Unitil
Unitil Service Corp.

Ex #6

April 16, 2012

ORIGINAL
N.H.P.U.C. Case No. DG12-068
Exhibit No. 6
Witness Panel
DO NOT REMOVE FROM FILE

VIA ELECTRONIC FILING AND OVERNIGHT MAIL

Alexander Speidel, Esq.
New Hampshire Public Utilities Commission
21 S. Fruit St., Suite 10
Concord, NH 03301-2429

Re: DG 12-068, Northern Utilities, Inc., Summer 2012 Cost of Gas Filing

Dear Attorney Speidel:

On behalf of Northern Utilities, Inc. ("Northern"), please find enclosed Northern's responses to the New Hampshire Public Utilities Commission Staff's First Set of Data Requests numbered Staff 1-1 and Staff 1-3 by Christopher A. Kahl, George H. Simmons and Francis X. Wells in the above-referenced docket.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

George H. Simmons

George H. Simmons Jr.

Enclosures

cc: Stephen Frink, NH PUC
Robert Wyatt, NH PUC
Amanda Noonan, NH PUC
Rorie Hollenberg, Consumer Advocate
Susan, Geiger, Esq.

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Date Request Received: 04/06/12 Date of Response: 04/16/12
Request No. Staff 1-1 Witness: Francis X. Wells

Request

Re. Chris Kahl's testimony, page 7, beginning at line 6, and Schedules 1A and 21 of the COG filing.

a. Describe the primary factors that have caused the company to change the annual fixed costs from the MPR (Schedule 21), normally set with each peak COG filing, have been revised in this off-peak filing.

b. Provide a summary of a) how actual fixed demand costs have been allocated between the two divisions each month, beginning with November 2011 supply resource invoices, b) how actual fixed demand costs will be allocated between the two divisions after the change, and c) when this change in allocations will occur.

c. Re. Schedule 1A, page 2, line 76. The annual Cap. Rel. and Asset Mgt. credits, net of PNGTS expense of $2,405,780 does not match Schedule 21, Lines 88 + 89. Explain why the amounts are not the same. Should Schedule 21, line 90 also be included in this amount in Schedule 1A, line 76?

d. Provide details of specific costs and credits that contribute to the increase in Schedule 1A, line 76, from $1,612,415 (revised peak period COG filing in DG 11-207) to $2,405,780 in the current off-peak COG filing

Response:

a. Northern elected to update its annual demand cost forecast for the period November 2011 through October 2012 due to updated information on TransCanada demand tolls. Specifically, the Canadian National Energy Board approved 2012 Interim Tolls at the 2011 Final Tolls rate, reflecting projected lower annual demand costs equal to $1.9 million on a total company basis. The purpose of the annual demand cost forecast update is to recalculate the allowed demand cost recovery for the 2012 Summer COG to account for the lower expected TransCanada demand costs. The Northern rate model is unable to recalculate the allowed demand cost recovery for the summer period without also recalculating the MPR.

b. Fixed demand costs are allocated to the 12 months of the year by the PR allocator which is established in the prior Winter Season Cost of Gas (COG) proceeding. For the period November 2011 through October 2012, the allocator

Date Request Received: 04/06/12 | Date of Response: 04/16/12
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was derived in the 2011/2012 Winter Season COG; 52.62% for the Maine Division and 47.38% for the New Hampshire Division. However, due to the lag between the activity and billing periods, November 2011 invoices are based on October 2011 activity and, therefore, on the prior year's PR allocator. A summary of the allocation of demand costs for November 2011 through March 2012 is provided in Attachment Staff 1-1 at Line 20. For May 2012 through October 2012, there is no change to the PR allocator.

c. The sum of Lines 88 and 89, on Schedule 21, equals ($2,065,226). This credit represents the total amount of capacity release and asset management revenue expected during the Winter Period. The amount listed on line 76 of Schedule 1A, ($2,405,780) represents the amount of capacity release and asset management revenue net of PNGTS litigation costs to be recovered from sales customers only during the Winter Period. Thus, these amounts will not be the same due to the assigned portion of these revenues and costs to third party providers. In the 2011/2012 Winter Period filing, this is illustrated in Schedule 1A, page 6 of 6. However, in the 2012 Summer Period filing, page 6 in Schedule 1A is not included in the filing because capacity release revenues are not collected in the Summer Period.

d. The amount listed on Line 76 of Schedule 1A is incorrect. It should be the same as the amount shown in the 2011 /2012 Winter Period filing, ($1,612,415). However, as mentioned above, because this is the Summer Period, this discrepancy has no impact on the cost of gas.

Northern Utilities, Inc.
Gas Supply Demand Allocation Summary
Invoices Paid since November 1, 2011

Line	Invoices Paid	Reference	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
1	Transportation Demand	General Ledger	$ 2,189,710	$ 4,674,609	$ 3,697,547	$ 5,718,874	$ 4,683,870
2	Supply Demand	General Ledger	$ 224,516	$ 74,750	$ 115,826	$ 183,343	$ 197,590
3	Storage Demand	General Ledger	$ 255,167	$ 253,046	$ 253,011	$ 253,010	$ 191,460
4	Total Demand	Sum Lines 1 through 3	$ 2,669,394	$ 5,002,405	$ 4,066,384	$ 6,155,227	$ 5,072,920
5							
6	Granite Demand Invoice	General Ledger	$ 310,000	$ 310,000	$ 310,000	$ 310,000	$ 310,000
7							
8	Month of Service	Note 1.	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
9	NH Demand Allocator	Note 2.	47.38%	47.38%	47.38%	47.38%	47.38%
10							
11	NH Allocated Granite Demand	Line 9 times Line 6	$ 146,878	$ 146,878	$ 146,878	$ 146,878	$ 146,878
12							
13	Non-Granite Demand Invoice						
14	Transportation Non-Granite Demand	Line 1 minus Line 11	$ 1,879,710	$ 4,364,609	$ 3,387,547	$ 5,408,874	$ 4,373,870
15	Supply Demand	Line 2	$ 224,516	$ 74,750	$ 115,826	$ 183,343	$ 197,590
16	Storage Demand	Line 3	$ 255,167	$ 253,046	$ 253,011	$ 253,010	$ 191,460
17	Total Non-Granite Transport Demand	Sum Lines 14 through 16	$ 2,359,394	$ 4,692,405	$ 3,756,384	$ 5,845,227	$ 4,762,920
18							
19	Month of Service	Note 3.	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12
20	NH Demand Allocator	Note 4.	48.64%	47.38%	47.38%	47.38%	47.38%
21							
22	NH Allocated Non-Granite Transport Demand	Line 20 times Line 14	$ 914,291	$ 2,067,952	$ 1,605,020	$ 2,562,725	$ 2,072,340
23	NH Allocated Supply Demand	Line 20 times Line 15	$ 109,205	$ 35,417	$ 54,878	$ 86,868	$ 93,618
24	NH Allocated Storage Demand	Line 20 times Line 16	$ 124,113	$ 119,893	$ 119,877	$ 119,876	$ 90,714
25	NH Allocated Non-Granite Demand Cost	Sum Lines 22 through 24	$ 1,147,609	$ 2,223,262	$ 1,779,775	$ 2,769,469	$ 2,256,672
26							
27	NH Allocated Transport Demand	Line 11 plus Line 22	$ 1,061,169	$ 2,214,830	$ 1,751,898	$ 2,709,603	$ 2,219,218
28	NH Allocated Supply Demand	Line 23	$ 109,205	$ 35,417	$ 54,878	$ 86,868	$ 93,618
29	NH Allocated Storage Demand	Line 24	$ 124,113	$ 119,893	$ 119,877	$ 119,876	$ 90,714
30	Total NH Allocated Demand Cost	Sum Lines 27 through 29	$ 1,294,487	$ 2,370,140	$ 1,926,653	$ 2,916,347	$ 2,403,550
31							
32	NH Recorded Transport Demand	General Ledger	$ 1,061,169	$ 2,214,830	$ 1,751,898	$ 2,709,603	$ 2,219,218
33	NH Recorded Supply Demand	General Ledger	$ 109,205	$ 35,417	$ 54,878	$ 86,868	$ 64,455
34	NH Recorded Storage Demand	General Ledger	$ 124,113	$ 119,893	$ 119,877	$ 119,876	$ 119,877
35	Total NH Recorded Demand Cost	Sum Lines 32 through 34	$ 1,294,487	$ 2,370,140	$ 1,926,653	$ 2,916,347	$ 2,403,550
36							
37	NH Transport Demand Variance	Line 27 minus Line 32	$ (0)	$ -	$ (0)	$ (0)	$ 0
38	NH Supply Demand Variance	Line 28 minus Line 33	$ -	$ -	$ -	$ -	$ 29,163
39	NH Storage Demand Variance	Line 29 minus Line 30	$ -	$ (0)	$ -	$ -	$ (29,163)
40	Total NH Demand Cost Variance	Line 30 minus Line 35	$ (0)	$ (0)	$ (0)	$ (0)	$ 0
41							

42 Note 1: Granite Invoices are paid via inter-company transfer during the month of service.

43 Note 2: NH Demand Allocator for October 2011 approved by Commission in Docket No. DG 10-250. NH Demand Allocator for November 2011 through October 2012 approved by Commission in Docket No. DG 11-207.

44 Note 3: Invoices for non-Granite service are typically paid in the month following service.

45 Note 4: NH Demand Allocator for November 2011 through October 2012 approved by Commission in Docket No. DG 11-207.

Date Request Received: 04/06/12 | Date of Response: 04/16/12
Request No. Staff 1-3 | Witnesses: Christopher A. Kahl and George H. Simmons Jr

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Request

Re. Kahl testimony, pages 16-18. Allocation adjustments related to company managed resource cost allocations between Northern's Maine and NH divisions.

a. Provide supporting data and documentation for the adjustments line in Schedule 4, page 1, of the 2011 Off-Peak COG reconciliation.

b. Have these adjustments been audited by either the Maine or NH PUC audit staffs?

c. Provide additional background related to when this first became a cost allocation issue, how and when it was discovered. Include the referenced Nisource written instructions to Unitil related to cost allocations between the Maine and NH divisions.

d. Provide data and spreadsheet analysis showing the historical cost allocation errors by month and the overall impact on cost of gas rates to Northern's NH division. Include the dollar amount and time frame that Northern proposes to pay back to NH rate-payers the costs related to this cost allocation error.

Response:

a. Attachment Staff 1-3 (a) includes support for the monthly Allocation Adjustments appearing in Schedule 4, page 1, of the Revised 2011 Summer Season COG Reconciliation. For the 12-months ended October 2011, these monthly Allocation Adjustments total $10,385.

b. The NH PUC Staff is currently auditing Northern's New Hampshire Division Revised 2011 Summer Season COG Reconciliation which includes specific monthly Allocation Adjustments. The ME PUC Staff has completed its review of Northern's Maine Division 2012 Off-Peak Period CGF Filing. That filing includes the Company's Revised 2011 Off-Peak Period CGF Annual Reconciliation which includes similar, but opposite, Allocation Adjustments totaling ($10,385).

c. Before beginning the complex task of integrating specific data from the NiSource to Unitil accounting systems, due to differences in software, personnel and accounting practices, NiSource forwarded and explained to Unitil specific instructions on how to account for various items in going from bills to books,

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including the recovery of Northern's gas costs. These instructions are included as Attachment Staff 1-3 (b), "Northern Utilities Revenue – From Bills to Books". As shown on page 10 of these instructions, "Company Managed volumes from invoice detail (should include) NH (volume) only". Since acquiring Northern, Unitil has followed these instructions.

During Spring 2011, Northern began questioning why the monthly divisional commodity cost allocator included only NH Company managed volume. In researching this issue, it was discovered monthly Allocation Adjustments to commodity costs in annual Cost of Gas reconciliations had been previously discussed/submitted in the 2008 Peak/Winter Period/Season CGF/COG filings made by NiSource to the Maine/New Hampshire PUCs before the sale of Northern to Unitil. See Attachment Staff 1-3 (c), Transcript from the Maine PUC proceeding at pages 45-64. Based on this investigation, Northern concluded the NiSource instructions were outdated, and in November 2011, Northern began including Company managed volumes for both divisions in its monthly commodity cost allocator in order to appropriately assign the Company's commodity costs between the Maine and New Hampshire Divisions. The reason for this adjustment is as follows:

Basically, Northern's gas supply and related commodity contracts serve both Divisions. Each month, the associated commodity costs by contract are aggregated and assigned to the Divisions based on their respective current or prior month sales volume adjusted for Company use and lost and unaccounted for volumes. Company managed sales are made using Northern's gas supply commodity contracts. Thus, Company managed sales volume from both Divisions should be included in the derivation of the Company's monthly commodity cost allocator to better track cost causation. Further, as shown on page 11 of the NiSource instructions, Unitil was instructed to include in its gas cost recovery mechanism revenue from Company managed sales. Since Company managed revenue dollars are credited to Division-specific commodity gas costs, then it is fair and equitable to include Company managed sales volume for both Divisions in the monthly commodity cost allocator.

d. As stated in response to c, above, since November 2011, Northern has included both New Hampshire and Maine Division Company managed volume in the derivation of its divisional monthly commodity cost allocator. Thus, on a going-forward basis, there is no need for future monthly Allocation Adjustments related to this issue. However, because the upcoming 2011-2012 New Hampshire Division Winter Season COG Reconciliation to be submitted in July 2012 will include the period May 2011 through April 2012, the Company's preliminary analysis at this time expects to include Allocation Adjustments for the months May 2011 through October 2011 totaling $8,288. See Attachment Staff 1-3 (d).

As requested by the NH PUC Staff at the April 9, 2012 technical session in this proceeding, for the 2010-2011 Winter Season COG Reconciliation, an overall Allocation Adjustment impact of ($1,904,666) for the May 2010 through April 2011 period would have been included in the derivation of Northern's New Hampshire Division COG gas rates if the monthly divisional commodity cost allocators included Maine Division Company managed volumes. See Attachment Staff 1-3 (e).

Northern's proposal in this 2012 Summer Season COG proceeding is to include monthly Allocation Adjustments in its 2011 New Hampshire Division Summer Season COG Reconciliation of $10,385. The Company is not proposing to make any other adjustments from more distant, prior and accepted Summer (or Winter) Season COG Reconciliations using the updated method of allocating monthly commodity costs to the divisions. This proposal is consistent with prospective seasonal rates reflecting adjustments for expenses/credits applied during the reconciliation of the prior year's respective season.

