VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.75 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$16.82per MMBtu** per MDPQ per month for November 2008 through April 2009.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Supplier Services and Associated Fees:

SERVICE	PRICING
Pool Administration (required) **Non-Daily Metered Pools only**	• $0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• $0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• $1.50/customer/month billed @ marketer level
Customer Administration (required)	• $10/customer/switch billed @ marketer level

Issued: September 15, 2008
Effective: November 1, 2008

Issued by: Stephen H. Bryant
Title: President

Authorized by NHPUC Order No. in Docket No. DG 07- , dated

Calculation Steps for Supplier Balancing Charge

The Company has derived the Supplier Balancing Charge based on its daily dispatch activity for the twelve-month period May 1, 2000 through April 30, 2001.

The steps taken to calculate the balancing charge are as follows:

1. Actual Daily Sendout from Dispatch Center.
2. Base Load = July and August's Daily Sendout divided by 62 days.
3. Heating Load = Actual Sendout less Base Load.
4. Use per Degree Day ("UPDD") = Heating Load divided by Actual Effective Degree Days ("EDD").
5. Actual Swing = Actual EDD less Estimated EDD multiplied by UPDD.
6. Adjusted Swing = Actual Swing less 10% of Scheduled Deliveries.
7. % Allocated to Balancing for Firm Transportation ("FT") and Deliverability = Sum of Positive Swings divided by Total Withdrawals (November 2000 through April 2001).
8. % Allocated to Balancing for Space = Sum of Total Northern Utilities' Absolute Swings divided by Total Northern Utilities' Storage Capacity.
9. Billing Determinant = Sum of Absolute Value of All Swings plus 10% of Scheduled Deliveries on days of swings.
10. % Maximum Daily Quantity ("MDQ") = Maximum Swing divided by New Hampshire's MDQ (NH's MDQ is calculated by taking the total MDQ for Northern Utilities and multiplying by the Current Demand Allocator for NH).
11. Balancing Costs = % MDQ multiplied by NH's share of storage costs (NH's share of storage costs are calculated by taking total Northern Utilities' storage costs and multiplying by the Current Demand Allocator for NH).
12. Costs Allocated to Balancing = (a) FT (for storage) and Deliverability costs multiplied by the percentage derived per #7 above; or, (b) space/capacity costs multiplied by the percentage derived per #8 above.

Northern Utilities, Inc.-New Hampshire
Calculation of Balancing Charge

November 2008 through October 2009

	MDQ		Max Swing	% MDQ	
New Hampshire Underground	17,251		3,532	20.47%	
LNG	4,827		0	0.00%	
Propane	1,931		0	0.00%	

	% MDQ	Costs	Balancing Costs	% Allocated (to Balancing)	Allocated Costs
New Hampshire Underground					
Del., Res., and Transp.	20.47%	$7,704,085	$1,577,358	0.20%	$3,098
Capacity	20.47%	$1,423,118	$291,374	35.51%	$103,455
LNG	0.00%	$110,864	$0	142.85%	$0
Propane	0.00%	$121,142	$0	0.00%	$0
Total		$9,359,208	$1,868,731		$106,553
Annual Sum of Absolute Swings					142,624
Balancing Rate Per MMBtu Swing					**$0.75**

Northern Utilities, Inc.
Calculation of Balancing Charge
Allocation of Costs Between Balancing and Supply Functions

	Maximum Swing	Sum of Positive Swings	Total Utilization	Ratio Pos. Swings to Tot. Utilization	Sum of Absolute Swings	Total Capacity	Ratio Abs. Swings to Capacity
New Hampshire Underground	3,532	3,811	1,940,177	0.20%	36,518	142,458	25.63%
Maine Underground	7,580	1,635	2,079,249	0.08%	68,023	151,972	44.76%
Total Northern					104,540	294,430	**35.51%**

	Maximum Swing	Sum of Swings	Tank Capacity	Ratio Swings to Tank Capacity
LNG	0	(26,271)	6,637	395.82%
Propane	0	0	12,421	0.00%

Northern Utilities, Inc.
Calculation of Balancing Charge
Costs of Balancing Resources
November 2008 through October 2009

