade Date 25-Sep-09 Swaps							
63 Hedge # 21	Trade Date 09-Oct-09 Swaps							
64 Hedge # 22	Trade Date 09-Oct-09 Swaps							
65 Hedge # 23	Trade Date 23-Oct-09 Swaps							
66 Hedge # 24	Trade Date 23-Nov-09 Swaps							
67 Hedge # 25	Trade Date 30-Nov-09 Swaps							
68 Hedge # 26	Trade Date 30-Nov-09 Swaps							
69 Hedge # 27	Trade Date 30-Nov-09 Swaps							
70 Hedge # 28	Trade Date 14-Dec-09 Swaps							
71 Hedge # 29	Trade Date 14-Dec-09 Swaps							
72 Hedge # 30	Trade Date 30-Dec-09 Swaps							
73 Hedge # 31	Trade Date 30-Dec-09 Swaps							
74 Hedge # 32	Trade Date 15-Jan-10 Swaps							
75 Hedge # 33	Trade Date 15-Jan-10 Swaps							
76 Hedge # 34	Trade Date 29-Jan-10 Swaps							
77 Hedge # 35	Trade Date 29-Jan-10 Swaps							
78 Hedge # 36	Trade Date 12-Feb-10 Swaps							
79 Hedge # 37	Trade Date 12-Feb-10 Swaps							
80 Hedge # 38	Trade Date 26-Feb-10 Swaps							
81 Hedge # 39	Trade Date 26-Feb-10 Swaps							
82 Hedge # 40	Trade Date 12-Mar-10 Swaps							
83 Hedge # 41	Trade Date 12-Mar-10 Swaps							
84 Hedge # 42	Trade Date 26-Mar-10 Swaps							
85 Hedge # 43	Trade Date 26-Mar-10 Swaps							
86 Hedge # 44	Trade Date 09-Apr-10 Swaps							
87 Hedge # 45	Trade Date 09-Apr-10 Swaps							
88 Hedge # 46	Trade Date 23-Apr-10 Swaps							
89 Hedge # 47	Trade Date 23-Apr-10 Swaps							
90 Hedge # 48	Trade Date 07-May-10 Swaps							
91 Hedge # 49	Trade Date 21-May-10 Swaps							
92 Hedge # 50	Trade Date 21-May-10 Swaps							
93 Hedge # 51	Trade Date 11-Jun-10 Swaps							
94 Hedge # 52	Trade Date 25-Jun-10 Swaps							
95 Hedge # 53	Trade Date 09-Jul-10 Swaps							
96 Hedge # 54	Trade Date 26-Jul-10 Swaps							
97								
98								
99								
100								
101								
102								
103								
104 Subtotal Hedge Volumes		330,000	760,000	870,000	820,000	530,000	180,000	3,490,000
105 Remaining		20,000	100,000	130,000	150,000	80,000	-	480,000
106 Total Volumes		350,000	860,000	1,000,000	970,000	610,000	180,000	3,970,000
107								
108								

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 NYMEX Futures @ Henry Hub and Hedged Contracts
5

Peak

6 For Month of:	7	(a)	Reference (b)	Nov-10 (c)	Dec-10 (d)	Jan-11 (e)	Feb-11 (f)	Mar-11 (g)	Apr-11 (h)	Strip Average (i) Weighted Average
109 Strike Price										
110 Hedge # 1	Trade Date	15-May-09	Swaps							
111 Hedge # 2	Trade Date	15-May-09	Swaps							
112 Hedge # 3	Trade Date	29-May-09	Swaps							
113 Hedge # 4	Trade Date	29-May-09	Swaps							
114 Hedge # 5	Trade Date	12-Jun-09	Swaps							
115 Hedge # 6	Trade Date	12-Jun-09	Swaps							
116 Hedge # 7	Trade Date	25-Jun-09	Swaps							
117 Hedge # 8	Trade Date	25-Jun-09	Swaps							
118 Hedge # 9	Trade Date	10-Jul-09	Swaps							
119 Hedge # 10	Trade Date	10-Jul-09	Swaps							
120 Hedge # 11	Trade Date	27-Jul-09	Swaps							
121 Hedge # 12	Trade Date	27-Jul-09	Swaps							
122 Hedge # 13	Trade Date	07-Aug-09	Swaps							
123 Hedge # 14	Trade Date	07-Aug-09	Swaps							
124 Hedge # 15	Trade Date	21-Aug-09	Swaps							
125 Hedge # 16	Trade Date	21-Aug-09	Swaps							
126 Hedge # 17	Trade Date	11-Sep-09	Swaps							
127 Hedge # 18	Trade Date	11-Sep-09	Swaps							
128 Hedge # 19	Trade Date	25-Sep-09	Swaps							
129 Hedge # 20	Trade Date	25-Sep-09	Swaps							
130 Hedge # 21	Trade Date	09-Oct-09	Swaps							
131 Hedge # 22	Trade Date	09-Oct-09	Swaps							
132 Hedge # 23	Trade Date	23-Oct-09	Swaps							
133 Hedge # 24	Trade Date	23-Nov-09	Swaps							
134 Hedge # 25	Trade Date	30-Nov-09	Swaps							
135 Hedge # 26	Trade Date	30-Nov-09	Swaps							
136 Hedge # 27	Trade Date	30-Nov-09	Swaps							
137 Hedge # 28	Trade Date	14-Dec-09	Swaps							
138 Hedge # 29	Trade Date	14-Dec-09	Swaps							
139 Hedge # 30	Trade Date	30-Dec-09	Swaps							
140 Hedge # 31	Trade Date	30-Dec-09	Swaps							
141 Hedge # 32	Trade Date	15-Jan-10	Swaps							
142 Hedge # 33	Trade Date	15-Jan-10	Swaps							
143 Hedge # 34	Trade Date	29-Jan-10	Swaps							
144 Hedge # 35	Trade Date	29-Jan-10	Swaps							
145 Hedge # 36	Trade Date	12-Feb-10	Swaps							
146 Hedge # 37	Trade Date	12-Feb-10	Swaps							
147 Hedge # 38	Trade Date	26-Feb-10	Swaps							
148 Hedge # 39	Trade Date	26-Feb-10	Swaps							
149 Hedge # 40	Trade Date	12-Mar-10	Swaps							
150 Hedge # 41	Trade Date	12-Mar-10	Swaps							
151 Hedge # 42	Trade Date	26-Mar-10	Swaps							
152 Hedge # 43	Trade Date	26-Mar-10	Swaps							
153 Hedge # 44	Trade Date	09-Apr-10	Swaps							
154 Hedge # 45	Trade Date	09-Apr-10	Swaps							
155 Hedge # 46	Trade Date	23-Apr-10	Swaps							
156 Hedge # 47	Trade Date	23-Apr-10	Swaps							
157 Hedge # 48	Trade Date	07-May-10	Swaps							
158 Hedge # 49	Trade Date	21-May-10	Swaps							
159 Hedge # 50	Trade Date	21-May-10	Swaps							
160 Hedge # 51	Trade Date	11-Jun-10	Swaps							
161 Hedge # 52	Trade Date	25-Jun-10	Swaps							
162 Hedge # 53	Trade Date	09-Jul-10	Swaps							
163 Hedge # 54	Trade Date	26-Jul-10	Swaps							
164										
165										
166										
167										
168										
169										
170										
171 Subtotal Weigthed Average Hedge Prices				\$5.9914	\$6.3488	\$6.5430	\$6.5327	\$6.3858	\$6.4812	6.4191
172 NYMEX				\$4.4789	\$4.7433	\$4.8824	\$4.8659	\$4.7875	\$4.6671	4.8156
173										
174										

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
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4 NYMEX Futures @ Henry Hub and Hedged Contracts
5

Peak

6 For Month of:	7	(a)	Reference (b)	Nov-10 (c)	Dec-10 (d)	Jan-11 (e)	Feb-11 (f)	Mar-11 (g)	Apr-11 (h)	Strip Average (i)
175 Hedge Dollars										
176 Hedge #	1	Trade Date	15-May-09 Swaps							
177 Hedge #	2	Trade Date	15-May-09 Swaps							
178 Hedge #	3	Trade Date	29-May-09 Swaps							
179 Hedge #	4	Trade Date	29-May-09 Swaps							
180 Hedge #	5	Trade Date	12-Jun-09 Swaps							
181 Hedge #	6	Trade Date	12-Jun-09 Swaps							
182 Hedge #	7	Trade Date	25-Jun-09 Swaps							
183 Hedge #	8	Trade Date	25-Jun-09 Swaps							
184 Hedge #	9	Trade Date	10-Jul-09 Swaps							
185 Hedge #	10	Trade Date	10-Jul-09 Swaps							
186 Hedge #	11	Trade Date	27-Jul-09 Swaps							
187 Hedge #	12	Trade Date	27-Jul-09 Swaps							
188 Hedge #	13	Trade Date	07-Aug-09 Swaps							
189 Hedge #	14	Trade Date	07-Aug-09 Swaps							
190 Hedge #	15	Trade Date	21-Aug-09 Swaps							
191 Hedge #	16	Trade Date	21-Aug-09 Swaps							
192 Hedge #	17	Trade Date	11-Sep-09 Swaps							
193 Hedge #	18	Trade Date	11-Sep-09 Swaps							
194 Hedge #	19	Trade Date	25-Sep-09 Swaps							
195 Hedge #	20	Trade Date	25-Sep-09 Swaps							
196 Hedge #	21	Trade Date	09-Oct-09 Swaps							
197 Hedge #	22	Trade Date	09-Oct-09 Swaps							
198 Hedge #	23	Trade Date	23-Oct-09 Swaps							
199 Hedge #	24	Trade Date	23-Nov-09 Swaps							
200 Hedge #	25	Trade Date	30-Nov-09 Swaps							
201 Hedge #	26	Trade Date	30-Nov-09 Swaps							
202 Hedge #	27	Trade Date	30-Nov-09 Swaps							
203 Hedge #	28	Trade Date	14-Dec-09 Swaps							
204 Hedge #	29	Trade Date	14-Dec-09 Swaps							
205 Hedge #	30	Trade Date	30-Dec-09 Swaps							
206 Hedge #	31	Trade Date	30-Dec-09 Swaps							
207 Hedge #	32	Trade Date	15-Jan-10 Swaps							
208 Hedge #	33	Trade Date	15-Jan-10 Swaps							
209 Hedge #	34	Trade Date	29-Jan-10 Swaps							
210 Hedge #	35	Trade Date	29-Jan-10 Swaps							
211 Hedge #	36	Trade Date	12-Feb-10 Swaps							
212 Hedge #	37	Trade Date	12-Feb-10 Swaps							
213 Hedge #	38	Trade Date	26-Feb-10 Swaps							
214 Hedge #	39	Trade Date	26-Feb-10 Swaps							
215 Hedge #	40	Trade Date	12-Mar-10 Swaps							
216 Hedge #	41	Trade Date	12-Mar-10 Swaps							
217 Hedge #	42	Trade Date	26-Mar-10 Swaps							
218 Hedge #	43	Trade Date	26-Mar-10 Swaps							
219 Hedge #	44	Trade Date	09-Apr-10 Swaps							
220 Hedge #	45	Trade Date	09-Apr-10 Swaps							
221 Hedge #	46	Trade Date	23-Apr-10 Swaps							
222 Hedge #	47	Trade Date	23-Apr-10 Swaps							
223 Hedge #	48	Trade Date	07-May-10 Swaps							
224 Hedge #	49	Trade Date	21-May-10 Swaps							
225 Hedge #	50	Trade Date	21-May-10 Swaps							
226 Hedge #	51	Trade Date	11-Jun-10 Swaps							
227 Hedge #	52	Trade Date	25-Jun-10 Swaps							
228 Hedge #	53	Trade Date	09-Jul-10 Swaps							
229 Hedge #	54	Trade Date	26-Jul-10 Swaps							
230										
231										
232										
233										
234										
235										
236										
237 Subtotal Hedge Dollars				\$1,977,169	\$4,825,118	\$5,692,412	\$5,356,810	\$3,384,449	\$1,166,608	\$22,402,566
238 Remaining				89,577	474,333	634,712	729,880	382,997	-	2,311,500
239										
240		Target Hedged Dollars		\$2,066,746	\$5,299,451	\$6,327,124	\$6,086,690	\$3,767,446	\$1,166,608	\$24,714,066
241										
242		Weighted Average Hedged Cost per Unit		\$5.9050	\$6.1622	\$6.3271	\$6.2749	\$6.1761	\$6.4812	\$6.2252
243										
244										

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4 NYMEX Futures @ Henry Hub and Hedged Contracts
5

Peak

6 For Month of:	Reference	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Strip Average
7 (a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
245	NYMEX Settlement - 15 Day Average							
246	Days	Date						
247		02-Aug	4.9080	5.1450	5.2820	5.2530	5.1520	4.9700
248		03-Aug	4.8510	5.1070	5.2450	5.2170	5.1190	4.9460
249		04-Aug	4.9090	5.1490	5.2850	5.2520	5.1520	4.9820
250	1	05-Aug	4.7950	5.0470	5.1840	5.1550	5.0580	4.9090
251	2	06-Aug	4.7270	5.0010	5.1390	5.1120	5.0350	4.8790
252		07-Aug						
253		08-Aug						
254	3	09-Aug	4.5960	4.8890	5.0280	5.0130	4.9230	4.7950
255	4	10-Aug	4.5550	4.8170	4.9490	4.9330	4.8470	4.7160
256	5	11-Aug	4.5460	4.7770	4.9060	4.8890	4.8110	4.6760
257	6	12-Aug	4.5730	4.8480	4.9730	4.9570	4.8750	4.7430
258	7	13-Aug	4.5850	4.8690	5.0020	4.9860	4.9030	4.7710
259		14-Aug						
260		15-Aug						
261	8	16-Aug	4.4560	4.7250	4.8650	4.8500	4.7720	4.6540
262	9	17-Aug	4.4730	4.7320	4.8690	4.8550	4.7750	4.6570
263	10	18-Aug	4.4730	4.7340	4.8720	4.8550	4.7780	4.6580
264	11	19-Aug	4.4020	4.6630	4.8100	4.7930	4.7170	4.6070
265	12	20-Aug	4.3420	4.6060	4.7520	4.7360	4.6620	4.5610
266		21-Aug						
267		22-Aug						
268	13	23-Aug	4.2790	4.5390	4.6840	4.6730	4.6030	4.5110
269	14	24-Aug	4.2490	4.4920	4.6360	4.6240	4.5580	4.4660
270	15	25-Aug	4.1320	4.4110	4.5670	4.5570	4.4950	4.4030
271								
272								
273	15 Day Average		4.4789	4.7433	4.8824	4.8659	4.7875	4.6671

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Residential Heating Rate R-3
5
6
7 November 1, 2010 - April 30, 2011
8 Residential Heating (R3)

			Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr
			109	150	187	188	166	132	932
Typical Usage (Therms)	07/01/2010	06/01/2010							
Winter:									
Cust. Chg	\$15.78		\$15.78	\$15.78	\$15.78	\$15.78	\$15.78	\$15.78	\$94.68
Headblock	\$0.2774		\$27.74	\$27.74	\$27.74	\$27.74	\$27.74	\$27.74	\$166.44
Tailblock	\$0.2091		\$1.88	\$10.46	\$18.19	\$18.40	\$13.80	\$6.69	\$69.42
HB Threshold	100								
Summer:									
Cust. Chg	\$15.78	\$15.62							
Headblock	\$0.2774	\$0.2747							
Tailblock	\$0.2091	\$0.2070							
HB Threshold	20	20							
Total Base Rate Amount			\$45.40	\$53.98	\$61.71	\$61.92	\$57.32	\$50.21	\$330.54
CGA Rate - (Seasonal)			\$0.8220	\$0.8220	\$0.8220	\$0.8220	\$0.8220	\$0.8220	\$0.8220
CGA amount			\$89.60	\$123.30	\$153.71	\$154.54	\$136.45	\$108.50	\$766.10
LDAC			\$0.0641	\$0.0641	\$0.0641	\$0.0641	\$0.0641	\$0.0641	0.0641
LDAC amount			\$6.99	\$9.62	\$11.99	\$12.05	\$10.64	\$8.46	\$59.74
Total Bill			\$141.99	\$186.89	\$227.41	\$228.51	\$204.41	\$167.18	\$1,156.39

Residential Heating (R3)

			Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr
			109	150	187	188	166	132	932
Typical Usage (Therms)	08/01/2009	07/01/2009							
Winter:									
Cust. Chg	\$14.03		\$14.03	\$14.03	\$14.03	\$14.03	\$14.03	\$14.03	\$84.18
Headblock	\$0.2467		24.67	24.67	24.67	24.67	24.67	24.67	\$148.02
Tailblock	\$0.1859		\$1.67	\$9.30	\$16.17	\$16.36	\$12.27	\$5.95	\$61.72
HB Threshold	100								
Summer:									
Cust. Chg	\$14.03	\$13.95							
Headblock	\$0.2467	\$0.2453							
Tailblock	\$0.1859	\$0.1849							
HB Threshold	20	20							
Total Base Rate Amount			\$40.37	\$48.00	\$54.87	\$55.06	\$50.97	\$44.65	\$293.92
CGA Rate - (Seasonal)			\$0.9663	\$0.9239	\$0.8975	\$0.9155	\$1.0230	\$0.9385	\$0.9416
CGA amount			\$105.33	\$138.58	\$167.83	\$172.12	\$169.82	\$123.88	\$877.54
LDAC			\$0.0404	\$0.0404	\$0.0404	\$0.0404	\$0.0404	\$0.0404	0.0404
LDAC amount			\$4.40	\$6.06	\$7.55	\$7.60	\$6.71	\$5.33	\$37.65
Total Bill			\$150.10	\$192.63	\$230.25	\$234.77	\$227.49	\$173.86	\$1,209.12

DIFFERENCE:

Total Bill	(\$8.12)	(\$5.74)	(\$2.84)	(\$6.26)	(\$23.08)	(\$6.69)	(\$52.73)
% Change	-5.41%	-2.98%	-1.23%	-2.67%	-10.15%	-3.85%	-4.36%
Base Rate	\$5.03	\$5.98	\$6.84	\$6.86	\$6.35	\$5.56	\$36.62
% Change	12.46%	12.46%	12.46%	12.46%	12.46%	12.46%	12.46%
CGA & LDAC	(\$13.15)	(\$11.72)	(\$9.68)	(\$13.12)	(\$29.43)	(\$12.25)	(\$89.35)
% Change	-12.48%	-8.46%	-5.77%	-7.63%	-17.33%	-9.89%	-10.18%

May 1, 2010 - October 31, 2010

May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
90	55	30	30	42	71	318	1,250
\$14.03	\$15.62	\$15.78	\$15.78	\$15.78	\$15.78	\$92.77	\$187.45
\$4.93	\$5.49	\$5.55	\$5.55	\$5.55	\$5.55	\$32.62	\$199.06
\$13.01	\$7.25	\$2.09	\$2.09	\$4.60	\$10.66	\$39.70	\$109.13
\$31.98	\$28.36	\$23.42	\$23.42	\$25.93	\$31.99	\$165.09	\$495.64
\$0.7126	\$0.7208	\$0.7998	\$0.7385	\$0.7385	\$0.7385	\$0.7339	\$0.7996
\$64.13	\$39.64	\$23.99	\$22.16	\$31.02	\$52.43	\$233.38	\$999.48
\$0.0404	\$0.0404	\$0.0404	\$0.0404	\$0.0404	\$0.0404	\$0.0404	\$0.0581
\$3.64	\$2.22	\$1.21	\$1.21	\$1.70	\$2.87	\$12.85	\$72.59
\$99.75	\$70.23	\$48.63	\$46.79	\$58.64	\$87.29	\$411.32	\$1,567.71

May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
90	55	30	30	42	71	318	1,250
\$11.46	\$11.46	\$13.95	\$14.03	\$14.03	\$14.03	\$78.96	\$163.14
\$6.71	\$6.71	\$4.91	\$4.93	\$4.93	\$4.93	\$33.13	\$181.15
\$13.65	\$6.83	\$1.85	\$1.86	\$4.09	\$9.48	\$37.75	\$99.47
\$31.82	\$25.00	\$20.71	\$20.82	\$23.05	\$28.44	\$149.85	\$443.76
\$0.6722	\$0.6324	\$0.6200	\$0.6077	\$0.5866	\$0.5272	\$0.6106	\$0.8574
\$60.50	\$34.78	\$18.60	\$18.23	\$24.64	\$37.43	\$194.18	\$1,071.72
\$0.0260	\$0.0260	\$0.0260	\$0.0260	\$0.0260	\$0.0260	\$0.0260	\$0.0367
\$2.34	\$1.43	\$0.78	\$0.78	\$1.09	\$1.85	\$8.27	\$45.92
\$94.66	\$61.21	\$40.09	\$39.83	\$48.78	\$67.72	\$352.29	\$1,561.41

\$5.09	\$9.02	\$8.54	\$6.95	\$9.86	\$19.57	\$59.03	\$6.30
5.37%	14.73%	21.30%	17.45%	20.21%	28.90%	16.75%	0.40%
\$0.15	\$3.36	\$2.71	\$2.60	\$2.87	\$3.55	\$15.25	\$51.87
0.49%	13.45%	13.11%	12.47%	12.47%	12.47%	10.18%	11.69%
\$4.93	\$5.65	\$5.83	\$4.36	\$6.98	\$16.02	\$43.78	(\$45.57)
8.15%	16.26%	31.32%	23.89%	28.35%	42.81%	22.54%	-4.25%

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Commercial Rate G-41
5
6
7 November 1, 2010 - April 30, 2011
8 Commercial Rate (G-41)

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr
Typical Usage (Therms)		193	269	298	262	234	171	1,427
Winter:	07/01/2010 06/01/2010							
Cust. Chg	\$39.45	\$39.45	\$39.45	\$39.45	\$39.45	\$39.45	\$39.45	\$236.70
Headblock	\$0.3344	\$33.44	\$33.44	\$33.44	\$33.44	\$33.44	\$33.44	\$200.64
Tailblock	\$0.2175	\$20.23	\$36.76	\$43.07	\$35.24	\$29.15	\$15.44	\$179.87
HB Threshold	100							
Summer:								
Cust. Chg	\$39.45 \$39.07							
Headblock	\$0.3344 \$0.3312							
Tailblock	\$0.2175 \$0.2154							
HB Threshold	20 20							
Total Base Rate Amount		\$93.12	\$109.65	\$115.96	\$108.13	\$102.04	\$88.33	\$617.21
CGA Rate - (Seasonal)		\$0.8234	\$0.8234	\$0.8234	\$0.8234	\$0.8234	\$0.8234	\$0.8234
CGA amount		\$158.92	\$221.49	\$245.37	\$215.73	\$192.68	\$140.80	\$1,174.99
LDAC		\$0.0422	\$0.0422	\$0.0422	\$0.0422	\$0.0422	\$0.0422	0.0422
LDAC amount		\$8.14	\$11.35	\$12.58	\$11.06	\$9.87	\$7.22	\$60.22
Total Bill		\$260.18	\$342.49	\$373.90	\$334.91	\$304.59	\$236.35	\$1,852.42

35 November 1, 2010 - April 30, 2011
36 Commercial Rate (G-41)

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr
Typical Usage (Therms)		193	269	298	262	234	171	1,427
Winter:	08/01/2009 07/01/2009							
Cust. Chg	\$35.08	\$35.08	\$35.08	\$35.08	\$35.08	\$35.08	\$35.08	\$210.48
Headblock	\$0.2974	29.74	29.74	29.74	29.74	29.74	29.74	\$178.44
Tailblock	\$0.1934	\$17.99	\$32.68	\$38.29	\$31.33	\$25.92	\$13.73	\$159.94
HB Threshold	100							
Summer:								
Cust. Chg	\$35.08 \$34.88							
Headblock	\$0.2974 \$0.2956							
Tailblock	\$0.1934 \$0.1923							
HB Threshold	20 20							
Total Base Rate Amount		\$82.81	\$97.50	\$103.11	\$96.15	\$90.74	\$78.55	\$548.86
CGA Rate - (Seasonal)	08/24/2008 \$28.58	\$0.9665	\$0.9241	\$0.8977	\$0.9157	\$1.0232	\$0.9387	\$0.9408
CGA amount	\$0.3732	\$186.53	\$248.57	\$267.50	\$239.92	\$239.43	\$160.52	\$1,342.47
	\$0.2427							
LDAC	20	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	0.0194
LDAC amount		\$3.74	\$5.22	\$5.78	\$5.08	\$4.54	\$3.32	\$27.68
Total Bill		\$273.08	\$351.30	\$376.40	\$341.15	\$334.70	\$242.38	\$1,919.01

63 DIFFERENCE:

Total Bill	(\$12.91)	(\$8.80)	(\$2.49)	(\$6.24)	(\$30.12)	(\$6.03)	(\$66.59)
% Change	-4.73%	-2.51%	-0.66%	-1.83%	-9.00%	-2.49%	-3.47%
Base Rate	\$10.31	\$12.14	\$12.84	\$11.97	\$11.30	\$9.78	\$68.35
% Change	12.45%	12.45%	12.45%	12.45%	12.45%	12.45%	12.45%
CGA & LDAC	(\$23.22)	(\$20.94)	(\$15.34)	(\$18.21)	(\$41.42)	(\$15.82)	(\$134.94)
% Change	-12.45%	-8.43%	-5.73%	-7.59%	-17.30%	-9.85%	-10.05%

May 1, 2010 - October 31, 2010

May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
117	81	72	72	89	142	573	2,000
\$35.08	\$39.07	\$39.45	\$39.45	\$39.45	\$39.45	\$231.95	\$468.65
\$5.95	\$6.62	\$6.69	\$6.69	\$6.69	\$6.69	\$39.32	\$239.96
\$18.76	\$13.14	\$11.31	\$11.31	\$15.01	\$26.54	\$96.06	\$275.93
\$59.79	\$58.83	\$57.45	\$57.45	\$61.15	\$72.67	\$367.34	\$984.55
\$0.7029	\$0.7111	\$0.7901	\$0.7288	\$0.7288	\$0.7288	\$0.7287	\$0.7963
\$82.24	\$57.60	\$56.89	\$52.47	\$64.86	\$103.49	\$417.55	\$1,592.54
\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0357
\$2.27	\$1.57	\$1.40	\$1.40	\$1.73	\$2.75	\$11.12	\$71.34
\$144.30	\$118.00	\$115.73	\$111.32	\$127.74	\$178.92	\$796.00	\$2,648.43

May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
117	81	72	72	89	142	573	2,000
\$28.58	\$28.58	\$34.88	\$35.08	\$35.08	\$35.08	\$197.28	\$407.76
\$7.46	\$7.46	\$5.91	\$5.95	\$5.95	\$5.95	\$38.68	\$217.12
\$23.54	\$14.80	\$10.00	\$10.06	\$13.34	\$23.59	\$95.34	\$255.28
\$59.59	\$50.85	\$50.79	\$51.08	\$54.37	\$64.62	\$331.31	\$880.17
\$0.6727	\$0.6329	\$0.6205	\$0.6082	\$0.5871	\$0.5277	\$0.6032	\$0.8440
\$78.71	\$51.26	\$44.68	\$43.79	\$52.25	\$74.93	\$345.62	\$1,688.09
\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0218
\$3.25	\$2.25	\$2.00	\$2.00	\$2.47	\$3.95	\$15.93	\$43.61
\$141.54	\$104.37	\$97.47	\$96.88	\$109.10	\$143.50	\$692.86	\$2,611.87

\$2.75	\$13.64	\$18.26	\$14.44	\$18.64	\$35.41	\$103.15	\$36.55
1.94%	13.07%	18.74%	14.91%	17.08%	24.68%	14.89%	1.40%
\$0.20	\$7.98	\$6.66	\$6.36	\$6.77	\$8.05	\$36.03	\$104.38
0.34%	15.70%	13.11%	12.46%	12.46%	12.46%	10.87%	11.86%
\$2.55	\$5.65	\$11.61	\$8.08	\$11.86	\$27.36	\$67.12	(\$67.83)
3.24%	11.03%	25.98%	18.45%	22.70%	36.52%	19.42%	-4.02%

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Commercial Rate G-42
5
6
7 November 1, 2010 - April 30, 2011
8 C&I High Winter Use Medium G-42

May 1, 2010 - October 31, 2010

Typical Usage (Therms)	07/01/2010 06/01/2010	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr
		1,553	2,578	3,265	4,103	3,402	2,473	17,374
Winter:								
Cust. Chg	\$112.73	\$112.73	\$112.73	\$112.73	\$112.73	\$112.73	\$112.73	\$676.38
Headblock	\$0.2971	\$297.10	\$297.10	\$297.10	\$297.10	\$297.10	\$297.10	\$1,782.60
Tailblock	\$0.1962	\$108.50	\$309.60	\$444.39	\$608.81	\$471.27	\$289.00	\$2,231.58
HB Threshold	1,000							
Summer:								
Cust. Chg	\$112.73 \$111.63							
Headblock	\$0.2971 \$0.2942							
Tailblock	\$0.1962 \$0.1943							
HB Threshold	400 400							
Total Base Rate Amount		\$518.33	\$719.43	\$854.22	\$1,018.64	\$881.10	\$698.83	\$4,690.56
CGA Rate - (Seasonal)		\$0.8234	\$0.8234	\$0.8234	\$0.8234	\$0.8234	\$0.8234	\$0.8234
CGA amount		\$1,278.74	\$2,122.73	\$2,688.40	\$3,378.41	\$2,801.21	\$2,036.27	\$14,305.75
LDAC		\$0.0422	\$0.0422	\$0.0422	\$0.0422	\$0.0422	\$0.0422	0.0422
LDAC amount		\$65.54	\$108.79	\$137.78	\$173.15	\$143.56	\$104.36	\$733.18
Total Bill		\$1,862.61	\$2,950.95	\$3,680.41	\$4,570.20	\$3,825.87	\$2,839.46	\$19,729.49

May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
1,258	701	414	213	364	699	3,649	21,023
\$100.24	\$111.63	\$112.73	\$112.73	\$112.73	\$112.73	\$662.79	\$1,339.17
\$105.68	\$117.68	\$118.84	\$63.28	\$108.14	\$118.84	\$632.47	\$2,415.07
\$149.72	\$58.48	\$2.75	\$0.00	\$0.00	\$58.66	\$269.62	\$2,501.19
\$355.64	\$287.79	\$234.32	\$176.01	\$220.87	\$290.23	\$1,564.87	\$6,255.43
\$0.7029	\$0.7111	\$0.7901	\$0.7288	\$0.7288	\$0.7288	\$0.7234	\$0.8060
\$884.25	\$498.48	\$327.10	\$155.23	\$265.28	\$509.43	\$2,639.78	\$16,945.53
\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0382
\$24.41	\$13.60	\$8.03	\$4.13	\$7.06	\$13.56	\$70.79	\$803.97
\$1,264.29	\$799.87	\$569.45	\$335.38	\$493.22	\$813.23	\$4,275.44	\$24,004.94

35 November 1, 2010 - April 30, 2011
36 C&I High Winter Use Medium G-42

Typical Usage (Therms)	08/01/2009 07/01/2009	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr
		1,553	2,578	3,265	4,103	3,402	2,473	17,374
Winter:								
Cust. Chg	\$100.24	\$100.24	\$100.24	\$100.24	\$100.24	\$100.24	\$100.24	\$601.44
Headblock	\$0.2642	264.20	264.20	264.20	264.20	264.20	264.20	\$1,585.20
Tailblock	\$0.1745	\$96.50	\$275.36	\$395.24	\$541.47	\$419.15	\$257.04	\$1,984.76
HB Threshold	1,000							
Summer:								
Cust. Chg	\$100.24 \$99.66							
Headblock	\$0.2642 \$0.2627							
Tailblock	\$0.1745 \$0.1735							
HB Threshold	400 400							
Total Base Rate Amount	08/24/08	\$460.94	\$639.80	\$759.68	\$905.91	\$783.59	\$621.48	\$4,171.40
CGA Rate - (Seasonal)	\$80.44	\$0.9665	\$0.9241	\$0.8977	\$0.9157	\$1.0232	\$0.9387	\$0.9424
CGA amount	\$0.3095	\$1,500.97	\$2,382.23	\$2,930.87	\$3,757.15	\$3,480.91	\$2,321.37	\$16,373.51
LDAC	\$0.2044	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	0.0194
LDAC amount	400	\$30.13	\$50.01	\$63.34	\$79.60	\$66.00	\$47.98	\$337.06
Total Bill		\$1,992.04	\$3,072.05	\$3,753.89	\$4,742.66	\$4,330.50	\$2,990.83	\$20,881.97

May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
1,258	701	414	213	364	699	3,649	21,023
\$80.44	\$80.44	\$99.66	\$100.24	\$100.24	\$100.24	\$561.26	\$1,162.70
\$123.80	\$123.80	\$105.08	\$56.27	\$96.17	\$105.68	\$610.80	\$2,196.00
\$175.38	\$61.52	\$2.43	\$0.00	\$0.00	\$52.18	\$291.50	\$2,276.27
\$379.62	\$265.76	\$207.17	\$156.51	\$196.41	\$258.10	\$1,463.57	\$5,634.97
\$0.6727	\$0.6329	\$0.6205	\$0.6082	\$0.5871	\$0.5277	\$0.6191	\$0.8863
\$846.26	\$443.66	\$256.89	\$129.55	\$213.70	\$368.86	\$2,258.92	\$18,632.43
\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0209
\$34.97	\$19.49	\$11.51	\$5.92	\$10.12	\$19.43	\$101.44	\$438.50
\$1,260.84	\$728.92	\$475.57	\$291.98	\$420.23	\$646.39	\$3,823.93	\$24,705.90

63 DIFFERENCE:

Total Bill	(\$129.44)	(\$121.10)	(\$73.48)	(\$172.47)	(\$504.63)	(\$151.37)	(\$1,152.47)
% Change	-6.50%	-3.94%	-1.96%	-3.64%	-11.65%	-5.06%	-5.52%
Base Rate	\$57.39	\$79.63	\$94.54	\$112.73	\$97.51	\$77.35	\$519.16
% Change	12.45%	12.45%	12.44%	12.44%	12.44%	12.45%	12.45%
CGA & LDAC	(\$186.83)	(\$200.73)	(\$168.02)	(\$285.19)	(\$602.14)	(\$228.72)	(\$1,671.63)
% Change	-12.45%	-8.43%	-5.73%	-7.59%	-17.30%	-9.85%	-10.21%

\$3.45	\$70.96	\$93.88	\$43.40	\$72.99	\$166.84	\$451.51	(\$700.96)
0.27%	9.73%	19.74%	14.86%	17.37%	25.81%	11.81%	-2.84%
(\$23.97)	\$22.03	\$27.15	\$19.50	\$24.47	\$32.14	\$101.31	\$620.46
-6.32%	8.29%	13.10%	12.46%	12.46%	12.45%	6.92%	11.01%
\$27.42	\$48.93	\$66.74	\$23.90	\$48.52	\$134.70	\$350.21	(\$1,321.42)
3.24%	11.03%	25.98%	18.45%	22.70%	36.52%	15.50%	-7.09%

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Annual Bill Comparisons, Nov 09 - Apr 10 vs Nov 10 - Apr 11 - Commercial Rate G-52
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7 November 1, 2010 - April 30, 2011
8 Commercial Rate (G-52)

		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Winter Nov-Apr
Typical Usage (Therms)		1,722	2,086	2,330	2,333	2,291	1,872	12,634
Winter:	07/01/2010 06/01/2010							
Cust. Chg	\$112.73	\$112.73	\$112.73	\$112.73	\$112.73	\$112.73	\$112.73	\$676.38
Headblock	\$0.1692	\$169.20	\$169.20	\$169.20	\$169.20	\$169.20	\$169.20	\$1,015.20
Tailblock	\$0.1148	\$82.89	\$124.67	\$152.68	\$153.03	\$148.21	\$100.11	\$761.58
HB Threshold	1,000							
Summer:								
Cust. Chg	\$112.73 \$111.63							
Headblock	\$0.1244 \$0.1232							
Tailblock	\$0.0716 \$0.0709							
HB Threshold	1,000 1,000							
Total Base Rate Amount		\$364.82	\$406.60	\$434.61	\$434.96	\$430.14	\$382.04	\$2,453.16
CGA Rate - (Seasonal)		\$0.8186	\$0.8186	\$0.8186	\$0.8186	\$0.8186	\$0.8186	\$0.8186
CGA amount		\$1,409.63	\$1,707.60	\$1,907.34	\$1,909.79	\$1,875.41	\$1,532.42	\$10,342.19
LDAC		\$0.0422	\$0.0422	\$0.0422	\$0.0422	\$0.0422	\$0.0422	0.0422
LDAC amount		\$72.67	\$88.03	\$98.33	\$98.45	\$96.68	\$79.00	\$533.15
Total Bill		\$1,847.11	\$2,202.23	\$2,440.28	\$2,443.20	\$2,402.23	\$1,993.45	\$13,328.51