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Off Peak Period

Line No.	Description	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
1	**Costs allocated on Current Month Ratios:**														
2	**Withdrawal Charges**														
3	NH Division		(5,102)	-	-	-	-	-	(529)	752	(297)	775	(2,678)	(137)	(7,216)
4	ME Division		(4,832)	-	-	-	-	-	(463)	638	(269)	681	(2,345)	(134)	(6,723)
5	**ATV Reconciliation Charges**														
6	NH Division		-	-	-	-	-	-	90,239	18,793	3,583	(17,344)	6,329	41,345	142,946
7	ME Division		-	-	-	-	-	-	79,002	15,938	3,242	(15,246)	5,541	40,478	128,955
8	**Net OBA Adjustment**														
9	NH Division		-	-	-	-	-	-	3,291	(8,977)	(8,710)	988	2,973	(10,532)	(20,967)
10	ME Division		-	-	-	-	-	-	2,881	(7,613)	(7,880)	993	2,602	(10,312)	(19,328)
11	**LNG Boiloff**														
12	NH Division		-	-	-	-	-	-	5,900	4,436	6,889	5,731	6,764	4,524	34,244
13	ME Division		-	-	-	-	-	-	5,165	3,762	6,233	5,038	5,922	4,429	30,549
14	Subtotal - Costs allocated on Current Month Ratios														
15	NH Division - Lines 3+6+9+12		(5,102)	-	-	-	-	-	98,901	15,005	1,465	(9,850)	13,388	35,199	149,007
16	ME Division - Lines 4+7+10+13		(4,832)	-	-	-	-	-	86,585	12,726	1,325	(8,533)	11,720	34,461	133,453
17															
18	**Costs allocated on Prior Month Ratios:**														
19	**Vendor Payments**														
20	NH Division		729,333	3,974	-	-	-	-	-	926,656	596,671	602,670	611,700	540,845	4,011,849
21	ME Division		690,457	3,763	-	-	-	-	-	811,257	506,029	545,273	537,680	473,493	3,567,952
22	**Non-Traditional Sales**														
23	NH Division		(69,697)	-	-	-	-	-	-	(340,132)	(164,840)	(283,329)	(162,598)	(170,241)	(1,190,837)
24	ME Division		(66,006)	-	-	-	-	-	-	(297,775)	(139,799)	(256,345)	(142,923)	(149,041)	(1,051,888)
25	**Transportation Charges**														
26	NH Division		14,248	(24,452)	-	-	-	2,535	-	1,394	(6,202)	-	2,017	(5,696)	(16,157)
27	ME Division		13,493	(21,476)	-	-	-	2,046	-	1,221	(5,259)	-	1,773	(4,987)	(13,190)
28	Subtotal - Costs allocated on Prior Month Ratios														
29	NH Division - Lines 20+23+26		673,884	(20,479)	-	-	-	2,535	-	587,918	425,629	319,341	451,119	364,908	2,804,855
30	ME Division - Lines 21+24+27		637,944	(17,713)	-	-	-	2,046	-	514,703	360,971	288,928	396,530	319,466	2,502,874
31															
32	**Commodity Costs Requiring Adjustment:**														
33	**NH Division - Lines 15+29**		**668,782**	**(20,479)**	**-**	**-**	**-**	**2,535**	**98,901**	**602,923**	**427,094**	**309,491**	**464,506**	**400,107**	**2,953,862**
34	**ME Division - Lines 16+30**		**633,112**	**(17,713)**	**-**	**-**	**-**	**2,046**	**86,585**	**527,428**	**362,296**	**280,395**	**408,251**	**353,926**	**2,636,327**
35															
36	**Updated Ratios:**														
37	NH Ratio	51.35%	49.04%	44.94%	48.99%	50.09%	49.75%	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	
38	ME Ratio	48.65%	50.96%	55.06%	51.01%	49.91%	50.25%	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	
39															
40	**Reallocated Costs based on Current Month ratios:**														
41	NH Division - Lines 15 x 37 (current month allocator)		(4,871)	-	-	-	-	-	99,254	15,061	1,471	(9,820)	13,438	35,339	149,870
42	ME Division - Lines 16 x 38 (current month allocator)		(5,062)	-	-	-	-	-	86,232	12,670	1,320	(8,563)	11,670	34,322	132,590
43	**Reallocated Costs based on Prior Month Ratios:**														
44	NH Division - Lines 29 x 37 (prior month allocator)		673,624	(18,729)	-	-	-	2,279	-	590,012	427,203	320,558	452,814	366,277	2,814,037
45	ME Division - Lines 30 x 38 (prior month allocator)		638,204	(19,462)	-	-	-	2,302	-	512,608	359,398	287,711	394,835	318,097	2,493,693
46															
47	**Adjusted Commodity Costs:**														
48	**NH Division - Lines 41+44**		**668,752**	**(18,729)**	**-**	**-**	**-**	**2,279**	**99,254**	**605,073**	**428,673**	**310,738**	**466,252**	**401,615**	**2,963,907**
49	**ME Division - Lines 42+45**		**633,142**	**(19,462)**	**-**	**-**	**-**	**2,302**	**86,232**	**525,278**	**360,718**	**279,148**	**406,505**	**352,418**	**2,626,282**
50															
51	**Allocation Adjustment (before Hedging):**														
52	**NH Division - Lines 48 - 33**		**(30)**	**1,750**	**-**	**-**	**-**	**(256)**	**352**	**2,150**	**1,579**	**1,246**	**1,746**	**1,508**	**10,045**
53	**ME Division - Lines 49 - 34**		**30**	**(1,750)**	**-**	**-**	**-**	**256**	**(352)**	**(2,150)**	**(1,579)**	**(1,246)**	**(1,746)**	**(1,508)**	**(10,045)**
54															
55	**Hedging Adjustment (separate analysis):**														
56	**NH Division**		-	-	-	-	-	-	83	-	-	-	-	256	340
57	**ME Division**		-	-	-	-	-	-	(83)	-	-	-	-	(256)	(340)
58															
59	**Allocation Adjustment:**														
60	**NH Division - Lines 52 + 56**		**(30)**	**1,750**	**-**	**-**	**-**	**(256)**	**436**	**2,150**	**1,579**	**1,246**	**1,746**	**1,764**	**10,385**
61	**ME Division - Lines 53 + 57**		**30**	**(1,750)**	**-**	**-**	**-**	**256**	**(436)**	**(2,150)**	**(1,579)**	**(1,246)**	**(1,746)**	**(1,764)**	**(10,385)**

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				
November 30, 2010	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	2,292,202		1,968,903		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.047		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	229,220	-	206,144	435,364	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	37		456	493	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	229,257		206,600	435,858	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	231,458		208,976	440,434	
Plus: Co-Managed (DTH)	8,269		40,172		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	239,727		249,148	488,875	
Commodity Allocation (Variable)	49.04%		50.96%	100%	

* NOTE: The INPUTS tab feeds this one *

	New Hampshire	Maine
Original	53.24%	46.76%
Change	-4.20%	4.20%

Northern Utilities

December 31, 2010

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	4,040,136		3,711,389		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.042		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	404,014	-	386,727	790,740	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	85		732	817	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	404,099		387,459	791,558	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	407,978		391,914	799,893	
Plus: Co-Managed (DTH)	78,355		204,028		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	486,333		595,942	1,082,276	
Commodity Allocation (Variable)	44.94%		55.06%	100%	

* NOTE: The INPUTS tab feeds this one *

	New Hampshire	Maine
Original	55.22%	44.78%
Change	-10.28%	10.28%

Northern Utilities
January 31, 2011

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

Converted revenue JE's must be posted.

	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	6,341,088		5,204,975		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.048		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	634,109	-	545,481	1,179,590	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	145		1,162	1,307	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	634,254		546,643	1,180,897	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	640,343		552,930	1,193,273	
Plus: Co-Managed (DTH)	91,811		209,466		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	732,154		762,396	1,494,550	
Commodity Allocation (Variable)	48.99%		51.01%	100%	

* NOTE: The INPUTS tab feeds this one *

	New Hampshire	Maine
Original	56.81%	43.19%
Change	-7.82%	7.82%

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
February 28, 2011	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	6,777,765		5,747,567		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.051		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	677,777	-	604,069	1,281,846	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	141		1,488	1,629	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	677,918		605,557	1,283,475	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	684,426		612,521	1,296,947	
Plus: Co-Managed (DTH)	76,612		145,645		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	761,038		758,166	1,519,204	
Commodity Allocation (Variable)	50.09%		49.91%	100%	

* NOTE: The INPUTS tab feeds this one *

	New Hampshire	Maine
Original	55.23%	44.77%
Change	-5.14%	5.14%

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
March 31, 2011	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	5,326,532		4,476,233		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.052		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	532,653	-	470,900	1,003,553	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	104		1,166	1,270	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	532,757		472,066	1,004,823	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	537,871		477,494	1,015,366	
Plus: Co-Managed (DTH)	57,793		124,173		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	595,664		601,667	1,197,332	
Commodity Allocation (Variable)	49.75%		50.25%	100%	

* NOTE: The INPUTS tab feeds this one *

Original	55.33%	44.67%
Change	-5.58%	5.58%

Northern Utilities
April 30, 2011
* DO NOT DIVIDE BY 10 on line 4 *

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

	New Hampshire		Maine	NU TOTAL
Billed Sales - Therm/CCF	3,955,400		3,357,642	
Conversion Factor for Dth	10		10	
ME BTU Conversion Factor:			1.054	
Tariff Sales Volumes DTH - -	395,540	-	353,895	749,435
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	76		858	934
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	395,616		354,753	750,369
Lost and Unaccounted for Estimate	1.0096		1.0115	
Subtot Volumes (DTH) - for Commodity Allocation	399,414		358,833	758,247
Plus: Co-Managed (DTH)	2,786		-	
Adj Volumes (DTH) - for Commodity Allocation	402,200		358,833	761,033
Commodity Allocation (Variable)	52.85%		47.15%	100%

Converted revenue JE's must be posted.

per G_NU_N_REV & G_NU_M_REV;
page: ME(NH) NON External Supplied (do NOT include External Supply)
line Total Consumption; column Total Billed CIS Revenue

* Do NOT include INTERRUPTIBLE units on line 4 *

* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *

Per NU Cost of Gas Proceedings - Energy Contracts

see tab *Co. mgd gas*

* NOTE: The INPUTS tab feeds this one *

	New Hampshire	Maine
Original	52.65%	47.35%
Change	0.20%	-0.20%

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
May 31, 2011	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	2,045,773		1,724,159		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.027		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	204,577	-	177,071	381,648	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	31		327	358	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	204,608		177,398	382,007	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	206,573		179,438	386,011	
Plus: Co-Managed (DTH)	-		-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	206,573		179,438	386,011	
Commodity Allocation (Variable)	53.51%		46.49%	100%	

* NOTE: The INPUTS tab feeds this one *

	New Hampshire	Maine
Original	53.32%	46.68%
Change	0.19%	-0.19%

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
June 30, 2011	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	1,337,725		1,062,322		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.057		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	133,773	-	112,287	246,060	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	29		75	104	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	133,802		112,362	246,164	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	135,086		113,655	248,741	
Plus: Co-Managed (DTH)	-		-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	135,086		113,655	248,741	
Commodity Allocation (Variable)	54.31%		45.69%	100%	

* NOTE: The INPUTS tab feeds this one *

Original	54.11%	45.89%
Change	0.20%	-0.20%

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
July 31, 2011	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	916,318		774,456		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.058		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	91,632	-	81,937	173,569	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	22		165	187	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	91,654		82,102	173,757	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	92,534		83,047	175,581	
Plus: Co-Managed (DTH)	0		-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	92,534		83,047	175,581	
Commodity Allocation (Variable)	52.70%		47.30%	100%	

* NOTE: The INPUTS tab feeds this one *

Original	52.50%	47.50%
Change	0.20%	-0.20%

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
August 31, 2011	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	771,977		635,947		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.055		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	77,198	-	67,092	144,290	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	21		119	140	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	77,218		67,211	144,430	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	77,960		67,984	145,944	
Plus: Co-Managed (DTH)	0		-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	77,960		67,984	145,944	
Commodity Allocation (Variable)	53.42%		46.58%	100%	

* NOTE: The INPUTS tab feeds this one *

Original	53.22%	46.78%
Change	0.20%	-0.20%

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
September 30, 2011	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	871,128		738,866		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.052		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	87,113	-	77,729	164,842	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	2,740		166	2,906	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	89,853		77,895	167,747	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	90,715		78,790	169,506	
Plus: Co-Managed (DTH)	0		-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	90,715		78,790	169,506	
Commodity Allocation (Variable)	53.52%		46.48%	100%	

* NOTE: The INPUTS tab feeds this one *

Original	53.32%	46.68%
Change	0.20%	-0.20%

Northern Utilities
October 31, 2011

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

Converted revenue JE's must be posted.

	New Hampshire		Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	1,016,794		938,589		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10		10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:			1.049		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	101,679	-	98,458	200,137	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	102		201	303	
Less: Interruptible (DTH)	0				see tab *Co. mgd gas*
Subtotal - Deliveries and Company Use	101,781		98,659	200,440	
Lost and Unaccounted for Estimate	1.0096		1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtot Volumes (DTH) - for Commodity Allocation	102,758		99,794	202,552	
Plus: Co-Managed (DTH)	0		-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	102,758		99,794	202,552	
Commodity Allocation (Variable)	50.73%		49.27%	**100%**	

* NOTE: The INPUTS tab feeds this one *

	New Hampshire	Maine
Original	50.53%	49.47%
Change	0.20%	-0.20%

Northern Utilities Revenue - - From Bills to Books

NH – THERMS on Financial Statements in DTH
ME – CCF on Financial Statements in MCF

Customer Types

- Residential – single family dwelling
- Commercial – single meter in commercial activities: apartment buildings, offices, stores, schools, hospitals, etc.
- Industrial – using gas primarily in a process which involves extraction of raw materials through use of heat, etc. (Manufacturing)

CIS (Customer Information System)

- All Bay State/Northern Utilities customers are billed through CIS
- Records all customer revenues and volumes
- Tariff and CHOICE customers are billed on billing cycles while Transportation customers are billed in a calendar month (this comes through CIS on a one month lag)

Tariff Sales

- Sales Service
- Billed by CIS
- Company provides both commodity (cost of gas) and delivery service to the customer

Transportation Service

- Traditional Transportation & CHOICE (Marketers)
- Customers obtain their own supply of gas (from a Marketer) but Bay State delivers the commodity
- Gas sometimes obtained from the Marketer at a cheaper rate than the average CGA (Cost of Gas Adjustment) rate – the rate at which Bay State sells it's gas for
- Customers who use over 250,000 (Mass) or 85,000 (NH & ME) Therms a year are daily metered – (mostly the Marketers)

CHOICE Program

- Customer may select their supplier of gas from participating marketers.
- Bay State/Northern Utilities still obligated to serve if the Marketer cannot deliver (provider of last resort).
- Customer eligibility: customers using less than 250,000 (Mass) & 85,000 Therms per year.
- ME is the only Northern jurisdiction in which customers are daily metered.
- Customers are billed all service charge rates (base rates) and all applicable LDAC rates.
- Customers are billed on a normal billing cycle through the CIS system.

