Tariff Pages

Unitil
Northern Utilities, Inc.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2009 - April 30, 2010

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 1,873,003	
Supply Costs:	$ 8,642,136	
Storage & Peaking Gas:		
Demand, Capacity:	$ 10,352,526	
Commodity Costs:	$ 5,928,967	
Hedging (Gain)/Loss	$ 2,123,189	
Interruptible Included Above	$ -	
Inventory Finance Charge	$ 122,792	
Capacity Release	$ (1,896,076)	
Total Anticipated Direct Cost of Gas		$ 27,146,537
ANTICIPATED INDIRECT COST OF GAS		
Adjustments:		
Prior Period Under/(Over) Collection	$ 2,944,781	
Interest	$ 25,680	
Refunds	$ -	
Capacity Reserve Charge Revenue	$ (90,228)	
Interruptible Margins	$ -	
Total Adjustments		$ 2,880,233
Working Capital:		
Total Anticipated Direct Cost of Gas	$ 27,146,537	
Working Capital Percentage	0.190%	
Working Capital Allowance	$ 51,578	
Plus: Working Capital Reconciliation (Acct 182.11)	$ 22,921	
Total Working Capital Allowance		$ 74,499
Bad Debt:		
Total Anticipated Direct Cost of Gas	$ 27,146,537	
Less: Capacity Reserve Charge Revenue	$ (90,228)	
Plus: Prior Period Under/(Over) Collection	$ 2,944,781	
Plus: Interest	$ 25,680	
Plus: Total Working Capital	$ 74,499	
Subtotal	$ 30,101,269	
Bad Debt Percentage	0.450%	
Bad Debt Allowance	$ 135,456	
Plus: Bad Debt Reconciliation (Acct 182.16)	$ 52,984	
Total Bad Debt Allowance		$ 188,440
Local Production and Storage Capacity		$ 686,673
Miscellaneous Overhead-77.11% Allocated to Winter Season		$ 95,845
Total Anticipated Indirect Cost of Gas		$ 3,925,690
Total Cost of Gas		$ 31,072,227

Issued: August 15, 2009
Effective Date: November 1, 2009

Issued By: [signature]
Treasurer

Authorized by NHPUC Order No. ______, in Docket No. DG 09-___, dated __________, 2009.

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2009 - April 30, 2010

(Col 1)		(Col 2)		(Col 3)	
Total Anticipated Direct Cost of Gas	$	27,146,537			
Projected Prorated Sales (11/01/09 - 04/30/10)		28,473,787			
Direct Cost of Gas Rate			$	0.9534	per therm
Demand Cost of Gas Rate	$	10,329,453	$	0.3628	per therm
Commodity Cost of Gas Rate	$	16,817,083	$	0.5906	per therm
Total Direct Cost of Gas Rate	$	27,146,537	$	0.9534	per therm
Total Anticipated Indirect Cost of Gas	$	3,925,690			
Projected Prorated Sales (11/01/09 - 04/30/10)		28,473,787			
Indirect Cost of Gas			$	0.1379	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/09			**$**	**1.0913**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/09		**COGwr**	**$**	**1.0913**	**per therm**
		Maximum (COG+25%)	**$**	**1.3641**	

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09			**COGwl**	**$**	**1.0549**	**per therm**
			Maximum (COG+25%)	**$**	**1.3186**	
C&I HLF Demand Costs Allocated per SMBA	$	635,773				
PLUS: Residential Demand Reallocation to C&I HLF	$	24,733				
C&I HLF Total Adjusted Demand Costs	$	660,506				
C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)		2,837,571				
Demand Cost of Gas Rate	**$**	**0.2328**				
C&I HLF Commodity Costs Allocated per SMBA	$	1,956,507				
PLUS: Residential Commodity Reallocation to C&I HLF	$	(15,057)				
C&I HLF Total Adjusted Commodity Costs	$	1,941,450				
C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)		2,837,571				
Commodity Cost of Gas Rate	**$**	**0.6842**				
Indirect Cost of Gas	**$**	**0.1379**				
Total C&I HLF Cost of Gas Rate	**$**	**1.0549**				

COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/09			**COGwh**	**$**	**1.0993**	**per therm**
			Maximum (COG+25%)	**$**	**1.3741**	
C&I LLF Demand Costs Allocated per SMBA	$	4,857,290				
PLUS: Residential Demand Reallocation to C&I LLF	$	188,959				
C&I LLF Total Adjusted Demand Costs	$	5,046,250				
C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)		12,893,460				
Demand Cost of Gas Rate	**$**	**0.3914**				
C&I LLF Commodity Costs Allocated per SMBA	$	7,406,555				
PLUS: Residential Commodity Reallocation to C&I LLF	$	(57,000)				
C&I LLF Total Adjusted Commodity Costs	$	7,349,554				
C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)		12,893,460				
Commodity Cost of Gas Rate	**$**	**0.5700**				
Indirect Cost of Gas	**$**	**0.1379**				
Total C&I LLF Cost of Gas Rate	**$**	**1.0993**				

Local Delivery Adjustment Clause

Rate Schedule	RLIAP	DSM	ERC	ITM	WLNG	CCE	RCE	LDAC
Residential Heating	$0.0052	$0.0200	$0.0051	$0.0000	$0.0000	$0.0000	$0.0000	$0.0303
Residential Non-Heating	$0.0052	$0.0200	$0.0051	$0.0000	$0.0000	$0.0000	$0.0000	$0.0303
Small C&I	$0.0052	$0.0062	$0.0051	$0.0000	$0.0000	$0.0000	$0.0000	$0.0165
Medium C&I	$0.0052	$0.0062	$0.0051	$0.0000	$0.0000	$0.0000	$0.0000	$0.0165
Large C&I	$0.0052	$0.0062	$0.0051	$0.0000	$0.0000	$0.0000	$0.0000	$0.0165
No Previous Sales Service								

Issued: September 15, 2009

Effective: With Service Rendered On and After November 1, 2009

Authorized by NHPUC Order No. ______ in Docket N. DG 09-___, dated __________, 2009

Issued by: [signature]

Title: Treasurer

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

WINTER SEASON RESIDENTIAL RATES

	Winter Season November 2009 - April 2009	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**			
	Monthly Customer Charge	$9.50	**$9.50**	**$9.50**
	First 50 therms	$0.4102	**$0.4405**	**$1.5318**
	All usage over 50 therms	$0.2990	**$0.3293**	**$1.4206**
	LDAC	**$0.0303**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0913**		
Residential Heating Low Income	**Tariff Rate R 10:**			
	Monthly Customer Charge	$3.80	**$3.80**	**$3.80**
	First 50 therms	$0.1641	**$0.1944**	**$1.2857**
	All usage over 50 therms	$0.1196	**$0.1499**	**$1.2412**
	LDAC	**$0.0303**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0913**		
Residential Non-Heating	**Tariff Rate R 6:**			
	Bi-monthly Customer Charge	$19.00	**$19.00**	**$19.00**
	First 20 therms	$0.4067	**$0.4370**	**$1.5283**
	All usage over 20 therms	$0.3082	**$0.3385**	**$1.4298**
	Monthly Customer Charge	$9.50	**$9.50**	**$9.50**
	First 10 therms	$0.4067	**$0.4370**	**$1.5283**
	All usage over 10 therms	$0.3082	**$0.3385**	**$1.4298**
	LDAC	**$0.0303**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0913**		
Residential Non-Heating Low Income	**Tariff Rate R 11:**			
	Bi-monthly Customer Charge	$13.80	**$13.80**	**$13.80**
	First 20 therms	$0.3084	**$0.3387**	**$1.4300**
	All usage over 20 therms	$0.2335	**$0.2638**	**$1.3551**
	Monthly Customer Charge	$6.90	**$6.90**	**$6.90**
	First 10 therms	$0.3084	**$0.3387**	**$1.4300**
	All usage over 10 therms	$0.2335	**$0.2638**	**$1.3551**
	LDAC	**$0.0303**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0913**		

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

WINTER SEASON C&I RATES

	Winter Season November 2009 - April 2009	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$18.70	**$18.70**	**$18.70**
	First 75 therms	$0.3077	**$0.3242**	**$1.4235**
	All usage over 75 therms	$0.2007	**$0.2172**	**$1.3165**
	LDAC	**$0.0165**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0993**		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$18.70	**$18.70**	**$18.70**
	First 75 therms	$0.3018	**$0.3183**	**$1.3732**
	All usage over 75 therms	$0.1969	**$0.2134**	**$1.2683**
	LDAC	**$0.0165**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0549**		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$60.30	**$60.30**	**$60.30**
	All usage	$0.1942	**$0.2107**	**$1.3100**
	LDAC	**$0.0165**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0993**		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$60.30	**$60.30**	**$60.30**
	First 1300 therms	$0.1862	**$0.2027**	**$1.2576**
	All usage over 1300 therms	$0.1467	**$0.1632**	**$1.2181**
	LDAC	**$0.0165**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0549**		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$254.00	**$254.00**	**$254.00**
	All usage	$0.1725	**$0.1890**	**$1.2883**
	LDAC	**$0.0165**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0993**		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$254.00	**$254.00**	**$254.00**
	All usage	$0.1262	**$0.1427**	**$1.1976**
	LDAC	**$0.0165**		
	Gas Cost Adjustment:			
	Cost of Gas	**$1.0549**		

Issued: September 15, 2009 **Issued by:** [signature]
Effective: With Service Rendered On and After November 1, 2009 **Title:** **Treasurer**
Authorized by NHPUC Order No. ______, in Docket No. DG 09-___, dated __________, 2009.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

WINTER SEASON DELIVERY RATES

	Winter Season November 2009 - April 2009		Tariff Rates	Total Delivery Rates (Includes LDAC)
C&I Low Annual/High Winter	**Tariff Rate T 40:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3077	**$0.3242**
	All usage over 75 therms		$0.2007	**$0.2172**
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		**$0.0165**	
C&I Low Annual/Low Winter	**Tariff Rate T 50:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3018	**$0.3183**
	All usage over 75 therms		$0.1969	**$0.2134**
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		**$0.0165**	
C&I Medium Annual/High Winter	**Tariff Rate T 41:**			
	Monthly Customer Charge		$60.30	**$60.30**
	All usage		$0.1942	**$0.2107**
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		**$0.0165**	
C&I Medium Annual/Low Winter	**Tariff Rate T 51:**			
	Monthly Customer Charge		$60.30	**$60.30**
	First 1300 therms		$0.1862	**$0.2027**
	All usage over 1300 therms		$0.1467	**$0.1632**
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		**$0.0165**	
C&I High Annual/High Winter	**Tariff Rate T 42:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		$0.1725	**$0.1890**
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		**$0.0165**	
C&I High Annual/Low Winter	**Tariff Rate T 52:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		$0.1262	**$0.1427**
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		**$0.0165**	
C&I Interruptible Transportation	**Tariff Rate IT:**			
	Monthly Customer Charge		$170.21	**$170.21**
	First 20,000 therms		$0.0407	**$0.0407**
	All usage over 20,000 therms		$0.0347	**$0.0347**

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

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

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

- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$16.49 per MMBtu** per MDPQ per month for November 2009 through April 2010.

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

III. Supplier Services and Associated Fees:

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

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, 2009 through October 31, 2010.

Commercial and Industrial

	High Winter Use	Low Winter Use
Pipeline:	6.09%	53.98%
Storage:	32.91%	16.13%
Peaking:	60.99%	29.89%

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX D

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

The Re-Entry Fee shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Firm Sales Service Re-Entry Fee Unit Charge shall be applicable for the period of November 1, 2009 through October 31, 2010.