35 November 1, 2010 - April 30, 2011
36 Commercial Rate (G-52)

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Winter Nov-Apr
Typical Usage (Therms)		1,722	2,086	2,330	2,333	2,291	1,872	12,634
Winter:	08/01/2009 07/01/2009							
Cust. Chg	\$100.24	\$100.24	\$100.24	\$100.24	\$100.24	\$100.24	\$100.24	\$601.44
Headblock	\$0.1505	150.50	150.50	150.50	150.50	150.50	150.50	\$903.00
Tailblock	\$0.1021	\$73.72	\$110.88	\$135.79	\$136.10	\$131.81	\$89.03	\$677.33
HB Threshold	1,000							
Summer:								
Cust. Chg	\$100.24 \$99.66							
Headblock	\$0.1106 \$0.1100							
Tailblock	\$0.0637 \$0.0633							
HB Threshold	1,000 1,000							
Total Base Rate Amount		\$324.46	\$361.62	\$386.53	\$386.84	\$382.55	\$339.77	\$2,181.77
CGA Rate - (Seasonal)	08/24/08 \$80.36	\$0.9658	\$0.9234	\$0.8970	\$0.9150	\$1.0225	\$0.9380	\$0.9429
CGA amount	\$0.1453	\$1,663.11	\$1,926.13	\$2,089.92	\$2,134.71	\$2,342.54	\$1,755.91	\$11,912.33
LDAC	\$0.0836	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	0.0194
LDAC amount	1,000	\$33.41	\$40.47	\$45.20	\$45.26	\$44.45	\$36.32	\$245.10
Total Bill		\$2,020.97	\$2,328.22	\$2,521.66	\$2,566.81	\$2,769.53	\$2,132.00	\$14,339.20

63 DIFFERENCE:

Total Bill	(\$173.86)	(\$125.99)	(\$81.38)	(\$123.61)	(\$367.31)	(\$138.55)	(\$1,010.69)
% Change	-8.60%	-5.41%	-3.23%	-4.82%	-13.26%	-6.50%	-7.05%
Base Rate	\$40.36	\$44.98	\$48.08	\$48.12	\$47.59	\$42.26	\$271.39
% Change	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%
CGA & LDAC	(\$214.22)	(\$170.97)	(\$129.46)	(\$171.73)	(\$414.89)	(\$180.81)	(\$1,282.08)
% Change	-12.88%	-8.88%	-6.19%	-8.04%	-17.71%	-10.30%	-10.76%

May 1, 2010 - October 31, 2010

May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Summer May-Oct	Total Nov-Oct
1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
\$100.24	\$111.63	\$112.73	\$112.73	\$112.73	\$112.73	\$662.79	\$1,339.17
\$110.60	\$123.20	\$124.40	\$124.40	\$124.40	\$124.40	\$731.40	\$1,746.60
\$32.49	\$26.52	\$17.69	\$13.60	\$15.04	\$23.20	\$128.53	\$890.11
\$243.33	\$261.35	\$254.82	\$250.73	\$252.17	\$260.33	\$1,522.72	\$3,975.88
\$0.7020	\$0.7102	\$0.7892	\$0.7279	\$0.7279	\$0.7279	\$0.7296	\$0.7845
\$1,060.02	\$975.81	\$984.13	\$866.20	\$880.76	\$963.74	\$5,730.67	\$16,072.86
\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0194	\$0.0335
\$29.29	\$26.66	\$24.19	\$23.09	\$23.47	\$25.69	\$152.39	\$685.54
\$1,332.64	\$1,263.82	\$1,263.14	\$1,140.02	\$1,156.40	\$1,249.75	\$7,405.77	\$20,734.28

May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Summer May-Oct	Total Nov-Oct
1,510	1,374	1,247	1,190	1,210	1,324	7,855	20,489
\$80.36	\$80.36	\$99.66	\$100.24	\$100.24	\$100.24	\$561.10	\$1,162.54
\$145.30	\$145.30	\$110.00	\$110.60	\$110.60	\$110.60	\$732.40	\$1,635.40
\$42.64	\$31.27	\$15.64	\$12.10	\$13.38	\$20.64	\$135.66	\$812.99
\$268.30	\$256.93	\$225.30	\$222.94	\$224.22	\$231.48	\$1,429.16	\$3,610.93
\$0.6707	\$0.6309	\$0.6185	\$0.6062	\$0.5851	\$0.5257	\$0.6081	\$0.8145
\$1,012.76	\$866.86	\$771.27	\$721.38	\$707.97	\$696.03	\$4,776.26	\$16,688.59
\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0278	\$0.0226
\$41.98	\$38.20	\$34.67	\$33.08	\$33.64	\$36.81	\$218.37	\$463.47
\$1,323.03	\$1,161.98	\$1,031.23	\$977.40	\$965.83	\$964.31	\$6,423.78	\$20,762.98

\$9.61	\$101.84	\$231.91	\$162.62	\$190.57	\$285.44	\$981.99	(\$28.70)
0.73%	8.76%	22.49%	16.64%	19.73%	29.60%	15.29%	-0.14%
(\$24.97)	\$4.42	\$29.52	\$27.79	\$27.95	\$28.85	\$93.56	\$364.95
-9.31%	1.72%	13.10%	12.47%	12.47%	12.46%	6.55%	10.11%
\$34.58	\$97.42	\$202.39	\$134.83	\$162.62	\$256.59	\$888.43	(\$393.65)
3.41%	11.24%	26.24%	18.69%	22.97%	36.87%	18.60%	-2.36%

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1 ENERGY NORTH NATURAL GAS, INC.

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

4 Residential Heating

	<u>Winter 2009-10</u>	<u>Winter 2010-11</u>
5		
6 Customer Charge	\$14.03	\$15.78
7 First 100 Therms	\$0.2467	\$0.2774
8 Excess 100 Therms	\$0.1859	\$0.2091
9 LDAC	\$0.0404	\$0.0641
10 CGA	\$0.9416	\$0.8220
11 Total Adjust	\$0.9820	\$0.8861

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	<u>Winter 2009-10 CGA @</u>	<u>Winter 2010-11 CGA @</u>
	\$0.9820	\$0.8861
19 Cooking alone	5 \$20.17	\$21.60
21	10 \$26.32	\$27.42
23	20 \$38.60	\$39.05
25 Water Heating alone	30 \$50.89	\$50.69
27	45 \$69.32	\$68.14
29	50 \$75.46	\$73.96
31 Heating Alone	80 \$106.18	\$103.04
33	125 \$175.44	\$168.27
35	150 \$195.29	\$186.89
37	200 \$253.68	\$241.65

Total		Base Rate		CGA		LDAC	
\$ Impact	% Impact	\$ Impact	% Impact	\$ Impact	% Impact	\$ Impact	% Impact
(\$0.10)	-10%						
\$1.42	7%	\$1.90	9%	-\$0.60	-3%	\$0.12	1%
\$1.10	4%	\$2.06	8%	-\$1.20	-4%	\$0.24	1%
\$0.45	1%	\$2.36	6%	-\$2.39	-6%	\$0.47	1%
(\$0.21)	0%	\$2.67	5%	-\$3.59	-7%	\$0.71	1%
(\$1.18)	-2%	\$3.13	5%	-\$5.38	-8%	\$1.07	2%
(\$1.51)	-2%	\$3.29	4%	-\$5.98	-8%	\$1.19	2%
(\$3.14)	-3%	\$4.05	4%	-\$8.97	-9%	\$1.78	2%
(\$7.17)	-4%	\$5.59	3%	-\$15.90	-9%	\$3.15	2%
(\$8.40)	-4%	\$5.98	3%	-\$17.94	-10%	\$3.56	2%
(\$12.03)	-5%	\$7.14	3%	-\$23.91	-10%	\$4.74	2%

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Variance Analysis of the Components of the 2009-10 Actual Results vs Proposed Winter 2010-11 Cost of Gas Rate**
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	WINTER SALES ACTUAL RESULTS (6 months actual)			WINTER 2010-11 (6 months Proposed)		
	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
11 Therm Sales	73,960,615			83,071,582		
16 Demand Charges	\$ 7,011,816	\$ 0.0948		\$ 9,370,456	\$ 0.1128	
18 Purchased Gas	70,464,050	41,899,383	0.5665	71,402,980	39,083,750	0.4705
20 Storage Gas	6,078,800	3,863,102	0.0522	13,072,818	7,649,468	0.0921
22 Produced Gas	276,060	230,970	0.0031	1,443,345	1,255,498	0.0151
24 Hedging (Gain)/Loss		16,493,046	0.2230		6,268,136	0.0755
27 Total Volumes and Cost	76,818,910	\$ 69,498,318	\$ 0.9397	85,919,143	\$ 63,627,308	\$ 0.7659
29 Prior Period Balance	\$ 779,942	\$ 0.0105		2,985,736	\$ 0.0359	
30 Interest	51,658	0.0007		101,158	0.0012	
31 Prior Period Adjustment	(116,154)	(0.0016)		-	-	
32 Broker Revenues	(777,372)	(0.0105)		(754,779)	(0.0091)	
33 Refunds from Suppliers	-	-		-	-	
34 Fuel Financing	130,926	0.0018		130,835	0.0016	
35 Transportation CGA Revenues	9,404	0.0001		(31,147)	(0.0004)	
36 280 Day Margin	-	-		-	-	
37 Interruptible Sales Margin	-	-		-	-	
38 Capacity Release and Off System Sales Margins	(391,544)	(0.0053)		(730,714)	(0.0088)	
39 Hedging Costs	-	-		-	-	
40 Misc Overhead	20,121	0.0003		5,281	0.0001	
41 Occupant Disallowance/Credits	-	-		-	-	
42 Production & Storage	1,749,387	0.0237		-	-	
43 FPO Admin Costs	-	-		40,691	0.0005	
44 Indirect Gas Costs	1,102,718	0.0149		2,909,211	0.0350	
46 Total Adjusted Cost	\$ 72,057,402	\$ 0.9743		\$ 68,283,580	\$ 0.8220	

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ENERGY NORTH NATURAL GAS, INC.**d/b/a National Grid NH****Peak 2010 - 2011 Winter Cost of Gas Filing****Capacity Assignment Calculations 2010-2011****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	619	651	0.5%		156	495
2	RATE R-3-Resi Htg	60,544	64,337	46.8%		3,993	60,344
3	RATE G-41 (T)	22,322	23,761	17.3%		851	22,910
4	RATE G-51 (S)	2,481	2,605	1.9%		627	1,978
5	RATE G-42 (V)	31,102	33,077	24.1%		1,653	31,424
6	RATE G-52	4,119	4,311	3.1%		1,247	3,064
7	RATE G-43	4,354	4,615	3.4%		463	4,152
8	RATE G-53	1,514	1,595	1.2%		297	1,298
9	RATE G-54	2,319	2,449	1.8%		384	2,065
10							
11	Total	129,373	137,401	100.0%		9,671	127,730
12							
13	Residential Total	61,163	64,988	47.298%		4,148	60,840
14	LLF Total	57,778	61,453	44.725%		2,966	58,487
15	HLF Total	10,432	10,960	7.977%		2,556	8,404
16	Total	129,373	137,401	100.0%		9,671	127,730
17							
18	C&I Breakdown						
19	LLF Total					2,966	58,487
20	HLF Total					2,556	8,404
21	Total					5,522	66,891
22							
23	C&I Breakdown Percentage						
24	LLF Total					53.715%	87.436%
25	HLF Total					46.285%	12.564%
26	Total					100.0%	100.0%
27							
28		Capacity Cost	MDQ, Dt	\$/Dt-Mo.			
29	Pipeline	\$5,110,048	53,718	\$7.9273			
30	Storage	\$3,917,934	28,115	\$11.6128			
31							
32	Peaking	\$7,016,421					
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)	\$853,183					
34	Subtotal Peaking Costs	\$7,869,604	55,567	\$11.8020			
35	Total	\$16,897,587	137,400	\$10.2484			
36							
37		Capacity Cost	MDQ, Dt	\$/Dt-Mo.			
38	Pipeline - Baseload	919,948	9,671	\$7.9273			
39	Pipeline - Remaining	4,190,100	44,047	\$7.9273			
40	Storage	3,917,934	28,115	\$11.6128			
41	Peaking	7,869,604	55,567	\$11.8020			
42	Total	16,897,587	137,400	\$10.2484			
43							
44							
45	Residential Allocation	Capacity Cost	MDQ, Dt	\$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	47.298%	435,117	4,574	\$7.9273	
47	Pipeline - Remaining	Line 39 * Line 13 Col C	47.298%	1,981,841	20,834	\$7.9273	
48	Storage	Line 40 * Line 13 Col C	47.298%	1,853,100	13,298	\$11.6128	
49	Peaking	Line 41 * Line 13 Col C	47.298%	3,722,162	26,282	\$11.8020	
50	Total		47.298%	7,992,199	64,987	\$10.2484	

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ENERGY NORTH NATURAL GAS, INC.

d/b/a National Grid NH

Peak 2010 - 2011 Winter Cost of Gas Filing

Capacity Assignment Calculations 2010-2011

Derivation of Class Assignments and Weightings

51									
52									
53	C&I Allocation		Capacity Cost	MDQ, Dt	\$/Dt-Mo.				Ratios for COG
54	Pipeline - Base	Line 38 - Line 46	484,831	5,097	\$7.9273				
55	Pipeline - Remaining	Line 39 - Line 47	2,208,259	23,214	\$7.9272				
56	Storage	Line 40 - Line 48	2,064,834	14,817	\$11.6128				
57	Peaking	Line 41 - Line 49	4,147,442	29,285	\$11.8020				
58	Total		52.702%	8,905,365	72,413	\$10.2484			1.0000
59									
60									
61	LLF - C&I Allocation		Capacity Cost	MDQ, Dt	\$/Dt-Mo.				
62	Pipeline - Base	Line 54 * Line 24 Col E	260,429	2,738	\$7.9264				
63	Pipeline - Remaining	Line 55 * Line 24 Col F	1,930,817	20,297	\$7.9273				
64	Storage	Line 56 * Line 24 Col F	1,805,411	12,956	\$11.6125				
65	Peaking	Line 57 * Line 24 Col F	3,626,364	25,606	\$11.8018				
66	Total		45.1131%	7,623,021	61,597	\$10.3130			1.0063
67			53.715%	86%					(Line 66 / Line 58)
68									
69	HLF - C&I Allocation		Capacity Cost	MDQ, Dt	\$/Dt-Mo.				
70	Pipeline - Base	Line 54 - Line 62	224,402	2,359	\$7.9272				
71	Pipeline - Remaining	Line 55 - Line 63	277,442	2,917	\$7.9260				
72	Storage	Line 56 - Line 64	259,423	1,861	\$11.6166				
73	Peaking	Line 57 - Line 65	521,078	3,679	\$11.8030				
74	Total		7.5889%	1,282,345	10,816	\$9.8800			0.9641
75									(Line 74 / Line 58)
76									
77	Unit Cost		Residential	LLF C&I	HLF C&I				
78									
79	Pipeline		\$ 7.9273	\$ 7.9273	\$ 7.9273				
80	Storage		\$ 11.6128	\$ 11.6128	\$ 11.6128				
81	Peaking		\$ -	\$ -	\$ -				
82	Total		\$ 10.2484	\$ 10.3130	\$ 9.8800				
83									
84									
85	Load Makeup		Residential	LLF C&I	HLF C&I				
86									
87	Pipeline		39.10%	37.40%	48.78%				
88	Storage		20.46%	21.03%	17.21%				
89	Peaking		<u>40.44%</u>	<u>41.57%</u>	<u>34.01%</u>				
90	Total		100.00%	100.00%	100.00%				
91									
92									
93	Supply Makeup		Residential	LLF C&I	HLF C&I	Total			
94									
95	Pipeline		47.30%	42.88%	9.82%	100.00%			
96	Storage		47.30%	46.08%	6.62%	100.00%			
97	Peaking		47.30%	46.08%	6.62%	100.00%			

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Correction Factor Calculation**

8 Data Source: Schedule 10B

	Nov	Dec	Jan	Feb	Mar	Apr	Total Sales
11 G-41	1,013,490	1,623,765	3,602,815	3,292,443	2,696,656	1,672,112	13,901,281
12 G-42	1,291,603	1,877,047	3,519,263	3,200,164	2,782,899	1,968,286	14,639,261
13 G-43	129,290	198,537	248,632	286,526	262,030	218,315	1,343,329
14 High Winter Use	2,434,383	3,699,349	7,370,710	6,779,133	5,741,584	3,858,713	29,883,871
16 G-51	223,039	287,505	476,133	409,819	371,687	292,921	2,061,103
17 G-52	335,738	410,527	586,983	540,696	490,622	413,803	2,778,369
18 G-53	43,174	43,488	56,534	60,359	55,763	55,709	315,027
19 G-54	1,415	1,454	1,520	1,424	1,150	1,438	8,401
20 Low Winter Use	603,365	742,974	1,121,170	1,012,298	919,222	763,870	5,162,900
22 Gross Total	3,037,748	4,442,323	8,491,880	7,791,431	6,660,807	4,622,582	35,046,771

25 Total Sales	35,046,771
26 Low Winter Use	5,162,900
27 Winter Ratio for Low Winter Use =	0.96410 Schedule 10A p 2, ln 74
28 High Winter Use	29,883,871
29 Winter Ratio for High Winter Use =	1.00630 Schedule 10A p 2, ln 66
31 Correction Factor =	Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use))
32 Correction Factor =	99.9917%

35 **Allocation Calculation for Miscellaneous Overhead**

37 Projected Winter Sales Volume	(11/1/10 - 4/30/11)	83,088,481	Sch.10B
38 Projected Annual Sales Volume	(11/1/10 - 10/31/11)	104,918,580	Sch.10B
39 Percentage of Winter to Annual Sales		79.19%	

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 2010 - 2011 Winter Cost of Gas Filing

	Dry Therms						Subtotal							Subtotal	
	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	PK 10-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	OP 11	Total
8															
9 R-1	76,097	96,615	140,412	123,354	112,712	96,897	646,087	87,137	70,277	66,408	53,127	46,749	62,700	386,397	1,032,484
10 R-3	3,995,775	5,849,614	10,924,311	9,875,535	7,206,755	5,034,076	42,886,065	2,964,508	1,771,182	1,470,839	1,181,263	1,183,200	2,040,145	10,611,137	53,497,203
11 R-4	164,200	373,422	719,297	724,855	1,546,824	980,960	4,509,559	463,564	300,279	132,413	104,546	94,095	154,337	1,249,234	5,758,793
12 Total Residential.	4,236,072	6,319,650	11,784,020	10,723,744	8,866,291	6,111,933	48,041,710	3,515,209	2,141,739	1,669,660	1,338,936	1,324,044	2,257,182	12,246,769	60,288,480
13															
14 G-41	1,013,490	1,623,765	3,602,815	3,292,443	2,696,656	1,672,112	13,901,281	817,486	386,769	272,735	217,398	209,535	410,348	2,314,272	16,215,553
15 G-42	1,291,603	1,877,047	3,519,263	3,200,164	2,782,899	1,968,286	14,639,261	1,207,425	589,484	426,425	345,772	350,132	643,693	3,562,930	18,202,191
16 G-43	129,290	198,537	248,632	286,526	262,030	218,315	1,343,329	98,627	56,346	32,774	33,235	29,862	37,488	288,332	1,631,661
17 G-51	223,039	287,505	476,133	409,819	371,687	292,921	2,061,103	253,731	214,431	197,394	172,814	172,517	198,794	1,209,682	3,270,785
18 G-52	335,738	410,527	586,983	540,696	490,622	413,803	2,778,369	359,635	323,765	305,024	278,393	280,256	307,632	1,854,706	4,633,074
19 G-53	43,174	43,488	56,534	60,359	55,763	55,709	315,027	47,737	43,129	38,736	35,704	37,637	39,841	242,783	557,810
20 G-54	1,415	1,454	1,520	1,424	1,150	1,438	8,401	17,484	18,210	19,505	18,956	17,648	18,822	110,626	119,027
21 Total C/I	3,037,748	4,442,323	8,491,880	7,791,431	6,660,807	4,622,582	35,046,771	2,802,126	1,632,134	1,292,591	1,102,273	1,097,587	1,656,618	9,583,329	44,630,100
22															
23 Sales Volume	7,273,820	10,761,973	20,275,900	18,515,175	15,527,097	10,734,516	83,088,481	6,317,335	3,773,873	2,962,251	2,441,209	2,421,631	3,913,800	21,830,099	104,918,580
24															
25 Transportation Sales															
26															
27 G-41	187,316	275,777	516,084	514,617	456,874	324,938	2,275,605	169,292	92,565	75,231	58,829	62,239	100,321	558,477	2,834,083
28 G-42	1,006,362	1,399,546	2,539,920	2,325,662	2,090,381	1,445,726	10,807,596	839,182	383,837	300,155	253,697	274,246	508,449	2,559,566	13,367,162
29 G-43	417,394	617,195	720,237	886,632	795,189	721,610	4,158,257	562,043	317,729	191,916	183,419	177,231	215,023	1,647,361	5,805,618
30 G-51	45,403	45,843	104,316	84,760	79,300	65,797	425,418	46,296	40,122	36,360	30,370	32,373	41,084	226,605	652,022
31 G-52	192,334	252,384	361,822	341,494	305,230	253,767	1,707,032	185,235	175,034	166,575	154,201	162,278	164,315	1,007,639	2,714,671
32 G-53	750,093	774,852	970,111	1,058,124	973,852	981,510	5,508,541	708,614	640,443	581,400	541,959	576,878	605,891	3,655,185	9,163,726
33 G-54	1,638,279	1,683,239	1,759,850	1,648,214	1,330,918	1,664,548	9,725,048	1,388,612	1,446,648	1,549,569	1,506,104	1,426,828	1,521,962	8,839,722	18,564,771
34															
35 Total Trans. Sales	4,237,181	5,048,836	6,972,340	6,859,501	6,031,744	5,457,896	34,607,498	3,899,275	3,096,379	2,901,204	2,728,580	2,712,074	3,157,045	18,494,555	53,102,053
36															
37 Total All Sales	11,511,001	15,810,809	27,248,240	25,374,676	21,558,841	16,192,412	117,695,979	10,216,609	6,870,252	5,863,455	5,169,789	5,133,705	7,070,844	40,324,654	158,020,633

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Normal and Design Year Volumes**

Schedule 11A

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7 **Volumes (Therms) Normal Year**

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9 **For the Months of November 10 - April 11**

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11

	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Nov - Apr
12 Pipeline Gas:							
14 Dawn Supply	992,558	985,941	1,025,643	870,970	1,025,643	992,558	5,893,314
15 Niagara Supply	66,998	675,767	728,703	624,485	800,664	31,431	2,928,047
16 TGP Supply (Direct)	5,300,261	5,472,304	5,524,413	4,910,681	5,537,647	4,063,699	30,809,005
17 Dracut Supply 1 - Baseload	-	5,590,584	5,590,584	5,049,640	-	-	16,230,807
18 Dracut Supply 2 - Swing	5,541,783	367,247	308,520	348,222	6,430,123	6,676,608	19,672,503
19 City Gate Delivered Supply	-	-	-	-	-	-	0
20 LNG Truck	23,160	23,987	535,154	196,030	47,974	-	826,305
21 Propane Truck	-	-	-	-	-	-	0
22 PNGTS	65,343	80,232	86,022	75,269	72,788	55,418	435,071
23 Granite Ridge	-	-	-	-	-	-	-
24 Subtotal Pipeline Volumes	11,990,103	13,196,061	13,799,040	12,075,297	13,914,838	11,819,713	76,795,052
25							
26 Storage Gas:							
27 TGP Storage	96,774	3,785,782	4,762,625	4,143,103	284,533	-	13,072,818
28							
29 Produced Gas:							
30 LNG Vapor	23,160	23,987	588,918	196,030	23,987	23,160	879,241
31 Propane	-	-	426,800	137,304	-	-	564,104
32 Subtotal Produced Gas	23,160	23,987	1,015,718	333,334	23,987	23,160	1,443,345
33							
34 Less - Gas Refills:							
35 LNG Truck	(23,160)	(23,987)	(535,154)	(196,030)	(47,974)	-	(826,305)
36 Propane	-	-	-	-	-	-	-
37 TGP Storage Refill	(645,163)	(38,048)	-	-	-	(3,882,557)	(4,565,768)
38 Subtotal Refills	(668,322)	(62,035)	(535,154)	(196,030)	(47,974)	(3,882,557)	(5,392,072)
39							
40 Total Sendout Volumes	11,441,714	16,943,795	19,042,228	16,355,704	14,175,385	7,960,316	85,919,143

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**

Schedule 11B

42 **Normal and Design Year Volumes**

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45 **Volumes (Therms) Design Year**

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47 **For the Months of November 10 - April 11**

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	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Peak Nov - Apr
51 Pipeline Gas:							
52 Dawn Supply	992,558	992,558	1,025,643	926,388	1,025,643	992,558	5,955,349
53 Niagara Supply	77,750	748,554	800,664	649,298	800,664	51,282	3,128,212
54 TGP Supply (Direct)	5,288,681	5,507,044	5,537,647	4,963,618	5,537,647	4,296,123	31,130,760
55 Dracut Supply 1 - Baseload	-	5,590,584	5,590,584	5,049,640	-	-	16,230,807
56 Dracut Supply 2 - Swing	6,598,030	1,053,766	1,483,874	980,978	7,446,668	7,295,302	24,858,619
57 City Gate Delivered Supply	-	-	-	-	-	-	0
58 LNG Truck	23,160	23,987	558,314	172,871	47,974	-	826,305
59 Propane Truck	-	-	-	-	-	-	0
60 PNGTS	65,343	80,232	86,022	75,269	72,788	55,418	435,071
61 Granite Ridge	-	-	-	-	-	-	-
62 Other Purchased Resources	-	-	-	-	-	-	-
63 Subtotal Pipeline Volumes	13,045,523	13,996,724	15,082,748	12,818,062	14,931,383	12,690,683	82,565,123
64							
65 Storage Gas:							
66 TGP Storage	287,842	4,550,052	5,528,549	4,775,032	624,485	30,604	15,796,563
67							
68 Produced Gas:							
69 LNG Vapor	23,160	23,987	612,905	172,871	23,987	23,160	880,068
70 Propane	-	-	239,868	297,767	-	-	537,636
71 Subtotal Produced Gas	23,160	23,987	852,773	470,638	23,987	23,160	1,417,704
72							
73 Less - Gas Refills:							
74 LNG Truck	(23,160)	(23,987)	(558,314)	(172,871)	(47,974)	-	(826,305)
75 Propane	-	-	-	-	-	-	-
76 TGP Storage Refill	(784,121)	(4,136)	-	-	-	(4,031,440)	(4,819,697)
77 Subtotal Refills	(807,281)	(28,122)	(558,314)	(172,871)	(47,974)	(4,031,440)	(5,646,002)
78							
79 Total Sendout Volumes	12,549,244	18,542,641	20,905,756	17,890,861	15,531,881	8,713,006	94,133,389

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1 ENERGY NORTH NATURAL GAS, INC.

Schedule 11C

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

4 Capacity Utilization

5 Volumes (Therms)

	Peak Period Normal Year		Seasonal Quantity	Utilization Rate	Peak Period Design Year		Seasonal Quantity	Utilization Rate
	Use (Therms)	MDQ (MMBtu/day)	(Therms)		Use (Therms)	MDQ (MMBtu/day)	(Therms)	
11 Pipeline Gas:								
12 Dawn Supply	5,893,314	4,000	7,240,000	81%	5,955,349	4,000	7,240,000	82%
13 Niagara Supply	2,928,047	3,122	5,650,820	52%	3,128,212	3,122	5,650,820	55%
14 TGP Supply (Direct)	30,809,005	21,596	39,088,760	79%	31,130,760	21,596	39,088,760	80%
15 Dracut Supply 1 & 2	35,903,310	50,000	90,500,000	40%	41,089,426	50,000	90,500,000	45%
18 LNG Truck	826,305	-	-	-	826,305	-	-	-
19 Propane Truck	-	-	-	-	-	-	-	-
20 PNGTS	435,071	1,000	1,810,000	24%	435,071	1,000	1,810,000	24%
21 Granite Ridge	-	-	-	-	-	-	-	-
22 Other Purchased Resources	-	-	-	-	-	-	-	-
23								
24 Subtotal Pipeline Volumes	76,795,052				82,565,123			
25								
26 Storage Gas:								
27 TGP Storage	13,072,818		25,801,310	51%	15,796,563		25,801,310	61%
28								
29 Produced Gas:								
30 LNG Vapor	879,241				880,068			
31 Propane	564,103.9				537,636			
32								
33 Subtotal Produced Gas	1,443,345				1,417,704			
34								
35 Less - Gas Refills:								
36 LNG Truck	(826,305)				(826,305)			
37 Propane	-				-			
38 TGP Storage Refill	(4,565,768)				(4,819,697)			
39								
40 Subtotal Refills	(5,392,072)				(5,646,002)			
41								
42 Total Sendout Volumes	85,919,143				94,133,389			

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

Schedule 11D

2 **d/b/a National Grid NH**

3 **Peak 2010 - 2011 Winter Cost of Gas Filing**

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Forecast of Upcoming Winter Period

6

Design Day Report

7

2010 / 11 Heating Season

8

(Therms)

9

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EnergyNorth Natural Gas, Inc.

11

d/b/a National Grid New Hampshire

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13

14

72 EDD at Manchester, N.H.

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16

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Requirements

18

19

Firm Sales

1,168,312

20

Interruptible Sales

0

21

Firm Transportation

205,688

22

Interruptible Transportation

0

23

24

Total Requirements

1,374,000

25

26

27

Resources

28

29

Purchased Pipeline Gas

790,100

30

Underground Storage Gas

281,100

31

Propane Air Production

197,500

32

LNG Produced Gas

105,300

33

Third-Party Supply

0

34

35

Total Resources

1,374,000

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37

38

Please refer to the ENGI 2010 IRP filing (DG 10-041)

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for a complete description of the methodology and

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assumptions used in the derivation of this data.

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Preparation of this report was supervised by:

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Theodore Poe, Jr.

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Manager, Energy Planning

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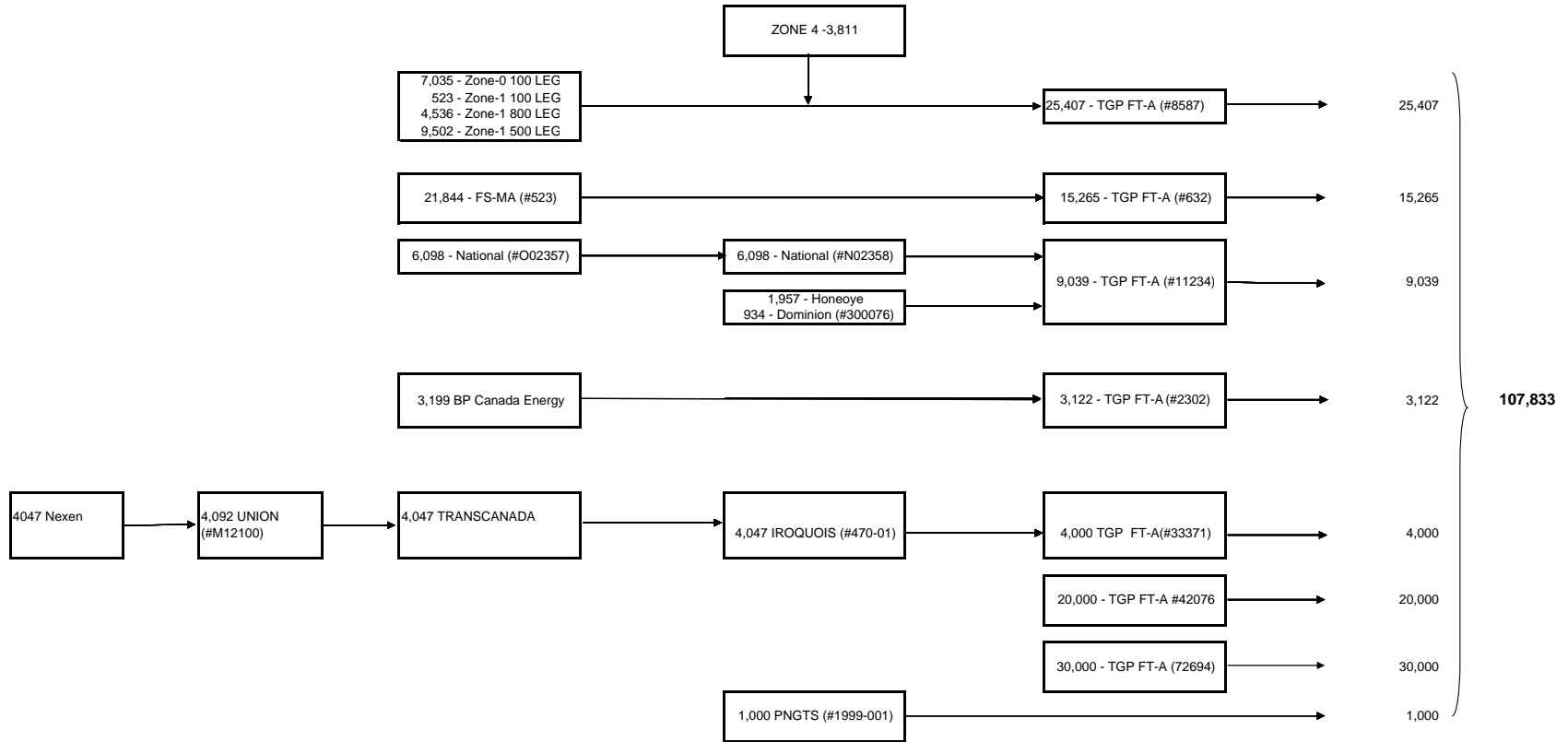
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Note: Forecasted Firm Transportation volumes are for customers
using utility capacity only.

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filling
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 (Formerly AES Londonderry, L.L.C.)	-	-	Supply	15,000	450,000	09/30/10	N/a	Mutually agreed upon.
BP Gas & Power Canada, Ltd	-	-	Supply	3,199	1,167,635	03/31/2012	N/a	Terminates
TBD	-	-	Supply	4,047	611,097	Peak Only	N/a	Terminates
No Supply for April through October 2010								
Distrigas of Massachusetts Corp. Renew	FLS	FLS160	Liquid Refill	Up to 15 trucks	1,000,000 National Grid Total	10/31/2010	-	Terminates
TBD	-	-	Supply	May 2010 = 21,000 Oct 2010 = 16,000	7,607,500	10/31/2010	-	Terminates
Corporation								
JP Morgan	-	-	Supply	21,596	3,908,876	04/30/2011	N/a	Terminates
Eastern Propane Gas			Trucking	28,500 Gallons	900,000 Gallons	03/31/2011	N/a	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	03/31/2016	03/31/2009	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	-	Storage	1,957	246,240	04/01/2011	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	03/31/2011	03/31/2011	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	03/31/2011	03/31/2011	Evergreen Provision
Iroquois Gas Transmission System	RTS-1	47001	Transportation	4,047	1,477,155	11/01/2017	10/31/2011	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	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2015	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	09/30/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	33371	Transportation	4,000	1,460,000	10/31/2011	10/31/2010	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2015	10/31/2010	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.