CHOICE Marketers

- In New Hampshire, suppliers are required to pay per customer fees for billing and administration.
- Marketers can be subjected to penalties for under-delivery, banking imbalances, etc. Neither Maine nor New Hampshire is allowed to retain any of the transportation penalties. All penalty revenue is to be passed-back (or recovered from) the customer.

Billing

- Customer Charge – flat amount billed monthly regardless of usage
- Base Rate – reflects cost of service; this is where we are allowed to make a profit, though not much (typically around 12%)

- CGA rate – recovered from customers \$1 for \$1; no profit
  - GAF (Gas Adjustment Factor) – broken down between demand and commodity

New Hampshire GAF		Maine GAF
DEMAND		**DEMAND**
Demand Gas Cost		Demand Gas Cost
Reconciliation Adj.		Reconciliation Adj.
Production & Storage		Production & Storage
Capacity Reserve Charge		Demand Working Capital
		Capacity Reserve Charge
		Stipulation Demand Charge
COMMODITY		**COMMODITY**
Commodity Gas Costs		Commodity Gas Costs
Reconciliation Adj.		Reconciliation Adj.
Working Capital		Commodity Working Capital
OTHER		**OTHER**
Bad Debt		Bad Debt
Supplier Refunds		Supplier Refunds
Miscellaneous Overhead		

  - NH - LDAC or ME - DAF (Local Distribution Adjustment Costs or Distribution Adjustment Factor)

New Hampshire LDAC		Maine DAF
DSM		DSM
ERC		ERC
RLIAP		

- Maine also bills for taxes on gas consumed

- All billed information is manually entered into the General Ledger from CIS (Schedule 15 – KBMCJ91-NIP2)
  - Total Billed Amount is:
    DR 142 Accounts Receivable
    CR 480/481 Tariff/CHOICE Revenue
    CR 484 Transportation Revenue

NORTHERN UTILITIES RECOVERIES:

RJ Journal 2007 - - Maine and New Hampshire Recovery of Gas Costs

The RJ 2007 journal records the recoveries for both New Hampshire and Maine. There are two key input elements for the recoveries voucher: 1) CGA recovery rates per Regulatory Accoutning – updated twice a year for the peak and off-peak filings (unless an interim rate filing is made) and 2) billed volumes from CIS – WD3 – Access Reports.

Volumes are inputted from the Access Reports on the NH and ME Sales Summary tabs. Rates are populated on the proper NH and ME rates tabs.

RJ Journal 2095 - - GAF/DAF Recovery Adj.

The purpose of the GAF/DAF Recovery Adj. journal voucher is to adjust the calculated recoveries to what was actually billed through the CIS billing system for the month. CIS billed recoveries are input into the Excel spreadsheet per the Access output by rate schedule (Schedule 15). The calculated recoveries are then inputted from what was recorded on the RJ 2007 journal.

NOTE: This journal cannot be completed until CIS (Schedule 15) and RJ 2007 has been completed and posted to the GL.

NORTHERN UTILITIES HEDGING ON GAS COSTS:

Hedging - - Method of minimizing price change. Since the movement of cash prices is usually in the same direction and about in the same degree as the movement of the present prices of futures contracts, any loss (or gain) resulting from carrying the actual merchandise is approximately offset by a corresponding gain (or loss) when the contract is liquidated. For more Hedging information see Hedging documentation (below).

RJ Journal 2000 - - FPO Deferred Entry

This journal entry records the current month hedging realized gains/losses as well as the current month hedging expenses and interest. For accounting purposes, these events need to be recognized in the month they occur. For regulatory purposes, the current month transactions relate to the following month purchase of gas. Therefore, the accounting group records the events on this journal in a reversing entry at a summary level.

If the dollar amount is Positive then the entry will be:
Debit 05BS-513605-034103 (Margin Deposit)
Credit 05420-519140-030905 (Deferred Hedging Costs)

If the dollar amount is Negative then the entry will be:
Debit 05420-519140-030905 (Deferred Hedging Costs)
Credit 05BS-513605-034103 (Margin Deposit)

RJ Journal 2005 - - Maine and New Hampshire Monthly Hedging Activity

In order to keep the cost of gas at a consistent level, the Commissions in both Maine and New Hampshire require the hedging of gas purchases. Each month a statement (P&L Report) is received from Risk Management Analyst (WD 1) showing the gains and losses as well as all the activity costs associated with these transactions. The profit (or loss) and associated fees are recorded. Note that the company is using short-term debt to finance these transactions, and the customers are charged back at the monthly short-term (Money Pool) interest rate for the cost of these transactions. This rate is obtained from the treasury end-of-the-month reports for the short-term borrowing funds. Costs are split using the current month's Commodity Allocation factor calculated in JE 2009. Total Gas Cost (Sch. 27) impact is to be keyed into the input tab of the RJ 2009 Excel file.

Northern Utilities - New Hampshire

FPO Futures Margin Account Detail

O:\Northern Gas Costs\Fy2007\Closing Worksheets\08 August\[JE 2005 - Gas Cost Hedging Impact 0807.xls]INPUTS

Beginning Margin Balance	$	1,039,619.40
Interest on Margin Deposit	$	1,317.61
Profit & (Loss) on Closed Trades	$	-
Monthly Transaction Costs	$	(83.06)
Total Monthly Activity	$	1,234.55
Ending Margin Balance	$	1,040,853.95

Journal Entries JE 2005 (NH):

			DR		CR
05BS 513605 034103	A/R Margin Deposits	$	1,234.55	$	-
05050 680704 080905	Hedging-Profit/Loss	$	-	$	-
05050 680705 080905	Hedging-Mgmt Fees and Margin Int.	$	-	$	1,234.55
05050 680705 080905	Hedging-Mgmt Fees and Margin Int.	$	5,088.14	$	-
05420 643107 071120	Interest Exp. - Misc.	$	-	$	5,088.14
		$	**6,322.69**	**$**	**6,322.69**
	Total Gas Cost Impact 680704/5 (Schedule 27):			**$**	**3,853.59**

Financial Hedge Accounting:

We are required to front money to a brokerage account. The intent of this account is to cover losses resulting from futures transactions.
DR 136 Temporary Cash Investments
    CR 131 Cash

A nominal transaction fee is incurred when the Company enters a Futures deal:
DR 807 Purchased Gas Expense
    CR 136 Temporary Cash Investments

Interest is earned monthly on the brokerage account:
DR 136 Temporary Cash Investments
    CR 807 Purchased Gas Expense

When the futures contract is settled for a gain, the following occurs:
DR 136 Temporary Cash Investments
    CR 807 Purchased Gas Expense

When the futures contract is settled for a loss, the following occurs:
DR 807 Purchased Gas Expense
    CR 136 Temporary Cash Investments

When the balance in the brokerage account needs to be increased, a "margin call is issued" and the following entry occurs:
DR 136 Temporary Cash Investments
    CR 131 Cash

NOTE: Each month before the futures contract settles, accounting is required to record a MTM entry (SFAS 133). This is not booked to the Over/Under (191) account but rather a regulatory asset/liability account (182/254) until the contract is settled.

NORTHERN UTILITIES OFF-SYSTEM SALES:

RJ Journal 2004 - - Maine and New Hampshire Off-System Sales

Off-System Sales - - Any point not on, or directly interconnected with, a transportation, storage, and/or distribution system operated by a natural gas company within a state.

This journal records the special deals revenue for the month. This information is provided in a spreadsheet received monthly from ESS/Gas Supply Analyst (WD 2). Neither ME nor NH get to keep any of the revenue from special deals. All revenue is credited to Gas Costs based on the current month's Commodity Allocation Factor spits. Special Deals include Off-System Sales, Asset Manager Deals, and Tank Rental Deals. RJ 2004 is located in the RJ 2009 Excel file – due to Gas Cost splits and links.

NORTHERN UTILITIES				Entry by:	T. Willis
JOURNAL ENTRY:	**2004**			Transaction Date:	09/26/07
JOURNAL ENTRY TITLE:	**Non-Traditional / Off-System Sales**			Accounting Period:	8
				Fiscal Year:	2007
Account Decsription:	SC DDS CCAT ACCT #		Debit	Credit	AUTO REVERSING
A/R 3rd Party Sales & Transp	90 05060 4101 514366		2,836.50		N
Supply Commodity	90 05060 0905 679925			0.00	N
Supply Commodity	90 06060 0905 679925			0.00	N
GSGT Supply Commodity	90 05060 0905 679922			0.00	N
GSGT Supply Commodity	90 06060 0905 679922			0.00	N
Non-Traditional Sales Margin	90 05060 0905 679861			1,601.86	N
Non-Traditional Sales Margin	90 06060 0905 679861			1,234.64	N
Bundled Revenue	90 05060 4102 648903			1,601.86	N
Bundled Revenue	90 06060 4102 648903			1,234.64	N
Bundled Service Expense	90 05060 4102 649505		0.00		N
Bundled Service Expense	90 06060 4102 649505		0.00		N
Bundled Margin	90 05060 4102 649506		1,601.86		N
Bundled Margin	90 06060 4102 649506		1,234.64		N
CONTROL TOTALS			**5,673.00**	**5,673.00**	

NORTHERN UTILITIES GAS COST ESTIMATE:

RJ Journal 2009 - - Maine and New Hampshire Gas Cost Estimate for the Current Month

The purpose of this journal is to record the monthly gas costs for NH and ME. This includes all current month natural gas purchase estimates, inventory (including LNG, LPG and underground storage) and related financing charges.

Note: NH bills in THERMS and records in DTH. ME bills in CCF and records in MCF.

ONLY cells in **BLUE** font in the RJ 2009 Excel file are inputs. All other cells are links or calculations.

INPUT Tab –

Inputs	Source	From	Day
Money Pool Rate (Short-term borrowing rate)	End-of-Month Daily Ops Report	Treasury	WD 2
PM Commodity Allocation Factor	Last Month's RJ 2009	--	WD -1
Fixed (Demand) Allocation Factor	Regulatory NOTE: Changes annually in November.	Regulatory Analyst	WD -1
Pipeline Conversion BTU Factor	Granite Unaccounted For Report	ESS/Gas Supply	WD 3
Company Use Margin Rates	Unbilled Rates Report	Financial Planning	WD -1
Company Use THERMS/CCF	Company Use Excel File	Company Use Volume Report – Information Technology	WD 3
LPG & LNG Electric Charges	CIS	Lawson (GL 90 or GL 290) - CIS	WD 4
Company Managed 672300	CIS	Lawson (GL 90 or GL 290) - CIS	WD 3
Hedging	RJ 2005 - PM P&L Statements	Lawson (GL 90 or GL 290) - CIS	WD 4

ALLOCATED VOLS Tab –

This tab in the file calculates the current month's split of Commodity Gas Costs between the two Northern Utilities divisions – Maine and New Hampshire. The split is derived using the calculation below:

Current Month Total Gas Cost Recovery Volumes
Plus: Company Use Volumes
Plus: Company Managed volumes from invoice detail (NH only)
Less: Interruptible Volumes
Plus: Unaccounted For Estimate (NH – 1% and ME 2%)

Input total New Hampshire recovery volumes (DTH) and total Maine recovery volumes (MCF) per RJ 2007 Recoveries journal (Sales Summary Tabs). The BTU Factor is linked to the INPUT tab – this is used to convert Maine's MCF to DTH.

SENDOUT ALLOC % Tab –

This tab is contains a history of the allocation factors (both variable (commodity) and fixed (demand)). Each month, a new line is created and the percentages are linked to the Input Tab.

SUPPLY:

DEMAND and COMMODITY GAS COST ESTIMATE Tabs –

Gas Cost estimates are supplied via e-mail by Energy Supply (ESS) Analyst on WD 2 in PDF format. Costs are inputted into the Demand and Commodity tabs by Gas Cost account.

NOTES:

1) LNG Purchases (679927 – as shown on the PDF Gas Cost Estimate-to-Actual) are not inputted into the estimate tabs. Current month LNG purchases are recorded to LNG Inventory (516452). *See LNG Inventory write-up below.*
2) LNG Purchases estimate/actual (dollars only) are to be subtracted from the Distrigas Supplier Commodity estimate (679925) as the purchase is recorded to Inventory (516452 LNG). From the Accounting analysis of the Distrigas estimate, it has been discovered that the Distrigas Supplier Commodity estimated costs for the month include the LNG purchase. Volumes are not impacted. The LNG purchase (both volumes and dollars) can be found in the estimate e-mail from Maureen.
3) DO NOT ENTER THE GRANITE ESTIMATES as per the Gas Supply PDF estimates. The Granite estimates are linked to the GRANITE BILL tab, which is received from Pipeline Accounting.

Input the Prior Month's true-up (adjustment-to-actual) as recorded on RJ 2001 for each Gas Cost account. This can be done by Lawson GL 90, GL 290 or retrieving the hardcopy of the journal.

Once CIS has been posted (WD 3), input the Company Managed dollars into the proper cells. This can be done by Lawson GL 90 or GL 290.

NOTE: Company Managed is posted through CIS on a one month lag.

Capacity Release/Capacity Mitigation (679943) for New Hampshire - the company is to retain a portion of these costs associated with Capacity Mitigation. This amount can be found on the supporting worksheet of the Capacity Mitigation Invoice Summary.