New Hampshire			
El Paso FS Storage	MMBtu	Rate	Costs
Capacity	125,182	$0.0185	$27,790
Deliverability	2,048	$1.1500	$28,264
Firm Transportation-Tenn	1,281	$5.8900	$90,513
Firm Transportation-GSGT	1,281	$1.2639	$19,423
Total			$165,990
Texas Eastern Storage	MMBtu	Rate	Costs
Space - SS-1	710	$0.1293	$92
Reservation - SS-1	10	$5.4760	$666
Space - FSS-1	154	$0.1293	$240
Reservation - FSS-1	31	$0.8950	$332
TETCO Reservation	31	$5.6560	$2,097
Firm Transportation-GSGT	31	$1.2639	$469
Firm Transportation-GSGT	10	$1.2639	$154
Total			$4,048
W-10 Storage	MMBtu	Rate	Costs
W-10	16,412	$ 7.0833	$ 1,394,996
PNGTS	9,654	$ 52.0632	$ 2,513,091
PNGTS	6,275	$ 52.0632	$ 1,633,509
Vector - In	8,289	$ 7.6042	$ 315,153
Vector -Out	8,247	$ 4.5625	$ 451,546
TCPL	15,929	$ 16.6047	$ 3,173,975
Firm Transportation-GSGT	15,929	$ 1.2639	$ 241,593
Total			$ 9,723,864
Maine			
El Paso FS Storage	MMBtu	Rate	Costs
Capacity	134,155	$0.0185	$29,782
Deliverability	2,195	$1.1500	$30,290
Firm Transportation-Tenn	1,372	$5.8900	$97,001
Firm Transportation-GSGT	1,372	$1.2639	$20,815
Total			$177,888
Texas Eastern Storage			
Space - SS-1	63	$0.1293	$8
Reservation - SS-1	11	$5.4880	$715
Space - FSS-1	166	$0.1293	$257
Reservation - FSS-1	33	$0.8950	$356
TETCO Reservation	33	$5.6560	$2,247
Firm Transportation-GSGT	33	$1.2639	$502
Firm Transportation-GSGT	11	$1.2639	$165
Total			$4,250
W-10 Storage	MMBtu	Rate	Costs
W-10	17,588	$ 7.0833	$ 1,494,990
PNGTS	10,346	$ 52.0632	$ 2,693,229
PNGTS	6,725	$ 52.0632	$ 1,750,599
Vector - In	8,883	$ 7.6042	$ 337,743
Vector -Out	8,839	$ 4.5625	$ 483,913
TCPL	17,071	$ 16.6047	$ 3,401,486
Firm Transportation-GSGT	17,071	$ 1.2639	$ 258,911
Total			$ 10,420,871
LNG	MMBtu		Costs
Capacity	10,000		$229,674
Total			$229,674
Propane	MMBtu		Costs
Capacity	4,000		$250,967
Total			$250,967

Northern Utilities, Inc.
Calculation on Balancing Charge

Derivation of Absolute Swings
May 2000 through April 2001
Summary

	Sum Positive Swings		Sum Negative Swings		Sum LP / LNG Swings		ABS all Swings		Total
	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	ABS Swings
May	1,060	1,484	8,125	1,162	0	0	9,185	2,646	11,832
June	0	28	1,213	5,553	0	0	1,213	5,582	6,794
July	1,125	0	0	0	0	0	1,125	0	1,125
Aug	45	0	99	1,027	0	0	145	1,027	1,172
Sept	0	0	301	11,279	0	0	301	11,279	11,580
Oct	1,196	123	2,821	26,853	0	0	4,017	26,976	30,993
Nov	384	0	3,976	7,620	(2,382)	(2,539)	1,978	5,081	7,059
Dec	0	0	7,956	12,177	0	0	7,956	12,177	20,133
Jan	0	0	1,873	174	(423)	(13,355)	1,450	(13,181)	(11,731)
Feb	0	0	2,807	542	(4,431)	(4,339)	(1,623)	(3,797)	(5,420)
March	0	0	1,048	0	(2,245)	(6,038)	(1,197)	(6,038)	(7,235)
April	0	0	2,487	0	0	0	2,487	0	2,487
Total	3,811	1,635	32,707	66,387	(9,481)	(26,271)	45,999	94,294	140,292
			add back 10% of the scheduled deliveries=				96,625	97,195	193,819
					Total ABS Swings =		**142,624**	**191,488**	334,112

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, 2008 through October 31, 2009.

	Commercial and Industrial	
	High Winter Use	Low Winter Use
Pipeline:	14.44%	58.11%
Storage:	30.23%	14.80%
Peaking:	55.34%	27.10%

Description of Calculation of Capacity Allocators

This brief report summarizes the method used to assign capacity costs to customers migrating from bundled sales to delivery service. The method is designed to be consistent with the gas cost allocation method implicit in the Company's COGC. This method is the basis for the development of the figures shown on Appendix C, Capacity Allocators, of the Delivery Service Terms and Conditions of the Northern Utilities' NHPUC Tariff No. 10.