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1 **ENERGY NORTH NATURAL GAS, INC.**
2 **d/b/a National Grid NH**
3 **Peak 2010 - 2011 Winter Cost of Gas Filing**
4 **Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes**
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6 **May 2009 - Apr 2010 Normalized Sales and Transportation Volumes (Therms)**
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C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	15,253,278	36.55%	85.10%
G-42	17,082,632	40.93%	57.55%
G-43	1,513,746	3.63%	21.68%
G-51	3,062,838	7.34%	83.30%
G-52	4,328,763	10.37%	62.88%
G-53	481,597	1.15%	5.29%
G-54	13,770	0.03%	0.08%
Total C/I	41,736,623	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	2,670,958	5.34%	14.90%
G-42	12,598,226	25.20%	42.45%
G-43	5,468,386	10.94%	78.32%
G-51	613,894	1.23%	16.70%
G-52	2,555,535	5.11%	37.12%
G-53	8,624,994	17.25%	94.71%
G-54	17,464,601	34.93%	99.92%
Total C/I	49,996,594	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	17,924,236	19.54%	100.00%
G-42	29,680,858	32.36%	100.00%
G-43	6,982,132	7.61%	100.00%
G-51	3,676,732	4.01%	100.00%
G-52	6,884,298	7.50%	100.00%
G-53	9,106,591	9.93%	100.00%
G-54	17,478,371	19.05%	100.00%
Total C/I	91,733,218	100.00%	

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

2 **d/b/a National Grid NH**

3 **Peak 2010 - 2011 Winter Cost of Gas Filing**

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

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	Off-Peak	Peak	Total	
	May 09 - Oct 09	Nov 09-Apr 10	May 09 - Apr 10	
	(Therms)	(Therms)	(Therms)	
Pipeline Deliveries	18,035,980	66,698,550	84,734,530	
All Others	2,126,110	10,120,360	12,246,470	
	20,162,090	76,818,910	96,981,000	
Total Winter Supplies				Ratio
Total Pipeline Deliveries				76,818,910
				84,734,530
Ratio Winter Supplies to Pipeline Supplies				0.907

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1 ENERGY NORTH NATURAL GAS, INC.

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

4 July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption

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C&I Sales						
Normalized (Therms)	Jul-09	Aug-09	Jul - Aug Total	Total Annual	% of Jul-Aug to Total	
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)	
G-41	241,351	248,603	489,954	15,656,710	3.13%	
G-42	393,635	309,516	703,151	19,079,103	3.69%	
G-43	22,764	33,583	56,347	1,167,489	4.83%	
G-51	181,820	160,551	342,371	3,173,321	10.79%	
G-52	277,488	251,228	528,716	4,950,208	10.68%	
G-53	27,840	19,980	47,820	491,411	9.73%	
G-54	957	846	1,803	9,741,926	0.02%	
Total C/I	1,145,855	1,024,307	2,170,162	54,260,169	4.00%	

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1 ENERGY NORTH NATURAL GAS, INC.

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

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

5
6 Underground Storage Gas

		May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Estimate)	Sep-10 (Estimate)	Oct-10 (Estimate)	Nov-10 (Estimate)	Dec-10 (Estimate)	Jan-11 (Estimate)	Feb-11 (Estimate)	Mar-11 (Estimate)	Apr-11 (Estimate)	Total
Beginning Balance (MMBtu)		1,900,153	1,948,021	1,976,602	2,006,247	2,006,247	2,151,861	2,297,475	2,352,314	1,977,540	1,501,278	1,086,968	1,058,514	1,900,153
Injections (MMBtu)	Sch 11A In 37 /10	51,376	28,783	29,841	-	145,614	145,614	64,516	3,805	-	-	-	-	469,549
Subtotal		1,951,529	1,976,804	2,006,443	2,006,247	2,151,861	2,297,475	2,361,991	2,356,119	1,977,540	1,501,278	1,086,968	1,058,514	
Storage Sale		-						-						
Withdrawals (MMBtu)	Sch 11A In 27 /10	(3,508)	(202)	(196)	-	-	-	(9,677)	(378,578)	(476,262)	(414,310)	(28,453)	-	(1,311,188)
Ending Balance (MMBTu)		1,948,021	1,976,602	2,006,247	2,006,247	2,151,861	2,297,475	2,352,314	1,977,540	1,501,278	1,086,968	1,058,514	1,058,514	1,058,514
Beginning Balance		\$ 11,826,132	\$ 12,042,348	\$ 12,163,507	\$ 12,316,225	\$ 12,316,225	\$ 12,884,957	\$ 13,500,745	\$ 13,766,544	\$ 11,571,426	\$ 8,784,613	\$ 6,360,307	\$ 6,193,815	11,826,132
Injections	In 11 * In 36	236,577	121,159	152,718	-	568,732	615,788	322,435	20,103	-	-	-	-	2,037,512
Subtotal		\$ 12,062,709	\$ 12,163,507	\$ 12,316,225	\$ 12,316,225	\$ 12,884,957	\$ 13,500,745	\$ 13,823,180	\$ 13,786,647	\$ 11,571,426	\$ 8,784,613	\$ 6,360,307	\$ 6,193,815	
Storage Sale		\$ -					\$ -							
Withdrawals	In 17 * In 34	\$ (20,361)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (56,636)	\$ (2,215,221)	\$ (2,786,813)	\$ (2,424,305)	\$ (166,492)	\$ -	\$ (7,669,829)
Ending Balance		\$ 12,042,348	\$ 12,163,507	\$ 12,316,225	\$ 12,316,225	\$ 12,884,957	\$ 13,500,745	\$ 13,766,544	\$ 11,571,426	\$ 8,784,613	\$ 6,360,307	\$ 6,193,815	\$ 6,193,815	\$ 6,193,815
Average Rate For Withdrawals	In 18 /In 9	\$6.1812	\$6.1531	\$6.1383	\$6.1389	\$5.9878	\$5.8763	\$5.8523	\$5.8514	\$5.8514	\$5.8514	\$5.8514	\$5.8514	
TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	\$4.6048	\$4.2094	\$5.1177	\$0.0000	\$3.9058	\$4.2289	\$4.9977	\$5.2836	\$5.4340	\$5.4161	\$5.3314	\$5.1454	
For Informational Purposes								Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
Summer Hedge Contracts - Vols Dth								85,700	85,700	85,700	85,700	85,700	85,700	514,200
Average Hedge Price								\$5.4995	\$5.4995	\$5.4995	\$5.4995	\$5.4995	\$5.4995	
NYMEX								\$4.2710	\$4.1482	\$4.2485	\$4.3322	\$4.3959	\$4.5087	
Hedged Volumes at Hedged Price								\$ 471,310	\$ 471,310	\$ 471,310	\$ 471,310	\$ 471,310	\$ 471,310	\$ 2,827,857
Less Hedged Volumes at NYMEX								366,025	355,501	364,094	371,270	376,731	386,398	2,220,019
Hedge (Savings)/Loss								\$ 105,285	\$ 115,809	\$ 107,216	\$ 100,040	\$ 94,578	\$ 84,911	\$ 607,838
Month Dollar Average	In (22 + In 32) /2				\$ 12,316,225	\$ 12,600,591	\$ 13,192,851	\$ 13,633,644	\$ 12,668,985	\$ 10,178,019	\$ 7,572,460	\$ 6,277,061	\$ 6,193,815	
Money Pool Finance Rate (per Nov 09 - Apr 10 Actuals)					0.77%	0.70%	1.36%	1.34%	1.28%	0.97%	0.80%	0.93%	0.52%	
Inventory Finance Charge	In 47 * In 49				\$ 7,855	\$ 7,366	\$ 14,905	\$ 15,214	\$ 13,495	\$ 8,244	\$ 5,063	\$ 4,865	\$ 2,709	
Financial Expenses					500	500	500	500	500	500	500	500	500	
Total Inventory Finance Charges					\$ 8,355	\$ 7,866	\$ 15,405	\$ 15,714	\$ 13,995	\$ 8,744	\$ 5,563	\$ 5,365	\$ 3,209	

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1 ENERGY NORTH NATURAL GAS, INC.
2 d/b/a National Grid NH
3 Peak 2010 - 2011 Winter Cost of Gas Filing
4 Storage Inventory, Underground, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas
5

Liquid Propane Gas (LPG)															
			May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Estimate)	Sep-10 (Estimate)	Oct-10 (Estimate)	Nov-10 (Estimate)	Dec-10 (Estimate)	Jan-11 (Estimate)	Feb-11 (Estimate)	Mar-11 (Estimate)	Apr-11 (Estimate)	Total
	Beginning Balance		136,265	136,253	136,158	136,101	136,101	136,101	136,101	136,101	136,101	93,421	79,691	79,691	136,265
	Injections	Sch 11A In 36 /10	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal		136,265	136,253	136,158	136,101	136,101	136,101	136,101	136,101	136,101	93,421	79,691	79,691	
	Withdrawals	Sch 11A In 31 /10	-	-	-	-	-	-	-	-	(42,680)	(13,730)	-	-	(56,410)
	Adjustment for change in temperature		(12)	(95)	(57)	-	-	-	-	-	-	-	-	-	(164)
	Ending Balance		136,253	136,158	136,101	136,101	136,101	136,101	136,101	136,101	93,421	79,691	79,691	79,691	79,691
	Beginning Balance		\$ 1,992,243	\$ 1,990,927	\$ 1,989,553	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,365,078	\$ 1,164,449	\$ 1,164,449	\$ 1,992,243
	Injections	In 63 * In 86	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal		\$ 1,992,243	\$ 1,990,927	\$ 1,989,553	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,365,078	\$ 1,164,449	\$ 1,164,449	
	Withdrawals	In 69 * In 84	(1,316)	(1,374)	(833)	-	-	-	-	-	(623,642)	(200,629)	-	-	(827,794)
	Ending Balance		\$ 1,990,927	\$ 1,989,553	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,365,078	\$ 1,164,449	\$ 1,164,449	\$ 1,164,449	\$ 1,164,449
	Average Rate For Withdrawals		\$14.6204	\$14.6120	\$14.6120	\$14.6120	\$14.6120	\$14.6120	\$14.6120	\$14.6120	\$14.6120	\$14.6120	\$14.6120	\$14.6120	
	Propane Rate for Injections	Actual or Sch. 6, In 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	
	Month Dollar Average	In (74 + In 82) /2				\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,988,720	\$ 1,676,899	\$ 1,264,763	\$ 1,164,449	\$ 1,164,449	
	Money Pool Finance Rate (per Nov 09 - Apr 10 Actuals)					0.77%	0.70%	1.36%	1.34%	1.28%	0.97%	0.80%	0.93%	0.52%	
	Inventory Finance Charge	In 89 * In 91				\$ 1,268	\$ 1,163	\$ 2,247	\$ 2,219	\$ 2,118	\$ 1,358	\$ 846	\$ 903	\$ 509	

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1 ENERGY NORTH NATURAL GAS, INC.

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

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

Liquid Natural Gas (LNG)		May-10 (Actual)	Jun-10 (Actual)	Jul-10 (Actual)	Aug-10 (Estimate)	Sep-10 (Estimate)	Oct-10 (Estimate)	Nov-10 (Estimate)	Dec-10 (Estimate)	Jan-11 (Estimate)	Feb-11 (Estimate)	Mar-11 (Estimate)	Apr-11 (Estimate)	Total
Beginning Balance		10,040	8,223	9,447	7,293	7,293	7,293	7,293	7,293	7,293	1,917	1,917	4,315	10,040
Injections	Sch 11A In 35 /10	43	3,054	(325)	-	-	-	2,316	2,399	53,515	19,603	4,797	-	85,402
Subtotal		10,083	11,277	9,122	7,293	7,293	7,293	9,609	9,692	60,808	21,520	6,714	4,315	
Withdrawals	Sch 11A In 30 /10	(1,860)	(1,830)	(1,829)	-	-	-	(2,316)	(2,399)	(58,892)	(19,603)	(2,399)	(2,316)	(93,443)
Ending Balance		8 223	9 447	7 293	7 293	7 293	7 293	7 293	7 293	1 917	1 917	4 315	1 999	1 999
Beginning Balance		\$ 56,349	\$ 45,714	\$ 51,112	\$ 39,458	\$ 39,458	\$ 39,458	\$ 39,458	\$ 37,821	\$ 37,022	\$ 9,402	\$ 9,333	\$ 20,760	\$ 56,349
Injections	In 103 * In 124	(294)	15,299	(1,758)	-	-	-	10,373	11,378	261,284	95,386	22,967	-	414,634
Subtotal		\$ 56,054	\$ 61,013	\$ 49,354	\$ 39,458	\$ 39,458	\$ 39,458	\$ 49,831	\$ 49,198	\$ 298,306	\$ 104,788	\$ 32,300	\$ 20,760	
Withdrawals	In 107 * In 122	(10,340)	(9,901)	(9,896)	-	-	-	(12,010)	(12,177)	(288,903)	(95,455)	(11,540)	(11,142)	(461,364)
Ending Balance		\$ 45,714	\$ 51,112	\$ 39,458	\$ 39,458	\$ 39,458	\$ 39,458	\$ 37,821	\$ 37,022	\$ 9,402	\$ 9,333	\$ 20,760	\$ 9,619	\$ 9,619
Average Rate For Withdrawals		\$5.5593	\$5.4104	\$5.4104	\$5.4104	\$5.4104	\$5.4104	\$5.1859	\$5.0764	\$4 9057	\$4 8694	\$4.8109	\$4.8109	
LNG Rate for Injections	Actual or Sch. 6, In 150 * 10	\$4.4789	\$5.0096	\$4 8824	\$4 8659	\$4.7875	\$4.6671	\$4.4789	\$4.7433	\$4 8824	\$4 8659	\$4.7875	\$4.6671	
Month Dollar Average	In (112 + In 120) /2				\$ 39,458	\$ 39,458	\$ 39,458	\$ 38,639	\$ 37,421	\$ 23,212	\$ 9,368	\$ 15,047	\$ 15,190	
Money Pool Finance Rate (per Nov 09 - Apr 10 Actuals)					0.77%	0.70%	1.36%	1.34%	1.28%	0.97%	0 80%	0.93%	0.52%	
Inventory Finance Charge	In 127 * In 129				\$ 25	\$ 23	\$ 45	\$ 43	\$ 40	\$ 19	\$ 6	\$ 12	\$ 7	
Total Fuel Financing	Ins 53 + 93 + 131				\$ 9,648	\$ 9,052	\$ 17,696	\$ 17,976	\$ 16,153	\$ 10,121	\$ 6,415	\$ 6,279	\$ 3,726	

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1 ENERGY NORTH NATURAL GAS, INC.

2 d/b/a National Grid NH

3 Peak 2010 - 2011 Winter Cost of Gas Filing

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

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138 Summer Hedge Program

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Trade Dates

Contracts

May-10
(a)

Jun-10
(b)

Jul-10
(c)

Aug-10
(d)

Sep-10
(e)

Oct-10
(f)

Total
(g)

85,700

85,700

85,700

85,700

85,700

85,700

514,200

Prices

29-May-09

25-Jun-09

27-Jul-09

21-Aug-09

10-Sep-09

23-Oct-09

23-Nov-09

30-Dec-09

29-Jan-10

26-Feb-10

26-Mar-10

23-Apr-10

Dollars

29-May-09

25-Jun-09

27-Jul-09

21-Aug-09

10-Sep-09

23-Oct-09

23-Nov-09

30-Dec-09

29-Jan-10

26-Feb-10

26-Mar-10

23-Apr-10

\$ 471,310 \$ 471,310 \$ 471,310 \$ 471,310 \$ 471,310 \$ 471,310 \$ 2,827,857

Average Hedge Contract Price
NYMEX

5.4995
4.2710

5.4995
4.1550

5.4995
4.7170

5.4995
4.7740

5.4995
4.2413

5.4995
4.2618

5.4995
4.4033

Hedged Volumes at Hedged Price
Less Hedged Volumes at NYMEX
Hedge (Savings)/Loss

\$ 471,310 \$ 471,310 \$ 471,310 \$ 471,310 \$ 471,310 \$ 471,310 \$ 2,827,857
366,025 356,084 404,247 409,132 363,477 365,236 2,264,200
\$ 105,285 \$ 115,226 \$ 67,063 \$ 62,178 \$ 107,833 \$ 106,073 \$ 563,657

Options Loss

\$ - \$ - \$ - - - - \$ -

Total

\$ 105,285 \$ 115,226 \$ 67,063 \$ 62,178 \$ 107,833 \$ 106,073 \$ 563,657

THIS PAGE HAS BEEN REDACTED

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

2 **d/b/a National Grid NH**

3 **Peak 2010 - 2011 Winter Cost of Gas Filing**

4 **Forecast of Firm Transportation Volumes and Cost of Gas Revenues**

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Firm Transportation

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	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
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Nov-10	4,237,181	\$0.0009	\$ 3,813
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15

Dec-10	5,048,836	0.0009	4,544
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16

Jan-11	6,972,340	0.0009	6,275
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17

Feb-11	6,859,501	0.0009	6,174
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18

Mar-11	6,031,744	0.0009	5,429
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19

Apr-11	<u>5,457,896</u>	0.0009	<u>4,912</u>
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Total	<u>34,607,498</u>		<u>\$ 31,147</u>
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1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.

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2/ Refer to Proposed Second Revised Page 89 for calculation of rate.

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McLane, Graf,
Raulerson & Middleton
Professional Association

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July 29, 2010

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

Re: DG 09-162
EnergyNorth Natural Gas, Inc d/b/a National Grid NH
2009-10 Winter Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Enclosed are seven copies of the redacted version of the 2009-10 Winter Period Cost of Gas reconciliation filing for EnergyNorth Natural Gas, Inc d/b/a National Grid NH ("the Company"). This filing is being submitted under protective order and confidential treatment granted by the Commission in Order No. 25,032 dated October 29, 2009 in Docket DG 09-162. 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 2009-10 Winter Period of \$2,985,736 summarized as follows:

Winter Period Beginning Balance	\$779,942
Less: Cost of Gas Revenue Billed	(\$67,990,127)
Add: Cost of Gas Allowable (5/1/09 -10/31/09)	\$2,563,524
Add: Cost of Gas Allowable (11/1/09 -4/30/10)	<u>\$67,632,398</u>
Winter Period Ending Balance	\$2,985,736

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

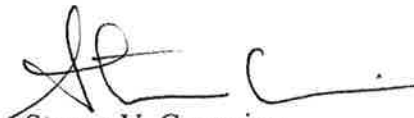
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filing, including the beginning balance, interest and other allowable adjustments to gas costs, gas costs and gas cost revenue. The result is a net under collection of \$2,985,736. Page 2 of the Summary compares the actual allowed Bad Debt and Working Capital costs to the filed projections submitted in the Company's filing, resulting in over collections of \$20,082 and \$481,137, respectively, for a net under collection for all the gas accounts of \$2,484,517. The Bad Debt and Working Capital over collections are the result of the Settlement Agreement in DG 10-051, which the Commission approved in its Order No. 25,094 dated April 29, 2010, revising the bad debt percentage from 1.75% to 2.54% effective May 1, 2009, and adjusting the working capital percentage from .148% to .091% effective May 1, 2009. Page 3 of the Summary compares actual demand charges of \$7,011,816 to the \$8,016,873 in demand charges estimated in the filing. Page 4 shows a similar comparison for commodity costs. The actual commodity costs were \$60,533,363 compared to \$68,266,408 in the filing. The \$7,733,045 decrease in commodity costs was caused mainly by lower sendout volumes and prices than originally forecast. The results show that the actual demand and commodity costs were \$8,738,103 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 (\$3,295,894), changes in demand (\$6,619,799), and changes in gas prices \$1,177,590. 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. The third page of Schedule 1 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 do not hesitate to contact me with questions regarding this filing.

Sincerely,



Steven V. Camerino

Enclosures

cc: Meredith A. Hatfield, Esq.
Thomas P. O'Neill, Esq.
Ann E. Leary

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162
NOVEMBER 2009 THROUGH APRIL 2010

	Original Filing 1/	Actual		Difference
<u>Peak Gas cost Account 175.20</u>				
Balance 05/01/09- (Over) / Under	\$935,450	\$779,942	2/	(\$155,508)
Peak Gas Costs 5/1/09 - 10/31/09	\$3,331,124	\$3,454,276	3/	123,152
Fuel Financing 5/1/09 - 10/31/09	97,371	45,531	3/	(51,840)
Prior Period Adjustment 5/1/09-10/31/09	-	(116,154)	3/	(116,154)
Broker Revenue 5/1/09 - 10/31/09	(622,400)	(572,339)	3/	50,061
280 Day Margins 5/1/09 - 10/31/09	-	-	4/	-
IT Sales Margins 5/1/09 - 10/31/09	-	-	4/	-
Off System Sales Margin 5/1/09 - 10/31/09	(73,523)	(13,070)	4/	60,453
Capacity Release 5/1/09 - 10/31/09	(354,811)	(266,941)	4/	87,870
Interest 5/1/09 - 10/31/09	38,237	32,222	3/	(6,015)
Sum 5/1/09 - 10/31/09 costs	\$2,415,998	\$2,563,524		\$147,526
Beginning Balance 10/31/09 (Over)/Under	\$3,351,448	\$3,343,466		(\$7,982)
Interest 11/1/09 - 4/30/10	17,216	40,615		23,399
Prior Period Adjustments	-	-		0
Interruptible Sales Margin 11/1/09 - 4/30/10	-	-		-
280-Day Margin 11/1/09 - 4/30/10	-	-		-
Off System Sales Margin 11/1/09 -4/30/10	(28,322)	(1,912)		26,410
Capacity Release Credits 11/1/09 - 4/30/10	(178,872)	(109,620)		69,252
Other Transportation Related Margins	0	0		0
Fixed Price Option Admin Costs	40,691	0		(40,691)
Broker Revenues 11/1/09 - 4/30/10	(268,209)	(205,033)		63,176
Production & Storage	1,749,387	1,749,387		0
Misc Overhead	20,121	20,121		0
Fuel Financing 11/1/09 - 4/30/10	112,934	85,395		(27,539)
Transportation Cost of Gas Revenue	8,654	9,404		750
Total Adjustment to Costs	\$1,473,600	\$1,588,356		\$114,756
Gas Costs 11/1/09 - 4/30/10	\$74,820,489	\$66,044,041		(\$8,776,448)
Total Gas Costs and Adjustments 11/09 - 4/10	\$76,294,089	\$67,632,398		(\$8,661,691)
Gas Cost Billed	(\$79,645,537)	(67,990,127)		\$11,655,410
Total (Over) / Under 04/30/09	\$0	\$2,985,736		\$2,985,736

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162
NOVEMBER 2009 THROUGH APRIL 2010

	<u>Original</u> <u>Filing 1/</u>	<u>Actual</u>	<u>Difference</u>
<u>Bad Debts Account 175.52</u>			
Beginning Balance	(\$212,161)	(\$212,161)	\$0
BD Costs 5/1/09-10/31/09	84,740	80,707 5/	(4,033)
Interest 5/1/09-10/31/09	(2,769)	(2,985) 5/	(216)
Beginning Balance 10/31/09 (Over)/Under	(\$130,190)	(\$143,116)	(\$4,248)
Bad Debt Costs 11/1/08 - 4/30/10	1,924,252	1,699,964	(224,288)
Bad Debt CGA Billed	(1,792,798)	(1,575,361)	217,437
Adjustment	-	-	0
Interest	(1,264)	(1,569)	(305)
Total (Over) / Under 04/30/09	\$0	(\$20,082)	(\$20,082)
<u>Working Capital Account 142.20</u>			
Beginning Balance	(\$63,719)	(\$63,719)	\$0
WC Costs 5/1/09-10/31/09	5,116	3,189 6/	(1,927)
Interest 5/1/09-10/31/09	(978)	(8,548) 6/	(7,570)
Beginning Balance 10/31/09 (Over)/Under	(\$59,581)	(\$525,428)	(\$9,496)
Working Capital Costs 11/1/08-4/30/10	65,724	59,764	(5,960)
Working Capital CGA Billed	(5,672)	(7,396)	(1,724)
Adjustment	-	-	0
Interest	(471)	(8,077)	(7,606)
Total (Over) / Under 04/30/09	\$0	(\$481,137)	(\$481,137)
Total 175.20, 175.52, 142.20	\$0	\$2,484,517	\$2,484,517

1/ As filed 09-01-09 in the Winter 2009-2010 Cost of Gas DG 09-162

2/ The beginning balance is the sum of the actual April 30, 2009 balance \$779,942 less the May 2009 Billings of \$3,541,223 plus reverse prior month unbilled \$3,541,223

3/ The 5/1/09 - 10/31/09 costs are per Schedule 1, page 1, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

4/ The 5/1/09 - 10/31/09 costs are per Schedule 4, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

5/ The 5/1/09 - 10/31/09 costs are per Schedule 1, page 3, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

6/ The 5/1/08 - 10/31/09 costs are per Schedule 5, of the Summer 2009 Reconciliation filed on January 28, 2010 in DG 09-050

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162

SUMMARY OF DEMAND CHARGES FOR PERIOD
NOVEMBER 2009 THROUGH APRIL 2010

	<u>Filing</u>	<u>1/ Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Difference</u>
	<u>(a)</u>	<u>May 09 - Oct 09</u>	<u>Nov 09 - Apr 10</u>	<u>Peak Demand</u>	<u>(e)=(d)-(a)</u>
<u>Supplies:</u>					
BP/Nexen					
IEC					
Subtotal Supply Demand Charges	\$4,922	\$0	\$8,609	\$8,609	\$3,687
<u>Pipelines:</u>					
Iroquois Gas Trans	\$160,191	\$0	\$139,186	\$139,186	(\$21,005)
TGP NET 33371	254,640	-	221,526	221,526	(\$33,114)
TGP FTA Z5-Z6 2302	92,349	-	80,178	80,178	(\$12,171)
TGP FTA Z0 - Z6 8587	2,158,540	-	1,864,372	1,864,372	(\$294,168)
TGP Dracut FTA Z6 - Z6 42076	379,200	-	236,669	236,669	(\$142,531)
TGP (Concord Lateral) Z6-Z6	2,190,600	-	2,183,055	2,183,055	(\$7,545)
Portland Natual Gas Pipeline	164,410	-	139,550	139,550	(\$24,861)
ANE (Uniongas and TransCanada)	196,023	-	252,877	252,877	\$56,854
TGP FTA 632	1,078,930	478,704	488,980	967,684	(\$111,246)
TGP FTA 11234	616,332	279,688	286,981	566,668	(\$49,664)
National Fuel	245,959	82,560	110,459	193,019	(\$52,940)
Subtotal Pipeline Demand Charges	\$7,537,174	\$840,951	\$6,003,833	\$6,844,785	(\$692,389)
<u>Peaking Supply</u>					
Granite Ridge					
Chevron					
DOMAC					
Repsol					
Transgas Trucking					
Subtotal Peaking Supply	\$608,069	\$116,999	\$376,158	\$493,157	(\$114,912)
<u>Propane</u>					
Energy North Propane	\$0	\$0	\$44	\$44	\$44
<u>Storage:</u>					
Demand & Capacity Charges	\$1,297,225	\$574,333	\$547,205	\$1,121,538	(\$175,687)
<u>Other:</u>					
Capacity Managed	(\$1,430,516)	\$ (31,146)	(\$865,595)	\$ (896,741)	\$533,775
Pipeline Refunds	\$0	\$ -	(\$559,575.60)	\$ (559,576)	(\$559,576)
Total Demand Charges (Forward to Page 4)	\$8,016,873	\$1,501,137	\$5,510,679	\$7,011,816	(\$1,005,058)

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2009 Cost of Gas Reconciliation, DG 09-050 filed January 28, 2010.

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ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162
SUMMARY OF COMMODITY COSTS FOR PERIOD
NOVEMBER 2009 THROUGH APRIL 2010

	<u>Filing</u>	Average Cost per <u>Therm</u>	<u>Actual</u>	Average Cost per <u>Therm</u>	<u>Difference</u>
Demand Charges (Brought from Page 3):	\$8,016,873		\$7,011,816		(\$1,005,058)
<u>TGP</u>					
Therms					
Cost					
<u>Spot Gas</u>					
Therms					
Cost					
<u>Canadian</u>					
Therms					
Cost					
<u>PNGTS</u>					
Therms					
Cost					
<u>Granite Ridge</u>					
Therms					
Cost					
<u>City Gate Delivered Supply</u>					
Therms					
Cost					
<u>DOMAC</u>					
Therms					
Cost					
<u>Storage gas - commodity withdrawn</u>					
Therms					
Cost					
<u>Propane</u>					
Therms					
Cost					
<u>LNG</u>					
Therms					
Cost					
<u>Hedging (Gains) Losses</u>					
Other - Cashout, Broker Penalty, Canadian Managed					
Therms					
Cost					
Prior period Adj					
Subtotal:					
Volumes (net of fuel retention)	86,404,722		76,818,910		(9,585,812)
Cost	\$ 68,266,408	0 7901	\$ 60,533,363	0 7880	\$ (7,733,045) (0 0021)
Total Demand and Commodity Costs	\$ 76,283,281		\$ 67,545,179		\$ (8,738,103)
Demand (therms):	86,404,722		76,818,910		(9,585,812)
Firm Gas Sales	84,282,098		73,960,615		(10,321,483)
Lost Gas (Unaccounted For)	1,280,734		1,997,292		716,558
Unbilled Therms	-		(7,431)		(7,431)
Fuel Retention	-		-		-
Company Use	841,891		868,434		26,543
Total Demand	86,404,722		76,818,910		(9,585,812)

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162

	(A) Actual Volume	(B) Normal Volume	(C) Actual Rate	(A-B)*C Difference
<u>Weather Variance - Volume Impact</u>				
TGP				
Spot Gas				
AES				
PNGTS				
ANE/BP NEXEN				
City Gate Delivered Supply				
DOMAC				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Volume Weather Variance	76,818,910	82,285,580		\$ (3,295,894)

	(A) Forecast Volume	(B) Actual Volume	(C) Forecast Rate	(B-A)*C Difference
<u>Demand Variance - Commodity Costs</u>				
TGP				
AES Londonderry				
PNGTS				
Canadian				
City Gate Delivered Supply				
DOMAC				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Demand Variance (Less: Fuel Retention)	86,404,722	76,818,910		\$ (9,915,693)
Demand Variance Net of Weather Variance				(6,619,799)

	(A) Actual Volume	(B) Forecast Rate	(C) Actual Rate	(C-B)*A Difference
<u>Rate Variance - Commodity Costs</u>				
TGP				
AES Londonderry				
PNGTS				
Canadian				
City Gate Delivered Supply				
DOMAC				
Storage gas - commodity withdrawn				
Propane				
LNG				
Total Commodity Cost Rate Variance	76,818,910			\$ (443,966)
Demand Charge Variance (from page 3)				(1,005,058)
Other Rate Variance (from page 4)				
Hedging (Gains)/Losses				2,912,564
Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments				(285,950)
Total Rate Variance				\$ 1,177,590
Due to Weather Variance				(3,295,894)
Due to Demand Variance (from above)				(6,619,799)
Total Gas Cost Variance				\$ (8,738,103)

ENERGY NORTH NATURAL GAS, INC
d/b/a KeySpan Energy Delivery New England
WINTER 2009-2010 COST OF GAS RESULTS
DG 09-162

	FILING	ACTUAL
Cost of Propane	\$ -	\$ 61,816
Cost of LNG	<u>657,484</u>	<u>128,020</u>
Total Costs	657,484	189,836
Percentage of Supplies Used For Pressure Support Purposes	<u>12.4%</u>	<u>12.4%</u>
Cost of Supplies Used For Pressure Support Purposes	<u>81,528</u>	<u>23,540</u>
 Firm Therms Sold	 83,801,811	 73,960,615
Firm Therms Transported	<u>28,847,194</u>	<u>31,345,540</u>
Total Therms	112,649,005	105,306,155
 Actual Liquid Cost/Therm	 0.0007	 0.0002
 Firm Therms Transported	 <u>28,847,194</u>	 <u>31,345,540</u>
 Liquid Costs Allocated to Transported Therms	 20,878	 7,007
Prior (Over) or under Collection	<u>(30,075)</u>	<u>(30,075)</u>
Total	<u>(9,197)</u>	<u>(23,068)</u>
 Costs Recovered:		
 Therms Transported	 28,847,194	 31,345,540
Recovery Rate	<u>(0.0003)</u>	<u>(0.0003)</u>
Costs Recovered	<u>(9,197)</u>	<u>(9,404)</u>
 (Over) / Under Collection For Period	 -	 (13,665)

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.20

FOR THE MONTH OF: DAYS IN MONTH	Nov-09 30	Dec-09 31	Jan-10 31	Feb-10 28	Mar-10 31	Apr-10 30	May-10	Total
1 BEGINNING BALANCE	\$ 3,343,466	\$ 2,489,552	\$ 1,445,581	\$ 2,545,270	\$ 2,983,595	\$ 2,543,469	\$ 3,011,016	\$ 3,343,466
2								
3 Add: Actual Costs	6,675,106	14,091,677	17,297,920	13,603,630	9,508,475	4,867,234		66,044,041
4								
5 Add FPO Admin Costs	-	-	-	-	-	-		-
6 Add: MISC OH	3,354	3,354	3,354	3,354	3,354	3,354		20,121
7 Add: Production and Storage	291,565	291,565	291,565	291,565	291,565	291,565		1,749,387
8 Add: Fuel Financing	9,252	14,776	19,101	20,197	7,923	14,146		85,394 88
9 Reverse Fuel Finance Estimate		-			-			-
10 Add new Fuel Finance Estimate		-			-			-
11								
12 Less: CUSTOMER BILLINGS	(2,430,541)	(9,215,917)	(17,691,580)	(15,224,509)	(12,138,410)	(8,030,486)	(3,249,282)	(67,980,724)
13 Estimated Unbilled	(5,344,722)	(11,542,794)	(10,314,221)	(8,518,906)	(6,609,220)	(3,224,002)		(45,553,865)
14 Reverse Prior Month Unbilled		5,344,722	11,542,794	10,314,221	8,518,906	6,609,220	3,224,002	45,553,865
15 Sub-Total Accrued Customer Billings	(7,775,262)	(15,413,989)	(16,463,007)	(13,429,194)	(10,228,724)	(4,645,268)	(25,280)	(67,980,724)
16								
17 Less: REFUND	-	-	-	-	-	-		-
18								
19 Less: Broker Revenues	(18,198)	(28,133)	(47,505)	(50,896)	(24,105)	(36,196)	-	(205,033)
20								
21 NON FIRM MARGIN AND CREDITS	(47,509)	(8,644)	(7,238)	(7,213)	(6,232)	(34,696)	-	(111,532)
22								
23 ENDING BALANCE PRE INTEREST	\$ 2,481,772	\$ 1,440,157	\$ 2,539,770	\$ 2,976,711	\$ 2,535,851	\$ 3,003,607	\$ 2,985,736	\$ 2,945,121
24								
25 MONTH'S AVERAGE BALANCE	2,912,619	1,964,854	1,992,676	2,760,991	2,759,723	2,773,538		
26								
27 INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
28								
29 INTEREST APPLIED	7,780	5,424	5,500	6,884	7,618	7,409		40,615
30								
31 ENDING BALANCE	\$ 2,489,552	\$ 1,445,581.15	\$ 2,545,270	\$ 2,983,595	\$ 2,543,469	\$ 3,011,016	\$ 2,985,736	\$ 2,985,736

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
OFF PEAK DEMAND AND COMMODITY
SCHEDULE 1
ACCOUNT 175.40

	FOR THE MONTH OF: DAYS IN MONTH	Nov-09 30	Dec-09 31	Jan-10 31	Feb-10 28	Mar-10 31	Apr-10 30	May-10	Total
1	BEGINNING BALANCE	\$ 520,566	\$ 42,382	\$ 42,499	\$ 42,616	\$ 42,722	\$ 42,840	\$ 42,954	520,566
2									
3	Add:ACTUAL COST	-	-	-	-	-	-		\$ -
4									
5	Add: MISC OH & PROD and STOR	-	-	-	-	-	-		-
6									
7	Less: CUSTOMER BILLINGS	(2,151,248)	-	-	-	-	-	-	(2,151,248)
8	Estimated Unbilled		-	-	-	-	-		-
9	Reverse Prior Month Unbilled	1,672,313	-	-	-	-	-	-	1,672,313
10	Sub-Total Accrued Customer Billings	(478,934)	-	-	-	-	-	-	(478,934)
11									
12	Add: ADJUSTMENTS	-	-	-	-	-	-	-	-
13									
14	ENDING BALANCE PRE INTEREST	\$ 41,631	\$ 42,382	\$ 42,499	\$ 42,616	\$ 42,722	\$ 42,840	\$ 42,954	\$ 41,631
15									
16	MONTH'S AVERAGE BALANCE	281,098	42,382	42,499	42,616	42,722	42,840		
17									
18	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
19									
20	INTEREST APPLIED	751	117	117	106	118	114		1,323
21									
22	ENDING BALANCE	\$ 42,382	\$ 42,499	\$ 42,616	\$ 42,722	\$ 42,840	\$ 42,954	\$ 42,954	\$ 42,954