GRANITE BILL Tab –

Granite is an affiliate pipeline of the Bay State Companies. The Granite Bill tab is a duplicate of the Granite Bill received via e-mail from Pipeline Accounting. Input all volumes and costs as shown on the Granite Bill.

Gas Cost Estimate Entries:

DR 67XXXX or 68XXXX (Gas Cost Expense)

CR 523269-1000 (Gas Cost Payable) or 523451 (Granite Payable)

STORAGE:

Natural gas-a colorless, odorless, gaseous hydrocarbon-may be stored in a number of different ways – on pipeline system, underground in working storage facilities, or as above liquid form above-ground LNG/LPG tanks. Storage acts as a sort of buffer between the pipeline and distribution companies, and the marketers and endusers. The principal owners/operators of underground storage facilities are (1) interstate pipeline companies, (2) intrastate pipeline companies, (3) local distribution companies (LDCs), and (4) independent storage service providers. If a storage facility serves interstate commerce, it is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC); otherwise, it is state-regulated.

Two of the most important characteristics of an underground storage reservoir are its capacity to hold natural gas for future use and the rate at which gas inventory can be withdrawn-its deliverability rate. Efficient use of storage results in the ability to withdraw gas from storage in order to meet customer demands during peak use periods. Storage also facilitates sales of fixed quantities of natural gas on the spot market during off-peak periods. Northern Utilities use the Weighted Average Cost of Gas (WACOG) method for pricing inventory.

In the past, LDCs have generally used underground storage exclusively to serve customer needs directly. However, some LDCs have both recognized and been able to pursue the opportunities for additional revenues available with the deregulation of underground storage. Northern Utilities manages their facilities such that they can lease a portion of their storage capacity to third parties (often marketers) while still fully meeting their obligations to serve core customers. (Of course, these arrangements are subject to approval by the LDCs' respective state-level regulators.) Such arrangements are known as Asset Management Deals - Michcon. For example, marketers and other third parties may move gas into and out of storage (subject to the operational capabilities of the site or the tariff limitations) as changes in price levels present arbitrage opportunities. Further, storage is used in conjunction with various financial instruments (e.g. futures and options contracts, swaps, etc.) in ever more creative and complex ways in an attempt to profit from market conditions. These facilities can cycle their inventories-i.e., completely withdraw and refill working gas (or vice versa)-more rapidly than can other types of storage, a feature more suitable to the flexible operational needs of today's storage users.

See also Handout #6 - Washington BG Energy 10 prepaid deal.

LPG INVENTORY –

LPG (Liquefied Petroleum Gas) – A gas containing certain specific hydrocarbons which are gaseous under normal atmospheric conditions, but can be liquefied under moderate pressure at normal temperatures. Propane and butane are examples. LPG is manufactured during the refining of crude oil, or extracted from oil or gas streams as they emerge from the ground. At normal temperatures and pressures, LPG will evaporate. Because of this, LPG is supplied in pressurized steel bottles. In order to allow for thermal expansion of the contained liquid, these bottles are not filled completely; typically, they are filled to between 80% and 85% of their capacity. The pressure at which LPG becomes liquid, called its vapor pressure. Northern Utilities currently maintains one LPG storage facility in Portland, Maine.

PORTLAND, ME

Account: 06100 - 516404		GALLONS	DTH	MCF	AVG. COST	DOLLARS
BEG BALANCE LPG INVENTORY	**September 30, 2006**	**64,555**	5,922	5,629	$ 7.6559	**$ 45,338.18**
Actual Purchases for the Current Month - A/P	October-06	**0**	0	0	$ -	**$ -**
Actual Purchases for the Current Month - Manual	October-06	**9,501**	872	829	$ -	**$ 10,894.80**
PRIOR MONTH ACCRUAL	September-06	**0**	0	0	$ -	**$ -**
ACCRUAL CURRENT MONTH	October-06	**0**	0	0	$ -	**$ -**
TOTAL PURCHASES -	October-06	9,501	872	829	$ 12.4940	10,894.80
TOTAL LPG AVAILABLE @	**October 31, 2006**	**74,056**	**6,794**	**6,458**	**$ 8.2769**	**56,232.98**
LPG USAGE SUMMARY	**October 31, 2006**					
VAPORIZED		0	0	0	$ 8.2769	0.00
PROCESSED		0	0	0	$ 8.2769	0.00
MISCELLANEOUS		**1,333**	122	116	$ 8.2769	1,009.78
TOTAL USAGE	**October 31, 2006**	**1,333**	**122**	**116**	**$ 8.2769**	**1,009.78**
TOTAL ENDING LPG INVENTORY	**October 31, 2006**	**72,723**	**6,672**	**6,342**	**$ 8.2769**	**$55,223.20**

LPG Entries:

Purchase LPG (Injection):
DR 516404 (Portland LPG Inventory)
CR 513135 (NU Cash)

LPG Miscellaneous Injection Adjustment:
DR 516404 (Portland LPG Inventory)
CR 672300 (LPG Expense)

Liquefaction/Boil-off (Withdraws):
DR 672300 (LPG Expense)
CR 516404 (Portland LPG Inventory)

Electric Expense (This is recorded to the GL from CIS and re-classed):
DR 673500 (LPG Expense Miscellaneous – Electric)
CR 672335 (LPG Fuel Vaporized – Electric)

LNG INVENTORY –

LNG (Liquefied Natural Gas) – Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. LNG's intended use is for peaking supply requirements. Typically, 100% of the LNG commodity purchases are stored until needed. LNG purchases are made from one vendor, Distrigas. (The current month's LNG purchases are communicated via e-mail from the Gas Supply Analyst.) In addition to the commodity, there is a monthly LNG demand fee paid to Distrigas and trucking charges to Transgas (Transgas invoices are paid by Accounts Payable). (A GL90 or GL290 can be ran in Lawson to obtain the Transgas invoice information.) Northern Utilities uses its own facilities to convert LNG to salable natural gas during peak periods. This process is called vaporization. Boil-off is the unavoidable conversion of LNG to salable natural gas that occurs year-round. It results from the natural heating of the storage units. Northern Utilities captures the boil-off and uses it in system supply gas. Northern Utilities currently maintains one LNG facility in Lewiston, Maine.

NOTE: Per DPU 4240-78-A dated October 17, 1980, NU is permitted to include electricity used in the liquefaction processes in the CGA. This order deviates from the FERC guidelines. Per the order, "fuels and energy sources used in the liquefaction process and the cost of fuels and energy sources used to vaporize should be included in the cost of inventory."

Note: According to FERC guidelines, the 804.1 "Liquefied Natural Gas Purchases" account should include "the cost, including transportation, at point of receipt by the utility, of the liquefied natural gas purchased for the purpose of vaporization and injection into the utility's transmission or distribution system for resale".

Account: 06060 516452		DTH	MCF		AVG. COST	DOLLARS
BEGINNING BALANCE LNG INVENTORY	**September 30, 2006**	**5,696**	5,414	$	8.9981	**$ 51,253.08**
Actual Distribution Charges - A/P (Transgas)	October-06					$ -
Actual Purchases for the Current Month - A/P (Distrigas)	October-06	**0**	0	$	-	$ -
REVERSAL OF PRIOR MONTH ACCRUAL	September-06	**0**	0	$	-	$ -
ACCRUAL FOR CURRENT MONTH - Distrigas (per EASY Est.)	October-06	**7,400**	7,034	$	6.6077	$ 48,896.98
TOTAL PURCHASES:	October-06	7,400	7,034	$	6.6077	$ 48,896.98
TOTAL LNG AVAILABLE @	**October 31, 2006**	**13,096**	**12,449**	**$**	**7.6474**	**$ 100,150.06**
LNG USAGE SUMMARY (Lewiston):	**October 31, 2006**					
VAPORIZED		0	0	$	7.6474	$ -
BOIL-OFF		**1,075**	1,022	$	7.6474	$ 8,220.93
MISCELLANEOUS		**269**	256	$	7.6474	$ 2,057.14
SOLD		0	0	$	-	$ -
TOTAL USAGE	**October 31, 2006**	**1,344**	**1,278**	$	7.6474	**$ 10,278.07**
TOTAL ENDING LNG INVENTORY	**October 31, 2006**	**11,752**	**11,171**	**$**	**7.6474**	**$ 89,871.99**

LNG Entries:

Purchase LNG (Injection):

Establish accrual for LNG Purchase to recognize the purchase in the proper month. NOTE: This is a reversing entry.

DR 516452 (Lewiston LNG Inventory) – Reversing entry
  CR 523269-1000 (Gas Cost Payable) – Reversing entry

The following month the LNG Purchase is included on the Distrigas Gas Purchase Invoice. Thus the above entry is reversed and the dollars are moved from the Gas Cost Payable to the LNG Inventory Account. (This entry is done on the RJ 2001 – Adjustment-to-Actual journal voucher.)

DR 516452 (Lewiston LPG Inventory)
  CR 523269-1000 (Gas Cost Payable)

LNG Miscellaneous Injection Adjustment:

DR 516452 (Lewiston LNG Inventory)
  CR 675800 (LNG Expense)

Vaporized (Withdraws):
DR 676810 (Vaporization LNG Expense)
CR 516452 (Lewiston LNG Inventory)

Liquefaction/Boil-off (Withdraws):
DR 675800 (LNG Expense)
CR 516452 (Lewiston LNG Inventory)

Electric Expense (This is recorded to the GL from CIS and re-classed):
DR 677530 (LNG Expense Miscellaneous – Electric)
CR 676335 (LNG Fuel Vaporized – Electric)

UNDERGROUND STORAGE –

Underground Storage is the utilization of subsurface facilities for storing gas which has been transferred from its original location for the primary purposes of load balancing. The facilities are usually natural geological reservoirs such as depleted oil or gas fields or water-bearing sands sealed on the top by an impermeable cap rock. The facilities may be man-made or natural caverns. Northern Utilities maintains three Underground Storage facilities 2 with TETCO (Texas Eastern Transmission Company), 1 with TGP (Tennessee Gas Pipeline) and one Undergound Storage/Exchange facility with Michcon (Michigan Consolidated). Natural Gas is injected into storage April – October and withdrawn from storage November – March.

For Northern Utilities, Underground Storage is priced using the Weighted-Average-Cost-of-Gas (WACOG) method. Injections for the three Underground Storage facilities (2 – TETCO & 1 – TGP) are priced at the current month's average Supplier Commodity rate (less the Michcon Inventory purchase – typically from supplier NJR) found on the Commodity Estimate Tab. Michcon Exchange uses the purchase rate from the applicable supplier for the current month. All Underground Storage/Exchange use the same rate for the pricing-out of transportation charges on injections by using the average Transportation Commodity estimate rate for the current month. Withdraws are priced-out at the current month's WACOG rate.

Underground Storage information is received from Gas Supply Analyst (WD 3). Input injection and withdraw volumes into the Underground Storage Tab.

Underground Storage Entries:

Underground Storage/Exchange (Injection):

DR 516414, 15, 16 (Underground Storage) / 517404 (Michcon Exchange)

CR 680820 (Underground Storage Injection) / 680620 (Exchange Injection)

Underground Storage/Exchange (Withdraw):

DR 680810 (Underground Storage Injection) / 680610 (Exchange Injection)

CR 516414, 15, 16 (Underground Storage) / 517404 (Michcon Exchange)

Michcon Asset Manager Entries: Historical purposes only, no longer booking.

NORTHERN UTILITIES
Asset Manager

RJ 2901

Closing Month: **Sep-07**

Ending Inventory Injection/(Withdraw): **271,335**

Ending Inventory Rate for Michon: **$ 6.9039**
(per RJ 2009)

Entries:

	DR	CR
05BS-523269-0002-0905	$ -	$1,873,269.71
05BS-517404-0905	$1,873,269.71	$ -
05050-680610-0905	$ -	$1,873,269.71
05050-680610-0905	$1,873,269.71	$ -

Per Gas Supply Storage worksheet.

Michcon Inventory CM Ending WACOG (after current month injections/withdraws)

Michcon Asset Manager Entries:

DR (if Withdraw)	05BS-523269-0002 (Gas Cost Payable)
CR (if Injection)	05BS-523269-0002 (Gas Cost Payable)
CR (if Withdraw)	05BS-517404-1000 (Michon Inventory)
DR (if Injection)	05BS-517404-1000 (Michon Inventory)
DR/CR	05050-680610-0905 (Asset Manager Gas Cost)

CARRYING COSTS ON INVENTORY:

Carrying Costs: Interest forgone on money invested in inventory, storage cost, taxes and insurance.

Northern Utilities recovers carrying costs storage/inventory from its customers through its Gas Costs deferral process. Carrying Costs are calculated as follows:

Current Month's TOTAL Ending Inventory Balance
+ Prior Month's TOTAL Ending Inventory Balance
(Includes: LPG, LNG, Underground Storage/Exchange)
Inventory Subtotal / 2 =

Average Inventory Balance X Current Month's Money Pool rate =

Current Month's Inventory Carrying Costs

Inventory Carrying Costs are split between ME and NH Gas Costs using the Fixed (Demand) Allocation Factor.

Inventory Carrying Cost Entry:
DR 680723 (Interest on Financed Inventory Gas Cost)
CR 643107 (Interest Expense Miscellaneous)

INTERRUPTIBLE SALES AND MARGIN:

Interruptible Sales: Low priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the claim of firm service customers and higher priority users. Gas is available at any time of the year if the supply is sufficient and the system supply is adequate. Maine is allowed to retain 10% of profits from Interruptible Sales.

Emergency Interruptible Sales: Per Maine's tariff, Emergency Sales are Interruptible Sales made during the Peak months December- March. Maine is allowed retain all profit margin related with Emergency Interruptible Sales.

RJ 2026 - - Interruptible Revenue Adjustment

Interruptible Sales revenue is posted to the GL from CIS on WD 3. The Interruptible Sales revenue can be found by running a GL 90 or GL 290 on the Interruptible revenue account 648119 – ME and 648150 – NH. This should tie to the actual bill received from Billing Analyst on WD 3 or 4. If the actual bill does not tie to CIS, a separate journal is recorded (RJ 2026 – Interruptible Workpaper) to accrue for any revenue recognized as current month revenue, but not yet entered into CIS.