Effective Dates:	**November 1, 2009 – October 31, 2010**
Annual Average Unit Cost:	$ 231.48
25% - Annual Charge for Re-Entry Fee:	$ 57.87
Monthly Unit Charge for Re-Entry Fee:	$ 4.823

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CALCULATION OF COST OF GAS ADJUSTMENT

New Hampshire Division
Period Covered: May 1, 2009 - October 31, 2009
Anticipated Cost of Delivered and Produced Gas

Delivered:	Therms	Rate	Amount
Product: - Commodity			
Pipeline Supply	9,327,652	$0.3347	$3,122,210
Storage Withdrawals	0		$0
Peaking Supply	45,688	$0.9190	$41,988
Hedging (Gain)/Loss			$1,594,727
Interruptible Included Above			($7,547)
Adjustment for Actual Costs			$0
Product: - Demand			
Granite State and Others			$196,751
Pipeline Reservation			
Granite State and Others			$833,449
Storage & Peaking Demand			
Tennessee and Others			$406,625
Capacity Release			$0
Interruptble Margins			$0
Less: Unaccounted For, Company Use & Interruptible Volumes	(175,446)		$0
TOTAL Anticipated Cost of Gas	**9,197,894**	**$0.6728**	**$6,188,203**

Issued: April 13, 2009
Effective Date: May 1, 2009

Issued by:
Title: Treasurer

Authorized by NHPUC Order No. 24,961, in Docket No. DG 09-052, dated April 30, 2009.

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Calculation of Anticipated Indirect Cost of Gas-New Hampshire Division

Working Capital Calculation		
Total Anticipated Direct Cost of Gas-Commodity	$4,751,379	
Total Anticipated Direct Cost of Gas-Demand	$1,436,825	
Interruptible Profits	$0	
LESS Anticipated Direct Costs assigned to Non-Grandfathered Transportation	$0	
Total Direct Cost of Gas (including Summer Deferred)	$6,188,204	
Total Direct gas Costs-Including Summer Deferred	$6,188,204	
Working Capital Percentage (NHPUC No. 10 Section IV, 6.1)	0.19%	
Working Capital Allowance (NHPUC No. 10 Section IV, 6.1)	$11,758	
Plus: Working Capital Reconciliation	$7,918	
Total Working Capital Allowance	**$19,676**	
Bad Debt Calculation		
Total Anticipated Direct Cost of Gas	$6,188,204	
Plus: Prior Period Under/(Over) Collection	$502,551	
Plus : Interest	$1,970	
Plus: Total Working Capital	$19,676	
Subtotal	$6,712,401	
Bad Debt Percentage (NHPUC No. 10 Section IV, 6.1)	0.45%	
Total Bad Debt Allowance	$30,206	
Plus: Bad Debt Reconciliation	$18,852	
Total Bad Debt Allowance	**$49,058**	
		Rate / Therm
Working Capital Allowance	$19,676	
Bad Debt Allowance	$49,058	
Miscellaneous Overhead-23.68% Allocated to Summer Season	$31,261	
Capacity Reserve (Forecasted Transportation Therms * $0.0055)	$0	
Production and Storage Capacity	$0	
Prior Period Under/(Over) Collection	$502,551	
Refunds	$0	
Interest	$1,970	
Total Anticipated Indirect Cost of Gas	$604,516	$0.0657
Total Anticipated Direct Cost of Gas-Commodity	$4,751,379	$0.5166
Total Anticipated Direct Cost of Gas-Demand	$1,436,825	$0.1562
Total Anticipated Period Cost of Gas	$6,792,720	$0.7385
Forecasted Off-peak Period Volumes (Therms)	9,197,893	

	Residential	C&I Low Winter	C&I High Winter
Forecasted Winter Season Cost of Gas Rate:			
COGw-Commodity	$0.5166	$0.4812	$0.5737
COGw-Demand	$0.1562	$0.1316	$0.1961
COGw-Indirect	$0.0657	$0.0657	$0.0657
COGw-Total (May 1, 2009 Billing Rate)	**$0.7385**	**$0.6785**	**$0.8355**
Maximum	**$0.9231**	**$0.8481**	**$1.0444**

Issued: April 13, 2009 **Issued by:**
Effective: With Service Rendered On and After May 1, 2009 **Title:** **Treasurer**
Authorized by NHPUC Order No. 24,961, in Docket No. DG 09-052, dated April 30, 2009.

Local Delivery Adjustment Clause

Rate Schedule	RLIAP	DSM	ERC	ITM	WLNG	CCE	RCE	LDAC
Residential Heating	~~$0.0039~~	~~$0.0113~~	~~$0.0103~~	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0255~~
Residential Non-Heating	~~$0.0039~~	~~$0.0113~~	~~$0.0103~~	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0255~~
Small C&I	~~$0.0039~~	~~$0.0069~~	~~$0.0103~~	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0211~~
Medium C&I	~~$0.0039~~	~~$0.0069~~	~~$0.0103~~	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0211~~
Large C&I	~~$0.0039~~	~~$0.0069~~	~~$0.0103~~	$0.0000	$0.0000	$0.0000	$0.0000	~~$0.0211~~
No Previous Sales Service								

Residential Heating	$0.0052	$0.0200	$0.0051					$0.0303
Residential Non-Heating	$0.0052	$0.0200	$0.0051					$0.0303
Small C&I	$0.0052	$0.0062	$0.0051					$0.0165
Medium C&I	$0.0052	$0.0062	$0.0051					$0.0165
Large C&I	$0.0052	$0.0062	$0.0051					$0.0165

~~Issued by: Stephen H. Bryant~~
~~Title: President~~

Issued: ~~November 7, 2008~~ September 15, 2009
Effective: With Service Rendered On and After November 1, 200~~8~~ 9
Authorized by NHPUC Order No. ~~24,912~~ in Docket N. DG ~~08-115~~, dated ~~October 31, 2008~~

Issued by:
Title: Treasurer

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

~~SUMMER~~ WINTER SEASON DELIVERY RATES

	~~Summer~~ Winter Season ~~May~~ November 2009 - ~~October~~ April 2009	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**			
	Monthly Customer Charge	$9.50	**$9.50**	**$9.50**
	First 50 therms	$0.4102	~~$0.4357~~ $0.4405	~~$1.1742~~ $1.5318
	All usage over 50 therms	$0.2990	~~$0.3245~~ $0.3293	~~$1.0630~~ $1.4206
	LDAC	~~$0.0255~~ $0.0303		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7385~~ $1.0913		

Residential Heating Low Income	**Tariff Rate R 10:**			
	Monthly Customer Charge	$3.80	**$3.80**	**$3.80**
	First 50 therms	$0.1641	~~$0.1896~~ $0.1944	~~$0.9281~~ $1.2857
	All usage over 50 therms	$0.1196	~~$0.1451~~ $0.1499	~~$0.8836~~ $1.2412
	LDAC	~~$0.0255~~ $0.0303		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7385~~ $1.0913		

Residential Non-Heating	**Tariff Rate R 6:**			
	Bi-monthly Customer Charge	$19.00	**$19.00**	**$19.00**
	First 20 therms	$0.4067	~~$0.4322~~ $0.4370	~~$1.1707~~ $1.5283
	All usage over 20 therms	$0.3082	~~$0.3337~~ $0.3385	~~$1.0722~~ $1.4298
	Monthly Customer Charge	$9.50	**$9.50**	**$9.50**
	First 10 therms	$0.4067	~~$0.4322~~ $0.4370	~~$1.1707~~ $1.5283
	All usage over 10 therms	$0.3082	~~$0.3337~~ $0.3385	~~$1.0722~~ $1.4298
	LDAC	~~$0.0255~~ $0.0303		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7385~~ $1.0913		

Residential Non-Heating Low Income	**Tariff Rate R 11:**			
	Bi-monthly Customer Charge	$13.80	**$13.80**	**$13.80**
	First 20 therms	$0.3084	~~$0.3339~~ $0.3387	~~$1.0724~~ $1.4300
	All usage over 20 therms	$0.2335	~~$0.2590~~ $0.2638	~~$0.9975~~ $1.3551
	Monthly Customer Charge	$6.90	**$6.90**	**$6.90**
	First 10 therms	$0.3084	~~$0.3339~~ $0.3387	~~$1.0724~~ $1.4300
	All usage over 10 therms	$0.2335	~~$0.2590~~ $0.2638	~~$0.9975~~ $1.3551
	LDAC	~~$0.0255~~ $0.0303		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7385~~ $1.0913		

Issued: ~~April 13, 2009~~ September 15, 2009 **Issued by:** [signature]

Effective: With Service Rendered On and After ~~May~~ November 1, 2009 **Title:** Treasurer

Authorized by NHPUC Order No. ~~24,961~~, in Docket No. DG 09-~~052~~, dated ~~April 30, 2009~~.

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

~~SUMMER~~ WINTER SEASON DELIVERY RATES

	~~Summer~~ Winter Season ~~May~~ November 2009 - ~~October~~ April 2009	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$18.70	**$18.70**	**$18.70**
	First 75 therms	$0.3077	~~$0.3288~~ $0.3242	~~$1.1643~~ $1.4235
	All usage over 75 therms	$0.2007	~~$0.2218~~ $0.2172	~~$1.0573~~ $1.3165
	LDAC	~~0.0211~~ 0.0165		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.8355~~ $1.0993		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$18.70	**$18.70**	**$18.70**
	First 75 therms	$0.3018	~~$0.3229~~ $0.3183	~~$1.0014~~ $1.3732
	All usage over 75 therms	$0.1969	~~$0.2180~~ $0.2134	~~$0.8965~~ $1.2683
	LDAC	~~0.0211~~ 0.0165		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.6785~~ $1.0549		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$60.30	**$60.30**	**$60.30**
	All usage	~~$0.1124~~ $0.1942	~~$0.1335~~ $0.2107	~~$0.9690~~ $1.3100
	LDAC	~~0.0211~~ 0.0165		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.8355~~ $1.0993		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$60.30	**$60.30**	**$60.30**
	First ~~1000~~ 1300 therms	~~$0.1112~~ $0.1862	~~$0.1323~~ $0.2027	~~$0.8108~~ $1.2576
	All usage over ~~1000~~ 1300 therms	~~$0.0780~~ $0.1467	~~$0.0991~~ $0.1632	~~$0.7776~~ $1.2181
	LDAC	~~0.0211~~ 0.0165		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.6785~~ $1.0549		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$254.00	**$254.00**	**$254.00**
	All usage	~~$0.0964~~ $0.1725	~~$0.1175~~ $0.1890	$0.9530 $1.2883
	LDAC	~~0.0211~~ 0.0165		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.8355~~ $1.0993		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$254.00	**$254.00**	**$254.00**
	All usage	~~$0.0653~~ $0.1262	~~$0.0864~~ $0.1427	~~$0.6785~~ $1.1976
	LDAC	~~0.0211~~ 0.0165		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.6785~~ $1.0549		