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.52

	FOR THE MONTH OF: DAYS IN MONTH	Nov-09 30	Dec-09 31	Jan-10 31	Feb-10 28	Mar-10 31	Apr-10 30	May-10	Total
1	BEGINNING BALANCE	\$ (143,116)	\$ (146,419)	\$ (148,132)	\$ (101,713)	\$ (68,213)	\$ (37,230)	\$ (19,924)	(143,116)
2									
3	Add: COST ALLOW	172,454	361,993	443,542	349,622	245,536	126,818		\$ 1,699,964
4									
5	Adjustment						-	-	-
6									
7	Less: CUSTOMER BILLINGS	(54,890)	(211,359)	(418,438)	(363,729)	(276,801)	(175,108)	(75,037)	(1,575,361)
8	Estimated Unbilled	(120,481)	(272,423)	(250,762)	(202,945)	(140,552)	(74,879)		(1,062,041)
9	Reverse Prior Month Unbilled		120,481	272,423	250,762	202,945	140,552	74,879	1,062,041
10	Sub-Total Accrued Customer Billings	(175,371)	(363,301)	(396,778)	(315,911)	(214,408)	(109,435)	(158)	(1,575,361)
11									
12	ENDING BALANCE PRE INTEREST	\$ (146,033)	\$ (147,726)	\$ (101,369)	\$ (68,001)	\$ (37,085)	\$ (19,848)	\$ (20,082)	\$ (18,513)
13									
14	MONTH'S AVERAGE BALANCE	(144,575)	(147,073)	(124,751)	(84,857)	(52,649)	(28,539)		
15									
16	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
17									
18	INTEREST APPLIED	(386)	(406)	(344)	(212)	(145)	(76)		\$ (1,569)
19									
20	ENDING BALANCE	\$ (146,419)	\$ (148,132)	\$ (101,713)	\$ (68,213)	\$ (37,230)	\$ (19,924)	\$ (20,082)	\$ (20,082)

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
OFF PEAK BAD DEBT
SCHEDULE 1
ACCOUNT 175.54

	FOR THE MONTH OF: DAYS IN MONTH	Nov-09 30	Dec-09 31	Jan-10 31	Feb-10 28	Mar-10 31	Apr-10 30	May-10	Total
1	BEGINNING BALANCE	\$ 57,023	\$ 62,362	\$ 62,534	\$ 62,707	\$ 62,863	\$ 63,037	\$ 63,205	57,023
2									
3	Add: COST ALLOW	-	-	-	-	-	-		\$ -
4									
5	Less: CUSTOMER BILLINGS	(24,895)	-	-	-	-	-	-	(24,895)
6	Estimated Unbilled		-	-	-	-	-		-
7	Reverse Prior Month Unbilled	30,074	-	-	-	-	-	-	30,074
8	Sub-Total Accrued Customer Billings	5,180	-	-	-	-	-	-	5,180
9									
10	ENDING BALANCE PRE INTEREST	\$ 62,203	\$ 62,362	\$ 62,534	\$ 62,707	\$ 62,863	\$ 63,037	\$ 63,205	\$ 62,203
11									
12	MONTH'S AVERAGE BALANCE	59,613	62,362	62,534	62,707	62,863	63,037		
13									
14	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
15									
16	INTEREST APPLIED	159	172	173	156	174	168		1,002
17									
18	ENDING BALANCE	\$ 62,362	\$ 62,534	\$ 62,707	\$ 62,863	\$ 63,037	\$ 63,205	\$ 63,205	\$ 63,205

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
GAS COSTS BY SOURCE
SCHEDULE 2A

FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
DEMAND							
ALBERTA NORTHEAST							
BP							
TOTAL CANADIAN	\$ 18,457.98	\$ 31,081.69	\$ 28,675.88	\$ 55,737.27	\$ 42,731.19	\$ 44,534.92	\$ 221,218.93
PEAKING SUPPLY	(12,047.78)	(12,608.75)	(12,608.75)	(13,403.46)	(12,004.25)	(1,515.03)	(64,188.02)
TRANSPORT CAPACITY	579,408.15	1,271,460.87	912,325.58	977,129.59	971,114.33	967,164.86	5,678,603.38
STORAGE FIXED COSTS	95,969.76	133,471.25	147,681.84	(3,905.12)	101,673.87	72,313.07	547,204.67
LNG	-	98,462.92	98,462.92	169,742.44	73,678.08	0.02	440,346.38
PROPANE	7.94	3.97	11.91	11.91	15.88	(7.94)	43.67
CANADIAN CAPACITY MANAGED	(6,104.43)	(6,303.43)	(25,883.07)	(43,094.40)	(157,497.69)	(626,711.50)	(865,594.52)
Pipeline Refunds	-	(421,568.97)	-	-	-	(138,006.63)	(559,575.60)
OTHER	500.00	500.00	500.00	500.00	500.00	500.00	3,000.00
CAPACITY RELEASE ADJUSTMENT	47,509.14	6,890.06	7,237.66	7,213.26	6,232.38	34,537.30	109,619.80
TOTAL DEMAND	\$ 723,700.76	\$ 1,101,389.61	\$ 1,156,403.97	\$ 1,149,931.49	\$ 1,026,443.79	\$ 352,809.07	\$ 5,510,678.69
COMMODITY							
ALBERTA NORTHEAST / BP							
Nexem							
SEMPRA							
SUBTOTAL CANADIAN COMMODITY							
PIPELINE TRANSPORT COMM							
Distrigas							
VPEM Citigate Delivery							
GAS SUPPLY							
STORAGE COMMODITY							
LNG							
PROPANE							
OTHER COST ADJUSTMENTS							
CANDIAN CAPACITY MANAGED							
SUPPLIER CASHOUT							
NET OTHER COST ADJUSTMENTS	(122,645.67)	4,614.55	(155,638.04)	(37,683.23)	(24,010.74)	49,412.65	(285,950.48)
SUBTOTAL COMMODITY COST	\$ 5,951,404.76	\$ 12,997,629.61	\$ 16,141,516.39	\$ 12,453,698.04	\$ 8,482,031.48	\$ 4,531,556.24	\$ 60,557,836.52
OFF SYSTEM SALES COST							
NON-FIRM COST							
TOTAL COMMODITY COST	\$ 5,951,404.76	\$ 12,990,287.05	\$ 16,141,516.39	\$ 12,453,698.04	\$ 8,482,031.48	\$ 4,514,425.00	\$ 60,533,362.72
<p style="text-align: center;">ENERGY NORTH NATURAL GAS, INC D/B/A NATIONAL GRID NH NOVEMBER 2009 THROUGH APRIL 2010 GAS COSTS SUMMARY SCHEDULE 2A</p>							
FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
Total Peak Demand	\$ 723,700.76	\$ 1,101,389.61	\$ 1,156,403.97	\$ 1,149,931.49	\$ 1,026,443.79	\$ 352,809.07	\$ 5,510,678.69
Off-Peak Demand	-	-	-	-	-	-	-
Total Demand	\$ 723,700.76	\$ 1,101,389.61	\$ 1,156,403.97	\$ 1,149,931.49	\$ 1,026,443.79	\$ 352,809.07	\$ 5,510,678.69
Total Peak Commodity	\$ 5,951,404.76	\$ 12,990,287.05	\$ 16,141,516.39	\$ 12,453,698.04	\$ 8,482,031.48	\$ 4,514,425.00	\$ 60,533,362.72
Off-Peak Commodity	-	-	-	-	-	-	-
Total Commodity	\$ 5,951,404.76	\$ 12,990,287.05	\$ 16,141,516.39	\$ 12,453,698.04	\$ 8,482,031.48	\$ 4,514,425.00	\$ 60,533,362.72
Firm Sendout Costs	\$ 6,675,105.52	\$ 14,091,676.66	\$ 17,297,920.36	\$ 13,603,629.53	\$ 9,508,475.27	\$ 4,867,234.07	\$ 66,044,041.41

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1 DEMAND							
2 Supply							
3 ALBERTA NORTHEAST							
4 Northeast Gas Markets/BP							
5 Subtotal Canadian Supply	\$ 18,457.98	\$ 31,081.69	\$ 28,675.88	\$ 55,737.27	\$ 42,731.19	\$ 44,534.92	\$ 221,218.93
6 Peaking Supply							
7 Repsol							
8 Granite Ridge							
9 Chevron							5,280.59
10 VPEM Demand Charges							
11 Subtotal Peaking Supply	\$ (12,047.78)	\$ (12,608.75)	\$ (12,608.75)	\$ (13,403.46)	\$ (12,004.25)	\$ (1,515.03)	\$ (64,188.02)
12							
13 Transport Capacity							
14 Iroquois 470-01-RTS	\$ 23,106.65	\$ 23,132.36	\$ 23,252.82	\$ 23,218.57	\$ 23,227.08	\$ 23,248.69	\$ 139,186.17
15 National Fuel N02358	20,438.86	18,127.56	18,069.82	17,958.90	17,932.01	17,932.01	110,459.16
16 PNGTS FT-1999-001	21,921.36	21,921.36	21,921.36	27,401.70	21,921.36	21,921.36	137,008.50
17 TGP 632 FTA	21,293.66	134,600.48	78,784.64	78,784.64	78,525.48	78,790.53	470,779.43
18 TGP 2302 FTA Zone 5-6	13,335.65	13,291.28	13,399.74	13,366.50	15,406.25	11,378.44	80,177.86
19 TGP 8587 FTA	368,134.36	246,362.99	312,910.77	312,178.12	312,024.79	312,761.20	1,864,372.23
20 TGP 11234 FTA	18,987.50	46,525.59	46,201.77	46,113.42	46,184.10	46,207.66	250,220.04
21 TGP 33371 NET	37,209.27	36,540.84	36,890.97	36,901.58	36,933.41	37,050.12	221,526.19
22 TGP 72694 NET	-	730,200.00	359,708.69	366,092.60	363,991.65	363,061.80	2,183,054.74
23 TGP 42076 FTA	54,980.84	758.41	1,185.00	55,113.56	54,968.20	54,813.05	221,819.06
24 Subtotal Transport Capacity	\$ 579,408.15	\$ 1,271,460.87	\$ 912,325.58	\$ 977,129.59	\$ 971,114.33	\$ 967,164.86	\$ 5,678,603.38
25							
26 Storage Fixed							
27 Sempra	\$ -	\$ -	\$ -	\$ -	\$ 6,000.00	\$ -	\$ 6,000.00
28 Dominion 300076-Storage	2,867.64	2,864.55	2,605.42	2,715.61	2,854.53	2,870.82	16,778.57
29 NFG Deliverability FSS 2357	36,594.09	74,327.30	33,636.29	(2,003.44)	36,849.14	36,911.36	216,314.74
30 Tenn Reservation FSMA 523	47,763.64	47,535.01	93,953.47	(4,619.41)	47,225.81	23,786.50	255,645.02
31 HONEOYE STORAGE SS-NY	8,744.39	8,744.39	17,486.66	2.12	8,744.39	8,744.39	52,466.34
32 Subtotal Storage	\$ 95,969.76	\$ 133,471.25	\$ 147,681.84	\$ (3,905.12)	\$ 101,673.87	\$ 72,313.07	\$ 547,204.67
33							
34 LNG / DISTRIGAS FLS 164							
35 LNG/ DISTRIGAS FLS160							
36 Transgas Trucking							
37 Subtotal DISTRIGAS	\$ -	\$ 98,462.92	\$ 98,462.92	\$ 169,742.44	\$ 73,678.08	\$ 0.02	\$ 440,346.38
38							
39 Propane							
40 En Propane	\$ 7.94	\$ 3.97	\$ 11.91	\$ 11.91	\$ 15.88	\$ (7.94)	\$ 43.67
41							
42 Intercontinental Exchange	\$ 500	\$ 500	\$ 500	\$ 500	\$ 500	\$ 500	\$ 3,000.00
43							
44 Capacity Managed - Canadian							
45							
46 PNGTS Refund per RP02-13							
47 TGP Pipeline Refund	\$ -	\$ (421,568.97)	\$ -	\$ -	\$ -	\$ (138,006.63)	\$ (559,575.60)
48							
49 Demand Subtotal	\$ 676,191.62	\$ 1,094,499.55	\$ 1,149,166.31	\$ 1,142,718.23	\$ 1,020,211.41	\$ 318,271.77	\$ 5,401,058.89
50							
51 Capacity Release Adjustment							
52 ALBERTA NORTHEAST							
53 TGP - FT-A 632							
54 TGP - FT-A 11234							
55 TGP - FT-A 8587							
56 PNGTS - FT							
57							
58							
59 TOTAL DEMAND	\$ 723,700.76	\$ 1,101,389.61	\$ 1,156,403.97	\$ 1,149,931.49	\$ 1,026,443.79	\$ 352,809.07	\$ 5,510,678.69

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
COMMODITY							
<u>Canadian Supply</u>							
BP							
Nexen							
Sempra							
Subtotal Canadian Commodity							
<u>Pipeline Transport</u>							
ANE Union/Dawn							
Dominion							
El Paso							
Iroquois							
National Fuel							
PNGTS							
HONEOYE							
Subtotal Transp Commodity							
City Gate Delivery							
DISTRIGAS							
VPEM							
Subtotal Citygate Delivery							
PNGTS Supply							
Dte Energy							
Emera							
Conoco							
Subtotal PNGTS							
<u>Gas Supply</u>							
Andarko							
Chevron							
Colonial Energy							
Cheniere							
Conoco							
Emera							
Enjet							
ETC							
FPL Energy							
Hess							
L. Dreyfus							
Macquarie							
NJR Energy							
Nextera							
PSE&G							
Repsol							
Shell US							
Tenaska							
Total Gas & Power							
United LLC							
Total Other TGP Supply							
Peaking Supply							
Granite Ridge (formerly AES)							
NYMEX Hedging - Settlement							
STORAGE WITHDRAWALS							
STORAGE INJECTIONS							
DISTRIGAS (FCS 064)							
LNG VAPOR							
LNG BOIL OFF							
Subtotal LNG							
PROPANE							
Propane Storage Withdrawal							
Energy North Propane							
Subtotal Propane							
Broker Cashout							
Other Taxes W. Virginia							
Subtotal Cashouts							
Capacity Managed - Canadian							
Broker Inventory							
Subtotal Capacity Managed							
TOTAL COMMODITY							
Off System Gas Sales Cost							
NON-FIRM COST							
NET COMMODITY COST	\$ 5,951,404.76	\$ 12,990,287.05	\$ 16,141,516.39	\$ 12,453,698.04	\$ 8,482,031.48	\$ 4,514,425.00	\$ 60,533,362.72

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
DETAIL GAS COSTS BY SOURCE
SCHEDULE 2B

147	FOR THE MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
148								
149	Peak Demand 175.20	\$ 723,700.76	\$ 1,101,389.61	\$ 1,156,403.97	\$ 1,149,931.49	\$ 1,026,443.79	\$ 352,809.07	\$ 5,510,678.69
150	Peak Commodity 175.20	5,951,404.76	12,990,287.05	16,141,516.39	12,453,698.04	8,482,031.48	4,514,425.00	60,533,362.72
151	Total Peak Gas Costs	\$ 6,675,105.52	\$ 14,091,676.66	\$ 17,297,920.36	\$ 13,603,629.53	\$ 9,508,475.27	\$ 4,867,234.07	\$ 66,044,041.41
152								
153	Off-Peak Demand 175.40 OP	-	-	-	-	-	-	-
154	Off-Peak Comm 175.40 OP	-	-	-	-	-	-	-
155	Total Off-Peak Gas Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
156								
157	Firm Sendout Costs	\$ 6,675,105.52	\$ 14,091,676.66	\$ 17,297,920.36	\$ 13,603,629.53	\$ 9,508,475.27	\$ 4,867,234.07	\$ 66,044,041.41

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 3
WINTER CGAC GAS REVENUES BILLED

FOR MONTH OF:	Nov-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Total	Total
	OffPeak	Peak						Peak	Peak	OffPeak
1 VOLUMES										
2 RESIDENTIAL										
3 R-1	43,546	22,466	83,309	123,502	105,569	91,502	74,363	43,220	543,931	43,546
4 R-1 FPO	3,683	1,658	6,882	10,639	8,833	7,571	6,289	3,509	45,381	3,683
5 R-3	1,926,915	1,278,405	4,633,856	9,007,885	7,823,752	5,202,330	3,335,509	1,401,539	32,683,276	1,926,915
6 R-3 FPO	308,576	216,678	771,969	1,477,771	1,259,546	841,274	562,296	236,050	5,365,584	308,576
7 R-4	75,205	41,616	274,425	546,899	534,276	1,082,384	640,163	311,203	3,430,966	75,205
8 R-4 FPO	22,832	13,683	70,664	143,113	132,266	213,564	106,428	51,776	731,494	22,832
9 Total Residential	2,380,757	1,574,506	5,841,105	11,309,809	9,864,242	7,438,625	4,725,048	2,047,297		
10 COMMERCIAL/INDUSTRIAL										
11 G41 - G43	1,316,110	734,804	3,139,779	6,705,088	5,860,033	4,393,269	2,643,016	1,027,128	24,503,117	1,316,110
12 G41 - G43 (FPO)	77,495	57,639	249,693	549,840	423,411	358,563	210,954	89,815	1,939,915	77,495
13 Total G41- G43	1,393,605	792,443	3,389,472	7,254,928	6,283,444	4,751,832	2,853,970	1,116,943		
14 G51 - G63	356,098	195,721	641,863	1,009,418	865,236	749,760	597,829	334,085	4,393,912	356,098
15 G51 - G63 (FPO)	18,631	14,303	50,525	70,821	63,546	55,118	44,189	24,537	323,039	18,631
16 Total G51-G63	374,729	210,024	692,388	1,080,239	928,782	804,878	642,018	358,622		
17 Total Sales Volumes	4,149,091	2,576,973	9,922,965	19,644,976	17,076,468	12,995,335	8,221,036	3,522,862	73,960,615	4,149,091
18 TRANSPORTATION										
19 G41 - G43	1,085,587	419,274	2,119,244	3,622,643	3,429,341	2,806,380	1,921,067	973,457	15,291,406	1,085,587
20 G51 - G63	2,404,030	70,393	2,602,036	3,029,009	2,949,257	2,459,644	2,680,676	2,263,119	16,054,134	2,404,030
21 Total Transportation Volumes	3,489,617	489,667	4,721,280	6,651,652	6,378,598	5,266,024	4,601,743	3,236,576	31,345,540	3,489,617
22 Total Volumes	7,638,708	3,066,640	14,644,245	26,296,628	23,455,066	18,261,359	12,822,779	6,759,438	105,306,155	7,638,708
23										
24 RATES										
25 Residential	0.51940	0.94490	0.92840	0.89230	0.88280	0.93500	0.97390	0.91710		
26 Residential (FPO)	0.51940	0.96490	0.96490	0.96490	0.96490	0.96490	0.96490	0.96490		
27 C/I Sales G41 to G43	0.51990	0.94510	0.92940	0.89330	0.88240	0.93100	0.97770	0.91730		
28 C/I Sales G41 to G43 (FPO)	0.51990	0.96510	0.96510	0.96510	0.96510	0.96510	0.96510	0.96510		
29 C/I Transport G41 to G43	0.00000	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030		
30 C/I Sales G51 to G63	0.51790	0.94440	0.92890	0.89240	0.88200	0.93320	0.97410	0.91660		
31 C/I Sales G51 to G63 (FPO)	0.51790	0.96440	0.96440	0.96440	0.96440	0.96440	0.96440	0.96440		
32 C/I Transport G51 to G63	0.00000	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030	-0.00030		
33										
34 REVENUES										
35 Residential	\$ 1,062,519	\$ 1,268,516	\$ 4,634,192	\$ 8,635,935	\$ 7,471,663	\$ 5,961,762	\$ 3,944,329	\$ 1,610,393	\$ 33,526,790	\$ 1,062,519
36 Residential (FPO)	\$ 174,046	\$ 223,875	\$ 819,697	\$ 1,574,257	\$ 1,351,482	\$ 1,025,118	\$ 651,320	\$ 281,109	\$ 5,926,859	\$ 174,046
37 C/I Sales G41 to G43	\$ 684,246	\$ 694,463	\$ 2,918,111	\$ 5,989,655	\$ 5,170,893	\$ 4,090,133	\$ 2,584,077	\$ 942,185	\$ 22,389,517	\$ 684,246
38 C/I Sales G41 to G43 (FPO)	\$ 40,290	\$ 55,627	\$ 240,979	\$ 530,651	\$ 408,634	\$ 346,049	\$ 203,592	\$ 86,680	\$ 1,872,212	\$ 40,290
39 C/I Transport G41 to G43	\$ -	\$ (126)	\$ (636)	\$ (1,087)	\$ (1,029)	\$ (842)	\$ (576)	\$ (292)	\$ (4,587)	\$ -
40 C/I Sales G51 to G63	\$ 184,423	\$ 184,839	\$ 596,227	\$ 900,805	\$ 763,138	\$ 699,676	\$ 582,345	\$ 306,222	\$ 4,033,252	\$ 184,423
41 C/I Sales G51 to G63 (FPO)	\$ 9,649	\$ 13,794	\$ 48,726	\$ 68,300	\$ 61,284	\$ 53,156	\$ 42,616	\$ 23,663	\$ 311,539	\$ 9,649
42 C/I Transport G51 to G63	\$ -	\$ (21)	\$ (781)	\$ (909)	\$ (885)	\$ (738)	\$ (804)	\$ (679)	\$ (4,816)	\$ -
43 Winter Gas Cost Rev filed	\$ 2,155,173	\$ 2,440,968	\$ 9,256,515	\$ 17,697,606	\$ 15,225,181	\$ 12,174,315	\$ 8,006,898	\$ 3,249,282	\$ 68,050,764	\$ 2,155,173
44										
45 Winter Proration	\$ -	\$ (10,427)	\$ (31,752)	\$ (3,508)	\$ 1,264	\$ (33,696)	\$ 24,182	\$ -	\$ (53,937)	\$ -
46										
47 Less Occupant Billing	\$ 3,925	\$ -	\$ 8,846	\$ 2,518	\$ 1,937	\$ 2,209	\$ 594	\$ -	\$ 16,104	\$ 3,925
48 Total	\$ 2,151,248	\$ 2,430,541	\$ 9,215,917	\$ 17,691,580	\$ 15,224,509	\$ 12,138,410	\$ 8,030,486	\$ 3,249,282	\$ 67,980,724	\$ 2,151,248
49										
50 Summer Gas Cost Billed (Acct 175.40)	\$ 2,151,248									\$ 2,155,173
51										
52 Winter Gas Costs Billed (Acct 175.20)		\$ 2,430,688	\$ 9,217,333	\$ 17,693,576	\$ 15,226,422	\$ 12,139,990	\$ 8,031,866	\$ 3,250,253	\$ 67,990,127	
53 Winter Transportation Gas Costs Billed (Acct 175.20)	-	(147)	(1,416)	(1,995)	(1,914)	(1,580)	(1,381)	(971)	(9,404)	-
54 Total Winter Gas Cost Billed (Acct 175.20)	\$ -	\$ 2,430,541	\$ 9,215,917	\$ 17,691,580	\$ 15,224,509	\$ 12,138,410	\$ 8,030,486	\$ 3,249,282	\$ 67,980,724	\$ 2,155,173
55										
56										
57 Total Sales CGA Billed	\$ 2,151,248	\$ 2,430,541	\$ 9,215,917	\$ 17,691,580	\$ 15,224,509	\$ 12,138,410	\$ 8,030,486	\$ 3,249,282	\$ 67,980,724	\$ 2,151,248
58										
59 Plus Working Capital Gas Cost Billed	7,468	258	992	1,964	1,708	1,300	822	352	7,396	7,468
60 Plus Bad Debt Cost Billed	24,895	54,890	211,359	418,438	363,729	276,801	175,108	75,037	1,575,361	24,895
61 Plus Broker Revenues	-	18,198.39	28,132.63	47,504.98	50,896.38	24,104.78	36,195.99	-	205,033	-
62										
63 Total Winter Gas Costs Billed	\$ 2,183,610	\$ 2,503,886	\$ 9,456,401	\$ 18,159,488	\$ 15,640,841	\$ 12,440,615	\$ 8,242,612	\$ 3,324,671	\$ 69,768,514	\$ 2,183,610

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**ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
MAY THROUGH OCTOBER 2009
SCHEDULE 3A- CALCULATION OF UNBILLED GAS COSTS (ACCRUED COG)**

	FOR MONTH OF:	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	Firm Gas Purchases		8,549,860	17,700,130	19,325,140	15,419,480	10,460,760	5,363,540	76,818,910
2	Firm Sales		2,576,973	9,922,965	19,644,976	17,076,468	12,995,335	8,221,036	70,437,753
3	Company Use		94,202	183,551	194,629	187,074	122,695	86,283	868,434
4	Unaccounted For %		2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	
5	Unaccounted For Gas		222,296	460,203	502,454	400,906	271,980	139,452	1,997,292
6	COG Factor- Gas Cost Only		\$0.9449	\$0.9025	\$0.8761	\$0.8941	\$1.0016	\$0.9171	
7	COG Factor- Bad Debt Factor		\$0.0213	\$0.0213	\$0.0213	\$0.0213	\$0.0213	\$0.0213	
8	COG Factor- Working Capital Factor		\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0001	
9									
10	Unbilled Volume								
11	Beginning Bal		-	5,656,389	12,789,799	11,772,881	9,527,912	6,598,662	
12	Incremental Unbilled		5,656,389	7,133,411	(1,016,919)	(2,244,968)	(2,929,250)	(3,083,231)	
13	Ending Balance		-	5,656,389	12,789,799	11,772,881	9,527,912	6,598,662	3,515,431
14									
15	COG Factor- Gas Cost Only		\$0.9449	\$0.9025	\$0.8761	\$0.8941	\$1.0016	\$0.9171	
16	Gross Unbilled Gas Cost	\$1,672,313	\$5,344,722	\$11,542,794	\$10,314,221	\$8,518,906	\$6,609,220	\$3,224,002	
17									
18	Monthly Incremental Gas Cost		\$3,672,409	\$6,198,072	(\$1,228,573)	(\$1,795,314)	(\$1,909,686)	(\$3,385,218)	
19									
20	COG Factor- Bad Debt Only		\$0.0213	\$0.0213	\$0.0213	\$0.0213	\$0.0213	\$0.0213	
21	Gross Unbilled Bad Debt Cost	\$19,318	\$120,481	\$272,423	\$250,762	\$202,945	\$140,552	\$74,879	
22									
23	Monthly Incremental Bad Debt Cost		\$101,163	\$151,942	(\$21,660)	(\$47,818)	(\$62,393)	(\$65,673)	
24									
25	COG Factor- Working Capital Only		\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0001	
26	Gross Unbilled Working Capital Cost	\$5,795	\$566	\$1,279	\$1,177	\$953	\$660	\$352	
27									
28	Monthly Incremental Working Capital Cost		(\$5,230)	\$713	(\$102)	(\$224)	(\$293)	(\$308)	

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**ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 4 - NONFIRM MARGIN**

FOR THE MONTH OF:		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1	INTERRUPTIBLE							
2								
3	280 DAY							
4								
5	OFF SYSTEM GAS SALES MARGIN							
6	PROPANE OFF SYSTEM SALES MARGIN							
7								
8	CAPACITY RELEASE CREDIT							
9								
10	TOTAL NON FIRM MARGIN AND CREDITS	\$ (47,509)	\$ (8,644)	\$ (7,238)	\$ (7,213)	\$ (6,232)	\$ (34,696)	\$ (111,532)

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
PEAK PERIOD WORKING CAPITAL
ACCOUNT 142.20
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH:	Nov-09 30	Dec-09 31	Jan-10 31	Feb-10 28	Mar-10 31	Apr-10 30	May-10	Total
1	BEGINNING BALANCE	\$ (525,428)	\$ (521,640)	\$ (512,006)	\$ (499,590)	\$ (489,980)	\$ (483,716)	\$ (481,136)	\$ (525,428)
2									
3	Add: COST ALLOW	6,008	12,765	15,673	12,324	8,613	4,380		59,764
4									
5	Less: CUSTOMER BILLINGS	(258)	(992)	(1,964)	(1,708)	(1,300)	(822)	(352)	(7,396)
6	Estimated Unbilled	(566)	(1,279)	(1,177)	(953)	(660)	(352)		(4,986)
7	Reverse Prior Month Unbilled	-	566	1,279	1,177	953	660	352	4,986
8	Subtotal: Accrued Customer Billings	(823)	(1,706)	(1,863)	(1,483)	(1,007)	(514)	(1)	(7,396)
9									
10	Adjustment	-	-	-	-	-	-	-	-
11									
12	ENDING BALANCE PRE INTEREST	(520,243)	(510,581)	(498,196)	(488,748)	(482,374)	(479,849)	(481,137)	(473,060)
13									
14	MONTH'S AVERAGE BALANCE	(522,836)	(516,111)	(505,101)	(494,169)	(486,177)	(481,783)		
15									
16	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
17	INTEREST APPLIED	(1,397)	(1,425)	(1,394)	(1,232)	(1,342)	(1,287)		(8,077)
18	ENDING BALANCE	\$ (521,640)	\$ (512,006)	\$ (499,590)	\$ (489,980)	\$ (483,716)	\$ (481,136)	\$ (481,137)	\$ (481,137)

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ENERGY NORTH NATURAL GAS, INC
D/B/A KEYSpan ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
OFF PEAK WORKING CAPITAL
ACCOUNT 142.40
SCHEDULE 5

	FOR THE MONTH OF: DAYS IN MONTH	Nov-09 30	Dec-09 31	Jan-10 31	Feb-10 28	Mar-10 31	Apr-10 30	May-10	Total
1	BEGINNING BALANCE	\$ (91,430)	\$ (93,349)	\$ (93,607)	\$ (93,865)	\$ (94,099)	\$ (94,359)	\$ (94,611)	(91,430)
2									
3	Add: ACTUAL COST	-	-	-	-	-	-		\$ -
4									0
5	Less: CUSTOMER BILLINGS	(7,468)	-	-	-	-	-	-	(7,468)
6	Estimated Unbilled	-	-	-	-	-	-	-	-
7	Reverse Prior Month Unbilled	5,795	-	-	-	-	-	-	5,795
8	Subtotal: Accrued Customer Billings	(1,673)	-	-	-	-	-	-	(1,673)
9									
10	ENDING BALANCE PRE INTEREST	(93,103)	(93,349)	(93,607)	(93,865)	(94,099)	(94,359)	(94,611)	(93,103)
11									
12	MONTH'S AVERAGE BALANCE	(92,266)	(93,349)	(93,607)	(93,865)	(94,099)	(94,359)		
13									
14	INTEREST RATE	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%		
15	INTEREST APPLIED	(246)	(258)	(258)	(234)	(260)	(252)		(1,508)
16	ENDING BALANCE	\$ (93,349)	\$ (93,607)	\$ (93,865)	\$ (94,099)	\$ (94,359)	\$ (94,611)	\$ (94,611)	\$ (94,611)

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 6
WINTER BAD DEBT AND WORKING CAPITAL COSTS

FOR MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1 Demand	\$ 676,192	\$ 1,092,746	\$ 1,149,166	\$ 1,142,718	\$ 1,020,211	\$ 318,113	5,399,147
2 Commodity	5,951,405	12,990,287	16,141,516	12,453,698	8,482,031	4,514,425	60,533,363
3 Total Gas Costs	\$ 6,627,596	\$ 14,083,033	\$ 17,290,683	\$ 13,596,416	\$ 9,502,243	\$ 4,832,538	\$ 65,932,509
4							
5 Lead Lag Days	10 18	10 18	10.18	10.18	10.18	10 18	
6 Prime Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
7							
8 Working Capital Rate	0 00091	0 00091	0 00091	0 00091	0 00091	0 00091	
9							
10 Total Working Capital Costs	\$ 6,008	\$ 12,765	\$ 15,673	\$ 12,324	\$ 8,613	\$ 4,380	\$ 59,764
11							
12 Prior Period Undercollection	155,908	155,908	155,908	155,908	155,908	155,908	935,450
13							
14 Subtotal Gas Costs, Working Capital & Under Collection	6,789,512	14,251,707	17,462,264	13,764,649	9,666,764	4,992,827	66,927,723
15							
16 Bad Debt Rate 1/	0 0254	0 0254	0 0254	0 0254	0 0254	0 0254	
17							
18 Total Bad Debt Cost	\$ 172,454	\$ 361,993	\$ 443,542	\$ 349,622	\$ 245,536	\$ 126,818	\$ 1,699,964

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ENERGY NORTH NATURAL GAS, INC
d/b/a KEYSpan ENERGY DELIVERY NEW ENGLAND
NOVEMBER 2009 THROUGH APRIL 2010
SCHEDULE 6
SUMMER BAD DEBT AND WORKING CAPITAL COSTS

FOR MONTH OF:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Total
1 Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2 Commodity	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3 Total Gas Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
4							
5 Working Capital Rate	0 00091	0 00091	0 00091	0 00091	0 00091	0 00091	
6							
7 Total Working Capital Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8							
9 Prior Period Undercollection	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10							
11 Subtotal Gas Costs, Working Capital & Under Collection	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
12							
13 Bad Debt Rate	0 0254	0 0254	0 0254	0 0254	0 0254	0 0254	
14							
15 Total Bad Debt Cost	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

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<p align="center">ENERGY NORTH NATURAL GAS, INC D/B/A NATIONAL GRID NH NOVEMBER 2009 THROUGH APRIL 2010 SCHEDULE 7 WORKING CAPITAL & BAD DEBT COLLECTED</p>									
FOR MONTH OF:	OffPeak Nov-09	Peak Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	Peak May-10	Total Peak
1 VOLUMES									
2 RESIDENTIAL									
3 R-1, R-3 and R-4	2,045,666	1,342,487	4,991,590	9,678,286	8,463,597	6,376,216	4,050,035	1,755,962	36,658,173
4 R-1, R-3 and R-4 (FPO)	335,091	232,019	849,515	1,631,523	1,400,645	1,062,409	675,013	291,335	6,142,459
5									
6 COMMERCIAL/INDUSTRIAL									
7 G41 - G43	1,316,110	734,804	3,139,779	6,705,088	5,860,033	4,393,269	2,643,016	1,027,128	24,503,117
8 G41 - G43 (FPO)	77,495	57,639	249,693	549,840	423,411	358,563	210,954	89,815	1,939,915
9 G51 - G63	356,098	195,721	641,863	1,009,418	865,236	749,760	597,829	334,085	4,393,912
10 G51 - G63 (FPO)	18,631	14,303	50,525	70,821	63,546	55,118	44,189	24,537	323,039
11									
12 TRANSPORTATION									
13 G41 - G43	1,085,587	419,274	2,119,244	3,622,643	3,429,341	2,806,380	1,921,067	973,457	15,291,406
14 G51 - G63	2,404,030	70,393	2,602,036	3,029,009	2,949,257	2,459,644	2,680,676	2,263,119	16,054,134
15									
16 TOTAL VOLUME	7,638,708	3,066,640	14,644,245	26,296,628	23,455,066	18,261,359	12,822,779	6,759,438	105,306,155
17									
18 WORKING CAPITAL RATES									
19 Residential R1, R3 & R4	\$ 0 0018	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	
20 Residential R1, R-3 & R4 (FPO)	\$ 0 0018	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	
21 C/I Sales G41 to G43	\$ 0 0018	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	
22 C/I Sales G41 to G43 (FPO)	\$ 0 0018	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	
23 C/I Sales G51 to G63	\$ 0 0018	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	
24 C/I Sales G51 to G63 (FPO)	\$ 0 0018	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	\$ 0 0001	
25									
26 WORKING CAPITAL COSTS COLLECTED									
27 Residential	\$ 3,682	\$ 134	\$ 499	\$ 968	\$ 846	\$ 638	\$ 405	\$ 176	\$ 3,666
28 Residential (FPO)	603	23	85	163	140	106	68	29	614
29 C/I Sales G41 to G43	2,369	73	314	671	586	439	264	103	2,450
30 C/I Sales G41 to G43 (FPO)	139	6	25	55	42	36	21	9	194
31 C/I Sales G51 to G63	641	20	64	101	87	75	60	33	439
32 C/I Sales G51 to G63 (FPO)	34	1	5	7	6	6	4	2	32
33									
34 SUMMER GAS COST WORKING CAPITAL COLLE	\$ 7,468	\$ 258	\$ 992	\$ 1,964	\$ 1,708	\$ 1,300	\$ 822	\$ 352	\$ 7,396
35									
36 BAD DEBT RATES									
37 Residential R1, R3 & R4	\$ 0 0060	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	
38 Residential R1 & R3 (FPO)	\$ 0 0060	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	
39 C/I Sales G41 to G43	\$ 0 0060	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	
40 C/I Sales G41 to G43 (FPO)	\$ 0 0060	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	
41 C/I Sales G51 to G63	\$ 0 0060	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	
42 C/I Sales G51 to G63 (FPO)	\$ 0 0060	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	\$ 0 0213	
43									
44 BAD DEBTS COLLECTED									
45 Residential R1, R3 & R4	\$ 12,274	\$ 28,595	\$ 106,321	\$ 206,147	\$ 180,275	\$ 135,813	\$ 86,266	\$ 37,402	\$ 780,819
46 Residential R1, R-3 & R4 (FPO)	2,011	4,942	18,094 67	34,751 44	29,833 74	22,629 31	14,377 78	6,205 44	130,834
47 C/I Sales G41 to G43	7,897	15,651	66,877 29	142,818 37	124,818 70	93,576 63	56,296 24	21,877 83	521,916
48 C/I Sales G41 to G43 (FPO)	465	1,228	5,318 46	11,711 59	9,018 65	7,637 39	4,493 32	1,913 06	41,320
49 C/I Sales G51 to G63	2,137	4,169	13,671 68	21,500 60	18,429 53	15,969 89	12,733 76	7,116 01	93,590
50 C/I Sales G51 to G63 (FPO)	112	305	1,076 18	1,508 49	1,353 53	1,174 01	941 23	522 64	6,881
51									
52 SUMMER BAD DEBTS COLLECTED	\$ 24,895	\$ 54,890	\$ 211,359	\$ 418,438	\$ 363,729	\$ 276,801	\$ 175,108	\$ 75,037	\$ 1,575,361