As part of its settlement in docket number DG 00-046, the Company implemented a gas cost recovery method that recovered average seasonal gas costs from the residential classes and recovered the remaining gas costs using the simplified Market Based Allocation method (MBA). The Company further revised the MBA Cost of Gas methodology effective May 1, 2007 in DG 07-033, 2007 Summer Period COG, further establishing a Simplified MBA ("SMBA") approach to assigning costs and capacity to the Commercial & Industrial high load factor (Low Winter) and low load factor (High Winter) class groupings. Under this SMBA method capacity costs are assigned to classes on the basis of their contribution to the system's design day load. The assignment is performed in two steps:

> Design Day Base Use - Base use is defined as that portion of the class's load that exists throughout the year, as measured by the average daily load in the warmest months. Pipeline supplies are used to satisfy the base use portion of each class's design day demand.
>
> Design Day Remaining Use – Remaining use is defined as the total class design day demand less that portion served by base use supplies. Remaining use is served by a combination of pipeline, storage and peaking supplies. Capacity costs for these supplies are allocated on the basis of design day demand less base use demand.

The following pages of this Attachment detail the development of capacity assignment allocators. Page 2 of 3 lists the major assumptions behind the calculations and tabulates the input data. Base use and remaining design day demand are shown by class. Beginning on line 33, the system pipeline capacity is assigned to the base use and remaining categories using the class base use load data above. Then on line 40, the residential allocation of supplies is performed. Since this class is assigned average costs, their assignment is simply computed as their proportion of the design day demand, irrespective of the supplies used to serve their loads.

Page 3 of 3 develops the allocation of capacity costs for the commercial and industrial (C&I) rates and summarizes the results of the allocation process. On lines 1 through 6 the supplies for the C&I classes are calculated by subtracting those supplies assigned to residential from the system totals. Then on lines 9 to 22 the C&I supplies are allocated to high and low load factor classes. In each case, base use pipeline supplies are allocated in proportion to class base use demand, while all other supplies are allocated on the basis of remaining design day demands. Unit costs for each class are summarized on lines 25 to 30. Lines 34 to 39 show the percentage of each supply necessary to serve class loads. Finally, lines 42 to 46 show the distribution of supplies among classes.

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2008-2009
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

		Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total	Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	1,900	196	0.3%	60	136
2	RATE B-Resi Htg	216,200	22,344	37.3%	1,080	21,264
3	RATE G-40 (R)	122,900	12,702	21.2%	290	12,412
4	RATE G-50 (Q)	9,500	982	1.6%	490	492
5	RATE G-41 (T)	101,900	10,531	17.6%	390	10,141
6	RATE G-51 (S)	19,800	2,046	3.4%	640	1,406
7	RATE G-42 (V)	13,700	1,416	2.4%	50	1,366
8	RATE G-52a (U)	4,500	465	0.8%	280	185
9	Special Contract	13,600	-	0.0%	1,090	-
10	RATE T-40	9,300	961	1.6%	40	921
11	RATE T-50	2,400	248	0.4%	30	218
12	RATE T-41	47,200	4,878	8.2%	210	4,668
13	RATE T-51	8,700	899	1.5%	280	619
14	RATE T-42	17,900	1,850	3.1%	60	1,790
15	RATE T-52	3,100	320	0.5%	110	210
16	Total	592,600	59,840	100.0%	5,100	55,830
17						-
18	Residential Total	218,100	22,541	**37.7%**	1,140	21,401
19	LLF Total	312,900	32,338	54.0%	1,040	31,298
20	HLF Total	61,600	4,961	8.3%	2,920	2,041
21	Total	592,600	59,840	100.0%	5,100	54,740

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		Capacity Cost	MDQ, Dt	$/Dt-Mo.
24				
25	Pipeline	6,792,131	11,986	47.22
26	Storage	5,138,705	17,401	24.61
27	Peaking	3,096,805	31,858	8.10
28	Total	15,027,642	61,245	20.45

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		Capacity Cost	MDQ, Dt	$/Dt-Mo.
32				
33	Pipeline - Baseload	2,890,066	5,100	47.22
34	Pipeline - Remaining	3,902,065	6,886	47.22
35	Storage	5,138,705	17,401	24.61
36	Peaking	3,096,805	31,858	8.10
37	Total	15,027,642	61,245	20.45

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	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
40					
41	Pipeline - Base	**37.7%**	1,088,641	1,921	47.22
42	Pipeline - Remaining	**37.7%**	1,469,845	2,594	47.22
43	Storage	**37.7%**	1,935,668	6,555	24.61
44	Peaking	**37.7%**	1,166,517	12,000	8.10
45	Total	**37.7%**	5,660,671	23,070	20.45