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

~~SUMMER~~ WINTER SEASON DELIVERY RATES

	~~Summer~~ Winter Season ~~May~~ November 2009 - ~~October~~ April 2009		Tariff Rates	Total Delivery Rates (Includes LDAC)
C&I Low Annual/High Winter	**Tariff Rate T 40:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3077	~~$0.3288~~ $0.3242
	All usage over 75 therms		$0.2007	~~$0.2218~~ $0.2172
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		~~0.0211~~ 0.0165	
C&I Low Annual/Low Winter	**Tariff Rate T 50:**			
	Monthly Customer Charge		$18.70	**$18.70**
	First 75 therms		$0.3018	~~$0.3229~~ $0.3183
	All usage over 75 therms		$0.1969	~~$0.2180~~ $0.2134
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		~~0.0211~~ 0.0165	
C&I Medium Annual/High Winter	**Tariff Rate T 41:**			
	Monthly Customer Charge		$60.30	**$60.30**
	All usage		~~$0.1124~~ $0.1942	~~$0.1335~~ $0.2107
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		~~0.0211~~ 0.0165	
C&I Medium Annual/Low Winter	**Tariff Rate T 51:**			
	Monthly Customer Charge		$60.30	**$60.30**
	First ~~1000~~ 1300 therms		~~$0.1112~~ $0.1862	~~$0.1323~~ $0.2027
	All usage over ~~1000~~ 1300 therms		~~$0.0780~~ $0.1467	~~$0.0991~~ $0.1632
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		~~0.0211~~ 0.0165	
C&I High Annual/High Winter	**Tariff Rate T 42:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		~~$0.0964~~ $0.1725	~~$0.1175~~ $0.1890
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		~~0.0211~~ 0.0165	
C&I High Annual/Low Winter	**Tariff Rate T 52:**			
	Monthly Customer Charge		$254.00	**$254.00**
	All usage		~~$0.0653~~ $0.1262	~~$0.0864~~ $0.1427
(Capacity exempt Customers Only)	Capacity Reserve Charge		$0.0055	
	LDAC		~~0.0211~~ 0.0165	
C&I Interruptible Transportation	**Tariff Rate IT:**			
	Monthly Customer Charge		$170.21	**$170.21**
	First 20,000 therms		$0.0407	**$0.0407**
	All usage over 20,000 therms		$0.0347	**$0.0347**

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VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

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

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

- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$16.49 per MMBtu** per MDPQ per month for November 2009 through April 2010

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

III. Supplier Services and Associated Fees:

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

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Issued: September 15, 2009 Issued by:_______

Effective: November 1, 2009 Title: Treasurer

Authorized by NHPUC Order No. in Docket No. DG 09-, dated.

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VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, 2009 through October 31, 2010.

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Commercial and Industrial

	High Winter Use	Low Winter Use
Pipeline:	6.09%	53.98%
Storage:	32.91%	16.13%
Peaking:	60.99%	29.89%

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Issued: September 15, 2009 Issued By: ______

Effective: November 1, 2009 Title: Treasurer

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VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX D

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

The Re-Entry Fee shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Firm Sales Service Re-Entry Fee Unit Charge shall be applicable for the period of November 1, 2009 through October 31, 2010.

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Effective Dates:	**November 1, 2009 – October 31, 2010**
Annual Average Unit Cost:	$ 231.48
25% - Annual Charge for Re-Entry Fee:	$ 57.87
Monthly Unit Charge for Re-Entry Fee:	$ 4.823

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Issued: September 15, 2009 Issued By: ______

Effective: November 1, 2009 Title: Treasurer

Authorized by NHPUC Order No., in Docket No. DG 09-, dated

Northern Utilities, Inc.

New Hampshire Division

2009 / 2010 WINTER PERIOD
PROPOSED COST OF GAS ADJUSTMENT

TO BE EFFECTIVE NOVEMBER 1, 2009

FILED SEPTEMBER 15, 2009

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc. – New Hampshire Division

2009/2010 Winter Period Proposed Cost of Gas Adjustment

To be Effective November 1, 2009

INDEX

Unitil
Northern Utilities, Inc.

INDEX (continued)

Unitil
Northern Utilities, Inc.

Prefiled Testimony of James D. Simpson

Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
PEAK PERIOD 2009 / 2010
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
JAMES D. SIMPSON

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is James D. Simpson. I am a Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Marlborough, Massachusetts 01752.

Q. Please describe your relevant work experience.

A. I have over 30 years experience in the energy industry in a variety of roles and responsibilities with an overall focus on economics, pricing, forecasting and regulatory matters. I was employed by Bay State Gas Company ("Bay State") from 1982 until 2000; for much of my time at Bay State, I was responsible for rates and regulatory affairs for Bay State and Northern Utilities, Inc. ("Northern" or "Northern Utilities"). I have been with Concentric Energy Advisors ("Concentric") since 2005. My professional qualifications and experience are provided in Attachment NUI-JDS-1 of this testimony.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes, I testified on behalf of Northern Utilities in the 2009 Summer Cost of Gas proceeding, Docket DG 09-052. In addition, while I was employed by Bay State, I testified before the Commission on behalf of Northern Utilities in many proceedings on a variety of issues related to rates, growth-related projects and other economic and regulatory matters.

Q. For what purpose has Northern Utilities retained Concentric?

A. As I explained in the Pre-filed testimony that I prepared in support of Northern's 2009 Summer COG filing, Unitil Service Corp. ("Unitil") initially requested Concentric's assistance with several tasks related to Cost of Gas factors ("COG") for the New Hampshire and Maine divisions of Northern Utilities. As part of the overall effort to integrate Northern Utilities' business and operating functions into Unitil after the acquisition of Northern from NiSource Inc. ("NiSource") on December 1, 2008, Unitil requested that Concentric: (1) review the Excel® files that NiSource had developed to calculate Winter and Summer Cost of Gas Factors for the New Hampshire and Maine divisions; (2) if necessary, revise the Excel® files to make the COG calculation process more efficient, transparent, and reviewable; (3) testify on behalf of Northern in the 2009 Summer COG proceedings; and (4) provide training to Unitil personnel concerning the COG calculation process and the COG file that Concentric developed.

Most recently, Unitil has requested that I testify on behalf of Northern in the 2009 / 2010 Winter COG proceedings.

Q. Please explain the purpose of your prepared direct testimony in this proceeding.

A. Francis X. Wells, Senior Energy Trader for Unitil, and I are sharing the responsibility in this proceeding for describing and explaining the proposed New Hampshire division 2009 / 2010 Winter COG. Mr. Wells will describe and explain the forecast of gas demand and the resulting forecasted gas sendout and gas costs that he developed for the New Hampshire and Maine divisions. Mr. Wells will also describe the impact of the Company's Hedging Program for the 2009 / 2010 Winter period.

I will describe and explain the calculation of the COG rates that the New Hampshire division proposes to bill from November 1, 2009 to April 30, 2010. I will also discuss the impact that the proposed COG will have on the bills of the Company's typical residential customer. Finally, I will provide the calculation and supporting documentation for the Supplier Balancing Charge that the New Hampshire division proposes to bill from November 1, 2009 to October 31, 2010.

Q. Please provide a list of the attachments that you have prepared in support of your testimony.

A. The attachments that I have prepared in support of my testimony are listed below.

Attachment NUI-JDS-1	James D. Simpson Professional Qualifications
Attachment NUI-JDS-2	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Attachment NUI-JDS-3	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons
Attachment NUI-JDS-4	Development of New Hampshire Division Rate Class Allocators
Attachment NUI-JDS-5	Allocation of New Hampshire Demand Costs To New Hampshire Firm Sales Rate Classes
Attachment NUI-JDS-6	Allocation of Commodity Costs To New Hampshire and Maine Divisions
Attachment NUI-JDS-7	New Hampshire Division Commodity Cost Analysis
Attachment NUI-JDS-8	Northern Utilities Inventory Activity
Attachment NUI-JDS-9	Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Attachment NUI-JDS-10	New Hampshire Division 2009 / 2010 Winter Tariff Sheets
Attachment NUI-JDS-11	Supporting Detail to the Tariff Sheets Supplier Detail, Residential Calculations
Attachment NUI-JDS-12	Comparison: 2009 / 2010 Winter Compared to 2008 / 2009 Winter
Attachment NUI-JDS-13	New Hampshire Division 2009 / 2010 Winter Typical Bill Analyses
Attachment NUI-JDS-14	Supplier Balancing Charge

II. COST OF GAS FACTOR

A. Preliminary Matters

Q. As you explained in your introductory comments and as you testified in Northern Utilities' 2009 Summer COG proceeding, in preparation for the 2009 Summer COG filing, Northern requested that you (a) review the COG files that NiSource had provided to Unitil and (b) revise these files, if necessary, to make the COG calculation process more efficient and reviewable. Please provide a summary of your review, and the modifications to Northern's COG calculation process that were made as a result of that review.

A. Although NiSource's COG model provided reasonable COG calculations that comply with Northern's currently effective Cost of Gas Clause[1] ("COGC"), Concentric found that it was difficult to perform "quality control" measures on the COG calculations because of the way that the NiSource COG model was organized. We also determined that it was difficult to maintain control of revisions to the COG filings that are made during the course of COG proceedings in New Hampshire and Maine. To address these matters, Concentric developed a single COG file in place of NiSource's separate, linked files. Concentric also re-organized the COG file in the following ways:

- A series of input spreadsheets was created so that all data from outside the COG model can be entered in an orderly manner into these dedicated spreadsheets.[2]
- Worksheet tabs were renamed and re-ordered by major function.

[1] As provided for in Second Revised Page 18 through First Revised Page 37.1 of the Company's gas tariffs.
[2] The dedicated data input spreadsheets enhance the process of checking for data entry errors and ensuring that all data updates have been made.

- Calculations in the COG file were reorganized to generally flow from worksheets located left to right and within worksheets from lower-numbered rows to higher-numbered rows.

Q. Please describe and explain any changes that you have made prior to the 2009 Summer COG filing that have also affected the 2009 / 2010 Winter COG calculations.

A. In preparation for Northern's 2009 Summer filing Concentric made the following minor changes to the calculation of Northern's Winter and Summer COG rates, to improve the accuracy of the calculations:

- Modifications were made to spreadsheet formulas and layout so that the COG rates are now determined from data that is specific to firm sales. For example, in contrast to COG rates prior to the 2009 Summer filing, the 2009 Summer COG rates and the proposed 2009 / 2010 Winter COG rates do not include imputed sendout volumes, imputed commodity costs, or sales volumes to firm transportation customers that are assigned capacity. I will explain this change in more detail in the following response.
- Related to the first modification, sales service demand costs are now calculated by subtracting estimated New Hampshire transportation customer capacity assignment revenues from total New Hampshire allocated demand costs.
- Modifications were made to the calculation of the COG rates so that total Northern hedging gains and losses are forecasted for each month in the forecast period and allocated to the New Hampshire and Maine divisions within the COG file in the same manner that monthly commodity costs are allocated to the divisions.

Q. Please explain the first modification that you listed, which was to base the COG calculation on data specific to firm sales.

A. During our initial review and assessment of the COG process and the Excel® spreadsheets that NiSource had developed, Unitil determined that the COG rates could be more accurately estimated and the overall COG process could be improved by using sales-specific data (e.g. forecast delivery volumes, forecast commodity costs and forecast demand costs for firm sales classes), rather than combined sales and assigned transportation data[3]. These changes to the COG calculations will allow Unitil to: (1) use results from the COG forecasts in Unitil's internal financial planning; (2) more accurately estimate and monitor monthly under and over collection balances; and (3) more readily perform variance analyses at the conclusion of each COG period to determine the reasons for differences between forecast and actual results.

Q. In addition to the changes that were implemented for the 2009 Summer COG filing, please describe and explain any additional changes that you have made to the calculation of Northern's 2009 / 2010 Winter COG rates.

A. As a preliminary matter, I made a change to the format of Attachments NUI-JDS-2 through NUI-JDS-7, and Attachments NUI-JDS-9 through NUI-JDS-11 that does not have an effect on the calculation of the COG rates. I added a column to these attachments that provides

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[3] Northern's COGC allows for the calculation of the peak period COG to be based on (1) data relating to sales service classes or (2) data relating to sales classes and transportation customers that are not exempt from the Company's Capacity Assignment provisions.

explanations for the calculations or identifies the source for the data in each row; this re-formatting was done to make these attachments easier to follow and audit.