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
COMMODITY AND RELATED VOLUMES
SCHEDULE 8

FOR THE MONTH OF:		Nov-09		Dec-09		Jan-10		Feb-10		Mar-10		Apr-10		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														
2	Off System Sales Gas Costs														
3	Pipeline Transport														
4	Storage Injections														
5	TOTAL TGP SUPPLY														
6															
7	PNGTS														
8	TOTAL TGP & PNGTS														
9															
10															
11															
12	CITIGATE DELIVERY														
13	VPEM														
14	Distrigas														
15															
16															
17	BP COMMODITY														
18	SEMPRA														
19	NEXEN														
20	TOTAL CANADIAN COMMODITY														
21															
22															
23	LNG														
24	Distrigas (FCS 064)														
25															
26	LNG Vapor														
27	LNG Injections														
28	Subtotal LNG														
29															
30															
31															
32	Propane														
33	Propane Withdrawal														
34	EN Propane														
35	Total Propane														
36															
37															
38	Storage Withdrawals														
39															
40															
41	Hedging Settlements														
42															
43	Cashouts														
44															
45	Capacity Managed														
46															
47	Taxes														
48															
49	Non-Firm Costs														
50															
51															
NET COMMODITY COST		\$ 5,951,405	854,986	\$ 12,990,287	1,770,013	\$ 16,141,516	1,932,514	\$ 12,453,698	1,541,948	\$ 8,482,031	1,046,076	\$ 4,514,425	536,354	\$ 60,533,363	7,681,891

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ENERGY NORTH NATURAL GAS, INC
D/B/A NATIONAL GRID NH
NOVEMBER 2009 THROUGH APRIL 2010
MONTHLY PRIME RATES
SCHEDULE 9

MONTH	DATES	PRIME RATE	DAYS IN MONTH	WEIGHTED RATE
Nov-09	11/01 - 11/30	3.25%	30	3.2500%
Dec-09	12/01 - 012/31	3.25%	31	3.2500%
Jan-10	01/01 - 01/31	3.25%	31	3.2500%
Feb-10	02/01 - 02/28	3.25%	28	3.2500%
Mar-10	03/01 - 03/31	3.25%	31	3.2500%
Apr-10	04/01 - 04/30	3.25%	30	3.2500%

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Local Distribution Adjustment Charge Calculation

Reference

Residential Non Heating Rates - R-1

Energy Efficiency Charge	\$0.0525	
Demand Side Management Charge	0.0000	
Conservation Charge (CCx)		\$0.0525
Relief Holder and pond at Gas Street, Concord, NH	0.0000	
Manufactured Gas Plants	0.0000	
Environmental Surcharge (ES)		0.0000
DG 06-107 Emergency Response Incentive		0.0000
Rate Case Expense Factor (RCEF)		0.0000
Residential Low Income Assistance Program (RLIAP)		0.0116
LDAC		\$0.0641 per therm

Energy Efficiency Page 1

Proposed First Revised Page 91
Emergency Response Incentive
Rate Case Expense Calculation
RLAP Page 1

Residential Heating Rates - R-3, R-4

Energy Efficiency Charge	\$0.0525	
Demand Side Management Charge	0.0000	
Conservation Charge (CCx)		\$0.0525
Relief Holder and pond at Gas Street, Concord, NH	0.0000	
Manufactured Gas Plants	0.0000	
Environmental Surcharge (ES)		0.0000
DG 06-107 Emergency Response Incentive		0.0000
Rate Case Expense Factor (RCEF)		0.0000
Residential Low Income Assistance Program (RLIAP)		0.0116
LDAC		\$0.0641 per therm

Energy Efficiency Page 1
Conservation Charge

Proposed First Revised Page 91
Emergency Response Incentive
Rate Case Expense Calculation
RLAP Page 1

Commercial/Industrial Low Annual Use Rates - G-41, G-51

Energy Efficiency Charge	\$0.0306	
Demand Side Management Charge	0.0000	
Conservation Charge (CCx)		\$0.0306
Relief Holder and pond at Gas Street, Concord, NH	0.0000	
Manufactured Gas Plants	0.0000	
Environmental Surcharge (ES)		0.0000
DG 06-107 Emergency Response Incentive		0.0000
Gas Restructuring Expense Factor (GREF)		0.0000
Rate Case Expense Factor (RCEF)		0.0000
Residential Low Income Assistance Program (RLIAP)		0.0116
LDAC		\$0.0422 per therm

Energy Efficiency Page 1
Conservation Charge

Proposed First Revised Page 91
Emergency Response Incentive
Rate Case Expense Calculation
RLAP Page 1

Commercial/Industrial Medium Annual Use Rates - G-42, G-52

Energy Efficiency Charge	\$0.0306	
Demand Side Management Charge	0.0000	
Conservation Charge (CCx)		\$0.0306
Relief Holder and pond at Gas Street, Concord, NH	0.0000	
Manufactured Gas Plants	0.0000	
Environmental Surcharge (ES)		0.0000
DG 06-107 Emergency Response Incentive		0.0000
Gas Restructuring Expense Factor (GREF)		0.0000
Rate Case Expense Factor (RCEF)		0.0000
Residential Low Income Assistance Program (RLIAP)		0.0116
LDAC		\$0.0422 per therm

Energy Efficiency Page 1
Conservation Charge

Proposed First Revised Page 91
Emergency Response Incentive
Rate Case Expense Calculation
RLAP Page 1

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54

Energy Efficiency Charge	\$0.0306	
Demand Side Management Charge	0.0000	
Conservation Charge (CCx)		\$0.0306
Relief Holder and pond at Gas Street, Concord, NH	0.0000	
Manufactured Gas Plants	0.0000	
Environmental Surcharge (ES)		0.0000
DG 06-107 Emergency Response Incentive		0.0000
Gas Restructuring Expense Factor (GREF)		0.0000
Rate Case Expense Factor (RCEF)		0.0000
Residential Low Income Assistance Program (RLIAP)		0.0116
LDAC		\$0.0422 per therm

Energy Efficiency Page 1
Conservation Charge

Proposed First Revised Page 91
Emergency Response Incentive
Rate Case Expense Calculation
RLAP Page 1

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

Rate Case Expense Factors for Residential Customers

Rate Case Expense	\$	-
Temporary Rate Reconciliation		-
Rate Case Expense Reconciliation Adjustment		
Total Rate Case Expense/Temporary Rate Reconciliation Recoverable	\$	-

Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	60,288,480
Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i)	97,732,153
Total Volumes	158,020,633

Rate Case Expense Factor	\$	-
---------------------------------	-----------	----------

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.
d/b/a National Grid NH
Residential Low Income Assistance Program (RLIAP)

Schedule 19
RLIAP
Page 1 of 2

1	Peak Period	Customer Charge	First Block	Last Block	Total
2	R-3 Base Rates	\$ 15.7800	\$ 0.2774	\$ 0.2091	
3	R-4 Rate at 40% of R-3	\$ 6.3100	\$ 0.1110	\$ 0.0836	
4	Program Subsidy	\$ 9.4700	\$ 0.1664	\$ 0.1255	
5	Average Annual Therms		572	203	775
6					
7	Peak Period RLIAP Subsidy	\$ 56.82	\$ 95.21	\$ 25.46	\$ 177.49
8					
9	<u>Off Peak Period</u>				
10	R-3 Base Rates	\$ 15.7800	\$ 0.2774	\$ 0.2091	
11	R-4 Rate at 40% of R-3	\$ 6.3100	\$ 0.1110	\$ 0.0836	
12	Program Subsidy	\$ 9.4700	\$ 0.1664	\$ 0.1255	
13	Average Annual Therms		118	52	170
14					
15	Off Peak Period RLIAP Subsidy	\$ 56.82	\$ 19.67	\$ 6.54	\$ 83.03
16					
17	Estimated Annual Subsidy	\$ 113.64	\$ 114.88	\$ 32.00	\$ 260.52
18					
19	Number of Estimated 2010/11 Participants				7,213 1/
20					
21	Annual Subsidy times Number of Participants (Ln 17 * Ln 19)				\$ 1,879,126
22	Prior Year Ending Balance - RLIAP Page 2				(56,043)
23	Estimated Annual Administrative Costs				8,600
24	Total Program Costs				\$ 1,831,683
25					
26	Estimated weather normalized firm therms billed for				
27	the twelve months ended 10/31/11 sales and transportation				158,020,633
28					
29	Total Residential Low Income Program Charge				\$ 0.0116

1/ Estimated number of participants for 2010-11 is based on the actual number participants as of June 2010, as provided in the RLIAP Quarterly Report as revised and filed on July 28, 2010.

00000104

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
NOVEMBER 2009 THROUGH OCTOBER 2010
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.39

1	FOR THE MONTH OF:		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	(Estimate)	(Estimate)	(Estimate)	
2	DAYS IN MONTH		30	31	31	28	31	30	31	30	31	Aug-10	Sep-10	Oct-10	Total
3	Beginning Balance	\$	(53,229)	(97,456)	(155,055)	(276,840)	(370,705)	(274,501)	(220,226)	(174,894)	(144,193)	(120,786)	(94,798)	(73,759)	(53,229)
4															
5	Add: Actual Costs		42,097	87,727	139,146	139,146	277,881	181,880	131,834	91,463	74,296	72,604	72,828	80,961	1,391,864
6															
7	Less: Collected Revenue		(86,122)	(144,978)	(260,337)	(232,205)	(180,787)	(126,946)	(85,957)	(60,336)	(50,524)	(46,319)	(51,565)	(63,066)	(1,389,141)
8															
9	Add: Administrative and Start Up Costs		-	-	-	-	-	-	-	-	-	-	-	-	-
10															
11	Ending Balance Pre-Interest	\$	(97,255)	(154,707)	(276,245)	(369,899)	(273,612)	(219,566)	(174,350)	(143,767)	(120,421)	(94,501)	(73,534)	(55,864)	(50,507)
12															
13	Month's Average Balance	\$	(75,242)	(126,081)	(215,650)	(323,370)	(322,159)	(247,034)	(197,288)	(159,331)	(132,307)	(107,644)	(84,166)	(64,812)	
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	\$	(201)	(348)	(595)	(806)	(889)	(660)	(545)	(426)	(365)	(297)	(225)	(179)	(5,536)
18															
19	Ending Balance	\$	(97,456)	(155,055)	(276,840)	(370,705)	(274,501)	(220,226)	(174,894)	(144,193)	(120,786)	(94,798)	(73,759)	(56,043)	(56,043)

00000105

Conservation Charge (CC) Factor Calculation

Conservation Charge Factors for Residential Customers (CCres)

DSM Expenses	\$0 Backup Page 4 Line 7
Residential Lost Margins	\$0 Backup Page 5 Line 5
Residential Conservation Reconciliation Adjustment (CCRres)	(4,523) Backup Page 2 Line 11
Total Rate Case Expense Recoverable	_____ (\$4,523)

Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres)	59,255,995
--	------------

Conservation Charge Factor for Residential Customers (CCres)	\$0.0000
---	-----------------

Conservation Charge Factors for Commercial Customers (CCcomm)

DSM Expenses	\$0 Backup Page 4 Line 24
Commercial Lost Margins	\$0 Backup Page 5 Line 16
Commercial Conservation Reconciliation Adjustment (CCRcomm)	(3,932) Backup Page 2 Line 28
Total Rate Case Expense Recoverable	_____ (\$3,932)

Forecasted Annual Throughput Volumes for Commercial Customer (A:VOLcomm)	97,732,153
--	------------

Conservation Charge Factor for Commercial Customers (CCres)	\$0.0000
--	-----------------

2009/2010 EnergyNorth Conservation Charge Reconciliation

Line No.	Actual 2009	Actual 2009	Actual 2009	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Actual 2010	Estimate 2010	2010	
	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUN</u>	<u>JUL</u>	<u>AUG</u>	<u>SEP</u>	<u>TOTAL</u>
Domestic Heating:													
1 Beginning balance	(32,464)	(\$33,899)	(\$31,658)	(\$28,288)	(\$21,650)	(\$15,851)	(\$11,484)	(\$8,725)	(\$6,974)	(\$5,968)	(\$5,208)	(\$4,511)	(\$32,464)
2 Therms sold	2,242,518	3,883,910	5,750,914	11,175,668	9,749,840	7,339,552	4,644,396	2,954,208	1,705,880	1,290,888	1,184,525	-	51,922,299
3 Surcharge (Tariff Pg 91)	(0 0006)	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	0 0006	-	
4 Revenue collected	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
5 Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Lost net rev (Pg 4 Ln 5)	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Under/(over)	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
8 Pre-interest ending balance	(33,809)	(31,569)	(28,207)	(21,583)	(15,800)	(11,447)	(8,698)	(6,952)	(5,950)	(5,193)	(4,497)	(4,511)	(4,002)
9 Average monthly balance	(33,137)	(32,734)	(29,932)	(24,935)	(18,725)	(13,649)	(10,091)	(7,839)	(6,462)	(5,580)	(4,853)	(4,511)	(18,233)
10 Interest for month	(90)	(89)	(81)	(68)	(51)	(37)	(27)	(21)	(18)	(15)	(13)	(12)	(521)
11 Month-end balance	(33,899)	(31,658)	(28,288)	(21,650)	(15,851)	(11,484)	(8,725)	(6,974)	(5,968)	(5,208)	(4,511)	(4,523)	(4,523)
12 Interest rate	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%
13													
14													
15	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	2010	
16 Commercial Heating:	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUN</u>	<u>JUL</u>	<u>AUG</u>	<u>SEP</u>	<u>TOTAL</u>
17 Beginning balance	(3,807)	(\$3,817)	(\$3,827)	(\$3,838)	(\$3,848)	(\$3,858)	(\$3,869)	(\$3,879)	(\$3,890)	(\$3,900)	(\$3,911)	(\$3,922)	(\$3,807)
18 Therms sold	4,661,905	6,750,085	8,803,140	14,986,819	13,590,824	10,822,734	8,097,731	5,663,319	4,332,261	3,714,352	3,527,312	-	84,950,482
19 Surcharge (Tariff Pg 91)	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Revenue collected	-	-	-	-	-	-	-	-	-	-	-	-	-
21 Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
22 Lost net rev (Pg 4 Ln 16)	-	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-	-
24 Under/(over)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Pre-interest ending balance	(3,807)	(3,817)	(3,827)	(3,838)	(3,848)	(3,858)	(3,869)	(3,879)	(3,890)	(3,900)	(3,911)	(3,922)	(3,807)
26 Average monthly balance	(3,807)	(3,817)	(3,827)	(3,838)	(3,848)	(3,858)	(3,869)	(3,879)	(3,890)	(3,900)	(3,911)	(3,922)	(3,807)
27 Interest for month	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(11)	(11)	(11)	(11)	(11)	(126)
28 Month-end balance	(3,817)	(3,827)	(3,838)	(3,848)	(3,858)	(3,869)	(3,879)	(3,890)	(3,900)	(3,911)	(3,922)	(3,932)	(3,932)
29 Interest rate	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%
30													
31	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	2010	
32	<u>2009</u>	<u>2009</u>	<u>2009</u>	<u>2010</u>	<u>2010</u>	<u>2010</u>	<u>2010</u>	<u>2010</u>	<u>2010</u>	<u>2010</u>	<u>2010</u>	<u>2010</u>	
33 TOTAL	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUN</u>	<u>JUL</u>	<u>AUG</u>	<u>SEP</u>	<u>TOTAL</u>
34 Beginning balance	(\$36,271)	(\$37,716)	(\$35,485)	(\$32,126)	(\$25,498)	(\$19,709)	(\$15,353)	(\$12,604)	(\$10,864)	(\$9,868)	(\$9,119)	(\$8,432)	(\$36,271)
35 Therms sold	6,904,423	10,633,995	14,554,054	26,162,487	23,340,664	18,162,286	12,742,127	8,617,527	6,038,141	5,005,240	4,711,837	-	136,872,781
36 Revenue collected	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
37 Expenses incurred	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Lost net revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
39 Under/(over)	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	-	28,462
40 Pre-interest ending balance	(37,616)	(35,386)	(32,034)	(25,420)	(19,648)	(15,306)	(12,567)	(10,832)	(9,840)	(9,094)	(8,408)	(8,432)	(7,808)
41 Interest for month	(100)	(99)	(91)	(78)	(61)	(47)	(38)	(32)	(28)	(26)	(24)	(23)	(647)
42 Month-end balance	(37,716)	(35,485)	(32,126)	(25,498)	(19,709)	(15,353)	(12,604)	(10,864)	(9,868)	(9,119)	(8,432)	(8,455)	(8,455)
43 Interest rate	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%	3 25%

00000107

2009/2010 EnergyNorth Conservation Charge Reconciliation

Line No.	Actual Throughput												TOTAL	
	2009 OCT	2009 NOV	2009 DEC	2010 JAN	2010 FEB	2010 MAR	2010 APR	2010 MAY	2010 JUN	2010 JUL	2010 AUG	2010 SEP		
Domestic Heating:														
1	Therms sold - actual	2,242,518	3,883,910	5,750,914	11,175,668	9,749,840	7,339,552	4,644,396	2,954,208	1,705,880	1,290,888	1,184,525	1,197,519	53,119,818
2	Surcharge (Tariff Pg 94)	(\$0 0006)	\$0 0006	\$0 0006	\$0 0006	\$0 0006	\$0 0006	\$0 0006	\$0 0006	\$0 0006	\$0 0006	\$0 0006	\$0 0006	
3	Revenue - actual	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	719	29,181
4														
5														
6														
Commercial Heating:														
8	Therms sold - actual	4,661,905	6,750,085	8,803,140	14,986,819	13,590,824	10,822,734	8,097,731	5,663,319	4,332,261	3,714,352	3,527,312	3,498,640	88,449,122
9	Surcharge (Tariff Pg 94)	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	\$0 0000	
10	Revenue - actual	-	-	-	-	-	-	-	-	-	-	-	-	-
11														
12														
Total:														
14	Therms sold - actual	6,904,423	10,633,995	14,554,054	26,162,487	23,340,664	18,162,286	12,742,127	8,617,527	6,038,141	5,005,240	4,711,837	4,696,159	141,568,940
15	Revenue - actual	(1,346)	2,330	3,451	6,705	5,850	4,404	2,787	1,773	1,024	775	711	719	29,181

00000108

2009/2010 EnergyNorth Conservation Charge Reconciliation

		Actual Expenses												
		2009 OCT	2009 NOV	2009 DEC	2010 JAN	2010 FEB	2010 MAR	2010 APR	2010 MAY	2010 JUN	2010 JUL	2010 AUG	2010 SEP	TOTAL
Line No.	Residential Expenses Incurred													
1	Administrative	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Total Residential Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9														
10														
11	Commercial Expenses Incurred													
12														
13	Administrative:													
14	Delivery Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Photocopies	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Telephone	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Travel	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Audit	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Legal	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Marketing	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Measures	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Rebates	-	-	-	-	-	-	-	-	-	-	-	-	-
23														
24	Total Commercial Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-

00000109

2009/2010 ENERGYNORTH LOST MARGIN SUMMARY

<u>Residential Heating</u>		2009	2009	2009	2010	2010	2010	2010	2010	2010	2010	2010	2010	
		<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug</u>	<u>Sep</u>	<u>TOTAL</u>
Line No.	fiscal 2008													
1	Lost Vol Therms (Pg 6 Ln 29)													-
2	Tailblock Rate	\$0.1859	\$0.1859	\$0.1859	\$0.1859	\$0.1859	\$0.1859	\$0.1859	\$0.1859	\$0.2070	\$0.2091	\$0.2091	\$0.2091	
3	Margin	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4	Recovery Rate	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>0%</u>	<u>57%</u>
5	Lost Margin	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>
6														
7														
8														
9	<u>Commercial and Industrial</u>													
10														
11	fiscal 2008													
12	Lost Vol Therms (Pg 5 Ln 53)													-
13	Tailblock Rate	\$0.1469	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1636	\$0.1652	\$0.1652	\$0.1652	
14	Margin	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Recovery Rate	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>0%</u>	<u>57%</u>
16	Lost Margin	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>
17														
18														
19	<u>Total</u>													
20														
21	fiscal 2008													
22	Lost Volume Therms	-	-	-	-	-	-	-	-	-	-	-	-	
23	Tailblock Rate													
24	Margin	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
25	recovery rate	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>57%</u>	<u>0%</u>	<u>57%</u>
26	recoverable portion	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>

00000110

ENERGYNORTH 2007/2008 LOST MARGIN CALCULATION BACKUP

Line No. Actual tailblock margin

	<u>Oct-09</u>	<u>Nov-09</u>	<u>Dec-09</u>	<u>Jan-10</u>	<u>Feb-10</u>	<u>Mar-10</u>	<u>Apr-10</u>	<u>May-10</u>	<u>Jun-10</u>	<u>Jul-10</u>	<u>Aug-10</u>	<u>Sep-10</u>	
1 Domestic Heating	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.2070	0.2091	0.2091	0.2091	
2													
3 Commercial Heating	0.1469	0.1757	0.1757	0.1757	0.1757	0.1757	0.1757	0.1757	0.1636	0.1652	0.1652	0.1652	
4													
5 Normal heating degree days (calendar):													
6	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUG</u>	<u>SEP</u>	<u>Total</u>
7													
8 Heating Degree Days	322	602	921	1,077	926	822	498	221	9	-	-	36	5,434
9													
10 Percent of Total	5.93%	11.08%	16.95%	19.82%	17.04%	15.13%	9.16%	4.07%	0.17%	0.00%	0.00%	0.66%	100.00%
11													

Residential Heating

Therms														Pg 8 Ln32	Pg 7 Ln31	Pg 6 Ln14			
15 program year 2010	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	Total	annual load	F Y 97	FY98	FY99	FY00	FY01
16 DH - therm savings fiscal															Savings	Savings	Savings	Savings	Savings
17 Oct-08													-	15,432	8,616	6,816	-	0	0
18 Nov-08													-	16,450	3,455	12,996	-	0	0
19 Dec-08													-	25,866	4,342	15,945	5,579	0	0
20 Jan-09													-	25,818	4,088	6,134	15,596	0	0
21 Feb-09													-	36,373	9,277	12,457	14,639	0	0
22 Mar-09													-	31,547	8,055	14,524	8,969	0	0
23 Apr-09													-	36,059	10,465	17,113	8,481	0	0
24 May-09													-	16,633	11,922	4,711	-	0	0
25 Jun-09													-	32,762	23,809	7,258	1,695	0	0
26 Jul-09													-	15,798	12,412	3,386	-	0	0
27 Aug-09													-	17,875	12,514	1,331	4,030	0	0
28 Sep-09													-	34,800	28,758	5,981	61	0	0
29 totals	-	-	-	-	-	-	-	-	-	-	-	-	-	305,409	137,710	108,649	59,050	-	-
30																			
31 Rate	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.1859	0.2070	0.2091	0.2091	0.2091							
32 Margin	-	-	-	-	-	-	-	-	-	-	-	-	-						
33 Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%						
34	-	-	-	-	-	-	-	-	-	-	-	-	-						

Commercial Heating

	<u>Therms</u>																		
39 program year 2010	<u>OCT</u>	<u>NOV</u>	<u>DEC</u>	<u>JAN</u>	<u>FEB</u>	<u>MAR</u>	<u>APR</u>	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUG</u>	<u>SEP</u>	<u>Total</u>	<u>Total</u>	Pg 8 Ln49 F Y 97 Savings	Pg 7 Ln48 FY98 Savings	FY99 Savings	FY00 Savings	FY01 Savings
40 CH - therm savings																			
41 Oct-08													-	189	-	189	0	0	0
42 Nov-08													-	567	378	189	0	0	0
43 Dec-08													-	1,189	439	750	0	0	0
44 Jan-09													-	945	189	756	0	0	0
45 Feb-09													-	399	189	210	0	0	0
46 Mar-09													-	945	378	567	0	0	0
47 Apr-09													-	189	-	189	0	0	0
48 May-09													-	378	-	378	0	0	0
49 Jun-09													-	1,256	567	689	0	0	0
50 Jul-09													-	549	549	-	0	0	0
51 Aug-09													-	189	189	-	0	0	0
52 Sep-09													-	1,000	-	1,000	0	0	0
53 totals													-	7,795	2,878	4,917	-	-	-
54																			
55 Rate	\$0.1469	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1757	\$0.1636	\$0.1652	\$0.1652	\$0.1652							
56 Margin	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0						
57 Recovery Rate	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%						
58 Total Recovery	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0						

00000111

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential Non Heating and Heating Classes
November 1, 2010 - October 31, 2011
Energy Efficiency Charge

Schedule 19
Energy Efficiency
Page 1 of 7

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures		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
						Residential	Low-Income								
May 10	Actual	(777,780)	(\$0.0466)	(140,695)	194,285	371,331	68,102	(479,042)	(628,411)	3.25%	(1,735)	(480,776)	3,689,942	3,019,211	31
June 10	Actual	(480,776)	(\$0.0466)	(82,124)	194,285	130,876	304	(431,721)	(456,249)	3.25%	(1,219)	(432,940)	1,849,958	1,762,309	30
July 10	Actual	(432,940)	(\$0.0466)	(62,377)	194,285	379,088	23,026	(93,202)	(263,071)	3.25%	(726)	(93,928)	1,349,637	1,338,555	31
August 10	Forecast	(93,928)	(\$0.0466)	(55,476)	194,285	0	0	(24,524)	(44,813)	3.25%	(68)	44,813	1,190,474	0	31
September 10	Forecast	44,813	(\$0.0466)	(60,598)	194,285	0	0	178,501	111,657	3.25%	298	178,799	1,300,391	0	30
October 10	Forecast	178,799	(\$0.0466)	(91,179)	194,285	0	0	281,905	230,352	3.25%	636	282,541	1,956,634	0	31
November 10	Forecast	282,541	(\$0.0525)	(222,182)	194,285	0	0	254,644	268,593	3.25%	717	255,362	4,236,072	0	30
December 10	Forecast	255,362	(\$0.0525)	(331,466)	194,285	0	0	118,182	186,772	3.25%	516	118,697	6,319,650	0	31
January 11	Forecast	118,697	(\$0.0525)	(618,072)	240,490	0	0	(258,884)	(70,093)	3.25%	(193)	(259,078)	11,784,020	0	31
February 11	Forecast	(259,078)	(\$0.0525)	(562,460)	240,490	0	0	(581,047)	(420,062)	3.25%	(1,047)	(582,095)	10,723,744	0	28
March 11	Forecast	(582,095)	(\$0.0525)	(465,037)	240,490	0	0	(806,641)	(694,368)	3.25%	(1,917)	(808,558)	8,866,291	0	31
April 11	Forecast	(808,558)	(\$0.0525)	(320,571)	240,490	0	0	(888,638)	(848,598)	3.25%	(2,267)	(890,905)	6,111,933	0	30
May 11	Forecast	(890,905)	(\$0.0525)	(184,373)	240,490	0	0	(834,787)	(862,846)	3.25%	(2,382)	(837,169)	3,515,209	0	31
June 11	Forecast	(837,169)	(\$0.0525)	(112,334)	240,490	0	0	(709,013)	(773,091)	3.25%	(2,065)	(711,078)	2,141,739	0	30
July 11	Forecast	(711,078)	(\$0.0525)	(87,574)	240,490	0	0	(558,161)	(634,619)	3.25%	(1,752)	(559,913)	1,669,660	0	31
August 11	Forecast	(559,913)	(\$0.0525)	(70,227)	240,490	0	0	(389,649)	(474,781)	3.25%	(1,311)	(390,960)	1,338,936	0	31
September 11	Forecast	(390,960)	(\$0.0525)	(69,446)	240,490	0	0	(219,916)	(305,438)	3.25%	(816)	(220,731)	1,324,044	0	30
October 11	Forecast	(220,731)	(\$0.0525)	(118,389)	240,490	0	0	(98,630)	(159,681)	3.25%	(441)	(99,071)	2,257,182	0	31
November 11	Forecast	(99,071)	(\$0.0525)	(222,182)	240,490	0	0	(80,762)	(89,917)	3.25%	(240)	(81,003)	4,236,072	0	30
December 11	Forecast	(81,003)	(\$0.0525)	(331,466)	240,490	0	0	(171,978)	(126,490)	3.25%	(349)	(172,327)	6,319,650	0	31

Estimated Residential Nonheating Conservation Charge Effective November 1, 2010 - October 31, 2011		
Beginning Balance	\$	282,541
Program Budget Nov 10-Oct 11		2,793,476
Projected Interest		(15,648)
Projected Budget with Interest	\$	3,060,369
Total Charges	\$	3,060,369
Projected Therm Sales		58,353,540
Residential Rate		\$0.0524
Total Charges with Interest	\$	3,060,369
Projected Therm Sales		58,353,540
Residential Rate		\$0.0525

Residential Non Heating Therm Sales	1%	1,051,312	1,032,484	1%
Residential Heating Therm Sales	38%	57,302,228	59,255,995	37%
C&I Therm Sales	61%	92,474,643	97,732,153	62%
Total Therms	100%	150,828,182	158,020,633	100%
Year One Budget Year Two Budget				
1/01/10 - 12/31/10 1/01/11 - 12/31/11				
Low-Income Program Budget	\$	635,997	\$	730,895
Other Refund		-		-
Total Shared Budget	\$	635,997	\$	730,895
Residential Program Budget	\$	1,939,128	\$	2,359,779
Residential Program Incentive		\$146,238		\$247,254
Total Residential Program Budget	\$	2,085,366	\$	2,607,032
Commercial/Industrial Program Budget	\$	2,411,290	\$	3,174,772
Commercial/Industrial Program Incentive		\$154,045		\$253,982
Total Commercial/Industrial Program Budget	\$	2,565,335	\$	3,428,754
Total Program Budget	\$	5,286,699	\$	6,766,682
Shared Expenses Allocation to Residential	\$	246,059	\$	278,853
Shared Expenses Allocation to C&I		389,938		452,042
Total Allocated Shared Expenses	\$	635,997	\$	730,895
Total Residential (including allocation of Shared Budget)	\$	2,331,426	\$	2,885,886
Total C&I (including allocation of Shared Budget)		2,955,273		3,880,796
Total Budget	\$	5,286,699	\$	6,766,682

00000112

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2010 - October 31, 2011
Energy Efficiency Charge

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Energy Efficiency
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Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures		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
						Com-Ind	Low-Income								
May 10	Actual	(1,282,952)	(\$0 0250)	(141,583)	246,273	82,708	90,275	(1,251,553)	(1,267,252)	3.25%	(3,498)	(1,255,051)	6,415,202	5,663,319	31
June 10	Actual	(1,255,051)	(\$0 0250)	(108,307)	246,273	46,243	403	(1,316,712)	(1,285,881)	3.25%	(3,435)	(1,320,147)	4,841,323	4,332,261	30
July 10	Actual	(1,320,147)	(\$0 0250)	(92,859)	246,273	86,534	30,522	(1,295,949)	(1,308,048)	3.25%	(3,611)	(1,299,560)	3,759,005	3,714,352	31
August 10	Forecast	(1,299,560)	(\$0 0250)	(87,325)	246,273	0	0	(1,140,612)	(1,220,086)	3.25%	(3,368)	(1,143,980)	3,492,988	0	31
September 10	Forecast	(1,143,980)	(\$0 0250)	(97,837)	246,273	0	0	(995,544)	(1,069,762)	3.25%	(2,858)	(998,402)	3,913,470	0	30
October 10	Forecast	(998,402)	(\$0 0250)	(110,504)	246,273	0	0	(862,633)	(930,518)	3.25%	(2,568)	(865,202)	4,420,152	0	31
November 10	Forecast	(865,202)	(\$0 0306)	(222,613)	246,273	0	0	(841,542)	(853,372)	3.25%	(2,280)	(843,822)	7,274,929	0	30
December 10	Forecast	(843,822)	(\$0 0306)	(290,429)	246,273	0	0	(887,978)	(865,900)	3.25%	(2,390)	(890,368)	9,491,159	0	31
January 11	Forecast	(890,368)	(\$0 0306)	(473,205)	323,400	0	0	(1,040,173)	(965,271)	3.25%	(2,664)	(1,042,838)	15,464,220	0	31
February 11	Forecast	(1,042,838)	(\$0 0306)	(448,319)	323,400	0	0	(1,167,757)	(1,105,297)	3.25%	(2,756)	(1,170,513)	14,650,932	0	28
March 11	Forecast	(1,170,513)	(\$0 0306)	(388,392)	323,400	0	0	(1,235,505)	(1,203,009)	3.25%	(3,321)	(1,238,826)	12,692,550	0	31
April 11	Forecast	(1,238,826)	(\$0 0306)	(308,463)	323,400	0	0	(1,223,889)	(1,231,357)	3.25%	(3,289)	(1,227,178)	10,080,479	0	30
May 11	Forecast	(1,227,178)	(\$0 0306)	(205,063)	323,400	0	0	(1,108,842)	(1,168,010)	3.25%	(3,224)	(1,112,066)	6,701,400	0	31
June 11	Forecast	(1,112,066)	(\$0 0306)	(144,693)	323,400	0	0	(933,359)	(1,022,712)	3.25%	(2,732)	(936,091)	4,728,513	0	30
July 11	Forecast	(936,091)	(\$0 0306)	(128,330)	323,400	0	0	(741,021)	(838,556)	3.25%	(2,315)	(743,336)	4,193,795	0	31
August 11	Forecast	(743,336)	(\$0 0306)	(117,224)	323,400	0	0	(537,160)	(640,248)	3.25%	(1,767)	(538,927)	3,830,853	0	31
September 11	Forecast	(538,927)	(\$0 0306)	(116,576)	323,400	0	0	(332,104)	(435,516)	3.25%	(1,163)	(333,267)	3,809,661	0	30
October 11	Forecast	(333,267)	(\$0 0306)	(147,298)	323,400	0	0	(157,166)	(245,216)	3.25%	(677)	(157,842)	4,813,663	0	31
November 11	Forecast	(157,842)	(\$0 0306)	(222,613)	323,400	0	0	(57,056)	(107,449)	3.25%	(287)	(57,343)	7,274,929	0	30
December 11	Forecast	(57,343)	(\$0 0306)	(290,429)	323,400	0	0	(24,372)	(40,857)	3.25%	(113)	(24,485)	9,491,159	0	31