Interruptible Accrual Entry (RJ 2026):

DR 648119-ME or 648150-NH (Interruptible Revenue)

CR 514223 (AR Manual)

Note: This is a reversing entry.

After RJ 2026 is recorded, the total revenue is entered into RJ 2009 Interruptible tab (seen on next page). The volumes are also entered into the Interruptible tab from the Actual Interruptible bill Excel file.

On WD 4, the Interruptible Margin Memo is received from Gas Supply Analyst and keyed into the Interruptible tab.

RJ 2009 - - (Continued)

The purpose of the Interruptible tab is to calculated the Interruptible Costs for the month, as well as the Interruptible profit to be retained (this applies to Maine only).

Interruptible Costs are calculated as follows:

Total Current Month Interruptible Sales
Less: Interruptible Margin
Total Interruptible Costs

Interruptible Profit Margin to be retained for Maine is calculated as follows:

Total Interruptible Margin
X 10%
Maine Retained Profit Margin

Interruptible Journal Entries:

Interruptible Costs:

DR 679900 (Interruptible Costs Commodity)

CR 679925 (Supplier Commodity Gas Costs) – Deferred to 191

Interruptible Profits:

New Hampshire - -

DR 680007 (Gas Purchase Interruptible Profits due to Customers)

CR 679891 (Interruptible Sales Margin)

Maine - -

DR 680007 (Gas Purchase Interruptible Profits due to Customers)

CR 679891 (Interruptible Sales Margin)

CR 642175 (Interruptible Profits Retained)

Once all Interruptible entries have been recorded and posted to the GL, the MassCheck Report (131201B) is ran in Lawson to verify that Interruptible entries were properly recorded. If properly recorded, the MassCheck Report totals will be zero.

NORTHERN UTILITIES
Calculation of Firm Sales and Interruptible
Profits/Passback for the Month of **September-07**

INTERRUPTIBLE SALES DETAIL:

	New Hampshire		Maine			TOTAL NORTHERN	
	DTH	$	MCFs	DTH	$	DTH	$
Interruptible Sales	2	$26.25	7,081	7,577	$73,764.71	7,579	$73,790.96
Emergency Sales (DEC.-MAR.)	0	$0.00	0	0	$0.00	0	$0.00
Total Interruptible Sales	**2**	**$26.25**	**7,081**	**7,577**	**$73,764.71**	**7,579**	**$73,790.96**
%AGE OF INTERRUPT.	**0.03%**			**99.97%**		**100.00%**	

INTERRUPTIBLE PROFITS:

	TOTAL MARGIN (NH)	TOTAL MARGIN (ME)	TOTAL MARGIN
Per Kelly Esposito's Memo:	**$ 9.98**	**$ 27,925.63**	$ 27,935.61

	NH	ME	TOTAL NU
TOTAL INTERRUPTIBLE SALES (DTH)	2	7,577	7,579
TOTAL INTERRUPTIBLE PROFITS ($$)	$ 9.98	$ 27,925.63	$ 27,935.61
TOTAL INTERRUPTIBLE SALES ($$)	$ 26.25	$ 73,764.71	$ 73,790.96
TOTAL INTERRUPTIBLE COSTS ($$)	$ 16.27	$ 45,839.08	$ 45,855.35
TOTAL INT. EMERGENCY PROFITS ($$)	$ -	$ -	$ -
TOTAL INTERRUPTIBLE EMERGENCY SALES ($$)	$ -	$ -	$ -
TOTAL INTERRUPTIBLE EMERGENCY COSTS ($$)	$ -	$ -	$ -
TOTAL INTERRUPTIBLE MARGIN	$ 9.98	$ 27,925.63	$ 27,935.61
ME 10% INT. PM RETAINED (APRIL-NOV.)		$ 2,792.56	$ 2,792.56
TOTAL INTERR. & EMER. PASS-BACK	**$ 9.98**	**$ 25,133.07**	**$ 25,143.05**

TRANSPORTATION COSTS:

Transportation Service: The act of moving gas from a receipt point to a delivery point pursuant to a contract between the shipper and the transporter. To the extent the shipper has paid for guaranteed, high-priority capacity in the pipeline, that shipper is entitled to firm service.

The following transportation charges/revenue are recoverable (or are to be passed back) from customers through the CGA (Cost of Gas Allowable) filing:

- Cash-In/Cash-Out
- Firm Standby Gas Supply Service
- Firm Daily Delivery Service
- Surcharge Revenue
- Overrun Penalities
- Energy Charge Revenue

For Northern Utilities, recoverable/passback transportation revenues are recorded to revenue accounts on the GL by CIS (WD 3). Once CIS revenues are posted, a GL 90 or GL 290 can be ran on the Transportation revenue accounts. The dollars posted to the various revenue accounts are then entered on the RJ 2009 Transportation Elimination tab the **opposite sign** as was recorded to the account. Thus, when the entries are recorded, these dollars are moved to the proper Gas Cost accounts and included in the deferred process.

TRANSPORATION BILLING SUMMARY

September 30, 2007

Transportation Account/Description		N.H.		MAINE		NU TOTAL	MONTH
Firm Standby Gas Supply Service (648402)	$	-	$	12.00	$	12.00	Sep-07
Firm Daily Delivery Service (648403)	$	-	$	-	$	-	Sep-07
Transportation Surcharge Revenue (648408)	$	(45,069.60)	$	(33,601.89)	$	(78,671.49)	Sep-07
Overrun Penalty (648431)	$	1.30	$	8.87	$	10.17	Sep-07
Energy Charge Revenue (648461)	$	(13,330.78)	$	7,644.84	$	(5,685.94)	Sep-07
Total	$	(58,399.08)	$	(25,936.18)	$	(84,335.26)	

Obtain a copy of the most current NH and ME Income Statement. Intent is to move the Transportation Expense account balances to Gas Costs at the end of each month. In other words, input the opposite sign as is on the Income Statement.

Transportation Costs Journal Entries:
DR/CR 64XXXX (Transportation Revenue)
CR/DR 679849.2000 (Commodity Transportation Gas Cost)
CR/DR 679854 (Demand Transportation Charges)

SCHEDULE 27:

Schedule 27 is a composite of the total gas costs recorded by account for each of the jurisdictions – New Hampshire and Maine. All amounts are linked to other tabs within the Excel file. Schedule 27 serves several purposes: 1) to properly allocated gas costs to the proper 191 accounts for deferral – the Schedule 27 Peak and Off-Peak tabs are linked to the RJ 2010 Deferred Gas Costs workbook; 2) for the audit of NU Gas Costs by Deloitte & Touche external audit and 3) to aid Regulatory Accounting in the reconciliation of Gas Costs in their CGA filings.

Once RJ 2009 has been reviewed and signed-off by Regulatory Accounting (this is a SOX testing requirement), the journal can be keyed into Lawson. After the RJ 2009 journal has been posted to the General Ledger, an Income Statement check is performed by inputting the Total Gas Costs Before Recovery per the Lawson Income Statement into the Schedule 27 Total tab. If all entries have been properly recorded, the difference will be zero. This check verifies that the proper amounts will be deferred to the correct 191 accounts.

The Schedule 27 Adjustment tab is used to link any prior period Gas Cost Adjustment(s) to the proper Schedule 27 Peak or Off-Peak tab(s) as so they can properly be included in the deferral process.

Note: If Gas Costs are misrepresented on Schedule 27 and/or not properly recorded to the General Ledger, then the books will not be Perfectly Deferred.

Perfectly Deferred: Books are perfectly deferred when Total Gas Costs Before Recovery is equal to the Gas Costs deferred to the 191 (680506 – Gas Costs Deferred) – Income Statement check.

Once Northern Utilities is confirmed to be Perfectly Deferred, Financial Planning is notified as so they can perform their Revenue analysis. All Gas Cost information needs to be complete and submitted to Financial Planning for review no later than noon on Workday 5.

NORTHERN UTILITIES DEFERRED GAS COSTS:

RJ Journal 2010 - - Maine and New Hampshire Deferred Gas Costs

This journal voucher is to be completed after RJ 2009 and Gas Costs on Schedule 27 have been verified to tie to total Gas Costs per the Financial Statement.

The Recoveries Input Tab is populated from the recoveries recorded on the Recoveries RJ 2007-CM Recoveries and RJ 2095-CIS Billing Adjustment. The Prime Interest Rate is provided by Regulatory Analyst and the ST Borrowing (Money Pool) Rate is per Treasury.

The Linked CM Gas Costs tab is populated and linked to Schedule 27 Peak and Off-Peak tabs of the RJ 2009 Excel journal file. Update all links in **RED** font and input totals from the Schedule 27 tabs – this is to insure that all links have properly updated.

The P&S and MISC OVHD Projctn Input tab of the RJ 2010 is populated per the Regulatory projected collections found on the Accounting Rate sheet. These numbers are updated twice a year.

The Deferred Gas Costs tabs for NH and ME are linked to the recoveries, gas costs and projected collections tabs within the RJ 2010 file. The beginning balances for the 191 accounts are entered and verified from GL290's and with the Regulatory reconciliations. This tab is calculating the Over/Under 191 recovery for each 191 account as well as calculating the carrying costs on 191 to be recorded for the month.

The Wrk. Cap. Allowance Calc. tab calculates the Working Capital Allowance for the various 182 Working Capital accounts. Allowance percentages are provided by Regulatory Accounting. Projected collections are updated/linked per the P&S and MISC OVHD Projctn Input tab of the RJ 2010 file.

The Wrk. Cap. Deferred, Production & Storage Deferred, NH Misc. OVHD Deferred, and Bad Debt Deferred tabs are set up to calculated the Over/Under and Carrying Costs for each of the 182 accounts. Beginning balances are to be updated per GL290's and verified with Regulatory Accounting reconciliation totals. Allowance rates are provided by Regulatory Accounting and projected collections are updated per the P&S and MISC OVHD Projctn Input tab.

NORTHERN UTILITIES ESTIMATED VS. ACTUAL GAS COSTS:

RJ Journal 2001 - - True-up of Estimated to Actual Gas Purchase

Each month gas supply sends out EASY reports which reasonably estimate gas purchases for each month. These reports break down gas costs by account and the expense is recorded accordingly on the RJ 2009. The following month, when actuals are paid, gas supply provides accounting with a copy of the actual invoices and a report from EASY which breaks down the variance between the EASY estimated reports and the actual invoices, by account. Accounting uses the invoices to book the difference of the estimated vs. actual costs to the various gas cost accounts.

NORTHERN UTILITIES INTEREST ON SUPPLIER REFUNDS:

RJ Journal 2025 - - Supplier Refund Interest

NH uses Prime Interest Rate
ME uses Money Pool (Short-term Borrowing) Rate

Recovery is inputted from the calculated recoveries per RJ 2007.

Entries:
Debit 05/(6)420 643107 1120
Credit 05(6)420 524585 0905 Peak Refunds
Credit 05(6)420 524586 0905 Off-Peak Refunds

NORTHERN UTILITIES DSM INTEREST & INCENTIVE:

RJ Journal 2029 & 2030 – DSM Interest & Incentive

Demand Side Management (DSM) is a program set up to help reduce customers' usage by improving efficiencies. The NH and ME Commission requires the company to do this program, therefore we are allowed to recover all expenses that are associated with the program as well as a portion of LNR (Lost Net Revenue) that we experience due to the company's efforts to reduce customer usage.

Recovery is inputted from the calculated recoveries per RJ 2007. Incentive amounts are provided by DSM Regulatory Analyst.

Entries:
Debit 932.13 (DSM O&M Expense)
Debit 431 (DSM Interest)
Credit 176.39 (DSM Lost Net Revenue)

NORTHERN UTILITIES RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM:

RJ Journal 2900 - - RLIAP Discount Deferral

This entry is to establish a Regulatory Asset for the 60% reduction in heating base rate for delivery service for the Residential Low-Income Assistance Program for New Hampshire.

Inputs:
NH RLIAP Report - Customers SONP (from CIS) - KLCL06-01
Calculated recoveries from RJ 2007
Invoices recorded by AP (GL 90 or 290)
Interest rates per Regulatory Accounting

Entries:
Debit 05BS-518299-4103 (Residential Discount – Regulatory Asset)
Credit 05050-648699-4103 (Residential Discount – Net Revenue)
Credit 05050-643107-1121 (Residential Discount – Interest)

NORTHERN UTILITIES UNCHARGED TRANSPORTATION:

RJ Journal 2805 Uncharged Transportation – Cycle 22

This journal is to record the Uncharged Transportation from Cycle 22. This entry consists of monthly transportation revenue and volumes which were recorded in CIS but have not yet been recorded to the GL due to the Revenue cut-off posting. This entry is reversed the following month when revenues come through CIS.

Input:
Cycle 22 from CIS.

Entries:
Debit 05BS-648410-4102 (Uncharged Transportation)
Credit 05BS-517300-3412 (Accrued Revenues)

NORTHERN UTILITIES REGULATORY RE-CLASSES:

RJ Journal 2051 - - 191 Credit Re-class monthly

This journal entry re-classifies any credit balance regulatory 191 to the liability side of the balance sheet. This entry is made on a quarterly basis.

Entry:
Debit 519139
Credit 524239

RJ Journal 2605 - - Regulatory Asset Credit Re-class quarterly

This journal entry re-classifies any credit balance regulatory asset (182) to the liability side of the balance sheet. This entry is made on a quarterly basis.

Entry:
Debit 518260
Credit 525455

except for unbilled

RJ Journal 2071. Newington Meter Issue - ask Jeff Gore

It could be a marketer. It could be another utility. It doesn't have to be Bay State.

MS. MACLENNAN: Okay.

MR. DAFONTE: It just happened to work out with Bay State because of the existing agency and exchange agreement that Northern, Bay State, and Granite were part of.

MS. MACLENNAN: Okay. Okay, great. Thank you. I guess I may as well ask this question even though it occurs to me that it would have been better asked in the acquisition docket. But are there any capacity or commodity contracts that Northern holds that will become stranded, in effect, by the acquisition and spin-off to Unitil?

MR. DAFONTE: No, there won't.

MS. MACLENNAN: Okay. Good.

MS. SMITH: I think you might have asked something along those lines --

MS. MACLENNAN: Okay.

MS. SMITH: -- in the acquisition case. So --

MS. MACLENNAN: Okay.

MS. SMITH: You ready to move on to the other?

MS. MACLENNAN: Yeah.