Also, as I will explain in more detail in Section II.B of my testimony, Allocation of Demand-Related Costs to New Hampshire and Maine divisions, I made minor revisions to the calculation of the allocation factors that are used to assign Northern total peaking demand costs to Winter period months. Finally, as I will explain in more detail in Section II.B of my testimony, I corrected the way that the costs of pipeline capacity used to transport commodity into Northern's contracted underground storage were reflected in the Storage demand costs and Pipeline demand costs.

B. Allocation of Demand-Related Costs to New Hampshire and Maine Divisions

Q. Please explain how the projected capacity-related costs, i.e. (a) pipeline reservation and gas supply demand charges, (b) underground storage capacity costs, and (c) peaking resource capacity costs are allocated between Northern's New Hampshire and Maine divisions.

A. Total Northern capacity-related costs are allocated between the New Hampshire and Maine divisions by application of Modified Proportional Responsibility ("MPR") allocators. The MPR methodology assigns fixed capacity-related gas costs to the New Hampshire and Maine divisions in a two-step process: (1) capacity-related costs, by resource type[4], are allocated to months by application of MPR allocation factors; and (2) the capacity-related costs allocated to each month are allocated to the New Hampshire and Maine divisions based on the

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[4] Pipeline, storage, and peaking

relative shares of Design Year demand[5] in that month. This MPR methodology was approved by the Commission on December 23, 2005 to be effective January 1, 2006, pursuant to the Commission-approved settlement in Docket DG 05-080.

As I will explain in more detail in the following responses, I used the MPR methodology to allocate total Northern annual demand costs to the New Hampshire and Maine divisions for the 2009 / 2010 Winter period, i.e. November, 2009 through April, 2010, and for the 2010 Summer COG, i.e. May through October, 2010.

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2009 through October, 2010 to the New Hampshire and Maine divisions.

A. I have prepared Attachment NUI-JDS-2 to explain how I calculated the MPR factors and then how I used these factors to allocate total Northern annual demand costs for the twelve month period November, 2009 through October, 2010 ("2009 / 2010 Gas Year") to the New Hampshire and Maine divisions. Attachment NUI-JDS-2 is arranged in three major sections: (1) total fixed capacity costs, by type of resource (pipeline, storage, and peaking) are summarized in Lines 1 through 10; (2) Lines 13 through 56 show the allocation of these fixed capacity costs for each resource type to each month in the 2009 / 2010 Gas Year according to MPR allocators that were developed specifically for each resource type based on design year sendout volumes for that resource type; and (3) the fixed capacity costs that

[5] For the MPR allocation process, Design Year demand is calculated as the actual demand to New Hampshire and Maine firm sales and assigned capacity / non-grandfathered transportation customers for the period May, 2008 through April, 2009, adjusted to reflect design winter conditions from November through April, and normal conditions from May through October.

are allocated to each month in Step 2 are then allocated to the New Hampshire and Maine divisions according to design year total firm sendout as shown in Lines 58 through 90. The last column of Pages 2 and 4 of Attachment NUI-JDS-2 is an example of the descriptions and explanations that I have added to the attachments, as I discussed in Section II.A, Preliminary Matters.

Q. Please explain in more detail how you allocated total Northern capacity costs to the months in the 2009 / 2010 Gas Year.

A. Lines 3 through 6 of Attachment NUI-JDS-2 show the total Northern annual projected demand costs for Pipeline, Storage, and Peaking resources; these forecasted demand costs were provided to me by Mr. Wells.[6] Line 7 shows the PNGTS Litigation Expense, which is discussed in Mr. Well's testimony. Throughout the remainder of the attachments that I have prepared, I have reflected the PNGTS litigation costs as an offset to Asset Management revenues.[7] Mr. Wells also provided estimates of Capacity Release revenues and Asset Management revenues, which I have summarized in Lines 8 and 9 of Attachment NUI-JDS-2.

The development of the MPR factors and the application of these factors to allocate Pipeline, Storage and Peaking demand costs to each month are shown on Lines 17 through 22, Lines 33 through 40, and Lines 44 though 49, respectively. In addition, Lines 26 through 29 show the calculation of the Injection Fees by month. Injection Fees are the capacity

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6 The forecast of demand costs that Mr. Wells prepared is provided in Attachment NUI-FXW-4.
7 For example, the total Asset Management credit on Line 55 of Attachment NUI-JDS-2, $3,335,905, is the sum of Asset Management revenues, $3,770,000, as shown on Line 9; less PNGTS litigation costs, $434,095 as shown on Line 7.

costs of that portion of Northern's pipeline capacity that is used to transport gas to the underground storage fields; these Injection Fees are added to the Storage demand costs, as shown on Line 39, and subtracted from the Pipeline demand costs, as shown on Line 53.

Northern capacity costs that have been allocated to each month are summarized and consolidated on Lines 50 through 56. Lines 50, 51 and 52 repeat the Pipeline, Storage, and Peaking capacity costs from Lines 22, 40, and 49. Line 53 shows the credit to Pipeline capacity costs that is related to the Injection Fees that have been added to the Storage capacity costs. In addition, (a) 1/5th of total Capacity Release revenues are allocated to each month from November through March, as shown on Line 54 and (b) 1/6th of total Asset Management revenues are allocated to each month from November through April, as shown on Line 55.

Q. In Section II.A, Preliminary Matters, you explained that a minor revision had been made to the calculation of the MPR factors that are used to allocate Northern total Peaking resource demand costs to each month. Please explain this revision.

A. Rows 44 through 49 of Attachment NUI-JDS-2 show the allocation of Peaking demand costs to the months; the Peaking demand cost MPR factor shown on Line 48 is derived from the estimated Peaking resource sendout volumes by month under design year conditions (Line 44, "Design Year Peaking Volumes"). In the 2008 / 2009 Winter COG filing, the Peaking demand costs were allocated to each month based on the Storage MPR factor; a Peaking demand cost MPR allocator was not prepared for the 2008 / 2009 Winter COG.

Q. Finally, how are the total demand costs and the capacity release and asset management revenues, which have been allocated to each month according to the process that you described above, allocated to the New Hampshire and Maine divisions?

A. Total Northern demand costs and capacity release and asset management revenues allocated to each month are then allocated to the New Hampshire and Maine divisions according to the design year total sendout for New Hampshire and Maine, which is shown in Lines 61 and 62 of Attachment NUI-JDS-2; the calculated percentages are provided in Lines 65 and 66. In accordance with the Commission-approved settlement in Docket DG 05-080, the design year sendout quantities for the COG period, as shown on Lines 61 and 62, are the sendout quantities required to serve New Hampshire and Maine firm sales customers and transportation customers that are subject to the capacity assignment requirements under Design Winter conditions from November, 2008 through April, 2009 and under normal weather conditions from May, 2009 through October, 2009.

As shown on Line 90 of Attachment NUI-JDS-2, 47.46% of total Northern demand costs from November, 2009 through October, 2010 will be allocated to New Hampshire and the remaining 52.54%, as shown on Line 81, will be allocated to Maine.

C. Allocation of New Hampshire Demand-Related Costs to Seasons

Q. Please explain how the projected annual demand costs that are allocated to New Hampshire are then assigned to be recovered in the 2009 / 2010 Winter period and the 2010 Summer period.

A. I used the Simplified Market Based Allocator ("SMBA") methodology, in accordance with the Company's COGC, to allocate New Hampshire demand costs for firm sales customers to months, and then to seasons; I have prepared Attachment NUI-JDS-3 to show detailed support for these calculations.

Lines 3 through 5 of Attachment NUI-JDS-3 summarize the Pipeline, Storage, and Peaking demand costs that are allocated to the New Hampshire division, as determined in Attachment NUI-JDS-2. Lines 7 through 23 of Attachment NUI-JDS-3 show the calculation of net demand costs for firm sales customers, which are the total demand costs allocated to New Hampshire less the capacity assignment revenues from New Hampshire non-exempt transportation customers; Mr. Wells prepared Attachment NUI-FXW-5 to calculate the capacity assignment revenue credit that is shown on Line 7 of Attachment NUI-JDS-3. The Winter and Summer rates that will be charged to New Hampshire firm sales customers from November, 2009 through October, 2010 will recover the following demand-related costs: (1) the net pipeline demand costs shown on Line 20; (2) the net storage costs shown on Line 21; and (3) the net peaking demand costs shown on Line 22 of Attachment NUI-JDS-3.

Lines 25 through 41 of Attachment NUI-JDS-3 show the calculation of pipeline demand costs for sales customers, separated into: (1) base use demand costs, and (2) remaining use demand costs.[8] The base use that is shown on Line 32 of Attachment NUI-JDS-3 is the average projected daily use in July and August, 2010[9] for all firm sales classes; the base pipeline demand cost that is shown on Line 40 of Attachment NUI-JDS-3 is calculated by

[8] This separation is necessary because the SMBA allocation methodology allocates base use demand costs to seasons on a different basis than remaining demand costs are allocated to seasons.

[9] Average Projected Daily demand by class is shown in Attachment NUI-JDS-4, Lines 36 through 48.

multiplying base use times the weighted average annual cost of pipeline capacity, as shown on Line 36 of Attachment NUI-JDS-3. Line 41 shows the remaining net pipeline demand costs for sales customers, which is the difference between total net pipeline demand costs and base use pipeline demand costs.

Lines 45 through 50 show the calculation of the "All Months" PR factor that is used to allocate the following costs to the 2009 / 2010 Gas Year: (a) remaining net pipeline demand costs; (b) storage costs; and (c) peaking costs. Lines 52 through 57 show the calculation of the "Peak Months Only" PR factor that is used to allocate: (d) capacity release and asset management revenues, (e) interruptible margins and (f) re-entry fee revenues to the six Winter months, November, 2009 through April, 2010. These PR factors are summarized by type of capacity cost in Lines 61 through 65. Finally, as shown on Lines 83 and 84, (g) local production and storage costs are assigned to the Winter period, and (h) miscellaneous overhead costs are assigned to the Winter and Summer periods based on Winter and Summer normal sales quantities. Line 69 of Attachment NUI-JDS-3 shows that one twelfth of the net annual base use pipeline demand costs are allocated to each month and Lines 70 through 80 show the detailed allocation to months of all other components that are included in the total net direct demand costs, based on the "All Months" and "Peak Months Only" allocation factors.

The total direct demand costs to be recovered in the 2009 / 2010 Winter COG rates, $10,329,453 are shown on Line 80 of Attachment NUI-JDS-3. The total indirect demand costs to be recovered in the 2009 / 2010 Winter COG rates, $782,518, are shown on Line 85 of Attachment NUI-JDS-3.

D. Allocation of New Hampshire Winter Period Demand Costs to Customer Classes

Q. Please explain how the New Hampshire division sales service demand-related costs that were allocated to the Winter period are then allocated to each sales rate class.

A. The New Hampshire division sales service base demand-related costs for each month are allocated to each sales service rate class based on that class' prorata share of total forecasted firm sendout to sales customers under normal weather conditions in that month. The remaining demand-related costs for a month are allocated to each sales service rate class based on that class' prorata share of total forecasted firm sales design day temperature sensitive demand.