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2008-2009
Derivation of Class Assignments and Weightings

C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		1,801,424	3,179	47.22
Pipeline - Remaining		2,432,220	4,292	47.22
Storage		3,203,038	10,847	24.61
Peaking		1,930,289	19,858	8.10
Total	**62.3%**	9,366,970	38,175	20.45

LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		473,101	835	47.22
Pipeline - Remaining		2,283,334	4,029	47.22
Storage		3,006,967	10,183	24.61
Peaking		1,812,128	18,642	8.10
Total	**50.4%**	7,575,531	33,689	**18.74**

HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		1,328,323	2,344	47.22
Pipeline - Remaining		148,886	263	47.22
Storage		196,070	664	24.61
Peaking		118,160	1,216	8.10
Total	**11.9%**	1,791,440	4,486	**33.28**

Unit Cost	Residential	LLF C&I	HLF C&I
Pipeline	$ 47.22	$ 47.22	$ 47.22
Storage	$ 24.61	$ 24.61	$ 24.61
Peaking	$ 8.10	$ 8.10	$ 8.10
Total	$ 20.45	$ 18.74	$ 33.28
Check total	$ 20.45	$ 18.74	$ 33.28

Load Makeup	Residential	**LLF C&I**	**HLF C&I**
Pipeline	19.57%	**14.44%**	**58.11%**
Storage	28.41%	**30.23%**	**14.80%**
Peaking	52.02%	**55.34%**	**27.10%**
Total	100.00%	**100.00%**	**100.00%**

$234.000000

Supply Makeup	Residential	LLF C&I	HLF C&I	Total
Pipeline	37.67%	40.58%	21.75%	100.00%
Storage	37.67%	58.52%	3.82%	100.00%
Peaking	37.67%	58.52%	3.82%	100.00%

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX D

Firm Sales Service Re-Entry Fee Bill Adjustment (continued)

The Re-Entry Fee shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Firm Sales Service Re-Entry Fee Unit Charge shall be applicable for the period of November 1, 2008 through October 31, 2009.

Effective Dates:	**November 1, 2008 – October 31, 2009**
Annual Average Unit Cost:	$ 256.11
25% - Annual Charge for Re-Entry Fee:	$ 64.03
Monthly Unit Charge for Re-Entry Fee:	$ 5.336

Issued: September 15, 2008
Effective: November 1, 2008

Issued By: Stephen H. Bryant
Title: President

Authorized by NHPUC Order No. ___ in Docket No____, dated _____.

Northern Utilities Inc. - N.H. Division
Re-Entry Fee Bill Adjustment Information

Winter 2008-2009 Report

Report Date: September 15, 2008

I. Annual System Average Unit Capacity Cost Applicable for Re-Entry Fee:

Date:	November 2008 - October 2009
Annual Average Unit Cost:	$ 256.11
25% - Annual Charge for Re-Entry Fee:	$ 64.03
Monthly Unit Charge for Re-Entry Fee:	$ 5.336

II. Re-Entry Fee Activity for Prior Year:

	No. of Customers	Charges Recovered
2007 Nov	0	$ -
Dec	0	$ -
2008 Jan	0	$ -
Feb	0	$ -
Mar	0	$ -
Apr	0	$ -
May	0	$ -
Jun	0	$ -
Jul	0	$ -
Aug	0	$ -
Sep	0	$ -
Oct	0	$ -
Year-to-date	**0**	**$ -**

Attachment Northern-A

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
NOV 2008 - OCT 2009 CAPACITY COSTS
Unit Capacity Cost for Re-Entry Fee

	Total Northern Capacity Costs	New Hamphire Capacity Costs	(Modified PR) NH Allocation %	Total MDQ, DTH	NH MDQ	Annual Per Unit Cost
Pipeline	$ 15,433,656	$ 7,449,826	48.27%	24,831	11,986	$621.55
Storage/PNGTS	$ 10,645,754	$ 5,138,705	48.27%	36,050	17,401	$295.30
Peaking	$ 6,160,339	$ 3,096,805	n/a *	66,000	31,858	$97.21
Total Reqmnts	$ 32,239,748	$ 15,685,336	48.27%	126,881	61,245	$256.11
25% of Unit Capacity Cost						$ 64.03

Total Unassigned (Grandfathered):

Requirements	9,816	
Total Max. Re-Entry Fee Costs	$ 628,484	

* Percentage of NH costs to total Northern does not equal MPR allocation because a portion of costs ($686,673) fixed from last rate case.

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