MS. SMITH: Tom's here, and --

MS. MACLENNAN: We're going to move onto the New Hampshire-Maine allocation issue (inaudible) you wanted to sit in on.

MR. AUSTIN: Oh, okay.

MS. SMITH: I have one question before we go into that. The reconciliation moving -- the adjustment moving three million to Maine from New Hampshire, and that was the response of ADR 1-11, does that have to do -- and the only reason I'm going to ask this is because I want -- I'm thinking it does with the capacity allocation issue that we talked about in -- we asked about in data request 1-6, we were asking about the change in the allocation of the capacity costs, why basically in the summer months it was so much lower for Maine to New Hampshire. I'm just wondering if -- if that's the reason for this adjustment that you were talking about?

MR. GIBBONS: Yes.

MS. SMITH: Okay. Okay. Now, maybe this is in part because I was not heavily involved in the case that dealt with capacity assignment provisions, I guess I was slightly wondering why there's such an impact on the commodity cost allocators, but no impact on the demand cost allocators, and -- because in my mind, the capacity assignment meant capacity assignment of capacity on pipelines. But Carol says it also included assignment of some of your actual commodity costs, as well?

MR. FERRO: No. The --

MS. MACLENNAN: I didn't say that. I said there's a question.

MS. SMITH: Okay.

MR. FERRO: Should I proceed?

MS. SMITH: Yes.

MS. MACLENNAN: Please. Sorry.

MR. FERRO: The dockets that you're referring to in the capacity assignment was just that: capacity. Commodity cost allocations has always based on some assessment of what the firm send out of the two divisions are, what are the volumes that are being dispatched to each division to satisfy Northern's obligation to provide commodity to its customers.

And through the capacity assignment arrangement, it does impact commodity requirements both in Maine and New Hampshire divisions, but became a new requirement, and a significant requirement, with respect to commodity in the Maine division starting in January 2006. And that's because upon the agreement in those dockets, we agreed to satisfy capacity assignment with company-managed resources. And company-managed resources provides for sort of a virtual assignment of resources where Northern Utilities dispatches, and therefore, provides the commodity for the suppliers to satisfy their customers.

So it obviously flows into the assessment of commodity cost allocation factors between the two divisions because some of the volumes, commodity purchases, whether it's pulling out of storage MCN for company managed or Duke, DOMAC, those resources that Northern dispatches is associated with company-managed assignment. So if one is trying to capture the volumes to satisfy firm demand, one has to capture those commodity volumes to satisfy company-managed.

MS. SMITH: So just -- so in looking at the allocators, is it actually that the -- because I was looking at it that summer supply was less in Maine. Is it actually that winter supply is more and that's why the allocators are different? I mean, I'm trying to figure out as to why we go from, you know, around 50 percent to 52 percent in certain months to down as low as 30 percent to 70 percent.

MR. FERRO: I'm sorry. Can you tell me what schedule you're --

MS. SMITH: I'm looking at schedule -- it's on page 60 of the filing.

MR. FERRO: Page --

MS. SMITH: The simplified market-based allocators.

MR. GIBBONS: The winter months would include the estimated company-managed estimates of the allocations November through March.

MS. SMITH: Uh-huh.

MR. GIBBONS: And then that program ends in Maine from April through October.

MR. FERRO: Yeah. The send-out model, Lucretia, has to recognize that it needs to dispatch volumes in Maine to satisfy company managed, and this schedule reflects that. And certainly you can see that Maine's allocation factors are higher in the winter than in the summer, at least in part due to the company-managed requirements in Maine solely in the winter.

MS. SMITH: Okay.

MS. MACLENNAN: You can continue if you'd like. I need to take a break.

MS. SMITH: Okay.

MR. GIBBONS: So we put those -- we have to put those costs into the Maine reconciliation, but then those are offset by company-managed commodity credits.

MR. FERRO: Excuse me. Off the record, is it okay we continue to --

MS. SMITH: Yeah, she said to go ahead, so --

MR. FERRO: Oh, I'm sorry, I didn't hear that. Okay. Sorry.

MS. SMITH: No, that's all right. I was debating that, as well. Okay, so there's -- I'm trying to get -- where would I see what you just told me?

MR. GIBBONS: The credits?

MS. SMITH: Yeah.

MR. GIBBONS: The credits are -- you would see those on page 38, which is the tariff page.

MS. SMITH: Okay.

MR. GIBBONS: The volumes associated with that assigned transportation is included and is reflective of the --

MS. SMITH: Okay. So that $2 million that's assigned to -- that's on the first line, that's peak demand?

MR. GIBBONS: Yes.

MS. SMITH: And then there's 12 million assigned transportation costs that's commodity?

MR. GIBBONS: Yes.

MS. SMITH: Okay. So the allocator is allocating more dollars to Maine, but then when we go through the tariff pages and are assigning it to classes, some of those dollars are being assigned to the transport customers; is that correct?

MR. GIBBONS: Yes.

MS. SMITH: Okay.

MS. MACLENNAN: Sorry.

MS. SMITH: That's all right. So what happened with the reconciliation? I guess I'm -- we've moved three million to Maine from New Hampshire.

MR. GIBBONS: The original -- when the costs came through originally, the allocation did not reflect the fact that these costs had to be assigned to Maine November through March because the credits were coming through also to offset t hose. You were getting the credits but you weren't getting the up-front costs associated with that. The gas that was being assigned through the company-managed program --

MS. SMITH: Uh-huh.

MR. GIBBONS: -- was not getting -- it was not being allocated to Maine.

MS. MACLENNAN: I'm sorry, if I cover ground you've already covered. But you're probably not surprised that we were surprised to see such a large dollar amount suddenly appear in your reconciliation without much explanation. Was it that the company overlooked this particular part of the calculation --

MR. GIBBONS: Yes.

MS. MACLENNAN: -- January '06 to the present?

MR. GIBBONS: It did not get in -- winter '07-'08 it did not get into the calculation of the allocation.

MS. MACLENNAN: So it's a one-season error?

MR. GIBBONS: It did not -- you were receiving the credits but the costs were not in on Maine's books. You were only receiving the credit side of things.

MS. SMITH: Let me just see if -- because this will bring -- hopefully bring Carol up to date but will also make sure I understand what was just stated. The allocation to Maine in total the allocators are higher because of the Maine send out because of the assignment of capacity management is higher. But when it goes -- comes to the allocation to actual customers on the tariff sheet, some of it is assigned directly to transport customers so, therefore, those costs aren't being assigned to the sales-only customers. Is that correct?

MR. FERRO: Yes. As it was last year -- if you look at last year's winter cost of gas, just what you say, Lucretia, that is, we back out the associated costs of commodity and capacity to the capacity assigned customers, and the net is charged to sales customers. But then when we -- as we proceeded in that period in the real world, we bill the supplier for company-managed resources. Some of is capacity, some is commodity. That is credited through the cost of gas in our accounting.

But when we were taking a look at the send outs, say, in November '07 or December '07 and we were assigning total Northern commodity costs to the Maine division and the New Hampshire division, we were developing allocation factors that excluded Northern's requirement to send out gas to satisfy company-managed resources to the transportation customers of Maine. And once Ron discovered that, we had -- we had to reverse the calculation. And what Ron was saying is the credit really is the charges that we bill the suppliers and ran that revenue through the cost of gas in the Maine division, that's the credit. The cost side of it is just allocating commodity costs to the Maine division associated with that requirement. That's what was not being done, the allocation of commodity costs associated with that requirement in the Maine division.

MS. SMITH: So if I were to look at the allocation tab in my filing from last year, which is still in my office, as is every filing since I've been here, I would not see this differential that I'm seeing this year?

MR. FERRO: You should not. If we modeled this correctly last year, you should --

MS. SMITH: Or you modeled incorrectly?

MR. FERRO: No, I don't think we modeled it incorrectly.

MS. SMITH: (Inaudible).

MR. FERRO: We modeled it correctly. We accounted it for it incorrectly, if you will. We modeled -- I think the person who runs out send out model, he did not --

MR. GIBBONS: I think you would see these same allocations last year.

MR. FERRO: That's the point I'm making. That's right.

MS. SMITH: Okay.

MR. FERRO: That's right. That's the point making. He modeled it correctly and, therefore, he was -- he was satisfying company-managed resources last year. So on a projected basis, they're not forecasts. The commodity allocation factor should have represented reasonably accurate assessment of the split.

MS. SMITH: Okay.

MR. FERRO: But then when we accounted for it in the real world, actual basis, we did not reflect the company-managed commodity requirements in the Maine division by way of allocating total Northern commodity requirements. The commodity allocation factors did not recognize the additional Maine demand for company-managed resources.

MR. JORTNER: Was there a reciprocal error made in the New Hampshire filing or was this only an error made in the Maine filing?

MR. GIBBONS: No, a reciprocating amount was in New Hampshire.

MR. JORTNER: So you had to correct the New Hampshire as well?

MR. GIBBONS: Yes. Now --

MR. JORTNER: By the same exact amount?

MR. GIBBONS: Yes. Now, you would not have seen the adjustment line in the reconciliation in the prior winter. Let's say the accounting department makes the allocation calculation based on actuals. They do not use these allocators --

MS. SMITH: Okay.

MR. GIBBONS: -- when they post commodity costs.

MS. SMITH: Okay.

MR. GIBBONS: They use the actuals. So, therefore, if the company managed were taken under consideration when the allocations were made originally, coming through this winter, there would be no need for the reallocation line because that $3.2 million in costs would be spread throughout the commodity costs on the reconciliation. You would not see a line for an extra allocation because of the company-managed and all that.

MS. SMITH: Okay.

MR. GIBBONS: They would be -- it would be included in the allocation amount and they would be spread amongst --

MS. SMITH: Because --

MR. GIBBONS: -- costs.

MS. SMITH: -- because they would have used these percentages or something along those --

MR. GIBBONS: Something similar.

MS. SMITH: -- percentages in booking it?

MR. GIBBONS: Something similar to that.

MS. SMITH: Something similar to that?

MR. GIBBONS: Yes.

MS. SMITH: So instead what they used to book it did not reflect the company-managed that's being added for Maine; is that --

MR. GIBBONS: Not originally.

MS. SMITH: Not originally, which caused the need of the $3 million reconciliation. But is it -- I guess I'm trying to figure out is it really a reconciliation as so much that it's a -- if the accounting had been correct each month, you know, your build up, you're saying we wouldn't have seen --

MS. MACLENNAN: The correction.

MS. SMITH: It's a correction within that so that you didn't have to go back and recalculate each month's?

MR. GIBBONS: Right, it was just --

MS. SMITH: Is that really what it is?

MR. GIBBONS: Yes, it would have just flowed through as it usually does.

MS. SMITH: Okay. So it's more that the individual months on the sheets weren't accurate, not that we're getting $3 million of costs that New Hampshire paid for in a prior period.

MR. GIBBONS: No. No. And it was done in this manner -- I made the decision to do it in this manner to preserve the audit trail --

MS. SMITH: Okay.

MR. GIBBONS: -- for when you do the audit because if you were to look at the allocated cover sheets and the invoices and such, you will see allocations like what is in the reconciliation. If I'd gone through and put the correct allocations on the spreadsheets and re-spread the dollars and made it look like you're accustomed to seeing, if you went and looked a the allocations between the two jurisdictions, two divisions --

MS. SMITH: Okay.

MR. GIBBONS: -- it wouldn't have tied out. The total costs to Northern are the same as the split between the two. So --

MS. SMITH: And the split between the two is really -- really what was estimated close to what -- other than, you know, the changes in costs and things, but the theory behind in the end is what was estimated when you made the filing for 2007-2008 winter period?

MR. GIBBONS: Yes, it should be.

MS. SMITH: Okay.

MS. MACLENNAN: Just so I fully understand. I think I understand the basic explanation for -- which is that Maine has a higher percentage of managed resources assigned to suppliers than does New Hampshire?

MR. GIBBONS: Yes.

MS. MACLENNAN: So there has to be a -- in your calculation of commodity allocation by jurisdiction, you have to somehow add in, for this one category of commodity, that difference?

MR. GIBBONS: Yes. And if you look at the reconciliation on page 136, two-thirds of the way down, you'll see company-managed propane which really is company-managed peaking resources or just company managed, and follow that across, you'll see a $3.9 million credit. The credits were --

are already in the commodity cost schedule. And those are not allocated. Those are division-by-division actual credits. Those are not part of the allocation process.

MS. SMITH: What page did you say, Ron?

MR. GIBBONS: 136.

MS. SMITH: Okay. I have it now.

MR. GIBBONS: 13 lines up or so.

MS. SMITH: Okay.

MR. FERRO: The three million nine dollar number right, Ron?

MR. GIBBONS: Yes.

MS. SMITH: Yeah.

MS. MACLENNAN: This seemed to come out of the blue for me and it could be my faulty memory, but I don't -- didn't think I recalled a discussion during the negotiations of the allocations between states for capacity assignment including this item, that there would be an acknowledgment of different -- I understand the logic but it wasn't something that rang a bell for me. Is that because I overlooked it or is this something that sort of bubbled up to everyone's -- New Hampshire's consciousness so the company is accommodating it, let's say.

MR. FERRO: No. You didn't overlook it. It was not an issue because this was a capacity-related docket, and no one was proposing to change the methodology of allocating commodity costs --

MS. MACLENNAN: Okay.

MR. FERRO: -- which is based on each division's firm send out requirements, volumes/commodity requirements. And that was not of issue.

MS. MACLENNAN: Okay. So this has really evolved out of the CGF commodity aspect?

MR. FERRO: That's correct.

MS. MACLENNAN: And -- but was it brought to your attention by the New Hampshire staff, say, in last year's -- last winter's CGF or this winter's CGF or did you just discover it, think it through yourselves?

MR. FERRO: I'll let Ron speak --

MS. MACLENNAN: Okay.

MR. FERRO: I mean, we haven't even discussed this with New Hampshire. I mean, this was discovered by Ron recently.

MS. MACLENNAN: Okay.

MR. GIBBONS: I discovered it doing the reconciliations because I had an enormous over collection in Maine, and a -- and a very large under collection in New Hampshire.

MS. MACLENNAN: Okay.

MR. GIBBONS: So that's how it came to light.

MS. MACLENNAN: I see.