I have prepared Attachment NUI-JDS-4 to show the calculation of the factors that are used to allocate New Hampshire division sales service Winter period base demand costs for each month to each sales service rate class. The firm sales forecast, shown on Lines 1 to 16, and the firm sendout forecast by class, shown on Lines 18 to 33, are used to determine: (1) daily base use, shown on Lines 35 to 48; (2) base sendout, shown on Lines 49 to 64; and (3) remaining sendout, shown on Lines 66 to 80. These base and remaining sendout values for each class are used to allocate the Winter period demand costs to New Hampshire division firm sales classes.

I have prepared Attachment NUI-JDS-5 to show the allocation of Winter period New Hampshire net demand costs to each firm Sales rate class, based on: (a) the New Hampshire net demand costs that are allocated to each Winter period month as shown in Attachment NUI-JDS-3, Lines 73 through 84, and (b) the rate class allocators as shown Attachment NUI-JDS-4, Lines 49 to 80. The base sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Attachment NUI-JDS-5 and the remaining design day allocators, which are used to allocate all other demand-related costs and credits to firm sales rate classes, are shown on Lines 39 through 48.

The following table shows the location in Attachment NUI-JDS-5 of the Net Demand-related costs and credits by component allocated to each firm sales rate class:

Demand Cost Component	Attachment NUI-JDS-5
Base Demand	Lines 24 through 37
Remaining Pipeline Demand	Lines 50 through 66
Peaking and Storage Demand	Lines 68 through 84
Capacity Release and Asset Management	Lines 86 through 102
Interruptible Margins	Lines 104 through 120
Re-Entry Fee Credit	Lines 122 through 138
Total Non-Base Demand Costs	Lines 140 through 154
Total Demand Costs	Lines 156through 170

E. Allocation of Variable Costs

Q. Please provide a description of variable costs, and explain how variable costs are allocated to Northern's New Hampshire and Maine divisions.

A. Variable costs include commodity costs and variable pipeline and storage costs[10] for firm sales. Mr. Wells prepared a forecast of Northern variable gas costs by month, which is provided in Attachment NUI-FXW-6. These variable gas costs have been allocated between the New Hampshire and Maine divisions based on each division's percentage of monthly

[10] Variable costs include Pipeline usage / commodity charges, Pipeline fuel retention, Storage commodity injection and withdrawal charges, and Storage Fuel retention.

firm normal sendout. I have prepared Attachment NUI-JDS-6 to show the allocation of the 2009 / 2010 Winter period variable gas costs between New Hampshire and Maine.

Q. Please explain Attachment NUI-JDS-6 in more detail.

A. Lines 1 through 9 of Attachment NUI-JDS-6 show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 11, and 18 through 20 of Attachment NUI-JDS-6. The pipeline commodity costs shown on Lines 11 and 18 are based on projected NYMEX prices as of August 10, 2009. Lines 23 through 29 show the estimated gains and losses based on the Company's hedging program and the projected NYMEX prices. The variable gas costs and hedging gains and losses for firm sales service that are summarized on Lines 40 and 41 are allocated to New Hampshire and Maine based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 46, 47, 51 and 52. Attachment NUI-JDS-6 also shows the allocation of (a) commodity costs (New Hampshire: Lines 66, 68, and 69; Maine: Lines 57, 59, and 60), and (b) hedging gains and losses (Lines 58 and 67) to New Hampshire and Maine. Finally, Attachment NUI-JDS-6 shows the inventory finance costs for underground storage and LNG resources (Lines 90 to 93), the allocation of these costs to New Hampshire and Maine (Lines 95 to 98), and the allocation of New Hampshire's allocated share of annual inventory finance costs to peak period months, using the firm sales remaining sendout allocators (Lines 107 to 109).

I have prepared Attachment NUI-JDS-7 to summarize the New Hampshire division variable gas costs that were determined in Attachment NUI-JDS-6; this attachment also shows the calculation of base and remaining commodity costs.

Q. Please explain how you calculated the inventory finance costs for underground storage and LNG resources that are included in Attachment NUI-JDS-6, Lines 63, 72, and 81.

A. The inventory finance costs that are shown on Lines 63, 72, and 81 of Attachment NUI-JDS-6 are derived from the inventory finance costs that are shown on Lines 91 and 92 of Attachment NUI-JDS-6[11]. These inventory finance costs were determined based on forecasted inventory activity calculations; I have prepared Attachment NUI-JDS-8 to show these calculations.

Q. Please explain how the New Hampshire division variable gas costs for Sales customers are allocated to each firm sales class.

A. I have prepared Attachment NUI-JDS-9 to show the allocation of New Hampshire division variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the base sendout allocators, by rate class. Lines 22 to 49 show the allocation of the monthly New Hampshire division base commodity and base hedging costs[12] to each rate class. Lines 51 to 70 show the calculation of the remaining sendout allocators, by rate class. Lines 71 to 98

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[11] Attachment NUI-JDS-6 shows November through April commodity costs; inventory finance costs for May through October are included in the 2009 / 2010 Gas Year costs shown in Column N of Lines 91 through 93. Total 2009 / 2010 inventory finance costs allocated to New Hampshire, $122,792 (Line 109), are recovered in the Winter period, as shown on Line 72 of Attachment NUI-JDS-6.

[12] New Hampshire Division Winter base commodity costs and hedging costs by month are shown in Attachment NUI-JDS-7 Lines 37 and 38.

show the allocation of the monthly New Hampshire division remaining commodity and remaining hedging costs[13] to each rate class. A summary of all commodity costs allocated to New Hampshire firm sales classes is shown on Lines 99 to 140.

F. Refunds

Q. Are there any refunds included in this filing?

A. No, there are no refunds included in this filing.

G. 2008 / 2009 Winter Period Reconciliation

Q. Please discuss the 2008 / 2009 Winter period over and under-collections.

A. The 2008 / 2009 Winter Period Cost of Gas Factor Clause Reconciliation (Form III), which was filed with the Commission on July 31, 2009, provides a detailed explanation of the Winter undercollection of $2,897,378.

H. Miscellaneous Charges and Credits

Q. Are you projecting that Northern will receive any Firm Sales Service Re-Entry Fee revenues from transportation customers returning to sales service during the 2009 / 2010 Winter period?

A. No. Northern is not projecting any Firm Sales Service Re-Entry Fee revenues in this period.

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13 New Hampshire Division Winter remaining commodity costs and hedging costs by month are shown in Attachment NUI-JDS-7 Lines 39 and 40.

I. Cost of Gas Factor

Q. Please explain Forty-third Revised Page 38; and Forty-third Revised Page 39, which show the calculation of the proposed New Hampshire division Cost of Gas factors for the 2009 / 2010 Winter period.

A. I have prepared Attachment NUI-JDS-10, which is a copy of Forty-third Revised Page 38 and Forty-third Revised Page 39, to explain the calculation of the proposed 2009 / 2010 COG factors; I have added explanations for the calculations on this tariff page and references for the sources of the data that appear on this tariff page from the other attachments that I prepared. As shown in Attachment NUI-JDS-10, Forty-third Revised Page 38 provides summaries of the forecasted direct and indirect gas costs that are to be recovered in the 2009 / 2010 Winter period and Forty-third Revised Page 39 provides calculations of the proposed COG factors for each of Northern's three COG Rate Groups: (1) Residential classes R-5, R-6, R-10, and R-11; (2) C&I Low Winter use classes G-50, G-51 and G-52; and (3) C&I High Winter use classes G-40, G-41 and G-42. Forty-third Revised Page 39 also provides the upper limit of the COG adjustments that Northern can make after providing five business days notification before the start of the next month, without further Commission action.

Q. Please provide additional explanation for Page 1 of Attachment NUI-JDS-10, which is a copy of Forty-third Revised Page 38.

A. The major components of the New Hampshire division 2009 / 2010 Winter direct gas costs are summarized on Lines 1 through 9, and the total Winter direct gas costs, $27,146,537, are shown on Line 10. The five major components to indirect gas costs are shown on Lines 12 through 37: (1) adjustments, which include the 2008 / 2008 peak period undercollection and calculated interest on the deferred gas cost balance; (2) working capital allowance; (3) bad debt allowance; (4) local production and storage costs[14] and (5) miscellaneous overhead[14]. The working capital allowance calculations are shown on Lines 19 through 24 and the bad debt allowance calculations are shown on Lines 25 through 35[15]. The total anticipated 2009 / 2010 Winter period indirect gas costs, $3,925,690, are shown on Line 38, and the total gas costs, $31,072,227, the sum of total direct and indirect gas costs, are shown on Line 39.

Q. Please provide additional explanation for Page 2 of Attachment NUI-JDS-10, which is a copy of Forty-third Revised Page 39.

A. The major components of the New Hampshire division 2009 / 2010 Winter average cost of gas, which is also the residential COG rate, are shown on Lines 40 through 50. The proposed residential COG rate, $1.0913 per therm (Line 49 or 50) consists of the demand cost of gas rate, $.3628 per therm (Line 43); plus the commodity cost of gas rate, $.5906 per therm (Line 44); plus the indirect cost of gas rate, $.1379 per therm (Line 48)

The C&I HLF and LLF rate calculations, which include reallocations of demand and commodity costs from the residential group, are shown on Lines 52 through 79 of Attachment NUI-JDS-10.

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14 The levels of local production and storage costs and miscellaneous overhead costs are established in Second Revised Page 21 of the Company's gas tariffs.

15 The working capital allowance percentage and the bad debt percentage that are used in these calculations are established in Second Revised Page 21 of the Company's gas tariffs.

Q. Do you have any additional analyses to explain or support the calculations that are provided in Forty-third Revised Pages 38 and 39, and Attachment NUI-JDS-10?

A. Yes, I have prepared Attachment NUI-JDS-11 to show details of: (1) New Hampshire division's allocated shares of: (a) pipeline commodity costs and associated volumes by month and major pipeline path; (b) storage commodity costs and associated volumes by month and storage service provider; (c) peaking commodity costs and associated volumes by month and resource; and (d) Winter period demand costs by pipeline path, or service provider (Pages 1 through 6); and (2) the calculations that I made to determine the reallocation of demand and commodity costs from the residential group to the C&I HLF and LLF groups (Page 7).

III. SUMMARY ANALYSES

Q. How does the proposed 2009 / 2010 Winter period COG rate compare with the 2008 / 2009 Winter period COG rate?

A. I have prepared Attachment NUI-JDS-12 to compare the proposed 2009 / 2010 Winter COG (Page 1) with the 2008 / 2009 Winter COG effective November 1, 2008 (Page 2). On Page 3 of Attachment NUI-JDS-12, I have provided calculations of the difference between 2009 / 2010 costs and rates and the corresponding values from the 2008 / 2009 filing for the November 1, 2008 COG rates. Attachment NUI-JDS-12, Line 122 indicates that the proposed residential 2009 / 2010 Winter period COG rate is $.1723 per therm, or 13.6% lower than the 2008 / 2009 Winter period COG rates. This decrease in the residential COG rate is the result of: (1) a significant decrease in commodity costs, $.3425 (Line 112), which is partially offset by: (2) an increase in unit demand costs, $.0389 (Line 111); and (3) an increase in indirect costs, $.1313. The increase in the COG rates that is related to the indirect costs is primarily the result of the 2008 / 2009 Winter undercollection, $2,897,378, which will be recovered in the 2009 / 2010 Winter period; by comparison, the 2008 / 2009 CGF rates reflected a credit to return an overcollection of $707,166 from the 2007 / 2008 Winter period.

Q. Please describe the impact that the proposed 2009 / 2010 Winter COG rates will have on Northern's residential customers.

A. I have prepared Attachment NUI-JDS-13 to compare the impact of the proposed 2009 / 2010 Winter COG with the 2008 / 2009 Winter COG.