Estimated C & I Conservation Charge	
Effective November 1, 2010 - October 31, 2011	
Beginning Balance	(\$865,202)
Program Budget	3,726,542
Projected Interest	(31,529)
Program Budget with Interest	\$2,829,811
Total Charges	\$2,829,811
Projected Therm Sales	92,474,643
C&I Rate	\$0.0306
Total Charges with Interest	\$2,829,811
Projected Therm Sales	92,474,643
Com/Ind Rate	\$0.0306
Com/Ind Rate from Prior Programs ⁽¹⁾	\$0.0000
Combined Com/Ind Rate	\$0.0306

00000113

EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2010 - October 31, 2011
Energy Efficiency Charge

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Energy Efficiency
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Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures				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
						Residential	Com-Ind	Low-Income	Total								
May 10	Actual	(2,060,732)	n/a	(282,278)	440,558	371,331	82,708	158,377	612,416	(1,730,594)	(1,895,663)	3.25%	(5,233)	(1,735,827)	10,105,145	8,682,530	31
June 10	Actual	(1,735,827)	n/a	(190,431)	440,558	130,876	46,243	706	177,825	(1,748,432)	(1,742,130)	3 25%	(4,654)	(1,753,086)	6,691,280	6,094,570	30
July 10	Actual	(1,753,086)	n/a	(155,236)	440,558	379,088	86,534	53,548	519,170	(1,389,152)	(1,571,119)	3 25%	(4,337)	(1,393,488)	5,108,643	5,052,907	31
August 10	Forecast	(1,393,488)	n/a	(142,801)	440,558	0	0	0	0	(1,095,731)	(1,244,610)	3 25%	(3,435)	(1,099,167)	4,683,462	0	31
September 10	Forecast	(1,099,167)	n/a	(158,435)	440,558	0	0	0	0	(817,044)	(958,105)	3 25%	(2,559)	(819,603)	5,213,861	0	30
October 10	Forecast	(819,603)	n/a	(201,683)	440,558	0	0	0	0	(580,728)	(700,166)	3 25%	(1,933)	(582,661)	6,376,786	0	31
November 10	Forecast	(582,661)	n/a	(444,795)	440,558	0	0	0	0	(586,897)	(584,779)	3 25%	(1,562)	(588,460)	11,511,001	0	30
December 10	Forecast	(588,460)	n/a	(621,895)	440,558	0	0	0	0	(769,796)	(679,128)	3 25%	(1,875)	(771,671)	15,810,809	0	31
January 11	Forecast	(771,671)	n/a	(1,091,277)	563,890	0	0	0	0	(1,299,057)	(1,035,364)	3 25%	(2,858)	(1,301,915)	27,248,240	0	31
February 11	Forecast	(1,301,915)	n/a	(1,010,779)	563,890	0	0	0	0	(1,748,804)	(1,525,360)	3 25%	(3,803)	(1,752,607)	25,374,676	0	28
March 11	Forecast	(1,752,607)	n/a	(853,429)	563,890	0	0	0	0	(2,042,146)	(1,897,377)	3 25%	(5,237)	(2,047,383)	21,558,841	0	31
April 11	Forecast	(2,047,383)	n/a	(629,034)	563,890	0	0	0	0	(2,112,527)	(2,079,955)	3 25%	(5,556)	(2,118,083)	16,192,412	0	30
May 11	Forecast	(2,118,083)	n/a	(389,436)	563,890	0	0	0	0	(1,943,629)	(2,030,856)	3 25%	(5,606)	(1,949,235)	10,216,609	0	31
June 11	Forecast	(1,949,235)	n/a	(257,027)	563,890	0	0	0	0	(1,642,372)	(1,795,803)	3 25%	(4,797)	(1,647,169)	6,870,252	0	30
July 11	Forecast	(1,647,169)	n/a	(215,904)	563,890	0	0	0	0	(1,299,182)	(1,473,175)	3 25%	(4,066)	(1,303,249)	5,863,455	0	31
August 11	Forecast	(1,303,249)	n/a	(187,451)	563,890	0	0	0	0	(926,810)	(1,115,029)	3 25%	(3,078)	(929,887)	5,169,789	0	31
September 11	Forecast	(929,887)	n/a	(186,022)	563,890	0	0	0	0	(552,019)	(740,953)	3 25%	(1,979)	(553,999)	5,133,705	0	30
October 11	Forecast	(553,999)	n/a	(265,687)	563,890	0	0	0	0	(255,796)	(404,897)	3 25%	(1,118)	(256,913)	7,070,844	0	31
November 11	Forecast	(256,913)	n/a	(444,795)	563,890	0	0	0	0	(137,818)	(197,366)	3 25%	(527)	(138,345)	11,511,001	0	30
December 11	Forecast	(138,345)	n/a	(621,895)	563,890	0	0	0	0	(196,350)	(167,348)	3 25%	(462)	(196,812)	15,810,809	0	31

Residential (R-1 & R-3) and C & I Conservation Charge Effective November 1, 2010 - October 31, 2011	
Beginning Balance	\$ (582,660 74)
Program Budget	6,520,017 78
Projected Interest	(47,176 88)
Program Budget with Interest	\$5,890,180
Total Charges	\$5,890,180

00000114

New Hampshire Program Year ONE (January 1, 2010 - December 31, 2010)

Program	Services	Vendor Admin/Support	Company Admin	Communication	Trade Ally Training	Evaluation & Reporting	Other	Budget Total	Participant Goal
Residential									
Low Income	\$ 397,977	\$ 124,376	\$ 90,847	\$ 8,890	\$ 4,070	\$ 9,838	\$ -	\$ 635,997	260
Residential Weatherization	\$ 901,484	\$ 61,372	\$ 34,464	\$ 88,436	\$ 42,929	\$ 3,380	\$ -	\$ 1,132,065	1,100
Residential High Efficiency Heating	\$ 254,000	\$ 10,120	\$ 28,200	\$ 142,600	\$ 22,000	\$ 19,880	\$ -	\$ 476,800	551
Residential Water Heating	\$ 77,730	\$ 2,055	\$ 5,720	\$ 12,180	\$ 5,000	\$ 2,715	\$ -	\$ 105,400	257
ES Windows	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0
Advanced Residential Controls	\$ 29,570	\$ 995	\$ 2,775	\$ 5,900	\$ 3,000	\$ 1,960	\$ -	\$ 44,200	704
ES Homes	\$ 14,400	\$ 2,640	\$ 1,680	\$ 3,600	\$ 480	\$ 2,044	\$ -	\$ 24,844	30
Energy Analysis: Internet Audit	\$ 16,007	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 16,007	1,053
Energy Audit and Home Performance	\$ 57,020	\$ 5,955	\$ 3,789	\$ 15,460	\$ 1,083	\$ 5,893	\$ -	\$ 89,200	900
Building Practices and Demo	\$ 30,000	\$ 5,500	\$ 3,500	\$ 7,500	\$ 1,000	\$ 3,112	\$ -	\$ 50,612	20
Net Zero Energy Homes	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0
Air Sealing	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	450
Residential Total	\$ 1,778,189	\$ 213,013	\$ 170,975	\$ 284,565	\$ 79,561	\$ 48,822	\$ -	\$ 2,575,126	4,875
Commercial & Industrial									
Comm Energy Efficiency Program	\$ 930,061	\$ 71,415	\$ 98,000	\$ 35,000	\$ 25,000	\$ 46,169	\$ -	\$ 1,205,645	227
Multifamily Housing Program	\$ 83,342	\$ 23,895	\$ 30,000	\$ 15,000	\$ 10,000	\$ 5,018	\$ -	\$ 167,255	20
Comm High Efficiency Heating	\$ 260,844	\$ 20,000	\$ 30,000	\$ 15,000	\$ 15,000	\$ 20,851	\$ -	\$ 361,695	160
Economic Redevelopment	\$ 261,334	\$ 17,000	\$ 45,000	\$ 10,010	\$ 7,500	\$ 20,851	\$ -	\$ 361,695	10
Building Practices and Demo	\$ 150,000	\$ 22,500	\$ 40,000	\$ 15,000	\$ -	\$ 22,500	\$ -	\$ 250,000	3
Energy Analysis: Internet Audit	\$ -	\$ 7,500	\$ 12,500	\$ 5,000	\$ -	\$ -	\$ -	\$ 25,000	60
Building Operator Certification	\$ 20,000	\$ 6,000	\$ 11,000	\$ 3,000	\$ -	\$ -	\$ -	\$ 40,000	60
Commercial Total	\$ 1,705,581	\$ 168,310	\$ 266,500	\$ 98,010	\$ 57,500	\$ 115,389	\$ -	\$ 2,411,290	540
GRAND TOTAL	\$ 3,483,770	\$ 381,323	\$ 437,475	\$ 382,575	\$ 137,061	\$ 164,211	\$ -	\$ 4,986,415	5,415

00000115

New Hampshire Program Year TWO (January 1, 2011 - December 31, 2011)

Program	Internal Admin	External Admin	Rebates/ Services	Internal Impl	Marketing	Evaluation	Budget Total	Participant Goal	Lifetime MMBTU Savings
Residential									
Low Income	\$ 52,000	\$ 275,278	\$ 397,977		\$ 5,641	\$ -	\$ 730,895	260	70,954
Residential High-Efficiency Heating, Water	\$ 23,067	\$ 166,136	\$ 475,294		\$ 48,592	\$ 1,375	\$ 714,464	1,983	306,840
New Home Construction with Energy Star	\$ 727	\$ 28,628	\$ 45,000		\$ 5,000	\$ -	\$ 79,355	30	20,400
Res Building Practices and Demo	\$ 1,556	\$ 4,523	\$ 15,000		\$ 3,750	\$ 500	\$ 25,329	10	0
Energy Audit with Home Performance and	\$ 30,967	\$ 131,244	\$ 1,329,164		\$ 36,534	\$ 12,722	\$ 1,540,631	1,200	338,400
Residential Total	\$ 108,316	\$ 605,809	\$ 2,262,435	\$ -	\$ 99,516	\$ 14,597	\$ 3,090,674	3,483	736,594
Commercial & Industrial									
Large C & I Retrofit Program	\$ 160,000	\$ 150,000	\$ 1,425,000		\$ 58,625	\$ 62,669	\$ 1,856,294	226	699,027
New Equipment and Construction Program	\$ 95,000	\$ 100,000	\$ 765,000		\$ 34,875	\$ 37,280	\$ 1,032,155	307	280,381
Small Business Energy Solutions Program	\$ 25,792	\$ 38,688	\$ 202,500		\$ 9,349	\$ 9,994	\$ 286,323	23	111,884
Commercial Total	\$ 280,792	\$ 288,688	\$ 2,392,500	\$ -	\$ 102,849	\$ 109,943	\$ 3,174,772	556	1,091,292
GRAND TOTAL	\$ 389,108	\$ 894,497	\$ 4,654,935	\$ -	\$ 202,365	\$ 124,540	\$ 6,265,446	4,039	1,827,886

00000116

Exhibit-C: KeySpan Energy Delivery - NH DSM/MT Program Year Three (2008-2009): Shareholder Incentive Calculation - August 27, 2009

Program	Expenditures (Budget) for Program Year 2	Design Goal for PY 1	Projected Lifetime Therms Savings	Actual Lifetime Therm Savings ²	Actual LTT/Projected LTT	Projected TRC ³	Actual TRC ⁴	Actual TRC/Projected TRC	Lifetime Savings Incentive	Cost-effectiveness Incentive	Actual Pre Tax Design Incentive
Residential											
Low Income	\$ 442,864	160 Participants	1,082,880	1,536,336	1.419	3.50	6.05	1.73			
Residential Weatherization	\$ 89,557	45 Rebates	331,200	1,449,920	4.378	3.52	7.20	2.04			
Residential High Efficiency Heating	\$ 271,179	500 Rebates	1,760,000	2,319,680	1.318	7.10	6.14	0.86			
Residential High Efficiency Water Heating	\$ 81,708	150 Rebates	227,100	292,202	1.287	3.20	3.17	0.99			
Energy Star Windows	\$ 63,008	300 Rebates	168,225	128,412	0.763	2.81	3.08	1.10			
Energy Star Residential Controls	\$ 35,231	325 Rebates	254,625	560,535	2.201	6.91	12.81	1.85			
Energy Star Homes	\$ 65,561	55 Participants	0	0		0.00					
Energy Analysis: Internet Audit Guide	\$ 43,136	600 New Users	0.000	0.00		0.00					
Building Practices and Demo	\$ 46,291	12 Projects	0.000	0.00		0.00					
Residential Conservation Services	\$ 86,459	200 Participants	0.000	0.00		0.00					
Total	\$ 1,224,992	2,347	3,824,030	6,287,085	1.644	3.70	5.31	1.4362	\$ 80,256	\$ 65,983	\$ 146,238
C&I and Multifamily											
Commercial Energy Efficiency Program	\$ 542,617	150 Participants	1,647,585	746,905	0.453	2.91	1.75	0.60			
Multifamily Housing	\$ 195,773	60 Participants	458,298	122,213	0.267	2.43	1.13	0.47			
Commercial High Efficiency Heating	\$ 121,803	50 Rebates	996,000	4,362,480	4.380	6.44	10.36	1.61			
Economic Redevelopment	\$ 330,182	3 Projects	591,396	2,562,717	4.333	2.56	29.21	11.39			
Commercial Building Practices & Technology Demonstration	\$ 215,301	6 Projects	2,368,277	789,426	0.333	15.7	134.75	8.56			
C&I Energy Analysis Internet Audit	\$ 21,122	50 New Users	0	0		0.00	0.00				
Total - C&I and Multifamily	\$ 1,426,799	319	6,061,556	8,583,741	1.416	4.52	7.30	1.61	\$ 80,819	\$ 73,226	\$ 154,045
Total of Column	\$2,651,791									TOTAL Incentive	\$ 300,283

Notes:

This shareholder incentive calculation is based on the methodology described in NH PUC Order 24,109 of December 31, 2002.

Threshold: KeySpan must achieve a minimum "threshold" performance before being eligible to earn an incentive

For the cost-effectiveness component, KeySpan must achieve an actual year-end TRC of 1.0 before any incentive can be earned

Once the threshold is achieved, the earned incentive will be on a sliding scale from 0% to 12%

Assumptions:

Design Target Incentive = 8%

Incentive Calculation Formula: $\text{Incentive}_{\text{RES}} = \text{Expenditures}_{\text{RES}} \times \{ [4\% \times (\text{TRC}_{\text{Actual}} / \text{TRC}_{\text{Projected}})] + [4\% \times \text{Lifetime Therm Savings}_{\text{Actual}} / \text{Lifetime Therm Savings}_{\text{Projected}}] \}$

Plus

$\text{Incentive}_{\text{C\&I}} = \text{Expenditures}_{\text{C\&I}} \times \{ [4\% \times (\text{TRC}_{\text{Actual}} / \text{TRC}_{\text{Projected}})] + [4\% \times \text{Lifetime Therm Savings}_{\text{Actual}} / \text{Lifetime Therm Savings}_{\text{Projected}}] \}$

¹Per a September 9, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the projected lifetime therm savings for each KED New Hampshire natural gas energy efficiency program and the source of the projected benefit/cost ratios by program is KeySpan's response to NH PUC Staff Data Request 2-31, Pages 3 to 6, Docket DG 04-152, filed by attorney Steven V. Camerino on November 22, 2004).

²From the updated Exhibit G showing actual Program Year 1 results.

^{3,4,5}Per a September 20, 2005 E-mail from Jim Cunningham of the NH PUC to Subid Wagley of KED, the source of the Lifetime savings and Cost Effectiveness incentive calculations are derived from the updated and streamlined version of the template used by the PUC called "Computation of Actual Performance Incentive-Program Year Two" of DG 02-106 and DG 05-141.

In the Commission approved Settlement Agreement that is part of Order 24,109, the Settling Parties and Staff agree to adopt the simplified Staff template of November 2002 ("Staff Template") attached to the Settlement Agreement as Exhibit G. This template shall be used only for purposes of establishing a benchmark for the Gas Utilities' incentive sharing mechanism described in Section II(H) of the Settlement Agreement. The Staff Template allows for an evaluation of the Programs on a year-by-year basis.

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Exhibit D - Shareholder Incentive Page 1 of 1

National Grid Gas Energy Efficiency Shareholder Incentive Year ONE- January 1, 2011 - December 31, 2011

Commercial/Industrial Incentive

1. Target Benefit/Cost Ratio	1.47
2. Threshold Benefit/Cost Ratio	1.00
3. Target lifetime MMBTU	1,091,292
4. Threshold MMBTU	709,340
5. Budget	\$3,174,772
6. CE Percentage	4.00%
7. Lifetime MMBTU Percentage	4.00%

8. Target C/I Incentive **\$253,982**

9. Cap **\$380,973**

Residential Incentive

10. Target Benefit/Cost Ratio	1.96
11. Threshold Benefit/Cost Ratio	1.00
12. Target lifetime MMBTU	736,594
13. Threshold MMBTU	478,786
14. Budget	\$3,090,674
15. CE Percentage	4.00%
16. Lifetime MMBTU Percentage	4.00%

17. Target Residential Incentive **\$247,254**

18. Cap **\$370,881**

19. TOTAL TARGET INCENTIVE **\$501,236**

Line No. Notes:

- 1, 3, 5, 10, 12, and 14. See Exhibit B
- 2, 6, 7, 11, 15, and 16. Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Energy Efficiency Issues in New Hampshire, Docket No. DR 96-150, page 21.
4. 65% of line 3.
8. 8% of line 5.
9. 12% of line 5.
13. 65% of line 12.
17. 8% of line 14.
18. 12% of line 14.
19. Line 8 plus line 17.

00000118

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required annual increase in rates	\$0
Estimated weather normalized firm therms billed for the twelve months ended 10/31/09- sales and transportation	158,020,633 therms
Surcharge per therm	<u>\$0.0000</u> per therm
<u>Total Environmental Surcharge</u>	<u><u>\$0.0000</u></u>

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.
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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	subtotal
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	6,250,410
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	6,250,410
Cash recoveries (i.o. 500061)	(1,080,580)	(434,476)	(499,684)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(2,094,376)
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)	(1,916,577)
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	4,333,833
Surcharge revenue:												
actual June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	(54,889)
actual November 1998 - October 1999	(287,010)	(251,133)	-	-	-	-	-	-	-	-	-	(538,143)
actual November 1999 - October 2000	(178,131)	(266,400)	(316,340)	-	-	-	-	-	-	-	-	(760,871)
actual November 2000 - October 2001	-	(292,420)	(334,194)	(13,925)	-	-	-	-	-	-	-	(640,539)
actual November 2001 - October 2002	-	(281,914)	(318,686)	(24,514)	-	-	-	-	-	-	-	(625,114)
actual November 2002 - October 2003	-	(258,347)	(334,331)	(15,197)	-	-	-	-	-	-	-	(607,874)
actual November 2003 - October 2004	-	(14,567)	(276,773)	(14,567)	-	-	-	-	-	-	-	(305,907)
Actual November 2004- October 2005	-	-	(56,719)	(14,180)	(14,180)	-	-	-	-	-	-	(85,078)
Actual November 2005- October 2006	-	-	-	(6,875)	(6,875)	-	-	-	-	-	-	(13,750)
Actual November 2006- October 2007	-	-	-	-	-	-	(14,091)	-	-	-	-	(14,091)
Actual November 2007- October 2008	-	-	-	-	-	-	-	-	-	-	-	-
AES collections	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(12,888)	(12,888)	(107,764)
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	-	-	-
C Surcharge Subtotal	(520,030)	(1,388,292)	(1,616,004)	(50,710)	(9,559)	39,108	34,729	104,437	234,190	(12,888)	(12,888)	(3,777,530)
D Net balance to be recovered (A-B+C)	-	21,038	38,548	45,088	50,734	60,721	116,708	246,787	329,564	102,691	124,048	556,303
E Allocation of Litigated Recovery	-	-	-	-	-	-	-	-	(329,564)	-	-	(329,564)
Surcharge calculation 2007/2008												
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	102,691	124,048	226,739
remaining life	-	-	-	-	24	36	48	60	72	84	84	-
one year	-	-	-	-	12	12	12	12	12	12	12	-
F amortization 2007/2008	-	-	-	-	-	-	-	-	-	14,670	17,721	-
Required annual increase in rates 2007/2008:												
smaller of D or F	-	-	-	-	-	-	-	-	-	14,670	17,721	32,391
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0001	\$0.0001	\$0.0002

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

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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

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Laconia & Liberty Hill										
	i.o. no. 500005 (through 9/15/99) pool #1	(9/99 - 9/00) pool #2	(9/00 - 9/01) pool #3	(9/04 - 9/05) pool #4	(9/05 - 9/06) pool #5	(9/06 - 9/07) pool #6	(9/07 - 9/08) pool #7 Incl. Audit Corr	(9/08 - 9/09) pool #8	(9/09 - 9/10) pool #9	subtotal
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	624,557	262,678	10,985,948
A Subtotal - remediation costs	1,027,747	3,513,285	700,000	9,702	2,330,555	2,089,199	428,225	624,557	262,678	10,985,948
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	624,557	262,678	11,019,320
Surcharge revenue:										
actual June 1998 - October 1998	-	-	-	-	-	-	-	-	-	-
actual November 1998 - October 1999	-	-	-	-	-	-	-	-	-	-
actual November 1999 - October 2000	(151,933)	-	-	-	-	-	-	-	-	(151,933)
actual November 2000 - October 2001	(153,172)	(543,065)	-	-	-	-	-	-	-	(696,237)
actual November 2001 - October 2002	(159,343)	(527,057)	(110,314)	-	-	-	-	-	-	(796,714)
actual November 2002 - October 2003	(151,969)	(547,087)	(106,378)	-	-	-	-	-	-	(805,434)
actual November 2003 - October 2004	(131,103)	(466,143)	(101,969)	-	-	-	-	-	-	(699,215)
Actual November 2004- October 2005	(127,617)	(439,570)	(85,078)	-	-	-	-	-	-	(652,264)
Actual November 2005- October 2006	(141,176)	(453,736)	(96,247)	-	-	-	-	-	-	(691,159)
Actual November 2006- October 2007	-	(549,539)	(98,635)	-	(309,996)	-	-	-	-	(958,171)
Actual November 2007- October 2008	-	-	-	-	-	-	-	-	-	-
AES collections	-	-	-	-	-	-	-	-	-	-
Gas Street overcollection	-	-	-	-	-	-	-	-	-	-
Prior Period Pool under/overcollection	-	11,434	(1,477)	99,902	109,604	2,130,162	4,231,004	-	-	-
C Surcharge Subtotal	(1,016,313)	(3,514,762)	(600,098)	99,902	(200,393)	2,130,162	4,231,004	-	-	(5,451,127)
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	624,557	262,678	5,568,193
E Allocation of Litigated Recovery	-	-	-	-	-	-	(4,680,958)	-	-	(4,680,958)
Surcharge calculation 2007/2008	-	-	-	-	-	-	-	624,557	262,678	887,235
Unrecovered costs (D+E)	-	-	-	36	48	60	72	84	84	-
remaining life	-	-	-	-	-	-	-	-	-	-
one year	-	-	-	12	12	12	12	12	12	-
F amortization 2007/2008	-	-	-	-	-	-	-	89,222	37,525	-
Required annual increase in rates 2007/21 smaller of D or F	-	-	-	-	-	-	-	89,222	37,525	126,748
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0006	\$0.0002	\$0.0008

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

00000121

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

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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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	subtotal
Remediation costs (i.o. 500061)	-	-		335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	8,830,965
Remediation costs (i.o. 500005)	495,106	329,986									825,092
A Subtotal - remediation costs	495,106	329,986	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	9,656,057
Cash recoveries (i.o. 500061)	-	-				(545,540)	(220,353)	(1,127,436)		(40,359)	(1,933,688)
Cash recoveries (i.o. 500004)	-	-									-
Recovery costs (i.o. 500004)	-	-		1,242,326			2,546	-			1,244,872
Transfer Credit from Gas Restructuring							-	-			-
B Subtotal - net recoveries	-	-	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(688,816)
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	8,967,241
Surcharge revenue:											
actual June 1998 - October 1998	-	-	-	-							-
actual November 1998 - October 1999	-	-	-	-							-
actual November 1999 - October 2000	-	-	-	-							-
actual November 2000 - October 2001	-	-	-	-							-
actual November 2001 - October 2002	(73,543)	-	-	-							(73,543)
actual November 2002 - October 2003	(75,984)	-	-	-							(75,984)
actual November 2003 - October 2004	(72,835)	(24,416)	(41,325)	-							(138,576)
Actual November 2004- October 2005	(70,898)	(42,539)	-	(212,695)	-			-	-	-	(326,132)
Actual November 2005- October 2006	(54,998)	(41,249)	-	(206,243)	(261,242)			-	-	-	(563,732)
Actual November 2006- October 2007	(70,454)	(56,363)	-	(211,361)	(281,815)	(42,272)					(662,265)
Actual November 2007- October 2008											-
AES collections											-
Gas Street overcollection											-
Prior Period Pool under/overcollection		76,393	241,813	200,488	1,147,852	2,594,644	2,882,534	3,225,936	-	-	
C Surcharge Subtotal	(418,713)	(88,173)	200,488	(429,812)	604,796	2,552,371	2,882,534	3,225,936	-	-	(1,840,233)
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	7,127,008
E Allocation of Litigated Recovery			-	-	-			(6,486,145)	-	-	(6,486,145)
Surcharge calculation 2007/2008											
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	312,185	328,678	640,863
remaining life	-	-	-	24	36	48	60	70	84	84	
one year	-	-	-	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	44,598	46,954	
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-	-	-	-	-	-	44,598	46,954	91,552
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0003	\$0.0003	\$0.0006

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

00000122

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

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Nashua											
	(9/00 - 9/01)	(9/01 - 9/02)	(9/02 - 9/03)	(9/03 - 9/04)	(9/04 - 9/05)	(9/05 - 9/06)	Corrected per 2/08 Audit (9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	subtotal
	pool #1	pool #2	pool #3	pool #4	pool #5	pool #6	pool #7	pool #8	pool #9	pool #9	
Remediation costs (i.o. 500061)	-	-	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	599,167
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	2,370,734
Cash recoveries (i.o. 500061)	-	-	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(159,145)
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)	(140,758)
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	2,229,976
Surcharge revenue:											
actual June 1998 - October 1998	-	-	-	-							-
actual November 1998 - October 1999	-	-	-	-							-
actual November 1999 - October 2000	-	-	-	-							-
actual November 2000 - October 2001	-	-	-	-							-
actual November 2001 - October 2002	(183,857)	-	-	-							(183,857)
actual November 2002 - October 2003	(182,362)	(60,787)	-	-							(243,150)
actual November 2003 - October 2004	(174,804)	(43,701)	(29,134)	-							(247,639)
Actual November 2004- October 2005	(170,156)	(42,539)	(28,359)	-							(241,054)
Actual November 2005- October 2006	(164,995)	(54,998)	(27,499)	-	(27,499)			-	-	-	(274,991)
Actual November 2006- October 2007	(169,089)	(56,363)	(28,181)	-	(28,181)	-					(281,815)
Actual November 2007- October 2008											-
AES collections											-
Gas Street overcollection											-
Prior Period Pool under/overcollection		188,463	292,737	354,741	365,582	516,269	526,492	545,015	-	-	
C Surcharge Subtotal	(1,045,263)	(69,925)	179,564	354,741	309,902	516,269	526,492	545,015	-	-	(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	757,470
E Allocation of Litigated Recovery	-	-	-	-	-	-	-	(642,206)	-	-	(642,206)
Surcharge calculation 2007/2008											
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	16,289	98,975	115,264
remaining life	-	-	12	24	36	48	60	72	84	84	
one year	-	12	12	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	-	2,327	14,139	
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-	-	-	-	-	-	2,327	14,139	16,466
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0001	\$0.0001

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

00000123

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.
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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	subtotal
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:								
actual June 1998 - October 1998	-							-
actual November 1998 - October 1999	-							-
actual November 1999 - October 2000	-							-
actual November 2000 - October 2001	-							-
actual November 2001 - October 2002	-							-
actual November 2002 - October 2003	-							-
actual November 2003 - October 2004	(29,134)							(29,134)
Actual November 2004 - October 2005	(28,359)							(28,359)
Actual November 2005 - October 2006	(27,499)	-			-	-	-	(27,499)
Actual November 2006 - October 2007	(28,181)	-	-					(28,181)
Actual November 2007 - October 2008								-
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	
one year	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	-	-	
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-	-	-	-	-	-
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000

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

00000124

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

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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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	subtotal
Remediation costs (i.o. 500061)	-							-
Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	60,949
A Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	60,949
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	-	80,604
Surcharge revenue:								-
actual June 1998 - October 1998	-							-
actual November 1998 - October 1999	-							-
actual November 1999 - October 2000	-							-
actual November 2000 - October 2001	-							-
actual November 2001 - October 2002	-							-
actual November 2002 - October 2003	-							-
actual November 2003 - October 2004	-							-
Actual November 2004- October 2005	-	-				-	-	-
Actual November 2005- October 2006	-	-				-	-	-
Actual November 2006- October 2007	-	-	(14,091)					(14,091)
Actual November 2007- October 2008								-
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	-	66,513
E Allocation of Litigated Recovery	-	-	-	-	(66,244)	-	-	(66,244)
Surcharge calculation 2007/2008								-
Unrecovered costs (D+E)	-	-	-			269	-	269
remaining life	24	36	48	60	72	84	84	
one year	12	12	12	12	12	12	12	
F amortization 2007/2008	-	-	-	-	-	38	-	
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-			38	-	38
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000

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

00000125

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.
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Concord								
	(9/03 - 9/04)	(9/04 - 9/05)	Corrected per 1/24/07 Audit (9/05 - 9/06)	Corrected per 2/08 Audit (9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	subtotal
	pool #1	pool #2	pool #3	pool #4	pool #5	pool #6	pool #7	
Remediation costs (i.o. 500061)	-							-
Remediation costs (i.o. 500005)	22,191	220,932	44,345	109,642	8,006	77,063	49,403	531,581
A Subtotal - remediation costs	22,191	220,932	44,345	109,642	8,006	77,063	49,403	531,581
Cash recoveries (i.o. 500061)	-		(22,239)	(47,977)	(12,601)	16,623	(3,213)	(69,407)
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)	(68,982)
A-B Total net expenses to recover	22,191	220,932	22,106	61,665	(3,163)	92,679	46,190	462,600
Surcharge revenue:								-
actual June 1998 - October 1998	-							-
actual November 1998 - October 1999	-							-
actual November 1999 - October 2000	-							-
actual November 2000 - October 2001	-							-
actual November 2001 - October 2002	-							-
actual November 2002 - October 2003	-							-
actual November 2003 - October 2004	-							-
Actual November 2004- October 2005								-
Actual November 2005- October 2006	-	(27,499)			-	-	-	(27,499)
Actual November 2006- October 2007	-	(28,181)	-					(28,181)
Actual November 2007- October 2008								-
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	-	-	(55,681)
D Net balance to be recovered (A-B+C)	22,191	187,442	209,549	271,214	268,051	92,679	46,190	406,919
E Allocation of Litigated Recovery	-	-	-	-	(268,051)	-	-	(268,051)
Surcharge calculation 2007/2008								-
Unrecovered costs (D+E)	-	-	-		-	92,679	46,190	138,869
remaining life	36	48	60		72	84	84	
one year	12	12	12		12	12	12	
F amortization 2007/2008	-	-	-		-	13,240	6,599	
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-		-	13,240	6,599	19,838
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0001	\$0.0000	\$0.0001

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

00000126

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.
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	General									2010 MGP
	(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	subtotal	Remediation subtotal
Remediation costs (i.o. 500061)	-								-	15,701,685
Remediation costs (i.o. 500005)	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	602,926	14,959,129
A Subtotal - remediation costs	3,208	538,903	208,128	34,355	22,017	(181,000)	(26,884)	4,199	602,926	30,660,813
Cash recoveries (i.o. 500061)	-				-	-	-		-	(4,256,616)
Cash recoveries (i.o. 500004)	-								-	(445,985)
Recovery costs (i.o. 500004)				290,155	31,826	16,012	23,953		361,946	2,302,441
Transfer Credit from Gas Restructuring	(3,331)			-					(3,331)	(3,331)
B Subtotal - net recoveries	(3,331)	-	-	290,155	31,826	16,012	23,953	-	358,615	(2,403,491)
A-B Total net expenses to recover	(123)	538,903	208,128	324,511	53,844	(164,988)	(2,931)	4,199	961,541	28,257,322
										28,257,322
										-
Surcharge revenue:										
actual June 1998 - October 1998	-	-							-	(54,889)
actual November 1998 - October 1999	-	-							-	(538,143)
actual November 1999 - October 2000	-	-							-	(912,804)
actual November 2000 - October 2001	-	-							-	(1,336,776)
actual November 2001 - October 2002	-	-							-	(1,679,228)
actual November 2002 - October 2003	-	-							-	(1,732,442)
actual November 2003 - October 2004	(8,265)	-							(8,265)	(1,428,735)
Actual November 2004- October 2005		(70,898)							(70,898)	(1,403,787)
Actual November 2005- October 2006		(68,748)	(27,499)			-	-	-	(96,247)	(1,694,877)
Actual November 2006- October 2007		(77,499)	(28,181)	(49,318)					(154,998)	(2,141,793)
Actual November 2007- October 2008									-	-
AES collections		-							-	(107,764)
Gas Street overcollection									-	(23,511)
Prior Period Pool under/overcollection		(8,388)	313,370	465,817	741,010	794,853	-	-	-	
C Surcharge Subtotal	(8,265)	(225,533)	257,689	416,499	741,010	794,853	-	-	(330,408)	(13,054,749)
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	631,133	15,202,573
E Allocation of Litigated Recovery	-	-	-	-	-	(629,865)	-	-	(629,865)	(13,192,066)
Surcharge calculation 2007/2008										
Unrecovered costs (D+E)	-	-	-	-	-	-	(2,931)	4,199	1,268	
remaining life		36	48	60	72	84	84	84		
one year		12	12	12	12	12	12	12		
F amortization 2007/2008		-	-	-	-	-	(419)	600		
Required annual increase in rates 2007/2008 smaller of D or F	-	-	-	-	-	-	-	600	600	2,010,507
forecasted therm sales	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404	155,445,404
surcharge per therm	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0129

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

000000127

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

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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Cash Recoveries ¹														
	(9/09 - 9/10)	(9/08 - 9/09)	(9/07 - 9/08)	(9/06 - 9/07)	(9/05 - 9/06)	(9/04 - 9/05)	(9/03 - 9/04)	(9/09 - 9/10)	(9/08 - 9/09)	(9/07 - 9/08)	(9/06 - 9/07)	(9/05 - 9/06)	(9/04 - 9/05)	(9/03 - 9/04)
	Concord Pond	Concord Pond	Concord Pond	Concord Pond	Concord Pond	Concord Pond	Concord Pond	Laconia	Laconia	Laconia	Laconia	Laconia	Laconia	Laconia
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)	-	-	-	-	-	(23,619)	(2,677,000)
Recovery costs (i.o. 500004)		-	-	-	73	-	658,508	-	-	-	45	22,240	486,894	1,492,967
Transfer Credit from Gas Restructuring		-	-	-	-	-	-							
B Subtotal - net recoveries	-	-	568	-	73	-	10,508	-	-	-	45	22,240	463,275	(1,184,033)
A-B Total net expenses to recover	-	-	568	-	73	-	10,508	-	-	-	45	22,240	463,275	(1,184,033)
Surcharge revenue:														
actual June 1998 - October 1998	-	-	-	-	-	-	-							
actual November 1998 - October 1999	-	-	-	-	-	-	-							
actual November 1999 - October 2000	-	-	-	-	-	-	-							
actual November 2000 - October 2001	-	-	-	-	-	-	-							
actual November 2001 - October 2002	-	-	-	-	-	-	-							
actual November 2002 - October 2003	-	-	-	-	-	-	-							
actual November 2003 - October 2004	-	-	-	-	-	-	-							
Actual November 2004- October 2005														
Actual November 2005- October 2006														
Actual November 2006- October 2007														
Actual November 2007- October 2008														
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	22,240	463,275	(1,184,033)
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 2007/2008														
smaller of D or F														
forecasted therm sales														
surcharge per therm														