MR. FERRO: Carol, you might not need this simple illustration and I think you understand it, but very simply, if we had a hundred dollars worth of commodity costs, and without reflecting the company-managed requirements in the Maine division, we allocated only 40 percent of that hundred dollars to Maine and 60 percent to New Hampshire and then realized the 60/40 split should have been 50/50 if we reflected company-managed resources.

MS. MACLENNAN: Uh-huh.

MR. FERRO: That instead of $40 being allocated to Maine, we should have allocated $50 to Maine; instead of 60 to New Hampshire, 50 to New Hampshire. That's the $10 adjustment that he's providing there.

MS. MACLENNAN: Okay.

MS. SMITH: And the reason it's done in one lump sum is for the audit trail, so we didn't have to ask him every month why is this number different, why is this number different, so we have -- all the numbers will match how they accounted for it.

MS. MACLENNAN: Uh-huh.

MS. SMITH: And then they'll have the one true up, which reflects how it was proposed in last year's filing.

MS. MACLENNAN: Just a question on why Maine has more company-managed assignment to suppliers than New Hampshire. Is that --

MR. FERRO: Well, two fold.

MS. MACLENNAN: Okay.

MR. FERRO: Certainly the unique provisions in the Maine capacity assignment is that we provide them with capacity only in the five months of November through March --

MS. MACLENNAN: Uh-huh.

MR. FERRO: -- while in New Hampshire it's year round. But secondly that all capacity assignment and, therefore, all capacity requirements that the suppliers need in Maine are satisfied by company managed, while in New Hampshire a good share of it is long-haul pipeline, as well as some company-managed storage and peaking.

So it's the entire requirement in Maine is satisfied by company managed while just a portion of New Hampshire's requirement is satisfied by company managed.

MS. MACLENNAN: And -- and why is that, again, Joe? Is it -- why isn't company-managed divided between the states equally? Why is there a particular designation of only company managed to Maine and a portion of New Hampshire's overall to New Hampshire?

MR. FERRO: Well, like any other requirement, you look at New Hampshire's firm demand --

MS. MACLENNAN: Uh-huh.

MR. FERRO: -- sales and company assignment, and Maine's firm demand, firm sales, and company -- and -- and -- and capacity assignment, excuse me. And so when you add -- if you isolate the pieces, the capacity assignment piece in Maine is made up of different -- solely company managed, a different component that New Hampshire. It has pipeline and a little company managed.

MS. MACLENNAN: But I'm asking why.

MR. FERRO: It's the tariff provisions in both -- both divisions; that is, New Hampshire gets a slice of the system every month --

MS. MACLENNAN: Okay.

MR. FERRO: -- while we had agreed upon, settled upon in Maine --

MS. MACLENNAN: Okay.

MR. FERRO: -- that they don't get a slice. They get specific resources.

MS. MACLENNAN: Okay. Good. That's all I was getting at.

MR. FERRO: Okay.

MS. MACLENNAN: Sorry I didn't remember that.

MR. GIBBONS: Well, the agreement also -- New Hampshire had a cut off back in '02 --

MR. FERRO: That's another element to this --

MR. GIBBONS: -- '03, whereas Maine was --

MR. FERRO: Right.

MR. GIBBONS: -- 50 percent of the firm transportation.

MR. FERRO: That's another element to this but that's -- that is just who was assigned capacity and who was not. And in New Hampshire I believe it was March 2001 grandfathered date; that is, all customers who switched to transportation service after that date was non-grandfathered or capacity assigned while the prior ones were.

MS. MACLENNAN: I remember that.

MR. GIBBONS: And the Maine division credits are much larger than the New Hampshire division credits.

MS. SMITH: So you have certain pipeline, gas, if you will, that New Hampshire transportation customers or commodity, they get a slice of that. How are -- and that's not at all reflected in any of these allocation factors or anything like that? What I'm trying to figure out is we have total Northern costs --

MR. FERRO: Right.

MS. SMITH: -- which include -- are those costs of that pipeline supply in that total Northern cost?

MR. FERRO: There's no commodity assignment associated with those resources --

MS. SMITH: Okay.

MR. FERRO: -- both in Maine -- well, Maine doesn't get any capacity assignment, but New Hampshire there's -- we just release the capacity to the suppliers to satisfy their long-haul pipeline needs.

MS. SMITH: Okay.

MR. FERRO: They buy their own gas. We don't dispatch for them or buy gas. So that's not part of Northern's send out.

MS. SMITH: Okay.

MR. FERRO: That's what we're trying to capture here, Northern's send out requirements. And only company managed affects Northern's send out requirements.

MS. MACLENNAN: Great. Now this makes sense. Thank you. Do you have any questions?

MS. SMITH: Well, that's wasn't as painful as I expected it to be.

MS. MACLENNAN: No.

MS. SMITH: I don't know that I have anything else on the cost of gas stuff specifically.

MS. MACLENNAN: When are you going to move to the ERC --

MS. SMITH: Oh, the ERC questions. On ADR number 1-9 and 1-10 --

MS. FRENCH: Sorry that it didn't occur to me to bring him up here.

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Peak Period - May 2011 through April 2012 - Estimated for Open Period

									Method of Calculating Variable Cost Allocation Ratios updated Nov-2011						
Line No.	Description	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	Total
1	Costs allocated on Current Month Ratios:														
2	**Withdrawal Charges**														
3	NH Division		-	-	(62,534)	-	-	-						-	(62,534)
4	ME Division		-	-	(51,500)	-	-	-						-	(51,500)
5	**ATV Reconciliation Charges**														
6	NH Division		-	-	-	-	-	-						-	-
7	ME Division		-	-	-	-	-	-						-	-
8	**Net OBA Adjustment**														
9	NH Division		-	-	62,534	-	-	-						-	62,534
10	ME Division		-	-	51,500	-	-	-						-	51,500
11	**LNG Boiloff**														
12	NH Division		-	-	-	-	-	-						-	-
13	ME Division		-	-	-	-	-	-						-	-
14	**Inventory Finance Charges**														
15	NH Division		158	396	635	849	957	956						-	3,951
16	ME Division		139	336	574	746	837	936						-	3,568
17	Subtotal - Costs allocated on Current Month Ratios														
18	NH Division - Lines 3+6+9+12+15		158	396	635	849	957	956	-	-	-	-	-	-	3,951
19	ME Division - Lines 4+7+10+13+16		139	336	574	746	837	936	-	-	-	-	-	-	3,568
20															
21	Costs allocated on Prior Month Ratios:														
22	**Vendor Payments**														
23	NH Division		1,209,890	33,798	147,912	(0)	(0)	(0)						-	1,391,601
24	ME Division		1,088,097	29,589	130,762									-	1,248,448
25	**Non-Traditional Sales**														
26	NH Division		(83,131)	406										-	(82,725)
27	ME Division		(74,762)	365										-	(74,398)
28	**Transportation Charges**														
29	NH Division		23,790											-	23,790
30	ME Division		21,395											-	21,395
31	Subtotal - Costs allocated on Prior Month Ratios														
32	NH Division - Lines 23+26+29		1,150,550	34,204	147,912	(0)	(0)	(0)	-	-	-	-	-	-	1,332,666
33	ME Division - Lines 24+27+30		1,034,730	29,954	130,762	-	-	-	-	-	-	-	-	-	1,195,446
34															
35	**Commodity Costs Requiring Adjustment:**														
36	**NH Division - Lines 18+32**		**1,150,708**	**34,600**	**148,547**	**849**	**957**	**956**	-	-	-	-	-	-	**1,336,617**
37	**ME Division - Lines 19+33**		**1,034,869**	**30,290**	**131,336**	**746**	**837**	**936**	-	-	-	-	-	-	**1,199,015**
38															
39	**Updated Ratios:**														
40	NH Ratio	52.85%	53.51%	54.31%	52.70%	53.42%	53.52%	50.73%	53.26%	48.01%	47.92%	49.71%	52.15%		
41	ME Ratio	47.15%	46.49%	45.69%	47.30%	46.58%	46.48%	49.27%	46.74%	51.99%	52.08%	50.29%	47.85%		
42															
43	Reallocated Costs based on Current Month ratios:														
44	NH Division - Lines (18+19) x 40 (current month allocator)		159	398	637	852	960	960	-	-	-	-	-	-	3,966
45	ME Division - Lines (18+19) x 41 (current month allocator)		138	335	572	743	834	932	-	-	-	-	-	-	3,553
46	Reallocated Costs based on Prior Month Ratios:														
47	NH Division - Lines (32+33) x 40 (prior month allocator)		1,154,920	34,331	151,348	(0)	(0)	(0)	-	-	-	-	-	-	1,340,599
48	ME Division - Lines (32+33) x 41 (prior month allocator)		1,030,359	29,827	127,326	(0)	(0)	(0)	-	-	-	-	-	-	1,187,513
49															
50	**Adjusted Commodity Costs:**														
51	**NH Division - Lines 44+47**		**1,155,079**	**34,729**	**151,985**	**852**	**960**	**960**	-	-	-	-	-	-	**1,344,565**
52	**ME Division - Lines 45+48**		**1,030,497**	**30,162**	**127,898**	**743**	**834**	**932**	-	-	-	-	-	-	**1,191,066**
53															
54	**Allocation Adjustment (before Hedging):**														
55	**NH Division - Lines 51-36**		**4,371**	**129**	**3,438**	**3**	**4**	**4**	-	-	-	-	-	-	**7,948**
56	**ME Division - Lines 52-37**		**(4,371)**	**(129)**	**(3,438)**	**(3)**	**(4)**	**(4)**	-	-	-	-	-	-	**(7,948)**
57															
58	**Hedging Adjustment (separate analysis):**														
59	**NH Division**		83	-	-	-	-	256	-	-	-	-	-	-	340
60	**ME Division**		(83)	-	-	-	-	(256)	-	-	-	-	-	-	(340)
61															
62	**Allocation Adjustment:**														
63	**NH Division - Lines 55+59**		**4,455**	**129**	**3,438**	**3**	**4**	**260**	-	-	-	-	-	-	**8,288**
64	**ME Division - Lines 56+60**		**(4,455)**	**(129)**	**(3,438)**	**(3)**	**(4)**	**(260)**	-	-	-	-	-	-	**(8,288)**

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *			Converted revenue JE's must be posted.
May 31, 2011	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	2,045,773	1,724,159		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.027		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	204,577	177,071	381,648	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	31	327	358	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	204,608	177,398	382,007	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	206,573	179,438	386,011	
Plus: Co-Managed (DTH) (updated)	-	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	206,573	179,438	386,011	
Commodity Allocation (Variable)	53.51%	46.49%	100%	
Original Ratios	53.32%	46.68%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *			Converted revenue JE's must be posted.
June 30, 2011	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	1,337,725	1,062,322		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.057		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	133,773	112,287	246,060	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	29	75	104	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	133,802	112,362	246,164	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	135,086	113,655	248,741	
Plus: Co-Managed (DTH) (updated)	-	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	135,086	113,655	248,741	
Commodity Allocation (Variable)	54.31%	45.69%	100%	
Original Ratios	54.11%	45.89%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *			Converted revenue JE's must be posted.
July 31, 2011	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	916,318	774,456		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.058		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	91,632	81,937	173,569	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	22	165	187	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	91,654	82,102	173,757	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	92,534	83,047	175,581	
Plus: Co-Managed (DTH) (updated)	-	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	92,534	83,047	175,581	
Commodity Allocation (Variable)	52.70%	47.30%	100%	
Original Ratios	52.50%	47.50%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities August 31, 2011	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	Converted revenue JE's must be posted.
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	771,977	635,947		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.055		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	77,198	67,092	144,290	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	21	119	140	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	77,218	67,211	144,430	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	77,960	67,984	145,944	
Plus: Co-Managed (DTH) (updated)	-	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	77,960	67,984	145,944	
Commodity Allocation (Variable)	53.42%	46.58%	100%	
Original Ratios	53.22%	46.78%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities September 30, 2011 * DO NOT DIVIDE BY 10 on line 4 *	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	Converted revenue JE's must be posted.
Billed Sales - Therm/CCF	871,128	738,866		per G_NU_N_REV & G_NU_M_REV; page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.052		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - - ** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per	87,113	77,729	164,842	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
Plus: Company Use (DTH)	2,740	166	2,906	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	89,853	77,895	167,747	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	90,715	78,790	169,506	
Plus: Co-Managed (DTH) (updated)	-	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	90,715	78,790	169,506	
Commodity Allocation (Variable)	53.52%	46.48%	100%	
Original Ratios	53.32%	46.68%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities October 31, 2011	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	Converted revenue JE's must be posted.
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	1,016,794	938,589		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.049		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	101,679	98,458	200,137	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	102	201	303	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	101,781	98,659	200,440	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	102,758	99,794	202,552	
Plus: Co-Managed (DTH) (updated)	-	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	102,758	99,794	202,552	
Commodity Allocation (Variable)	50.73%	49.27%	**100%**	
Original Ratios	50.53%	49.47%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities, Inc.
Summary of Allocation Adjustment calculation - Peak Period - May 2010 through April 2011