The total 2009 / 2010 Winter cost of gas service for a typical residential heating customer with winter gas usage of 932 therms will be $1,414.36, which is $93.65 or 6.21% less than the 2008 / 2009 Winter cost of gas service to this typical residential heating customer.

Q. Please explain why the proposed 2009 / 2010 Residential COG rate decreases by 13.6% compared to the 2008 / 2009 COG rate, yet the proposed Residential 2009 / 2010 Winter COG will decrease an average customer's bills by less than that, 6.21%.

A. There are two major reasons that the rate decreases that are shown in Attachments NUI-JDS-12 and NUI-JDS-13 are different.

First, the decrease shown in Attachment NUI-JDS-12, 13.6%, is based on an analysis using: (1) the COG rate effective November 1, 2008 compared to (2) the COG rate effective November 1, 2009. However, during the 2008 / 2009 Winter period, Northern decreased the COG rate, effective March 1, 2009; the COG rate that was charged in March and April 2009, $1.0540 per therm, was $0.2096 per therm, or 16.6% less than the COG rate that was charged in the first four months of the 2008 / 2009 Winter period. As a result, the decrease shown in Attachment NUI-JDS-13, 6.21%, is based on an analysis using: (1) the COG rates effective November 1, 2009 compared to (2) the COG rates effective November 1, 2008 and March 1, 2009.

In addition, the 6.21% decrease in a typical residential customer's bills is a weighted average of the impact of changes in several components of customer bills: (1) residential base rates, which did not change from the 2008 / 2009 Winter period; (2) residential COG rates, which decreased by an average of 8.8%[16]; and (3) the Local Delivery Adjustment Clause rates.

Q. Please explain how the proposed decrease in the residential Winter COG, 13.6% that you calculated in Attachment NUI-JDS-13 compares with changes in supply prices.

A. I have prepared the following table to quantify the effect that the current market for gas has had on the Company's projected commodity costs.

	Pipeline Supplies - Excluding Hedging			Underground Storage Supplies			Peaking Supplies			Total Supplies		
	2008 / 2009[17]	2009 / 2010	$ Δ	2008 / 2009[17]	2009 / 2010	$ Δ	2008 / 2009[17]	2009 / 2010	$ Δ	2008 / 2009[17]	2009 / 2010	$ Δ
Nov	$6.41	$4.66	-$1.75	$8.70	$0.00	-$8.70	$9.51	$8.98	-$0.53	$7.88	$4.67	-$3.21
Dec	$6.94	$5.83	-$1.11	$10.90	$4.20	-$6.71	$9.05	$8.55	-$0.51	$9.32	$5.30	-$4.02
Jan	$7.28	$6.14	-$1.13	$10.81	$4.19	-$6.62	$9.61	$3.89	-$5.72	$9.58	$4.68	-$4.90
Feb	$7.37	$6.20	-$1.17	$10.64	$4.21	-$6.43	$8.95	$5.84	-$3.11	$9.45	$4.98	-$4.47
Mar	$7.55	$6.08	-$1.47	$10.25	$4.18	-$6.07	$8.88	$4.05	-$4.83	$8.26	$5.04	-$3.22
Apr	$7.25	$5.95	-$1.30	$139.27	$4.75	-$134.52	$24.47	$4.09	-$20.37	$7.29	$5.80	-$1.49
Total	$7.20	$5.76	-$1.44	$10.44	$4.20	-$6.24	$9.25	$4.90	-$4.35	$8.84	$5.05	-$3.79
			-20.0%			-59.7%			-47.0%			-42.9%

16 The weighted average 2008 / 2009 Winter COG rate for the typical residential heating customer is $1.1965 per therm, which is greater than the proposed 2009 / 2010 COG by $0.1052 per therm or 8.8%.

17 Average projected costs of supplies for 2008 / 2009 are based on the forecasted commodity costs from the 2008 / 2009 peak COG filing.

As I explained in a prior response, the 13.6% decrease in the Residential COG rate is the result of the combined effects of the overall decrease in commodity cost of gas, $.3425, or 36.7%, and increases in the demand cost and indirect cost rates that total $.1702 per therm.

IV. ANCILLARY RATES

A. Supplier Balancing Charge

Q. Have you updated the Supplier Balancing Charge for the period November 1, 2009 through October 31, 2010?

A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1, 2009, $0.75 per MMBtu, is unchanged from the currently effective Supplier Balancing Charge. I have prepared Attachment NUI-JDS-14 to support the updated Supplier Balancing Charge.

V. FINAL MATTERS

Q. Will the Company propose to revise the COG if it receives any new or updated information on supplier or transportation rates?

A. Yes. The Company plans to file a revised calculation of its 2009 / 2010 Winter Period COG to reflect updated gas cost projections and/or other information a few weeks prior to the effective date of November 1, 2009.

Q. Does this conclude your testimony?

A. Yes it does.

Attachment NUI-JDS-1

James D. Simpson Professional Qualifications

Unitil
Northern Utilities, Inc.

James D. Simpson
Vice President

Mr. Simpson is a senior executive with more than 30 years of experience in the energy industry. He has held positions at a natural gas utility; an entrepreneurial company providing a proprietary service to generating companies; and state regulatory agencies. His responsibilities have included pricing strategy, regulatory affairs, analysis and planning, and business development.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Affairs

Representative engagements and responsibilities include:

- Designed decoupling mechanism and prepared supporting testimony for several New England utilities.
- Prepared testimony in support of Concentric sales forecast for two New England utilities.
- Designed rates, provided supporting testimony for a New England utility
- Prepared strategic assessment of PBR options for a South Central utility
- Prepared validation of sales forecast and analysis of declining use per customer for Northeast utility
- Prepared rate design for Mid Atlantic utility for rate increase filing
- Prepared marginal cost study and testimony for a Northeast utility
- Prepared Marginal Cost Study and rate design for a Northeast utility
- Preparing an assessment of forecast methodology and forecast accuracy for a Northeast utility
- Served as primary rate design witness for Bay State Gas Company, Northern Utilities (Maine and New Hampshire) and Granite State Gas Transmission on issues including rate reclassification, restructuring, market competitiveness, and earnings stability

Business Strategy and Operations

Representative engagements and responsibilities include:

- Held position of Chief Operating Officer for major New England gas company, responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning
- Developed marketing plan and developed and implemented sales strategies
- Developed brand awareness strategy; created coordinated electronic and physical marketing materials; created and implemented a trade publication strategy. Simplified and shortened sales process; focused on prospective client decision making and understanding of company value proposition
- Implemented new Optimal Growth strategy to identify opportunities and track investments
- Led team that created plan to align company structure and culture with new competition-based growth and customer-focus strategy. Led organization during implementation of new strategy, structure, and culture

Contract Negotiations

Representative engagements and responsibilities include:

- Successfully negotiated contract for first new North America operations site in four years
- Persuaded state regulators to reverse established regulatory policies in conflict with company strategy
- Successfully negotiated unique contract with largest customer on company's system, reversing ten years of unproductive discussions
- Directed negotiation of groundbreaking labor contract that allowed company to use outside contractors and to reduce the union work force by 10%
- Negotiated agreement with pipeline for short term incremental capacity at significant savings
- Negotiated company's commitment to conduct residential customer choice pilot program that provided stakeholders with residential unbundling experience
- Successfully argued for changes to regulators' rate design policies, to improve growth opportunities and customer understanding of pricing. Changes resulted in improved growth rate and customer satisfaction

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PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2005 – Present)
Vice President
Assistant Vice President
Executive Advisor

Separation Technologies, Inc. (2001 – 2004)
Vice President, Business Development

Bay State Gas Company (1982 – 2000)
Senior Vice President, Large Customer Sales and Regulatory Affairs (1999 – 2000)
Senior Vice President/COO of Regulated Utility Business (1996 – 1999)
Vice President, Market Analysis and Pricing (1993 – 1996)
Director/Manager of Rates (1982 – 1993)

Massachusetts Department of Public Utilities (1978 – 1982)
Director
Senior Analyst

Wisconsin Public Service Commission (1977 – 1978)
Senior Analyst

EDUCATION

M.S., Economics, University of Wisconsin
B.A., Economics, University of Minnesota, magna cum laude

Attachment NUI-JDS-2

Allocation of Northern Fixed Capacity Costs

To New Hampshire and Maine

Unitil
Northern Utilities, Inc.

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	$ 6,642,704
Storage Demand	$ 19,732,486
Peaking Demand	$ 5,040,783
Subtotal Demand	$ 31,415,974
Litigation Expense - PNGTS	$ 434,095
Capacity Release (Credit)	$ (565,644)
Asset Management (Credit)	$ (3,770,000)
Total Net Demand Costs	$ 27,514,425

Proportional Responsibility (PR) Allocators

Allocation of Product and Pipeline Demand Costs (including Injections) to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Pipeline Sendout	737,320	730,905	719,723	649,699	709,268	677,285	673,624	564,493	363,991	378,816	347,638	549,202	7,101,963
Rank	1	2	3	7	4	5	6	8	11	10	12	9	
% Max Month	100.00%	99.13%	97.61%	88.12%	96.20%	91.86%	91.36%	76.56%	49.37%	51.38%	47.15%	74.49%	
PR	0.87%	0.76%	0.47%	1.65%	1.08%	0.10%	0.54%	0.26%	0.20%	0.20%	3.93%	2.57%	12.64%
CumPR	12.64%	11.76%	11.01%	8.81%	10.53%	9.45%	9.35%	7.16%	4.13%	4.33%	3.93%	6.90%	100.00%
Product and Pipeline Demand Costs	$ 839,316	$ 781,514	$ 731,144	$ 585,190	$ 699,747	$ 627,711	$ 621,116	$ 475,527	$ 274,390	$ 287,746	$ 260,996	$ 458,307	$ 6,642,704

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Storage Injection Volume	-	-	-	-	-	5,234	472,551	464,677	503,099	503,099	486,870	503,099	2,938,629
Design Year Pipeline Sendout	737,320	730,905	719,723	649,699	709,268	677,285	673,624	564,493	363,991	378,816	347,638	549,202	7,101,963
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	41.2%	45.2%	58.0%	57.0%	58.3%	47.8%	29.3%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 4,814	$ 256,077	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 1,170,333

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Storage	-	591,730	955,218	778,530	309,026	201,863	31,220	-	-	-	-	-	2,867,586
Rank	7	3	1	2	4	5	6	7	7	7	7	7	
% Max Month	0.00%	61.95%	100.00%	81.50%	32.35%	21.13%	3.27%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	9.87%	18.50%	9.78%	2.80%	3.57%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	45.06%
CumPR	0.00%	16.79%	45.06%	26.57%	6.92%	4.12%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ -	$3,312,594	$8,891,960	$5,242,009	$1,365,932	$ 812,503	$ 107,488	$ -	$ -	$ -	$ -	$ -	$ 19,732,486
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ 4,814	$ 256,077	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 1,170,333
TOTAL	$ -	$3,312,594	$8,891,960	$5,242,009	$1,365,932	$ 817,317	$ 363,565	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 20,902,819

Allocation of Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
Design Year Peaking Volumes	161,537	160,854	234,895	352,284	510,379	127,700	115,441	36,231	1,395	1,395	1,350	1,395	1,704,855
Rank	4	5	3	2	1	6	7	8	11	10	12	9	
% Max Month	31.65%	31.52%	46.02%	69.02%	100.00%	25.02%	22.62%	7.10%	0.27%	0.27%	0.26%	0.27%	
PR	0.03%	1.30%	4.79%	11.50%	30.98%	0.40%	2.22%	0.85%	0.00%	0.00%	0.02%	0.00%	52.09%
CumPR	4.83%	4.79%	9.62%	21.12%	52.09%	3.49%	3.09%	0.88%	0.02%	0.02%	0.02%	0.02%	100.00%
Peaking Demand Costs	$ 243,274	$ 241,587	$ 484,785	$1,064,481	$2,625,914	$ 176,099	$ 155,919	$ 44,159	$ 1,152	$ 1,152	$ 1,111	$ 1,152	$ 5,040,783