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

00000128

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

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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	Corrected per 1/24/07 Audit													
	(9/09 - 9/10)	(9/08 - 9/09)	(9/07 - 9/08)	(9/06 - 9/07)	(9/05 - 9/06)	(9/04 - 9/05)	(9/03 - 9/04)	(9/09 - 9/10)	(9/08 - 9/09)	(9/07 - 9/08)	(9/06 - 9/07)	(9/05 - 9/06)	(9/04 - 9/05)	(9/03 - 9/04)
	Manchester	Manchester	Manchester	Manchester	Manchester	Manchester	Manchester	Nashua	Nashua	Nashua	Nashua	Nashua	Nashua	Nashua
Remediation costs (i.o. 500061)								-	-	-			-	
Remediation costs (i.o. 500005)								-	-	-			-	
A Subtotal - remediation costs								-	-	-			-	
Cash recoveries (i.o. 500061)														
Cash recoveries (i.o. 500004)		9,679	-	(630,000)	(1,725,792)	(754,938)	-	-		(1,032,186)	(544,402)	(625,000)	(782,450)	(795,000)
Recovery costs (i.o. 500004)	-	(2,008,365)	77,222	195,929	941,433	307,062	951,425			561,030	78,298	645,302	537,552	655,683
Transfer Credit from Gas Restructuring														
B Subtotal - net recoveries	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
A-B Total net expenses to recover	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
Surcharge revenue:														
actual June 1998 - October 1998	-	-	-		-	-								
actual November 1998 - October 1999	-	-	-	-	-	-								
actual November 1999 - October 2000	-	-	-	-	-	-								
actual November 2000 - October 2001	-	-	-	-	-	-								
actual November 2001 - October 2002	-	-	-	-	-	-								
actual November 2002 - October 2003	-	-	-	-	-	-								
actual November 2003 - October 2004	-	-	-	-	-	-								
Actual November 2004- October 2005														
Actual November 2005- October 2006					-	-								
Actual November 2006- October 2007														
Actual November 2007- October 2008														
AES collections	-	-	-	-		-								
Gas Street overcollection	-	-	-	-		-								
Prior Period Pool under/overcollection					-	-								
C Surcharge Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D Net balance to be recovered (A-B+C)	-	(1,998,686)	77,222	(434,071)	(784,359)	(447,876)	951,425	-	-	(471,155)	(466,104)	20,302	(244,898)	(139,317)
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 2007/2008														
smaller of D or F														
forecasted therm sales														
surcharge per therm														

1. Where 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
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	(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
Remediation costs (i.o. 500061)	-	-	-		-	-	
Remediation costs (i.o. 500005)	-	-	-		-	-	
A Subtotal - remediation costs	-	-	-		-	-	
Cash recoveries (i.o. 500061)							
Cash recoveries (i.o. 500004)	-	-	(2,133)	-	(237,489)	(7,150)	(645,500)
Recovery costs (i.o. 500004)		(92,947)	-	14,848	117,621	517,891	500,868
Transfer Credit from Gas Restructuring							
B Subtotal - net recoveries	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)
A-B Total net expenses to recover	-	(92,947)	(2,133)	14,848	(119,868)	510,741	(144,632)
Surcharge revenue:							
actual June 1998 - October 1998							
actual November 1998 - October 1999							
actual November 1999 - October 2000							
actual November 2000 - October 2001							
actual November 2001 - October 2002							
actual November 2002 - October 2003							
actual November 2003 - October 2004							
Actual November 2004- October 2005							
Actual November 2005- October 2006							
Actual November 2006- October 2007							
Actual November 2007- October 2008							
AES collections							
Gas Street overcollection							
Prior Period Pool under/overcollection							
C Surcharge Subtotal	-	-	-	-	-	-	-
D Net balance to be recovered (A-B+C)	-	(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 2007/2008							
smaller of D or F							
forecasted therm sales							
surcharge per therm							

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

00000130

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

EnergyNorth Natural Gas, Inc.
Environmental Remediation - MGPs
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	(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	2010 subtotal	MGP TOTAL
Remediation costs (i.o. 500061)					-	-			-	15,701,685
Remediation costs (i.o. 500005)					-	-			-	14,959,129
A Subtotal - remediation costs					-	-			-	30,660,813
Cash recoveries (i.o. 500061)					(700,000)	(211,213)	0	(10,760,900)	-	(4,256,616)
Cash recoveries (i.o. 500004)	-	116		28,211	309,618	56,392	121,018	(22,792,408)	(23,238,393)	
Recovery costs (i.o. 500004)			1,559					7,178,376	9,480,817	
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)	(4,853,133)	(7,256,623)
A-B Total net expenses to recover	-	116	1,559	28,211	(390,382)	(154,821)	121,018	(10,760,900)	(15,614,032)	12,643,290
Surcharge revenue:										
actual June 1998 - October 1998									-	(54,889)
actual November 1998 - October 1999									-	(538,143)
actual November 1999 - October 2000									-	(912,804)
actual November 2000 - October 2001									-	(1,336,776)
actual November 2001 - October 2002									-	(1,679,228)
actual November 2002 - October 2003									-	(1,732,442)
actual November 2003 - October 2004									-	(1,428,735)
Actual November 2004- October 2005									-	(1,403,787)
Actual November 2005- October 2006										(1,694,877)
Actual November 2006- October 2007										(2,141,793)
Actual November 2007- October 2008										-
AES collections									-	(107,764)
Gas Street overcollection									-	(23,511)
Prior Period Pool under/overcollection									-	
C Surcharge Subtotal				-	-	-	-		-	(13,054,749)
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)	(411,459)
E Allocation of Litigated Recovery									13,192,066	
Surcharge calculation 2007/2008									(2,421,966)	
Unrecovered costs (D+E)										
remaining life										
one year										
F amortization 2007/2008										
Required annual increase in rates 2007/2008										
smaller of D or F										
forecasted therm sales										
surcharge per therm										

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

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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)	Total
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	15,701,685
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	675,005	316,280	14,959,129
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	1,193,912	991,045	30,660,813
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)	(4,256,616)
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)	-	9,480,817
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)	(18,017,523)
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	(932,890)	877,655	12,643,290
Surcharge revenue:															
actual June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
actual November 1998 - October 1999	(287,010)	(251,133)	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
actual November 1999 - October 2000	(178,131)	(266,400)	(468,273)	-	-	-	-	-	-	-	-	-	-	-	(912,804)
actual November 2000 - October 2001	-	(292,420)	(487,366)	(556,990)	-	-	-	-	-	-	-	-	-	-	(1,336,776)
actual November 2001 - October 2002	-	(281,914)	(478,029)	(551,571)	(367,714)	-	-	-	-	-	-	-	-	-	(1,679,228)
actual November 2002 - October 2003	-	(258,347)	(486,300)	(562,284)	(364,725)	(60,787)	-	-	-	-	-	-	-	-	(1,732,442)
actual November 2003 - October 2004	-	(14,567)	(407,875)	(480,710)	(349,608)	(43,701)	(132,274)	-	-	-	-	-	-	-	(1,428,735)
Actual November 2004- October 2005	-	-	(184,336)	(453,749)	(326,132)	(42,539)	(99,258)	(297,773)	-	-	-	-	-	-	(1,403,787)
Actual November 2005- October 2006	-	-	(141,176)	(460,610)	(316,240)	(54,998)	(96,247)	(281,866)	(343,739)	-	-	-	-	-	(1,694,877)
Actual November 2006- October 2007	-	-	-	(549,539)	(338,178)	(56,363)	(112,726)	(288,860)	(366,359)	(429,768)	-	-	-	-	(2,141,793)
Actual November 2007- October 2008	-	-	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,597)	(12,888)	(12,888)	(107,764)
AES collections	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
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)	(12,597)	(12,888)	(12,888)	(13,054,749)
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)	3,328,072	(945,778)	864,767	(411,459)
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 2007/2008															
smaller of D or F															
forecasted therm sales															
surcharge per therm															

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

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ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

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 remedy, and determine if additional treatment may be necessary. **A groundwater sampling round for the MGP site will be conducted in August 2010 and will include monitoring wells located on the MGP site itself as well as a number of wells located offsite.**

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 KeySpan requesting submission of a schedule and scope of work for a site investigation of the gas plant by mid-September

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

CONCORD FORMER MGP

LINE
NO.

2003. ENGI proposed a May 2005 date for submission of a site investigation report for the former manufactured gas plant 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 workplan on August 3, 2010 and the work is scheduled to occur in September 2010.

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

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

CONCORD FORMER MGP

LINE
NO.

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 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 will coordinate further discussions with the parties once all have reviewed the draft design plans.**

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. In May 2007, NHDES approved ENGI's April 2007 scope of work to conduct additional investigations around this well to determine the extent of the coal tar impacts and the feasibility of removing it from the subsurface. The issues associated with this well will be included in the overall site strategy.

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 Report will be submitted for the river portion of the site, but 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

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

CONCORD FORMER MGP

LINE
NO.

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.

In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the gas plant. ENGI submitted the scope to NHDES in May 2004, and implemented it between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was 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. **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 workplan on August 3, 2010 and the work is scheduled to occur in September 2010.**

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 POND - REMEDIATION
 KEYSpan PROJECT DEF056

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	GEI Consultants	50385	5,335.70			5,335.70
	GEI Consultants	49607	2,048.19			2,048.19
	Anchor Environmental	17087	3,430.99			3,430.99
	Anchor Environmental	18409	30,659.10			30,659.10
	GEI Consultants	49711	3,730.36			3,730.36
	New Hampshire Department of Environmental Services		123.61			123.61
	Anchor Environmental	19146	10,726.25			10,726.25
	Anchor Environmental	18775	27,119.05			27,119.05
	GEI Consultants	49958	2,812.35			2,812.35
	GEI Consultants	50020	3,374.75			3,374.75
	GEI Consultants	50250	3,281.00			3,281.00
	Anchor Environmental	19919	28,435.04			28,435.04
	GEI Consultants	50543	6,494.57			6,494.57
	Clean Harbors	SB0945748	1,074.43			1,074.43
	GEI Consultants	50670	3,039.95			3,039.95
	GEI Consultants	50779	663.25			663.25
	GEI Consultants	50935	2,023.47			2,023.47
	GEI Consultants	51108	3,263.17			3,263.17
	New Hampshire Department of Environmental Services		112.25			112.25
	GEI Consultants	51280	5,252.57			5,252.57
Total Pool Activity			143,000.05	-	(6,063.97)	136,936.08

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

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
	GZA GeoEnvironmental	0612229	15,225.54			15,225.54
	GZA GeoEnvironmental	0618660	16,189.72			16,189.72
	McLane	2009080477	171.00			171.00
	GZA GeoEnvironmental	0620704	4,157.42			4,157.42
	McLane	2010010067	2,058.50			2,058.50
	GZA GeoEnvironmental	0622424	2,773.13			2,773.13
	McLane	2010030032	758.10			758.10
	McLane	2010040323	649.80			649.80
	Department of Environmental Services	198904063-04	4,187.15			4,187.15
	McLane	2010050382	3,232.40			3,232.40
Total Pool Activity			49,402.76	-	(3,213.24)	46,189.52

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

LINE NO.	VENDOR	REF NO.	100 % RECOVERABLE EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
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NO ACTIVITY FOR THIS PERIOD

Total Pool Activity

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

1. SITE LOCATION: The former MGP was located on Messer Street in Laconia. Sometime in the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford. At the time of the disposal, the property was utilized as a gravel pit, and the disposal reportedly occurred with the permission of the gravel pit owner. The property currently comprises part of a residential neighborhood.
2. DATE SITE WAS FIRST INVESTIGATED: In 1994 and 1995, Public Service Company of New Hampshire (PSNH), one of the former owners and operators of the Laconia Manufactured Gas Plant (MGP), conducted limited site investigations at the plant. In 1996, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and its parent company, Northeast Utilities Services Company (NU), and to EnergyNorth Natural Gas, Inc. (ENGI), another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

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

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Winnepesaukee River. The full nature and extent of contamination is unknown at this time. 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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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

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

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

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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. ENGI is awaiting a decision from NHDES on the RAP Addendum No. 2 and anticipates receiving the decision in the Summer of 2010.**

ENGI has also performed numerous other activities requested by NHDES between 2008 and 2010, 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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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 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
	McLane	2009080476	1,504.80			1,504.80
	McLane	2009070320	6,615.10			6,615.10
	Ostrow & Partners	07 09 01	1,670.00			1,670.00
	GEI Consultants	49605	41,821.26			41,821.26
	Public Service of New Hampshire		8.84			8.84
	Ostrow & Partners	08 09 01	310.00			310.00
	Ostrow & Partners	09 09 01	1,070.00			1,070.00
	GEI Consultants	49710	27,464.13			27,464.13
	Blue Chip Films	00861	725.00			725.00
	Departmental of Environmental Services	200411113-06	8,059.90			8,059.90
	McLane	2009090845	2,120.40			2,120.40
	Ostrow & Partners	10 09 01	1,726.00			1,726.00
	Public Service of New Hampshire		9.84			9.84
	Public Service of New Hampshire		19.95			19.95
	Public Service of New Hampshire		29.31			29.31
	GEI Consultants	49957	49,542.95			49,542.95
	Ostrow & Partners	11 09 01	310.00			310.00
	McLane	2009110669	444.60			444.60
	GEI Consultants	50019	28,441.30			28,441.30
	Ostrow & Partners	12 09 01	460.00			460.00
	GEI Consultants	50276	7,624.54			7,624.54
	Public Service of New Hampshire		9.87			9.87
	McLane	2009120992	171.00			171.00
	Ostrow & Partners	01 10 01	310.00			310.00
	GEI Consultants	50352	2,344.75			2,344.75
	Public Service of New Hampshire		7.57			7.57
	Public Service of New Hampshire		7.57			7.57
	GEI Consultants	50537	1,694.38			1,694.38
	Clean Harbors	SB0945743	1,137.97			1,137.97
	McLane	2010030031	108.30			108.30
	GEI Consultants	50679	7,024.25			7,024.25
	Public Service of New Hampshire		22.36			22.36
	Public Service of New Hampshire		48.44			48.44
	Ostrow & Partners	02 10 01	310.00			310.00
	GEI Consultants	50778	34,984.58			34,984.58
	Public Service of New Hampshire		28.09			28.09
	Clean Harbors	NH1015788	1,003.85			1,003.85
	Public Service of New Hampshire		20.06			20.06
	Public Service of New Hampshire		20.47			20.47
	Public Service of New Hampshire		32.45			32.45
	Public Service of New Hampshire		58.94			58.94
	GEI Consultants	50934	4,802.45			4,802.45
	McLane	2010050381	877.20			877.20
	Ostrow & Partners	04 10 01	479.50			479.50
	GEI Consultants	51107	2,741.65			2,741.65
	Ostrow & Partners	05 10 01	870.75			870.75
	GEI Consultants	51279	2,626.50			2,626.50
	Departmental of Environmental Services	2004111113-07	18,904.22			18,904.22
	Blue Chip Films	00916	700.00			700.00
	Ostrow & Partners	06 10 01	479.50			479.50
	Ostrow & Partners	07 10 01	636.00			636.00
	Blue Chip Films	00919	237.50			237.50
			-			-
Total Pool Activity			262,678.09	-	-	262,678.09

LINE NO.	VENDOR	REF NO.	100 % RECOVERABL E EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
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NO ACTIVITY FOR THIS PERIOD

Total Pool Activity

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

LINE NO.	VENDOR	REF NO.	100 % RECOVERABL E EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
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NO ACTIVITY FOR THIS PERIOD

Total Pool Activity						
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ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

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. It is understood that NHDES intended to solicit site investigation reports on all MGPs and then prioritize them for remedial action.
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 submitted a summary report to NHDES in January 2001 on behalf of ENGI 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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

MANCHESTER FORMER MGP

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 since April 2003, until they ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment are being addressed concurrently and that ENGI avoids incurring costs associated with another entity's contamination.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

MANCHESTER FORMER MGP

LINE
NO.

- 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, in portions of Singer Park at depth and in the Merrimack River sediment. Further investigations were recommended by ENGI to completely bound 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 a Remedial Action Plan for the upland and Merrimack River is 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 RAP 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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

MANCHESTER FORMER MGP

LINE
NO.

- Certain predesign investigations were completed on the upland portion of the former MGP site in 2008/2009. ENGI completed certain 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 replacement of a portion of the site drainage system. 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 a Remedial Action Plan for the Site to NHDES for review 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; 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. ENGI has not received any formal NHDES review comments yet on the Remedial Action Plan.**
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 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 Remedial Action Plan (RAP) for the site was submitted to NHDES for review on June 30, 2010.**
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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

MANCHESTER FORMER MGP

LINE
NO.

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 will 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
URS		3947276	2,666.80			2,666.80
URS		3976971	3,710.00			3,710.00
Maxymillian Technologies			3,852.85			3,852.85
Clean Harbors		NH0901797	152.64			152.64
Clean Harbors		NH0906475	514.47			514.47
URS		3995747	16,209.45			16,209.45
Clean Harbors		NH0962661	721.02			721.02
NH Department of Environmental Services		200003011-04	1,480.35			1,480.35
URS		4038177	7,770.00			7,770.00
URS		4038176	24,621.92			24,621.92
Curry Printing		174596	470.81			470.81
Clean Harbors		NH0985443	2,462.45			2,462.45
Shaw Environmental		494198-R8-00501	805.00			805.00
URS		4122632	1,019.77			1,019.77
Shaw Environmental		491479-R8-00501	3,009.95			3,009.95
URS		4107239	4,107.00			4,107.00
Clean Harbors		NH0960987	1,581.41			1,581.41
Clean Harbors		NH0944943	7,182.16			7,182.16
Clean Harbors		NH0962838R	368.88			368.88
Shaw Environmental		497590-R8-00501	1,163.75			1,163.75
Shaw Environmental		495513-R8-00501	2,814.00			2,814.00
GEI Consultants		50222	3,900.00			3,900.00
Shaw Environmental		497586-R8-00501	10,363.13			10,363.13
URS		4141174	2,328.52			2,328.52
URS		4141179	3,630.00			3,630.00
GZA Geo Environmental		0620705	552.00			552.00
Shaw Environmental		502864-R8-00501	3,896.25			3,896.25
URS		4175715	3,914.52			3,914.52
URS		4141183	7,705.27			7,705.27
Clean Harbors		NH0985320	326.48			326.48
GZA Geo Environmental		0622427	9,279.88			9,279.88
URS		4206129	5,663.53			5,663.53
Shaw Environmental		503998-R8-00501	14,001.20			14,001.20
Shaw Environmental		509352-R8-00501	25,813.25			25,813.25
URS		4235574	2,087.85			2,087.85
Clean Harbors		NH0926715	6,183.02			6,183.02
Clean Harbors		NH1071878	2,541.98			2,541.98
Clean Harbors		NH1070083	2,843.11			2,843.11
GZA Geo Environmental		0624333	25,548.66			25,548.66
Clean Harbors		NH1014297R	707.02			707.02
Shaw Environmental		506112-R8-00501	26,379.77			26,379.77
Shaw Environmental		511642-R8-00501	9,774.75			9,774.75
Clean Harbors		NH1039917	191.86			191.86
Clean Harbors		NH1027866	217.04			217.04
Clean Harbors		NH1039934	1,418.58			1,418.58
Clean Harbors		NH1027449	1,740.41			1,740.41
NH Department of Environmental Services			100.00			100.00
Shaw Environmental		514982-R8-00501	37,584.83			37,584.83
Clean Harbors		NH1070656	1,013.46			1,013.46
NH Department of Environmental Services		200003011-05	808.23			808.23
Shaw Environmental		517751-R8-00501	22,107.00			22,107.00
URS		4359632	1,298.53			1,298.53
GZA Geo Environmental		0628303	48,432.23			48,432.23
Century Indemnity					(23,538.97)	(23,538.97)
UGI Insurance			-		(16,820.48)	(16,820.48)
Total Pool Activity			369,037.04	-	(40,359.45)	328,677.59

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
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NO ACTIVITY FOR THIS PERIOD

Total Pool Activity

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

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 KeySpan Energy Delivery New England (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 a 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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.
- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.
- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.
- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.
- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.
- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.
- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.
- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.
- ENGI and ESE developed a letter discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and from PSNH/NU and submitted the document in August 2000 along with a proposed schedule for implementation.
- NHDES approved the Revised Phase II Work Plan for the 38 Bridge Street 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.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

- Harding ESE submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.
- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH/NU 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 river borings and sediment samples as well as borings and monitoring wells completed 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 and Harding ESE 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 NHDES met in early June 2001 to discuss draft site conceptual model and the overall site objectives and approach.
- 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.
- 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.

ENERGYNORTH NATURAL GAS, INC.

d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

- 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 made, and verbal approval obtained, on November 19, 2001.
- 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

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

- 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 completed in October 2004 and Remedial Completion Report submitted to NHDES in January 2005, and 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 that additional 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 was 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 109 gallons of DNAPL through July 2010. ENGI is currently evaluating the effectiveness of the pilot DNAPL recovery system, and expects to submit the Installation Summary and Progress Report on DNAPL Recovery Pilot Test to NHDES in September 2010.**

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the Fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. Pilot testing of the DNAPL recovery system in the approved RAP 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 NHLPC 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

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

NASHUA FORMER MGP

LINE
NO.

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.

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
_____	Innovative Engineering Solutions, Inc.	7778	10,272.17			10,272.17
_____	Environmental Soil Management	1006425	6,816.27			6,816.27
_____	Department of Environmental Services	199810022-06	351.26			351.26
_____	Innovative Engineering Solutions, Inc.	7991	1,483.92			1,483.92
_____	Innovative Engineering Solutions, Inc.	8050	4,459.96			4,459.96
_____	Innovative Engineering Solutions, Inc.	7851	44,060.74			44,060.74
_____	Innovative Engineering Solutions, Inc.	7920	53,323.53			53,323.53
_____	Innovative Engineering Solutions, Inc.	8105	5,934.41			5,934.41
_____	Clean Harbors	NH0913109	4,271.48			4,271.48
_____	Innovative Engineering Solutions, Inc.	8165	5,711.71			5,711.71
_____	Innovative Engineering Solutions, Inc.	8211	1,562.40			1,562.40
_____	Innovative Engineering Solutions, Inc.	8276	4,680.60			4,680.60
_____	Innovative Engineering Solutions, Inc.	8357	2,188.72			2,188.72
_____	Innovative Engineering Solutions, Inc.	8430	2,317.89			2,317.89
_____	Innovative Engineering Solutions, Inc.	8507	1,015.70			1,015.70
_____	Innovative Engineering Solutions, Inc.	8563	14,277.78			14,277.78
Total Pool Activity			\$162,728.54	\$0.00	(\$63,753.10)	\$98,975.44

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

LINE NO.	VENDOR	REF NO.	100 % RECOVERABL E EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL
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NO ACTIVITY FOR THIS PERIOD

Total Pool Activity						
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ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID

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

ENERGYNORTH NATURAL GAS, INC.

d/b/a NATIONAL GRID

DOVER FORMER MGP

LINE
NO.

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

ENERGYNORTH NATURAL GAS, INC.

d/b/a NATIONAL GRID

DOVER FORMER MGP

LINE
NO.

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

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

1108						
LINE			100 %	INSURANCE &	INSURANCE &	
NO.	VENDOR	REF NO.	RECOVERABL	THIRD PARTY	THIRD PARTY	TOTAL
			E EXPENSES	EXPENSE	RECOVERIES	SUBMITTED

NO ACTIVITY FOR THIS PERIOD

Total Pool Activity

LINE NO.	VENDOR	REF NO.	100 % RECOVERABL E EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
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NO ACTIVITY FOR THIS PERIOD

Total Pool Activity						
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ENERGYNORTH NATURAL GAS, INC.

d/b/a NATIONAL GRID

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 response in February 2007 NHDES requested 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 Phase II RAP implementation is underway.**

ENERGYNORTH NATURAL GAS, INC.

d/b/a NATIONAL GRID

KEENE FORMER MGP

LINE
NO.

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 so 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.
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 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"

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID
KEENE FORMER MGP

LINE
NO.

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.

LINE NO.	VENDOR	REF NO.	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
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NO ACTIVITY FOR THIS PERIOD

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

LINE NO.	VENDOR	REF NO.	100 % RECOVERABL E EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
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NO ACTIVITY FOR THIS PERIOD

Total Pool Activity

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
	McLane	2009080475	513.00			513.00
	McLane	2009090869	2,428.20			2,428.20
	McLane	2009110668	307.80			307.80
	GZA Geo Environmental	0619733	7,200.00			7,200.00
	Curry Printing	173216	1,271.36			1,271.36
	Departmental of Environmental Services		800.00			800.00
	Curry Printing	180080	604.63			604.63
	McLane	2010050380	361.00			361.00
	McLane	2010060340	108.30			108.30
	Interest on Over Recovery Balance Aug 09-July 10		(9,395.63)			(9,395.63)
	Total Pool Activity		4,198.66	-	-	4,198.66

III DELIVERY TERMS AND CONDITIONS

**NHPUC NO. 5 - GAS
KEYSPAN ENERGY DELIVERY**

**Proposed Second Revised Page 155
Superseding First Revised Page 155**

ATTACHMENT B

Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	\$0.11 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	\$18.48 MMBTU of Peak MDQ.

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

**ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH**

Calculation of Supplier Balancing Charge

Rate: \$0.11 /MMBtu

	Rate	Volume	Total
Injection Cost	\$0.0102	664,014	\$6,773
Withdrawal Cost	\$0.0102	308,811	\$3,150
Delivery Rate	\$0.0378	308,811	\$11,676
FTA Demand Charge	\$0.1936	308,811	\$59,799
FTA Commodity Charge	\$0.0834	308,811	\$25,755
Total Cost			\$107,153
Absolute Value of the Sendout Error			972,826 MMBtu
Rate \$			0.11 /MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in Tab 6

TGP FSMA Injection Charge	\$0.0102 / MMBtu
TGP FSMA Withdrawal Charge	\$0.0102 / MMBtu
TGP FSMA Deliverability Charge	\$1.15 / MMBtu per month
	\$0.0378 / MMBtu per day
TGP Z4-6 Demand Charge	\$5.89 / MMBtu per month
	\$0.1936 / MMBtu per day
TGP Z4-6 Commodity Charge	\$0.0834 / MMBtu

00000175

EnergyNorth Natural Gas Inc.
d/b/a National Grid NH

Calculation of Supplier Balancing Charge

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	644	605	39	1,092,809	1,040,650	52,159	127,053	89,606	37,447
Dec	1,152	1,125	27	2,139,485	2,088,603	50,883	179,032	114,957	64,075
Jan	1,248	1,206	42	2,320,402	2,241,251	79,151	177,147	128,149	48,998
Feb	1,018	960	58	1,890,006	1,780,702	109,304	150,764	130,034	20,730
Mar	719	700	19	1,328,274	1,298,222	30,051	131,278	80,665	50,613
Apr	475	464	11	882,433	868,117	14,316	58,567	36,442	22,125
May	203	212	-9	450,972	456,503	-5,531	41,173	17,821	23,352
Jun	48	66	-18	331,227	337,601	-6,374	14,872	4,249	10,623
Jul	14	28	-14	305,687	305,687	0	0	0	0
Aug	9	17	-8	284,882	284,882	0	0	0	0
Sep	141	144	-3	351,741	352,838	-1,097	12,794	5,849	6,945
Oct	526	503	23	847,625	815,285	32,340	80,147	56,244	23,904
Total	6,197	6,030	167	12,225,543	11,870,341	355,203	972,826	664,014	308,811

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

Calculation of Supplier Balancing Charge

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, 09	23	24	-1	38,742	40,043	-1,301	1,301	0	1,301
Apr 2, 09	17	13	4	30,933	25,727	5,206	5,206	5,206	0
Apr 3, 09	18	16	2	32,234	29,631	2,603	2,603	2,603	0
Apr 4, 09	22	23	-1	37,440	38,742	-1,301	1,301	0	1,301
Apr 5, 09	20	20	0	34,837	34,837	0	0	0	0
Apr 6, 09	20	23	-3	34,837	38,742	-3,904	3,904	0	3,904
Apr 7, 09	24	26	-2	40,043	42,646	-2,603	2,603	0	2,603
Apr 8, 09	25	26	-1	41,345	42,646	-1,301	1,301	0	1,301
Apr 9, 09	18	14	4	33,536	32,234	1,301	1,301	1,301	0
Apr 10, 09	18	26	0	32,234	27,028	5,206	5,206	5,206	0
Apr 11, 09	26	26	0	42,646	42,646	0	0	0	0
Apr 12, 09	28	30	-2	45,249	47,852	-2,603	2,603	0	2,603
Apr 13, 09	24	21	3	40,043	36,139	3,904	3,904	3,904	0
Apr 14, 09	20	19	1	34,837	33,536	1,301	1,301	1,301	0
Apr 15, 09	20	20	0	34,837	34,837	0	0	0	0
Apr 16, 09	19	19	0	33,536	33,536	0	0	0	0
Apr 17, 09	9	7	2	20,521	17,918	2,603	2,603	2,603	0
Apr 18, 09	15	14	1	28,330	27,028	1,301	1,301	1,301	0
Apr 19, 09	23	20	3	38,742	34,837	3,904	3,904	3,904	0
Apr 20, 09	21	19	2	36,139	33,536	2,603	2,603	2,603	0
Apr 21, 09	14	15	-1	27,028	28,330	-1,301	1,301	0	1,301
Apr 22, 09	10	15	-5	21,822	28,330	-6,507	6,507	0	6,507
Apr 23, 09	15	16	-1	28,330	29,631	-1,301	1,301	0	1,301
Apr 24, 09	5	4	1	15,315	14,014	1,301	1,301	1,301	0
Apr 25, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 26, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 27, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 28, 09	0	0	0	8,808	8,808	0	0	0	0
Apr 29, 09	13	12	1	25,727	24,425	1,301	1,301	1,301	0
Apr 30, 09	7	4	3	17,918	14,014	3,904	3,904	3,904	0
May 1, 09	2	2	0	11,752	11,752	0	0	0	0
May 2, 09	10	9	1	16,669	16,054	615	615	615	0
May 3, 09	11	9	2	17,283	16,054	1,229	1,229	1,229	0
May 4, 09	11	4	7	17,283	12,981	4,302	4,302	4,302	0
May 5, 09	17	17	0	20,970	20,970	0	0	0	0
May 6, 09	7	8	-1	14,825	15,440	-615	615	0	615
May 7, 09	6	9	-3	14,211	16,054	-1,844	1,844	0	1,844
May 8, 09	4	0	4	12,981	10,523	2,458	2,458	2,458	0
May 9, 09	0	1	-1	10,523	11,138	-615	615	0	615
May 10, 09	11	11	0	17,283	17,283	0	0	0	0
May 11, 09	16	10	6	20,356	16,669	3,687	3,687	3,687	0
May 12, 09	11	10	1	17,283	16,669	615	615	615	0
May 13, 09	6	5	1	14,211	13,596	615	615	615	0
May 14, 09	6	6	0	14,211	14,211	0	0	0	0
May 15, 09	1	0	1	11,138	10,523	615	615	615	0
May 16, 09	2	3	-1	11,752	12,367	-615	615	0	615
May 17, 09	14	12	2	19,127	17,898	1,229	1,229	1,229	0
May 18, 09	13	15	-2	18,512	19,741	-1,229	1,229	0	1,229
May 19, 09	5	3	2	13,596	12,367	1,229	1,229	1,229	0
May 20, 09	0	0	0	10,523	10,523	0	0	0	0
May 21, 09	0	0	0	10,523	10,523	0	0	0	0
May 22, 09	0	0	0	10,523	10,523	0	0	0	0
May 23, 09	3	8	-5	12,367	15,440	-3,073	3,073	0	3,073
May 24, 09	2	0	2	11,752	10,523	1,229	1,229	1,229	0
May 25, 09	3	5	-2	12,367	13,596	-1,229	1,229	0	1,229
May 26, 09	5	10	-5	13,596	16,669	-3,073	3,073	0	3,073
May 27, 09	14	18	-4	19,127	21,585	-2,458	2,458	0	2,458
May 28, 09	10	17	-7	16,669	20,970	-4,302	4,302	0	4,302
May 29, 09	5	5	0	13,596	13,596	0	0	0	0
May 30, 09	2	2	0	11,752	11,752	0	0	0	0
May 31, 09	6	13	-7	14,211	18,512	-4,302	4,302	0	4,302
Jun 1, 09	0	2	-2	10,474	11,183	-708	708	0	708
Jun 2, 09	1	0	1	10,828	10,474	354	354	354	0
Jun 3, 09	0	1	-1	10,474	10,828	-354	354	0	354
Jun 4, 09	2	1	1	11,183	10,828	354	354	354	0
Jun 5, 09	5	6	-1	12,245	12,599	-354	354	0	354
Jun 6, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 7, 09	3	0	3	11,537	10,474	1,062	1,062	1,062	0
Jun 8, 09	3	0	3	11,537	10,474	1,062	1,062	1,062	0
Jun 9, 09	10	11	-1	14,015	14,369	-354	354	0	354
Jun 10, 09	7	8	-1	12,953	13,307	-354	354	0	354
Jun 11, 09	2	8	-6	11,183	13,307	-2,125	2,125	0	2,125
Jun 12, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 13, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 14, 09	0	7	-7	10,474	12,953	-2,479	2,479	0	2,479
Jun 15, 09	3	8	-5	11,537	13,307	-1,770	1,770	0	1,770
Jun 16, 09	4	6	-2	11,891	12,599	-708	708	0	708
Jun 17, 09	1	1	0	10,828	10,828	0	0	0	0
Jun 18, 09	2	3	-1	11,183	11,537	-354	354	0	354
Jun 19, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 20, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 21, 09	3	0	3	11,537	10,474	1,062	1,062	1,062	0
Jun 22, 09	2	1	1	11,183	10,828	354	354	354	0
Jun 23, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 24, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 25, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 26, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 27, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 28, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 29, 09	0	0	0	10,474	10,474	0	0	0	0
Jun 30, 09	0	3	-3	10,474	11,537	-1,062	1,062	0	1,062
Jul 1, 09	2	6	-4	9,861	9,861	0	0	0	0
Jul 2, 09	1	6	-5	9,861	9,861	0	0	0	0
Jul 3, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 4, 09	0	0	0	9,861	9,861	0	0	0	0