Line No.	Description	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	Total
1	**Costs allocated on Current Month Ratios:**														
2	**Withdrawal Charges**														
3	NH Division		-	-	-	-	-	-	982,785	2,454,160	2,544,470	1,576,288	1,213,681	870	8,772,254
4	ME Division		-	-	-	-	-	-	863,167	1,992,463	1,936,158	1,275,774	979,930	733	7,048,224
5	**ATV Reconciliation Charges**														
6	NH Division		-	-	-	-	-	-	(30,606)	72,894	111,901	85,224	102,352	22,329	364,093
7	ME Division		-	-	-	-	-	-	(26,881)	59,113	85,073	69,083	82,632	20,081	289,101
8	**Net OBA Adjustment**														
9	NH Division		-	-	-	-	-	-	10,250	1,739	11,720	31,076	(188)	7,938	62,534
10	ME Division		-	-	-	-	-	-	9,002	1,410	8,910	25,190	(152)	7,139	51,500
11	**LNG Boiloff**														
12	NH Division		-	-	-	-	-	-	4,008	6,370	7,304	1,225	3,279	4,889	27,075
13	ME Division		-	-	-	-	-	-	3,520	5,166	5,553	993	2,647	4,397	22,276
14	**Inventory Finance Charges**														
15	NH Division		404	579	774	957	1,048	1,087	1,095	1,060	727	355	183	46	8,312
16	ME Division		322	496	690	803	903	1,029	961	860	553	288	148	41	7,093
17	Subtotal - Costs allocated on Current Month Ratios														
18	NH Division - Lines 3+6+9+12+15		404	579	774	957	1,048	1,087	967,531	2,536,223	2,676,123	1,694,167	1,319,306	36,071	9,234,268
19	ME Division - Lines 4+7+10+13+16		322	496	690	803	903	1,029	849,770	2,059,011	2,036,247	1,371,328	1,065,205	32,390	7,418,194
20															
21	**Costs allocated on Prior Month Ratios:**														
22	**Vendor Payments**														
23	NH Division		906,977	3,925	-	-	(1,983)	-	11,402	365,766	1,631,662	2,012,108	1,785,157	1,444,491	8,159,504
24	ME Division		745,564	3,226	-	-	(1,772)	-	10,798	320,074	1,348,528	1,529,712	1,427,502	1,166,192	6,549,824
25	**Non-Traditional Sales**														
26	NH Division		(425,015)	-	-	-	-	-	(4,520)	(2,316)	(848,206)	(141,454)	(129,906)	(27,350)	(1,578,766)
27	ME Division		(349,376)	-	-	-	-	-	(4,280)	(2,034)	(687,843)	(107,541)	(105,303)	(22,081)	(1,278,457)
28	**Transportation Charges**														
29	NH Division		47,189	160,076	(213,177)	117,743	-	-	-	3,498	95,263	28,758	92,402	69,554	401,304
30	ME Division		38,791	127,468	40,166	105,002	-	-	-	3,072	77,252	21,863	74,902	56,154	544,670
31	Subtotal - Costs allocated on Prior Month Ratios														
32	NH Division - Lines 23+26+29		529,151	164,000	(213,177)	117,743	(1,983)	-	6,882	366,948	878,718	1,899,411	1,747,652	1,486,695	6,982,041
33	ME Division - Lines 24+27+30		434,979	130,694	40,166	105,002	(1,772)	-	6,518	321,112	737,937	1,444,034	1,397,101	1,200,265	5,816,036
34															
35	**Commodity Costs Requiring Adjustment:**														
36	**NH Division - Lines 18+32**		**529,555**	**164,579**	**(212,403)**	**118,699**	**(935)**	**1,087**	**974,414**	**2,903,171**	**3,554,841**	**3,593,578**	**3,066,959**	**1,522,766**	**16,216,310**
37	**ME Division - Lines 19+33**		**435,300**	**131,190**	**40,856**	**105,805**	**(869)**	**1,029**	**856,288**	**2,380,124**	**2,774,184**	**2,815,362**	**2,462,305**	**1,232,655**	**13,234,230**
38															
39	**Updated Ratios:**														
40	NH Ratio	54.88%	55.67%	53.86%	52.86%	54.34%	53.70%	51.35%	49.04%	44.94%	48.99%	50.09%	49.75%	52.85%	
41	ME Ratio	45.12%	44.33%	46.14%	47.14%	45.66%	46.30%	48.65%	50.96%	55.06%	51.01%	49.91%	50.25%	47.15%	
42															
43	**Reallocated Costs based on Current Month ratios:**														
44	NH Division - Lines (18+19) x 40 (current month allocator)		404	579	774	956	1,048	1,086	891,205	2,065,098	2,308,590	1,535,506	1,186,294	36,182	8,027,722
45	ME Division - Lines (18+19) x 41 (current month allocator)		322	496	690	804	904	1,029	926,097	2,530,136	2,403,780	1,529,988	1,198,217	32,279	8,624,741
46	**Reallocated Costs based on Prior Month Ratios:**														
47	NH Division - Lines (32+33) x 40 (prior month allocator)		529,112	164,061	(93,183)	117,743	(2,040)	-	6,881	337,425	726,525	1,637,954	1,575,207	1,336,763	6,336,446
48	ME Division - Lines (32+33) x 41 (prior month allocator)		435,017	130,634	(79,827)	105,002	(1,715)	-	6,519	350,636	890,130	1,705,491	1,569,546	1,350,197	6,461,631
49															
50	**Adjusted Commodity Costs:**														
51	**NH Division - Lines 44+47**		**529,516**	**164,640**	**(92,410)**	**118,699**	**(993)**	**1,086**	**898,086**	**2,402,523**	**3,035,115**	**3,173,460**	**2,761,501**	**1,372,944**	**14,364,168**
52	**ME Division - Lines 45+48**		**435,339**	**131,130**	**(79,137)**	**105,805**	**(811)**	**1,029**	**932,616**	**2,880,771**	**3,293,910**	**3,235,480**	**2,767,763**	**1,382,477**	**15,086,372**
53															
54	**Allocation Adjustment (before Hedging):**														
55	**NH Division - Lines 51-36**		**(38)**	**61**	**119,993**	**(0)**	**(58)**	**(0)**	**(76,328)**	**(500,648)**	**(519,726)**	**(420,118)**	**(305,458)**	**(149,821)**	**(1,852,142)**
56	**ME Division - Lines 52-37**		**38**	**(61)**	**(119,993)**	**0**	**58**	**0**	**76,328**	**500,648**	**519,726**	**420,118**	**305,458**	**149,821**	**1,852,142**
57															
58	**Hedging Adjustment (separate analysis):**														
59	**NH Division**		-	-	-	-	-	-	(9,103)	(19,471)	(8,688)	(7,343)	(8,262)	343	(52,524)
60	**ME Division**		-	-	-	-	-	-	9,103	19,471	8,688	7,343	8,262	(343)	52,524
61															
62	**Allocation Adjustment:**														
63	**NH Division - Lines 55+59**		**(38)**	**61**	**119,993**	**(0)**	**(58)**	**(0)**	**(85,431)**	**(520,119)**	**(528,414)**	**(427,461)**	**(313,720)**	**(149,478)**	**(1,904,666)**
64	**ME Division - Lines 56+60**		**38**	**(61)**	**(119,993)**	**0**	**58**	**0**	**85,431**	**520,119**	**528,414**	**427,461**	**313,720**	**149,478**	**1,904,666**

Northern Utilities
May 31, 2010

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	1,902,734	1,434,714		page: ME(NH) NON External Supplied (do NOT include Exter
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.05519		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	190,273	151,390	341,663	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per RJ 2007 (Recoveries)				*(Cycle 22 is recorded in JE's 930/930U)*
Plus: Company Use (DTH)	25	337	362	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	190,298	151,727	342,025	
Unaccounted for Estimate	101%	102%		
Subtot Volumes (DTH) - for Commodity Allocation	192,201	154,761	346,962	
Plus: Co-Managed (DTH) (updated)	2,161	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	194,362	154,761	349,123	
Commodity Allocation (Variable)	55.6715%	44.3285%	100%	
Original	55.67%	44.33%		

Northern Utilities
June 30, 2010

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	1,048,526	858,729		page: ME(NH) NON External Supplied (do NOT include Exter
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.0547		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	104,853	90,570	195,423	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per RJ 2007 (Recoveries)				
Plus: Company Use (DTH)	7	162	169	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	104,859	90,732	195,591	
Unaccounted for Estimate	101%	102%		
Subtot Volumes (DTH) - for Commodity Allocation	105,908	92,547	198,455	
Plus: Co-Managed (DTH) (updated)	2,108	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	108,016	92,547	200,563	
Commodity Allocation (Variable)	53.86%	46.14%	100%	
Original	53.86%	46.14%		

Northern Utilities
July 31, 2010

	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *			per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	883,627	758,839		page: ME(NH) NON External Supplied (do NOT include Exter
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.0514		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	88,363	79,784	168,147	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per RJ 2007 (Recoveries)				
Plus: Company Use (DTH)	2	145	147	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	88,365	79,929	168,294	
Unaccounted for Estimate	101%	102%		
Subtot Volumes (DTH) - for Commodity Allocation	89,248	81,528	170,776	
Plus: Co-Managed (DTH) (updated)	2,167	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	91,415	81,528	172,943	
Commodity Allocation (Variable)	52.86%	47.14%	100%	
Original	52.86%	47.14%		

Northern Utilities August 31, 2010	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	803,799	653,412		page: ME(NH) NON External Supplied (do NOT include Exter
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.0485		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	80,380	68,510	148,890	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per RJ 2007 (Recoveries)				
Plus: Company Use (DTH)	2	120	122	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	80,382	68,630	149,012	
Unaccounted for Estimate	101%	102%		
Subtot Volumes (DTH) - for Commodity Allocation	81,186	70,003	151,188	
Plus: Co-Managed (DTH) (updated)	2,121	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	83,307	70,003	153,309	
Commodity Allocation (Variable)	54.34%	45.66%	100%	
Original	54.35%	45.65%		

Northern Utilities
September 30, 2010

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	880,919	728,403		page: ME(NH) NON External Supplied (do NOT include Exter
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.055		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	88,092	76,846	164,938	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	6	121	127	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	88,097	76,967	165,065	
Unaccounted for Estimate	101%	102%		
Subtot Volumes (DTH) - for Commodity Allocation	88,978	78,507	167,485	
Plus: Co-Managed (DTH) (updated)	2,076	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	91,054	78,507	169,561	
Commodity Allocation (Variable)	53.70%	46.30%	100%	
Original	53.71%	46.29%		

Northern Utilities October 31, 2010	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	1,089,612	983,828		page: ME(NH) NON External Supplied (do NOT include Exterr
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.057		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	108,961	103,991	212,952	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	17	254	271	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	108,978	104,245	213,222	
Less: Lost and Unaccounted for Estimate (updated)	101%	102%		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	110,068	106,329	216,397	
Plus: Co-Managed (DTH) (updated)	2,180	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	112,248	106,329	218,577	
Commodity Allocation (Variable)	51.35%	48.65%	100%	
Original Ratios	51.36%	48.64%		Ratios Before Corrections for Company Managed and Lost & U

Northern Utilities
November 30, 2010

	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *			
	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	2,292,202	1,968,903		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.047		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	229,220	206,144	435,364	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	37	456	493	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	229,257	206,600	435,858	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	231,458	208,976	440,434	
Plus: Co-Managed (DTH) (updated)	8,269	40,172		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	239,727	249,148	488,875	
Commodity Allocation (Variable)	49.04%	50.96%	100%	
Original Ratios	53.24%	46.76%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities December 31, 2010	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	4,040,136	3,711,389		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.042		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	404,014	386,727	790,740	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	85	732	817	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	404,099	387,459	791,558	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	407,978	391,914	799,893	
Plus: Co-Managed (DTH) (updated)	78,355	204,028		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	486,333	595,942	1,082,276	
Commodity Allocation (Variable)	44.94%	55.06%	100%	
Original Ratios	55.22%	44.78%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities
January 31, 2011

* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *

Converted revenue JE's must be posted.

	New Hampshire	Maine	NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	6,341,088	5,204,975		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.048		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	634,109	545,481	1,179,590	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	145	1,162	1,307	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	634,254	546,643	1,180,897	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	640,343	552,930	1,193,273	
Plus: Co-Managed (DTH) (updated)	91,811	209,466		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	732,154	762,396	1,494,550	
Commodity Allocation (Variable)	48.99%	51.01%	100%	
Original Ratios	56.81%	43.19%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities February 28, 2011	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	Converted revenue JE's must be posted.
* DO NOT DIVIDE BY 10 on line 4 *				per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	6,777,765	5,747,567		page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.051		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	677,777	604,069	1,281,846	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per				
Plus: Company Use (DTH)	141	1,488	1,629	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	677,918	605,557	1,283,475	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	684,426	612,521	1,296,947	
Plus: Co-Managed (DTH) (updated)	76,612	145,645		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	761,038	758,166	1,519,204	
Commodity Allocation (Variable)	50.09%	49.91%	100%	
Original Ratios	55.23%	44.77%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Northern Utilities	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED *				Converted revenue JE's must be posted.
March 31, 2011	New Hampshire	Maine		NU TOTAL	
* DO NOT DIVIDE BY 10 on line 4 *					per G_NU_N_REV & G_NU_M_REV;
Billed Sales - Therm/CCF	5,326,532	4,476,233			page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10			line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.052			* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - -	532,653	470,900		1,003,553	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per					
Plus: Company Use (DTH)	104	1,166		1,270	
Less: Interruptible (DTH)					
Subtotal - Deliveries and Company Use	532,757	472,066		1,004,823	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115			*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	537,871	477,494		1,015,366	
Plus: Co-Managed (DTH) (updated)	57,793	124,173			see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	595,664	601,667		1,197,332	
Commodity Allocation (Variable)	49.75%	50.25%		100%	
Original Ratios	55.33%	44.67%			Ratios Before Corrections for Company Managed and Lost & Unaccounted For

Converted revenue JE's must be posted.

Northern Utilities April 30, 2011 * DO NOT DIVIDE BY 10 on line 4 *	* ONLY NON-EXTERNAL SUPPLY UNITS MUST BE USED * New Hampshire	Maine	NU TOTAL	
Billed Sales - Therm/CCF	3,955,400	3,357,642		per G_NU_N_REV & G_NU_M_REV; page: ME(NH) NON External Supplied (do NOT include External Supply)
Conversion Factor for Dth	10	10		line Total Consumption; column Total Billed CIS Revenue
ME BTU Conversion Factor:		1.054		* Do NOT include INTERRUPTIBLE units on line 4 *
Tariff Sales Volumes DTH - - ** Includes Billed Tariff, Unbilled Tariff and Interruptible Sales per	395,540	353,895	749,435	* Do NOT include EXTERNAL SUPPLY/Cycle 22 units on line 4 *
Plus: Company Use (DTH)	76	858	934	
Less: Interruptible (DTH)				
Subtotal - Deliveries and Company Use	395,616	354,753	750,369	
Less: Lost and Unaccounted for Estimate (updated)	1.0096	1.0115		*Per NU Cost of Gas Proceedings - Energy Contracts*
Subtotal Volumes (DTH) - for Commodity Allocation	399,414	358,833	758,247	
Plus: Co-Managed (DTH) (updated)	2,786	-		see tab *Co. mgd gas*
Adj Volumes (DTH) - for Commodity Allocation	402,200	358,833	761,033	
Commodity Allocation (Variable)	52.85%	47.15%	100%	
Original Ratios	52.65%	47.35%		Ratios Before Corrections for Company Managed and Lost & Unaccounted For