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

1		
2		
3	Pipeline Demand	Attachment NUI-FXW-4
4	Storage Demand	Attachment NUI-FXW-4
5	Peaking Demand	Attachment NUI-FXW-4
6	Subtotal Demand	Sum LN 3 : LN 5
7	Litigation Expense - PNGTS	Attachment NUI-FXW-8
8	Capacity Release (Credit)	Attachment NUI-FXW-4
9	Asset Management (Credit)	Attachment NUI-FXW-4
10	Total Net Demand Costs	Sum LN 6 : LN 9
11		
12		
13	**Proportional Responsibility (PR) Allocators**	
14		
15	**Allocation of Product and Pipeline Demand Costs (including Injections) to Months**	
16		
17	Design Year Pipeline Sendout	Company Analysis
18	Rank	LN 17 Ranking
19	% Max Month	LN 17 / LN 17 MAX
20	PR	The difference between LN 19 for the month and LN 19 for next highest rank
21	CumPR	Cumulative Values, LN 20
22	Product and Pipeline Demand Costs	LN 21 * LN 3
23		
24	**Allocation of Storage Injection Fees to Months**	
25		
26	Storage Injection Volume	Company Analysis
27	Design Year Pipeline Sendout	LN 17
28	% of Deliveries Injected	LN 26 / Sum (LN 26 : LN 27)
29	Injection Fees	LN 28 * LN 22
30		
31	**Allocation of Storage Demand Costs to Months**	
32		
33	Design Year Storage	Company Analysis
34	Rank	LN 33 Ranking
35	% Max Month	LN 33 / LN 33 MAX
36	PR	The difference between LN 35 for the month and LN 35 for next highest rank
37	CumPR	Cumulative Values, LN 36
38	Storage Demand Costs	LN 37 * LN 4
39	Plus Injection Fees	LN 29
40	TOTAL	LN 38 + LN 39
41		
42	**Allocation of Peaking Demand Costs to Months**	
43		
44	Design Year Peaking Volumes	Company Analysis
45	Rank	Rank LN 44
46	% Max Month	LN 44 / LN 44 MAX
47	PR	The difference between LN 46 for the month and LN 46 for next highest rank
48	CumPR	Cumulative Values, LN 47
49	Peaking Demand Costs	LN 48 * LN 5

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
50	Pipeline & Product Demand	$ 839,316	$ 781,514	$ 731,144	$ 585,190	$ 699,747	$ 627,711	$ 621,116	$ 475,527	$ 274,390	$ 287,746	$ 260,996	$ 458,307	$ 6,642,704
51	Storage	$ -	$3,312,594	$8,891,960	$5,242,009	$1,365,932	$ 817,317	$ 363,565	$ 214,704	$ 159,205	$ 164,148	$ 152,271	$ 219,114	$ 20,902,819
52	Peaking	$ 243,274	$ 241,587	$ 484,785	$1,064,481	$2,625,914	$ 176,099	$ 155,919	$ 44,159	$ 1,152	$ 1,152	$ 1,111	$ 1,152	$ 5,040,783
53	Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (4,814)	$(256,077)	$(214,704)	$(159,205)	$(164,148)	$(152,271)	$(219,114)	$ (1,170,333)
54	Less: Capacity Release	$ (113,129)	$ (113,129)	$ (113,129)	$ (113,129)	$ (113,129)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (565,644)
55	Less: Asset Mgmt	$ (555,984)	$ (555,984)	$ (555,984)	$ (555,984)	$ (555,984)	$ (555,984)	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,335,905)
56	Total Demand	$ 413,477	$3,666,582	$9,438,776	$6,222,567	$4,022,480	$1,060,329	$ 884,523	$ 519,686	$ 275,541	$ 288,898	$ 262,108	$ 459,459	$ 27,514,425

57

58 **Capacity Cost Allocator based on Design Year Firm Sendout**

59		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
60	**Therms**													
61	Maine	436,834	781,046	1,058,729	870,820	793,156	511,874	397,079	311,210	215,411	219,924	199,155	294,565	6,089,803
62	New Hampshire	462,023	702,442	851,107	909,692	735,516	494,974	423,206	289,514	149,975	160,287	149,833	256,032	5,584,601
63	Total	898,857	1,483,488	1,909,836	1,780,512	1,528,672	1,006,848	820,285	600,724	365,386	380,211	348,988	550,597	11,674,404

64	**Percentage of Total**	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL
65	Maine	48.60%	52.65%	55.44%	48.91%	51.89%	50.84%	48.41%	51.81%	58.95%	57.84%	57.07%	53.50%	52.54%
66	New Hampshire	51.40%	47.35%	44.56%	51.09%	48.11%	49.16%	51.59%	48.19%	41.05%	42.16%	42.93%	46.50%	47.46%
67	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

68

69 **Allocation of Demand Costs by Division**

70	Maine	$200,945	$1,930,430	$5,232,442	$3,043,358	$2,087,076	$539,063	$428,175	$269,228	$162,444	$167,106	$149,575	$245,807	$14,455,648
71	New Hampshire	$212,532	$1,736,153	$4,206,334	$3,179,209	$1,935,404	$521,266	$456,348	$250,459	$113,098	$121,792	$112,532	$213,652	$13,058,777
72	Total	$ 413,477	$ 3,666,582	$ 9,438,776	$ 6,222,567	$ 4,022,480	$ 1,060,329	$ 884,523	$ 519,686	$ 275,541	$ 288,898	$ 262,108	$ 459,459	$ 27,514,425

73 **Detailed Allocation of Demand Costs by Division**

74	**Maine**	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL	
75	Pipeline & Product Demand	$ 407,898	$ 411,461	$ 405,314	$ 286,207	$ 363,066	$ 319,123	$ 300,666	$ 246,351	$ 161,765	$ 166,440	$ 148,941	$ 245,191	$ 3,462,423	52.12%
76	Storage		$ 1,744,058	$ 4,929,311	$ 2,563,783	$ 708,718	$ 415,518	$ 175,992	$ 111,229	$ 93,858	$ 94,948	$ 86,896	$ 117,224	$ 11,041,535	52.76%
77	Peaking	$ 118,228	$ 127,194	$ 268,743	$ 520,621	$ 1,362,463	$ 89,528	$ 75,476	$ 22,877	$ 679	$ 666	$ 634	$ 616	$ 2,587,725	51.34%
78	Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,447)	$ (123,960)	$ (111,229)	$ (93,858)	$ (94,948)	$ (86,896)	$ (117,224)	$ (630,562)	
79	Capacity Release (Credit)	$ (54,979)	$ (59,562)	$ (62,714)	$ (55,329)	$ (58,697)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (291,281)	51.50%
80	Asset Management (Credit)	$ (270,202)	$ (292,722)	$ (308,213)	$ (271,923)	$ (288,474)	$ (282,658)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,714,192)	51.39%
81	**Total Allocated Demand**	$ 200,945	$ 1,930,430	$ 5,232,442	$ 3,043,358	$ 2,087,076	$ 539,063	$ 428,175	$ 269,228	$ 162,444	$ 167,106	$ 149,575	$ 245,807	$ 14,455,648	52.54%

82

83	**New Hampshire**	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	TOTAL	
84	Pipeline & Product Demand	$ 431,418	$ 370,052	$ 325,830	$ 298,983	$ 336,681	$ 308,587	$ 320,449	$ 229,176	$ 112,625	$ 121,306	$ 112,055	$ 213,117	$ 3,180,281	47.88%
85	Storage	$ -	$ 1,568,537	$ 3,962,649	$ 2,678,226	$ 657,214	$ 401,799	$ 187,572	$ 103,475	$ 65,347	$ 69,201	$ 65,375	$ 101,890	$ 9,861,284	47.24%
86	Peaking	$ 125,046	$ 114,393	$ 216,041	$ 543,860	$ 1,263,451	$ 86,572	$ 80,442	$ 21,282	$ 473	$ 485	$ 477	$ 535	$ 2,453,058	48.66%
87	Injection Fees	$ -	$ -	$ -	$ -	$ -	$ (2,367)	$ (132,116)	$ (103,475)	$ (65,347)	$ (69,201)	$ (65,375)	$ (101,890)	$ (539,770)	
88	Capacity Release	$ (58,150)	$ (53,567)	$ (50,415)	$ (57,799)	$ (54,432)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (274,363)	48.50%
89	Asset Management (Credit)	$ (285,782)	$ (263,262)	$ (247,771)	$ (284,061)	$ (267,510)	$ (273,326)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,621,713)	48.61%
90	**Total Allocated Demand**	$ 212,532	$ 1,736,153	$ 4,206,334	$ 3,179,209	$ 1,935,404	$ 521,266	$ 456,348	$ 250,459	$ 113,098	$ 121,792	$ 112,532	$ 213,652	$ 13,058,777	47.46%

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS

50	Pipeline & Product Demand	LN 22
51	Storage	LN 40
52	Peaking	LN 49
53	Less: Injection Fees	-(LN 29)
54	Less: Capacity Release	LN 8 / 5
55	Less: Asset Management	(LN 9 + LN 7) / 6
56	Total Demand	Sum (LN 50 : LN 55)
57		
58	**Capacity Cost Allocator based on Design Year Firm Sendout**	
59		
60	**Therms**	
61	Maine	Company Analysis
62	New Hampshire	Company Analysis
63	Total	LN 61 + LN 62
64	**Percentage of Total**	
65	Maine	LN 61 / LN 63
66	New Hampshire	LN 62 / LN 63
67	Total	LN 65 + LN 66
68		
69	**Allocation of Demand Costs by Division**	
70	Maine	LN 56 * LN 65
71	New Hampshire	LN 56 * LN 66
72	Total	LN 70 + LN 71
73	**Detailed Allocation of Demand Costs by Division**	
74	**Maine**	
75	Pipeline & Product Demand	LN 50 * LN 65
76	Storage	LN 51 * LN 65
77	Peaking	LN 52 * LN 65
78	Injection Fees	LN 53 * LN 65
79	Capacity Release (Credit)	LN 54 * LN 65
80	Asset Management (Credit)	LN 55 * LN 65
81	**Total Allocated Demand**	Sum (LN 75 : LN 80)
82		
83	**New Hampshire**	
84	Pipeline & Product Demand	LN 50 * LN 66
85	Storage	LN 51 * LN 66
86	Peaking	LN 52 * LN 66
87	Injection Fees	LN 53 * LN 66
88	Capacity Release	LN 54 * LN 66
89	Asset Management (Credit)	LN 55 * LN 66
90	**Total Allocated Demand**	Sum (LN 84 : LN 89)

Attachment NUI-JDS-3

Allocation of New Hampshire Fixed Capacity Costs

To Months and Seasons

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH Division Total Annual Demand Cost Allocation