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

Calculation of Supplier Balancing Charge

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, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 6, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 7, 09	2	4	-2	9,861	9,861	0	0	0	0
Jul 8, 09	4	6	-2	9,861	9,861	0	0	0	0
Jul 9, 09	2	3	-1	9,861	9,861	0	0	0	0
Jul 10, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 11, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 12, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 13, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 14, 09	1	0	1	9,861	9,861	0	0	0	0
Jul 15, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 16, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 17, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 18, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 19, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 20, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 21, 09	0	2	-2	9,861	9,861	0	0	0	0
Jul 22, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 23, 09	1	1	0	9,861	9,861	0	0	0	0
Jul 24, 09	1	0	1	9,861	9,861	0	0	0	0
Jul 25, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 26, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 27, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 28, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 29, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 30, 09	0	0	0	9,861	9,861	0	0	0	0
Jul 31, 09	0	0	0	9,861	9,861	0	0	0	0
Aug 1, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 2, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 3, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 4, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 5, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 6, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 7, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 8, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 9, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 10, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 11, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 12, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 13, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 14, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 15, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 16, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 17, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 18, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 19, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 20, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 21, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 22, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 23, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 24, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 25, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 26, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 27, 09	3	0	3	9,190	9,190	0	0	0	0
Aug 28, 09	1	3	-2	9,190	9,190	0	0	0	0
Aug 29, 09	3	9	-6	9,190	9,190	0	0	0	0
Aug 30, 09	0	0	0	9,190	9,190	0	0	0	0
Aug 31, 09	2	5	-3	9,190	9,190	0	0	0	0
Sep 1, 09	3	3	0	11,103	11,103	0	0	0	0
Sep 2, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 3, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 4, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 5, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 6, 09	3	9	-6	11,103	13,297	-2,193	2,193	0	2,193
Sep 7, 09	0	3	-3	10,007	11,103	-1,097	1,097	0	1,097
Sep 8, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 9, 09	3	6	-3	11,103	12,200	-1,097	1,097	0	1,097
Sep 10, 09	7	8	-1	12,565	12,931	-366	366	0	366
Sep 11, 09	5	6	-1	11,834	12,200	-366	366	0	366
Sep 12, 09	2	2	0	10,738	10,738	0	0	0	0
Sep 13, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 14, 09	0	1	-1	10,007	10,372	-366	366	0	366
Sep 15, 09	3	1	2	11,103	10,372	731	731	731	0
Sep 16, 09	12	10	2	14,393	13,662	731	731	731	0
Sep 17, 09	11	11	0	14,028	14,028	0	0	0	0
Sep 18, 09	8	6	2	12,931	12,200	731	731	731	0
Sep 19, 09	13	13	0	14,759	14,759	0	0	0	0
Sep 20, 09	6	7	-1	12,200	12,565	-366	366	0	366
Sep 21, 09	1	4	-3	10,372	11,469	-1,097	1,097	0	1,097
Sep 22, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 23, 09	0	0	0	10,007	10,007	0	0	0	0
Sep 24, 09	4	2	2	11,469	10,738	731	731	731	0
Sep 25, 09	13	13	0	14,759	14,759	0	0	0	0
Sep 26, 09	12	11	1	14,393	14,028	366	366	0	0
Sep 27, 09	7	3	4	12,565	11,103	1,462	1,462	1,462	0
Sep 28, 09	4	1	3	11,469	10,372	1,097	1,097	1,097	0
Sep 29, 09	7	7	0	12,565	12,565	0	0	0	0
Sep 30, 09	17	17	0	16,221	16,221	0	0	0	0
Oct 1, 09	18	18	0	28,794	28,794	0	0	0	0
Oct 2, 09	9	11	-2	16,139	18,952	-2,812	2,812	0	2,812
Oct 3, 09	9	5	4	16,139	10,515	5,624	5,624	5,624	0
Oct 4, 09	6	6	0	11,921	11,921	0	0	0	0
Oct 5, 09	10	11	-1	17,545	18,952	-1,406	1,406	0	1,406
Oct 6, 09	11	9	2	18,952	16,139	2,812	2,812	2,812	0
Oct 7, 09	13	9	4	21,764	16,139	5,624	5,624	5,624	0
Oct 8, 09	14	12	2	23,170	20,358	2,812	2,812	2,812	0

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

Calculation of Supplier Balancing Charge

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, 09	8	8	0	14,733	14,733	0	0	0	0
Oct 10, 09	18	18	0	28,794	28,794	0	0	0	0
Oct 11, 09	17	19	-2	27,388	30,200	-2,812	2,812	0	2,812
Oct 12, 09	21	18	3	33,012	28,794	4,218	4,218	4,218	0
Oct 13, 09	24	23	1	37,231	35,825	1,406	1,406	1,406	0
Oct 14, 09	27	26	1	41,449	40,043	1,406	1,406	1,406	0
Oct 15, 09	26	26	0	40,043	40,043	0	0	0	0
Oct 16, 09	27	28	-1	41,449	42,855	-1,406	1,406	0	1,406
Oct 17, 09	24	22	2	37,231	34,419	2,812	2,812	2,812	0
Oct 18, 09	27	28	-1	41,449	42,855	-1,406	1,406	0	1,406
Oct 19, 09	23	25	-2	35,825	38,637	-2,812	2,812	0	2,812
Oct 20, 09	15	14	1	24,576	23,170	1,406	1,406	1,406	0
Oct 21, 09	13	9	4	21,764	16,139	5,624	5,624	5,624	0
Oct 22, 09	11	17	-6	18,952	27,388	-8,437	8,437	0	8,437
Oct 23, 09	22	21	1	34,419	33,012	1,406	1,406	1,406	0
Oct 24, 09	9	11	-2	16,139	18,952	-2,812	2,812	0	2,812
Oct 25, 09	18	16	2	28,794	25,982	2,812	2,812	2,812	0
Oct 26, 09	20	19	1	31,606	30,200	1,406	1,406	1,406	0
Oct 27, 09	19	17	2	30,200	27,388	2,812	2,812	2,812	0
Oct 28, 09	22	21	1	34,419	33,012	1,406	1,406	1,406	0
Oct 29, 09	20	17	3	31,606	27,388	4,218	4,218	0	0
Oct 30, 09	14	14	0	23,170	23,170	0	0	0	0
Oct 31, 09	11	5	6	18,952	10,515	8,437	8,437	8,437	0
Nov 1, 09	18	20	-2	31,791	34,465	-2,675	2,675	0	2,675
Nov 2, 09	22	23	-1	37,140	38,478	-1,337	1,337	0	1,337
Nov 3, 09	23	19	4	38,478	33,128	5,350	5,350	5,350	0
Nov 4, 09	26	23	3	42,490	38,478	4,012	4,012	0	0
Nov 5, 09	26	28	-2	42,490	45,165	-2,675	2,675	0	2,675
Nov 6, 09	27	29	-2	43,827	46,502	-2,675	2,675	0	2,675
Nov 7, 09	24	20	4	39,815	34,465	5,350	5,350	5,350	0
Nov 8, 09	17	19	-2	30,453	33,128	-2,675	2,675	0	2,675
Nov 9, 09	16	4	12	29,116	13,067	16,049	16,049	16,049	0
Nov 10, 09	16	13	3	29,116	25,104	4,012	4,012	0	4,012
Nov 11, 09	23	26	-3	38,478	42,490	-4,012	4,012	0	4,012
Nov 12, 09	23	24	-1	38,478	39,815	-1,337	1,337	0	1,337
Nov 13, 09	19	17	2	33,128	30,453	2,675	2,675	2,675	0
Nov 14, 09	19	14	5	33,128	26,441	6,687	6,687	6,687	0
Nov 15, 09	14	11	3	26,441	22,429	4,012	4,012	0	4,012
Nov 16, 09	21	20	1	35,803	34,465	1,337	1,337	1,337	0
Nov 17, 09	26	28	-2	42,490	45,165	-2,675	2,675	0	2,675
Nov 18, 09	24	29	-5	39,815	46,502	-6,687	6,687	0	6,687
Nov 19, 09	18	12	6	31,791	23,766	8,024	8,024	8,024	0
Nov 20, 09	19	16	3	33,128	29,116	4,012	4,012	0	4,012
Nov 21, 09	21	20	1	35,803	34,465	1,337	1,337	1,337	0
Nov 22, 09	22	23	-1	37,140	38,478	-1,337	1,337	0	1,337
Nov 23, 09	20	21	-1	34,465	35,803	-1,337	1,337	0	1,337
Nov 24, 09	22	18	4	37,140	31,791	5,350	5,350	5,350	0
Nov 25, 09	18	19	-1	31,791	33,128	-1,337	1,337	0	1,337
Nov 26, 09	17	19	-2	30,453	33,128	-2,675	2,675	0	2,675
Nov 27, 09	23	22	1	38,478	37,140	1,337	1,337	1,337	0
Nov 28, 09	29	20	9	46,502	34,465	12,037	12,037	12,037	0
Nov 29, 09	27	21	6	43,827	35,803	8,024	8,024	8,024	0
Nov 30, 09	24	27	-3	39,815	43,827	-4,012	4,012	0	4,012
Dec 1, 09	31	29	2	57,404	53,635	3,769	3,769	3,769	0
Dec 2, 09	19	15	4	34,790	27,252	7,538	7,538	7,538	0
Dec 3, 09	19	12	7	34,790	21,598	13,192	13,192	13,192	0
Dec 4, 09	26	23	3	47,982	42,328	5,654	5,654	5,654	0
Dec 5, 09	31	32	-1	57,404	59,289	-1,885	1,885	0	1,885
Dec 6, 09	34	37	-3	63,058	68,712	-5,654	5,654	0	5,654
Dec 7, 09	33	36	-3	61,174	66,827	-5,654	5,654	0	5,654
Dec 8, 09	27	34	-7	49,866	63,058	-13,192	13,192	0	13,192
Dec 9, 09	30	30	0	55,520	55,520	0	0	0	0
Dec 10, 09	38	36	2	70,596	66,827	3,769	3,769	3,769	0
Dec 11, 09	42	43	-1	78,134	80,019	-1,885	1,885	0	1,885
Dec 12, 09	40	43	-3	74,365	80,019	-5,654	5,654	0	5,654
Dec 13, 09	32	37	0	59,289	59,289	0	0	0	0
Dec 14, 09	30	27	3	55,520	49,866	5,654	5,654	5,654	0
Dec 15, 09	32	29	3	59,289	53,635	5,654	5,654	5,654	0
Dec 16, 09	45	44	1	83,788	81,904	1,885	1,885	1,885	0
Dec 17, 09	53	55	-2	98,864	102,634	-3,769	3,769	0	3,769
Dec 18, 09	47	48	-1	87,557	89,442	-1,885	1,885	0	1,885
Dec 19, 09	40	43	-3	74,365	80,019	-5,654	5,654	0	5,654
Dec 20, 09	43	44	-1	80,019	81,904	-1,885	1,885	0	1,885
Dec 21, 09	46	41	5	85,673	76,250	9,423	9,423	9,423	0
Dec 22, 09	46	45	1	85,673	83,788	1,885	1,885	1,885	0
Dec 23, 09	47	43	4	87,557	80,019	7,538	7,538	7,538	0
Dec 24, 09	36	37	-1	66,827	68,712	-1,885	1,885	0	1,885
Dec 25, 09	37	35	2	66,827	64,943	1,885	1,885	1,885	0
Dec 26, 09	33	27	6	61,174	49,866	11,307	11,307	11,307	0
Dec 27, 09	34	28	6	63,058	51,751	11,307	11,307	11,307	0
Dec 28, 09	43	37	6	80,019	68,712	11,307	11,307	11,307	0
Dec 29, 09	61	55	6	113,941	102,634	11,307	11,307	11,307	0
Dec 30, 09	43	44	-1	80,019	81,904	-1,885	1,885	0	1,885
Dec 31, 09	34	41	-7	63,058	76,250	-13,192	13,192	0	13,192
Jan 1, 10	40	36	-4	63,058	66,827	-3,769	3,769	0	3,769
Jan 2, 10	43	38	5	80,019	70,596	9,423	9,423	9,423	0
Jan 3, 10	39	39	0	72,481	72,481	0	0	0	0
Jan 4, 10	40	38	2	74,365	70,596	3,769	3,769	3,769	0
Jan 5, 10	43	37	6	80,019	70,596	9,423	9,423	9,423	0
Jan 6, 10	43	37	6	80,019	68,712	11,307	11,307	11,307	0
Jan 7, 10	43	45	-2	80,019	83,788	-3,769	3,769	0	3,769
Jan 8, 10	51	51	0	95,095	95,095	0	0	0	0
Jan 9, 10	47	49	-2	87,557	91,326	-3,769	3,769	0	3,769
Jan 10, 10	42	37	5	78,134	68,712	9,423	9,423	9,423	0
Jan 11, 10	47	47	0	83,788	83,788	0	0	0	0
Jan 12, 10	45	47	-2	83,788	87,557	-3,769	3,769	0	3,769

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

Calculation of Supplier Balancing Charge

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, 10	44	46	-2	81,904	85,673	-3,769	3,769	0	3,769
Jan 14, 10	39	34	5	72,481	63,058	9,423	9,423	9,423	0
Jan 15, 10	35	28	7	64,943	51,751	13,192	13,192	13,192	0
Jan 16, 10	35	30	5	64,943	55,520	9,423	9,423	9,423	0
Jan 17, 10	35	32	3	64,943	59,289	5,654	5,654	5,654	0
Jan 18, 10	39	34	5	72,481	63,058	9,423	9,423	9,423	0
Jan 19, 10	37	34	3	68,712	63,058	5,654	5,654	5,654	0
Jan 20, 10	37	36	1	68,712	66,827	1,885	1,885	1,885	0
Jan 21, 10	40	40	0	74,365	74,365	0	0	0	0
Jan 22, 10	42	43	-1	78,134	80,019	-1,885	1,885	0	1,885
Jan 23, 10	44	43	1	81,904	80,019	1,885	1,885	1,885	0
Jan 24, 10	27	30	-3	49,866	55,520	-5,654	5,654	0	5,654
Jan 25, 10	26	19	7	47,982	34,790	13,192	13,192	13,192	0
Jan 26, 10	34	30	4	63,058	55,520	7,538	7,538	7,538	0
Jan 27, 10	35	34	1	64,943	63,058	1,885	1,885	1,885	0
Jan 28, 10	39	44	-5	72,481	81,904	-9,423	9,423	0	9,423
Jan 29, 10	54	57	-3	100,749	106,403	-5,654	5,654	0	5,654
Jan 30, 10	51	52	-1	95,095	96,980	-1,885	1,885	0	1,885
Jan 31, 10	45	42	3	83,788	78,134	5,654	5,654	5,654	0
Feb 1, 10	51	42	9	95,095	78,134	16,961	16,961	16,961	0
Feb 2, 10	40	40	0	74,365	74,365	0	0	0	0
Feb 3, 10	37	39	-2	68,712	72,481	-3,769	3,769	0	3,769
Feb 4, 10	45	42	3	83,788	78,134	5,654	5,654	5,654	0
Feb 5, 10	42	42	0	78,134	78,134	0	0	0	0
Feb 6, 10	46	47	-1	85,673	87,557	-1,885	1,885	0	1,885
Feb 7, 10	44	42	2	81,904	78,134	3,769	3,769	3,769	0
Feb 8, 10	42	40	2	78,134	74,365	3,769	3,769	3,769	0
Feb 9, 10	38	33	5	70,596	61,174	9,423	9,423	9,423	0
Feb 10, 10	41	34	7	76,250	63,058	13,192	13,192	13,192	0
Feb 11, 10	41	36	5	76,250	66,827	9,423	9,423	9,423	0
Feb 12, 10	43	37	6	80,019	68,712	11,307	11,307	11,307	0
Feb 13, 10	37	35	2	68,712	64,943	3,769	3,769	3,769	0
Feb 14, 10	37	31	6	68,712	57,404	11,307	11,307	11,307	0
Feb 15, 10	36	34	2	66,827	63,058	3,769	3,769	3,769	0
Feb 16, 10	36	36	0	66,827	66,827	0	0	0	0
Feb 17, 10	31	32	0	59,289	59,289	0	0	0	0
Feb 18, 10	31	28	3	57,404	51,751	5,654	5,654	5,654	0
Feb 19, 10	32	30	2	59,289	55,520	3,769	3,769	3,769	0
Feb 20, 10	32	27	5	59,289	49,866	9,423	9,423	9,423	0
Feb 21, 10	34	33	1	63,058	61,174	1,885	1,885	1,885	0
Feb 22, 10	31	27	4	57,404	49,866	7,538	7,538	7,538	0
Feb 23, 10	29	30	-1	53,635	55,520	-1,885	1,885	0	1,885
Feb 24, 10	29	26	3	53,635	47,982	5,654	5,654	5,654	0
Feb 25, 10	27	25	2	49,866	46,097	3,769	3,769	3,769	0
Feb 26, 10	28	30	-2	51,751	55,520	-3,769	3,769	0	3,769
Feb 27, 10	29	33	-4	53,635	61,174	-7,538	7,538	0	7,538
Feb 28, 10	28	29	-1	51,751	53,635	-1,885	1,885	0	1,885
Mar 1, 10	28	25	4	52,031	45,705	6,327	6,327	6,327	0
Mar 2, 10	28	27	1	50,450	48,868	1,582	1,582	1,582	0
Mar 3, 10	30	29	1	53,613	52,031	1,582	1,582	1,582	0
Mar 4, 10	31	28	3	55,195	50,450	4,745	4,745	4,745	0
Mar 5, 10	31	28	3	55,195	50,450	4,745	4,745	4,745	0
Mar 6, 10	31	22	9	48,868	40,960	7,908	7,908	7,908	0
Mar 7, 10	26	19	7	47,286	36,215	11,072	11,072	11,072	0
Mar 8, 10	26	19	7	47,286	36,215	11,072	11,072	11,072	0
Mar 9, 10	27	28	-1	48,868	50,450	-1,582	1,582	0	1,582
Mar 10, 10	24	25	-1	44,123	45,705	-1,582	1,582	0	1,582
Mar 11, 10	21	26	-5	39,378	47,286	-7,908	7,908	0	7,908
Mar 12, 10	25	28	-3	45,705	50,450	-4,745	4,745	0	4,745
Mar 13, 10	23	27	-4	42,541	48,868	-6,327	6,327	0	6,327
Mar 14, 10	26	25	1	47,286	45,705	1,582	1,582	1,582	0
Mar 15, 10	23	26	-3	42,541	47,286	-4,745	4,745	0	4,745
Mar 16, 10	23	21	2	42,541	39,378	3,163	3,163	3,163	0
Mar 17, 10	18	13	5	34,633	26,725	7,908	7,908	7,908	0
Mar 18, 10	16	15	1	31,470	29,888	1,582	1,582	1,582	0
Mar 19, 10	14	12	2	28,307	25,143	3,163	3,163	3,163	0
Mar 20, 10	10	8	2	21,980	18,817	3,163	3,163	3,163	0
Mar 21, 10	18	22	-4	34,633	40,960	-6,327	6,327	0	6,327
Mar 22, 10	16	23	-7	31,470	42,541	-11,072	11,072	0	11,072
Mar 23, 10	21	23	-2	39,378	42,541	-3,163	3,163	0	3,163
Mar 24, 10	24	23	1	44,123	42,541	1,582	1,582	1,582	0
Mar 25, 10	16	17	-1	31,470	33,051	-1,582	1,582	0	1,582
Mar 26, 10	35	35	0	61,521	61,521	0	0	0	0
Mar 27, 10	31	32	-1	55,195	56,776	-1,582	1,582	0	1,582
Mar 28, 10	21	21	0	39,378	39,378	0	0	0	0
Mar 29, 10	19	16	3	39,378	31,470	7,908	7,908	7,908	0
Mar 30, 10	18	19	0	36,215	36,215	0	0	0	0
Mar 31, 10	18	18	0	34,633	34,633	0	0	0	0
Apr 1, 10	0	0	0	0	0	0	0	0	0
Apr	475	464	11	882,433	868,117	14,316	58,567	36,442	22,125
May	203	212	-9	450,972	456,503	-5,531	41,173	17,821	23,352
Jun	48	66	-18	331,227	337,601	-6,374	14,872	4,249	10,623
Jul	14	28	-14	305,687	305,687	0	0	0	0
Aug	9	17	-8	284,882	284,882	0	0	0	0
Sep	141	144	-3	351,741	352,838	-1,097	12,794	5,849	6,945
Oct	526	503	23	847,625	815,285	32,340	80,147	56,244	23,904
Nov	644	605	39	1,092,809	1,040,650	52,159	127,053	89,606	37,447
Dec	1,152	1,125	27	2,138,485	2,088,603	50,883	179,032	114,957	64,075
Jan	1,248	1,206	42	2,320,402	2,241,251	79,151	177,147	128,149	48,998
Feb	1,018	960	58	1,890,006	1,780,702	109,304	150,764	130,034	20,730
Mar	719	700	19	1,328,274	1,298,222	30,051	131,278	80,665	50,613
Total	6,197	6,030	167	12,225,543	11,870,341	355,203	972,826	664,014	308,811
Datacheck	0	0	0	0	0	0	0	0	0

00000180

ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

Source:

1	Peak Day		137,400	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 33371	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: 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		55,567	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		\$4,165,430		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		\$1,749,387		Attachment B: Order No. 23,675 (page 15), Docket DG 00-063,
26	Granite Ridge		\$247,522		Attachment B Page 3 Line 1
27	Total		\$6,162,340		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		\$110.90		Line 27 divided by Line 20
30					
31	Monthly Peaking MDQ		\$18.48 /Dekatherm		Line 29 divided by 6 month

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ENERGY NORTH NATURAL GAS

Tennessee Allocations

Resource Type	High Load Factor	Low Load Factor
Pipeline	50.00%	38.00%
Storage	17.00%	21.00%
Peaking	33.00%	41.00%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2009

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate \$/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	ANE II*	Supply at Waddington		4,000		\$11.8810		10/31/2017	X
	Iroquois	RTS to Wright	470-01	4,047		\$6.5971		11/01/2017	
	TGP	NET-NE	33371	4,000		\$10.6100		10/31/2011	
	BP Canada Energy Co.**	Supply at Niagara		3,199		\$0.0000		03/31/2012	X
	TGP	FT-A (Z5-Z6)	2302	3,122		\$4.9300		10/31/2015	
	TGP	FT-A (Z0-Z6)	8587	7,035		\$16.5900		10/31/2015	
	TGP	FT-A (Z1-Z6)	8587	14,561		\$15.1500		10/31/2015	
	TGP	FT-A (Z6-Z6)	42076	20,000		\$3.1600		10/31/2015	
	TGP	FT-A (Z6-Z6)	72694	4,000		\$12.1700		09/30/2029	
Storage									
	TGP	FS-MA (Storage)	523***	21,844	1,560,391	\$1.1500	\$0.0185	10/31/2015	
	TGP	FT-A (Z4-Z6)	632	15,265		\$5.8900		10/31/2015	
	TGP	FT-A (Z4-Z6)	8587	3,811		\$5.8900		10/31/2015	
	National Fuel	FSS-1 (Storage)	002357***	6,098	670,800	\$2.1556	\$0.0432	03/31/2011	
	National Fuel	FST (Transport)	N02358	6,098		\$3.3612		03/31/2011	
	TGP	FT-A (Z4-Z6)	11234	6,150		\$5.8900		10/31/2011	
	Honeoye	SS-NY (Storage)	SS-NY***	1,957	245,280	\$4.4683	\$0.0000	04/01/2011	X
	TGP	FT-A (Z5-Z6)	11234	1,957		\$4.9300		10/31/2011	
	Dominion	GSS (Storage)	300076***	934	102,700	\$1.8773	\$0.0145	03/31/2011	
	TGP	FT-A (Z4-Z6)	11234	932		\$5.8900		10/31/2011	
Peaking									
	Energy North	LNG/Propane****		29,567	-	\$18.4800	\$0.0000		X
	TGP	FT-A (Z6-Z6)	72694	26,000	-	\$12.1700	\$0.0000	09/30/2029	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 \$27.4017/dth.

00000182

ENERGYNORTH NATURAL GAS, INC.
d/b/a National Grid NH
Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

	Volume	Rate	Monthly Cost	Months/Year	Annual Cost
1 <u>Granite Ridge - 30 days @ 15,000/dt</u>					
2					
3					
4 Concord Lateral					
5 DOMAC * FLS 160					
6					
7 Subtotal					\$4,165,430 *
8					
9 Total					\$4,412,953
10					

* Contract currently being negotiated for an effective date of November 1, 2010.

THIS PAGE HAS BEEN REDACTED

00000183

III DELIVERY TERMS AND CONDITIONS

NHPUC NO. 5 - GAS
KEYSPAN ENERGY DELIVERY

Proposed Second Revised Page 156
Superseding *First Revised* Page 156

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	50.0%	17.0%	33.0%	100.0%
G-42	Medium Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-52	High Annual / Low Winter Use	50.0%	17.0%	33.0%	100.0%
G-43	High Annual / High Winter	38.0%	21.0%	41.0%	100.0%
G-53	High Annual / Load Factor < 90%	50.0%	17.0%	33.0%	100.0%
G-54	High Annual / Load Factor < 90%	50.0%	17.0%	33.0%	100.0%

00000184

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			Pipeline	% of Peak Day Requirement		Total
				Storage	Peaking	
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	50.0%	17.0%	33.0%	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	50.0%	17.0%	33.0%	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%	50.0%	17.0%	33.0%	100.0%
G-54	HALWG90	High Annual C&I - LF > 90%	50.0%	17.0%	33.0%	100.0%

HLF	High Load Factor	50%	17%	33%	100%
LLF	Low Load Factor	38%	21%	41%	100%
	Total	39%	20%	40%	99%

00000185

Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Allocate Class Design Day Throughput to Supply Sources

% of Peak Day Requirement

Design DD		72			Base	Remaining	Sub-total										
		Base load	Heat load	Total			Pipeline	Pipeline	Pipeline	Storage	Peaking	Total	Pipeline	Storage	Peaking	Total	
HLF	R-1 RNSH	156	495	651	R-1 RNSH	156	171	326	109	215	651	R-1 RNSH	50.2%	16.7%	33.1%	100 0%	
LLF	R-3 RSH	3,993	60,343	64,336	R-3 RSH	3,993	20,809	24,802	13,282	26,252	64,336	R-3 RSH	38.6%	20 6%	40.8%	100 0%	
LLF	G-41 SL	851	22,911	23,761	G-41 SL	851	7,901	8,751	5,043	9,967	23,761	G-41 SL	36.8%	21 2%	41.9%	100 0%	
HLF	G-51 SH	627	1,978	2,605	G-51 SH	627	682	1,309	435	861	2,605	G-51 SH	50.3%	16.7%	33.0%	100 0%	
LLF	G-42 ML	1,653	31,424	33,077	G-42 ML	1,653	10,837	12,489	6,917	13,671	33,077	G-42 ML	37.8%	20 9%	41.3%	100 0%	
HLF	G-52 MH	1,247	3,064	4,311	G-52 MH	1,247	1,057	2,304	674	1,333	4,311	G-52 MH	53.4%	15 6%	30.9%	100 0%	
LLF	G-43 LL	463	4,152	4,615	G-43 LL	463	1,432	1,895	914	1,806	4,615	G-43 LL	41.1%	19 8%	39.1%	100 0%	
HLF	G-53 LLL90	297	1,298	1,595	G-53 LLL90	297	448	745	286	565	1,595	G-53 LLL90	46.7%	17 9%	35.4%	100 0%	
HLF	G-54 LLG90	384	2,064	2,449	G-54 LLG90	384	712	1,096	454	898	2,449	G-54 LLG90	44.8%	18 6%	36.7%	100 0%	
	TOTAL	9,671	127,729	137,400	TOTAL	9,671	44,047	53,718	28,115	55,567	137,400	TOTAL	39.1%	20 5%	40.4%	100 0%	
HLF		2,712	8,899	11,611	HLF		3,069	5,781	1,959	3,872	11,611	High Load Factor		50%	17%	33%	100%
LLF		6,959	118,830	125,789	LLF		40,978	47,937	26,156	51,695	125,789	Low Load Factor		38%	21%	41%	100%
Total		9,671	127,729	137,400	Total		44,047	53,718	28,115	55,567	137,400	Total		39%	20%	40%	100%

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**Energy North Natural Gas, Inc
d/b/a National Grid NH
Calculation of Capacity Allocators
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Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Design DD

72

	Daily Baseload * 1000	February Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total
R-1 RNSH	156	6.440	464	619
R-3 RSH	3,993	785.433	56,551	60,544
G-41 SL	851	298.209	21,471	22,322
G-51 SH	627	25.748	1,854	2,481
G-42 ML	1,653	409.017	29,449	31,102
G-52 MH	1,247	39.884	2,872	4,119
G-43 LL	463	54.041	3,891	4,354
G-53 LLL90	297	16.892	1,216	1,514
G-54 LLG90	384	26.872	1,935	2,319
TOTAL	9,671	1,637.058	119,703	129,373

HLF	2,712	116	8,340	11,052
LLF	6,959	1,521	111,362	118,321
Total	9,671	1,637	119,703	129,373

Design Day from 2009-2010 Resource Plan		137,400
Design Day from Billing Calculation		129,373
Variance		8,027

**Allocate Design Day Sendout to
Rate Classes**

Baseload as % of Total Class Load	Heat Load as % of Total
25%	0.387%
7%	47.243%
4%	17.937%
25%	1.549%
5%	24.602%
30%	2.399%
11%	3.250%
20%	1.016%
17%	1.616%
	100.000%

Base Load	Heat Load	Total
156	495	651
3,993	60,343	64,336
851	22,911	23,761
627	1,978	2,605
1,653	31,424	33,077
1,247	3,064	4,311
463	4,152	4,615
297	1,298	1,595
384	2,064	2,449
9,671	127,729	137,400

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CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total	Monthly Baseload	Daily Baseload
															(Jul+Aug)/2	
HLF	R-1 RNSH	7	9	13	11	10	8	7	6	5	5	4	6	91	4 830	0 156
LLF	R-3 RSH	388	575	1,118	975	734	464	295	171	129	118	120	224	5,312	123 771	3 993
LLF	G-41 SL	110	174	403	352	261	147	80	41	28	25	24	53	1,697	26 367	0 851
HLF	G-51 SH	25	32	55	46	39	30	24	21	20	19	19	23	354	19 440	0 627
LLF	G-42 ML	200	287	565	496	389	250	148	82	51	51	53	105	2,676	51 229	1 653
HLF	G-52 MH	49	60	88	79	68	57	48	42	39	39	39	44	651	38 662	1 247
LLF	G-43 LL	26	35	55	72	60	49	33	23	17	11	8	4	394	14 360	0 463
HLF	G-53 LLL90	13	(4)	14	27	16	27	13	12	15	4	4	(1)	138	9 221	0 297
HLF	G-54 LLL110	8	1	22	40	(18)	26	5	9	8	16	(1)	2	117	11 911	0 384
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	0	0 000	0 000
TOTAL		826	1,169	2,332	2,098	1,560	1,058	654	406	312	288	270	459	11,432	299 791	9 671
HLF		102	98	192	203	116	147	97	90	86	82	66	73	1,352	84 065	2 712
LLF		725	1,071	2,140	1,895	1,444	911	557	316	225	206	205	386	10,079	215 726	6 959

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

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total		
		30	31	31	28	31	30	31	30	31	31	30	31	365		
HLF	R-1 RNSH	5	5	5	4	5	5	5	5	5	5	4	5	57		
LLF	R-3 RSH	120	124	124	112	124	120	124	120	129	118	120	124	1,457		
LLF	G-41 SL	26	26	26	24	26	26	26	26	28	25	24	26	310		
HLF	G-51 SH	19	19	19	18	19	19	19	19	20	19	19	19	229		
LLF	G-42 ML	50	51	51	46	51	50	51	50	51	51	50	51	603		
HLF	G-52 MH	37	39	39	35	39	37	39	37	39	39	37	39	455		
LLF	G-43 LL	14	14	14	13	14	14	14	14	17	11	8	4	169		
HLF	G-53 LLL90	9	(4)	9	8	9	9	9	9	15	4	4	(1)	109		
HLF	G-54 LLL110	8	1	12	11	(18)	12	5	9	8	16	(1)	2	117		
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0		
TOTAL		316	306	331	299	301	320	324	318	343	319	295	300	3,530		
HLF		77	59	84	76	55	81	77	79	86	82	64	63	967		
LLF		209	216	216	195	216	209	216	209	225	206	202	206	2,540		

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

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
HLF	R-1 RNSH	2	4	9	7	5	3	2	1	0	0	0	1	34
LLF	R-3 RSH	269	451	994	863	610	345	172	51	0	0	0	100	3,855
LLF	G-41 SL	84	148	376	328	234	122	54	15	0	0	0	26	1,386
HLF	G-51 SH	6	13	35	28	20	11	5	2	0	0	0	3	125
LLF	G-42 ML	151	236	513	450	337	201	97	33	0	0	3	53	2,073
HLF	G-52 MH	12	22	49	44	30	19	10	4	0	0	2	5	196
LLF	G-43 LL	12	21	41	59	46	35	19	9	0	0	0	0	225
HLF	G-53 LLL90	4	0	4	19	7	18	4	3	0	0	0	0	30
HLF	G-54 LLL110	0	0	10	30	0	14	0	0	0	0	0	0	0
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	510	863	2,001	1,799	1,259	738	330	88	(31)	(31)	(25)	159	7,902

HLF	24	39	108	127	62	66	20	11	0	0	2	10	385
LLF	516	856	1,924	1,700	1,228	702	341	107	0	0	3	180	7,539

Actual BDD	553.5	866.0	1167.0	1099.0	846.0	545.5	269.0	92.0	19.0	22.5	81.0	324.0	5884.5
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Heat Factors

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
HLF	R-1 RNSH	0.0044	0.0048	0.0074	0.0064	0.0060	0.0062	0.0062	0.0105	0.0000	0.0000	0.0000	0.0039	
LLF	R-3 RSH	0.4853	0.5212	0.8516	0.7854	0.7213	0.6318	0.6381	0.5523	0.0000	0.0000	0.0000	0.3101	
LLF	G-41 SL	0.1525	0.1706	0.3223	0.2982	0.2771	0.2227	0.2000	0.1652	0.0000	0.0000	0.0000	0.0812	
HLF	G-51 SH	0.0117	0.0149	0.0303	0.0257	0.0235	0.0207	0.0183	0.0219	0.0000	0.0000	0.0048	0.0103	
LLF	G-42 ML	0.2720	0.2721	0.4400	0.4090	0.3989	0.3681	0.3593	0.3549	0.0000	0.0000	0.0373	0.1646	
HLF	G-52 MH	0.0213	0.0248	0.0422	0.0399	0.0350	0.0353	0.0356	0.0473	0.0000	0.0000	0.0225	0.0161	
LLF	G-43 LL	0.0221	0.0241	0.0349	0.0540	0.0541	0.0640	0.0694	0.0946	0.0000	0.0000	0.0000	0.0000	
HLF	G-53 LLL90	0.0067	0.0000	0.0038	0.0169	0.0085	0.0323	0.0149	0.0369	0.0000	0.0000	0.0000	0.0000	
HLF	G-54 LLL110	0.0000	0.0000	0.0087	0.0269	0.0000	0.0261	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
HLF	G-63 LLG110	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
	TOTAL	0.9219	0.9968	1.7145	1.6371	1.4876	1.3523	1.2266	0.9576	-1.6316	-1.3778	-0.3058	0.4906	

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Actual BillingDD	553.5	866.0	1167.0	1099.0	846.0	545.5	269.0	92.0	19.0	22.5	81.0	324.0	5884.5
Norm Billing DD	561.7	889.5	1144.4	1131.9	973.4	712.3	384.4	149.1	28.1	8.2	63.0	263.4	6309.3

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

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
HLF	R-1 RNSH	7	9	13	12	11	9	7	6	5	5	4	6	94
LLF	R-3 RSH	392	587	1,098	1,001	826	570	369	202	129	118	120	205	5,618
LLF	G-41 SL	111	178	395	361	296	184	103	50	28	25	24	48	1,804
HLF	G-51 SH	25	33	54	47	42	34	26	22	20	19	19	22	363
LLF	G-42 ML	202	293	555	509	440	312	189	102	51	51	52	95	2,852
HLF	G-52 MH	49	61	87	80	73	63	52	44	39	39	39	43	668
LLF	G-43 LL	26	36	54	74	67	59	41	28	17	11	8	4	427
HLF	G-53 LLL90	13	(4)	14	27	17	32	15	14	15	4	4	(1)	149
HLF	G-54 LLL110	8	1	22	41	(18)	30	5	9	8	16	(1)	2	122
HLF	G-63 LLG110	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	834	1,193	2,293	2,152	1,749	1,283	795	461	297	308	276	429	12,069

HLF	102	99	190	207	126	167	106	97	86	82	65	71	1,398
LLF	732	1,095	2,103	1,946	1,628	1,125	703	383	225	206	204	352	10,702

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	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 1/					\$0.8403	\$0.8203	\$1,169.53	\$1,150.89	\$ 18.64	1.62%	\$0.8418	\$0.8218	\$1,874.98	\$1,846.44	\$ 28.54	1.55%
14																
15 Total									\$ 437.16						\$ 654.55	

1/ The total bill calculation reflects the increase in base distribution rates as approved in Order 25,104 in DG 10-017 (Temporary Rates)

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ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2010 - 2011 Winter Cost of Gas Filing
Short Term Debt Limitations

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	For Purposes of Fuel Financing
Total Direct Gas Costs	\$ 65,369,088
Total Indirect Gas Costs	<u>2,914,492</u>
Total Gas Costs	\$ 68,283,580
% of Debt to Total Gas Costs	30%
Short Term Debt	\$ 20,485,074

	For Purposes Other Than Fuel Financing
12/1/2011 Projected Net Plant	\$ 262,642,601
% of Debt to Net Plant	20%
Short Term Debt	\$ 52,528,520

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