Line		
1	**Resource**	Costs
2	Pipeline & Product Demand	$ 2,640,510
3	Storage	$ 9,861,284
4	Peaking	$ 2,453,058
5	Total Gross Demand Cost	$ 14,954,853
6		
7	Capacity Assignment Demand Revenue Estimate	$ 1,683,859
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 14,954,853
9	Capacity Assignment as % of Total Gross Demand Cost	11.26%
10		
11	NH Non-Grandfathered Transportation Allocated Capacity Assignment Costs	
12		**Costs**
13	Pipeline & Product Demand	$ 297,311
14	Storage	$ 1,110,343
15	Peaking	$ 276,205
16	Total Capacity Assignment Credit	$ 1,683,859
17		
18	NH Net Annual Demand Cost (Less Capacity Assignment)	
19		**Costs**
20	Pipeline & Product Demand	$ 2,343,199
21	Storage	$ 8,750,941
22	Peaking	$ 2,176,853
23	Total Net Demand Cost (Less Capacity Assignment)	$ 13,270,994
24		
25	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
26		MMBtu/day
27	Pipeline MDQ	11,441
28	Less 11.26% NH Transp. Capacity Assignment	(1,288)
29	Net Pipeline MDQ	10,152
30		
31	Net Pipeline MDQ	10,152
32	Less: Firm Sales Base Use	3,359
33	Remaining Pipeline MDQ	6,793
34		
35		**Unit Cost**
36	Pipeline Unit Cost	$230.80
37		
38		**Costs**
39	Pipeline & Product Demand	$ 2,343,199
40	Less: Base Pipeline Use	$ 775,316
41	Remaining Pipeline Use	$ 1,567,883

Northern Utilities - NEW HAMPSHIRE D
Simplified Market Based Allocator (SME
DEMAND COSTS

NH Division Total Annual Demand Cost

LN		
1	**Resource**	
2	Pipeline & Product Demand	Attachment NUI-JDS-2, LN 84 + Attachment NUI-JDS-2, LN 87
3	Storage	Attachment NUI-JDS-2, LN 85
4	Peaking	Attachment NUI-JDS-2, LN 86
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Company Analysis
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11	NH Non-Grandfathered Transportation Alloc	
12		
13	Pipeline & Product Demand	LN 2 * LN 9
14	Storage	LN 3 * LN 9
15	Peaking	LN 4 * LN 9
16	Total Capacity Assignment Credit	Sum (LN 13 : LN 15)
17		
18	NH Net Annual Demand Cost (Less Capacit	
19		
20	Pipeline & Product Demand	LN 2 - LN 13
21	Storage	LN 3 - LN 14
22	Peaking	LN 4 - LN 15
23	Total Net Demand Cost (Less Capacity Ass	LN 5 - LN 16
24		
25	**DEVELOPMENT OF BASE AND REMAINI**	
26		
27	Pipeline MDQ	Company Analysis
28	Less 11.26% NH Transp. Capacity Assignm	-(LN 27) * LN 9
29	Net Pipeline MDQ	Sum (LN 27 : LN 28)
30		
31	Net Pipeline MDQ	LN 29
32	Less: Firm Sales Base Use	Attachment NUI-JDS-4, LN 48 / 10
33	Remaining Pipeline MDQ	LN 31 - LN 32
34		
35		
36	Pipeline Unit Cost	LN 20 / LN 31
37		
38		
39	Pipeline & Product Demand	LN 20
40	Less: Base Pipeline Use	LN 36 * LN 32
41	Remaining Pipeline Use	LN 39 - LN 40

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)
(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)

All Months	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for All Months	1,739,533	3,689,187	5,196,877	5,587,144	4,059,530	2,524,544
Rank	6	4	2	1	3	5
% Max Month	31.13%	66.03%	93.01%	100.00%	72.66%	45.18%
PR	1.34%	5.21%	10.18%	6.99%	2.21%	2.81%
CumPR	4.31%	12.33%	24.72%	31.71%	14.54%	7.12%

Peak Months Only	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Remaining Load for Peak Months Only	1,739,533	3,689,187	5,196,877	5,587,144	4,059,530	2,524,544
Rank	6	4	2	1	3	5
% Max Month	31.13%	66.03%	93.01%	100.00%	72.66%	45.18%
PR	5.19%	5.21%	10.18%	6.99%	2.21%	2.81%
CumPR	5.19%	13.21%	25.60%	32.58%	15.42%	8.00%

DEMAND COST PR ALLOCATORS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
Pipeline - Remaining	4.31%	12.33%	24.72%	31.71%	14.54%	7.12%
Storage & Peaking	4.31%	12.33%	24.72%	31.71%	14.54%	7.12%
Capacity Release	5.19%	13.21%	25.60%	32.58%	15.42%	8.00%
Interr. Margins & Off Sys Sales	5.19%	13.21%	25.60%	32.58%	15.42%	8.00%

DEMAND COSTS ALLOCATED TO MONTHS

	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
Pipeline - Base	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610
Pipeline - Remaining	$ 67,603	$ 193,368	$ 387,593	$ 497,111	$ 228,010	$ 111,661
Total Pipeline	$ 132,212	$ 257,977	$ 452,203	$ 561,721	$ 292,620	$ 176,271
Storage & Peaking	$ 471,175	$ 1,347,729	$ 2,701,436	$ 3,464,753	$ 1,589,179	$ 778,253
Less Credits to Demand Cost						
Cap Rel Margins & Asset Mgt Credit	$ 98,389	$ 250,480	$ 485,361	$ 617,803	$ 292,373	$ 151,670
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -
Total Direct Demand Costs	$ 504,999	$ 1,355,227	$ 2,668,279	$ 3,408,670	$ 1,589,425	$ 802,854

Indirect Demand Costs/(Credits)	
Miscellaneous Overhead	
Local Production & Storage	
Subtotal	

Northern Utilities - NEW HAMPSHIRE D
Simplified Market Based Allocator (SME
DEMAND COSTS

42 **NH DIVISION MONTHLY PROPORTIONAL**
43 (Based on NH Firm Sales Sendout for Rema

		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
45	**All Months**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Total**	**Winter**	**Summer**
46	Remaining Load for All Months	1,290,632	653,011	20,697	9,832	84,638	390,752	25,246,378	22,796,816	2,449,562
47	Rank	7	8	11	12	10	9			
48	% Max Month	23.10%	11.69%	0.37%	0.18%	1.51%	6.99%			
49	PR	1.63%	0.59%	0.02%	0.01%	0.11%	0.61%	31.71%		
50	CumPR	2.97%	1.34%	0.03%	0.01%	0.15%	0.76%	100.00%	94.74%	5.26%

		Total	Winter	Summer
52	**Peak Months Only**	**Total**	**Winter**	**Summer**
53	Remaining Load for Peak Months Only	22,796,816		
54	Rank			
55	% Max Month			
56	PR	32.58%		
57	CumPR	100.00%	100.00%	0.00%

59 **DEMAND COST PR ALLOCATORS**

60		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer
61	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
62	Pipeline - Remaining	2.97%	1.34%	0.03%	0.01%	0.15%	0.76%	100.00%	94.74%	5.26%
63	Storage & Peaking	2.97%	1.34%	0.03%	0.01%	0.15%	0.76%	100.00%	94.74%	5.26%
64	Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

67 **DEMAND COSTS ALLOCATED TO MONT**

68		May	Jun	Jul	Aug	Sep	Oct	Total	Winter	Summer	Winter	Summer
69	Pipeline - Base	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 775,316	$ 387,658	$ 387,658	50.00%	50.00%
70	Pipeline - Remaining	$ 46,607	$ 21,046	$ 507	$ 230	$ 2,301	$ 11,846	$ 1,567,883	$ 1,485,346	$ 82,538	94.74%	5.26%
71	Total Pipeline	$ 111,217	$ 85,655	$ 65,117	$ 64,840	$ 66,911	$ 76,456	$ 2,343,199	$ 1,873,003	$ 470,195	79.93%	20.07%
72												
73	Storage & Peaking	$ 324,842	$ 146,684	$ 3,534	$ 1,602	$ 16,041	$ 82,565	$ 10,927,795	$ 10,352,526	$ 575,269	94.74%	5.26%
74												
75	Less Credits to Demand Cost											
76	Cap Rel Margins & Asset Mgt Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,896,076	$ 1,896,076	$ -	100.00%	0.00%
77	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
78	Re-Entry Fee Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
79												
80	Total Direct Demand Costs	$ 436,059	$ 232,339	$ 68,651	$ 66,442	$ 82,952	$ 159,021	$ 11,374,918	$ 10,329,453	$ 1,045,464	90.81%	9.19%
81												
82	Indirect Demand Costs/(Credits)											
83	Miscellaneous Overhead							$ 124,297	$ 95,845	$ 28,452	77.11%	22.89%
84	Local Production & Storage							$ 686,673	$ 686,673	$ -	100.00%	0.00%
85	Subtotal							$ 810,970	$ 782,518	$ 28,452	96.49%	3.51%

Northern Utilities - NEW HAMPSHIRE D
Simplified Market Based Allocator (SME
DEMAND COSTS

42	**NH DIVISION MONTHLY PROPORTIONAIS)**	
43	(Based on NH Firm Sales Sendout for Rema	
44		
45	**All Months**	
46	Remaining Load for All Months	Attachment NUI-JDS-4, LN 80
47	Rank	Rank LN 46
48	% Max Month	LN 46 / MAX Month LN 46
49	PR	The difference between LN 48 for the month and LN 48 for next highest rank
50	CumPR	Cumulative Values, LN 49
51		
52	**Peak Months Only**	
53	Remaining Load for Peak Months Only	LN 46
54	Rank	Rank LN 53
55	% Max Month	LN 53 / MAX Month LN 53
56	PR	The difference between LN 55 for the month and LN 55 for next highest rank
57	CumPR	Cumulative Values, LN 56
58		
59	**DEMAND COST PR ALLOCATORS**	
60		
61	Pipeline - Base	1/12
62	Pipeline - Remaining	LN 50
63	Storage & Peaking	LN 50
64	Capacity Release	LN 57
65	Interr. Margins & Off Sys Sales	LN 57
66		
67	**DEMAND COSTS ALLOCATED TO MONT**	
68		
69	Pipeline - Base	LN 40 * LN 61
70	Pipeline - Remaining	LN 41 * LN 62
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & Peaking	LN 63 * (Sum LN 21 : LN 22)
74		
75	Less Credits to Demand Cost	
76	Cap Rel Margins & Asset Mgt Credit	LN 64 * Sum (Attachment NUI-JDS-2 LN 88, Attachment NUI-JDS-2 LN 89)
77	Interruptible Margins	
78	Re-Entry Fee Credits	
79		
80	Total Direct Demand Costs	LN 71 + LN 73 - (Sum LN 76 : LN 78)
81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

Attachment NUI-JDS-4

Development of New Hampshire Division

Rate Class Allocators

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Forecasted Normal Sales (Volumes in Dth)
2009 - 2010 Period

Line No.	Firm Sales	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL	Winter
1	Res Heat	113,976	191,385	267,274	295,342	229,120	157,757	1,587,282	1,254,852
2	Res General	2,557	3,147	3,959	3,887	3,186	2,687	30,695	19,423
3	**Total Residential**	**116,533**	**194,531**	**271,233**	**299,230**	**232,306**	**160,443**	**1,617,977**	**1,274,276**
4	G50 Low Annual-Low Winter	13,147	16,145	18,313	17,620	15,953	11,729	174,104	92,907
5	G40 Low Annual-High Winter	48,208	107,670	161,408	162,731	121,616	76,478	800,890	678,111
6	G51 Med Annual-Low Winter	25,265	30,816	32,690	31,280	25,546	25,111	292,973	170,708
7	G41 Med Annual-High Winter	56,018	100,301	120,160	121,913	96,941	65,620	704,420	560,954
8	G52 High Annual-Low Winter	3,197	3,827	3,845	3,643	3,223	2,408	34,270	20,142
9	G42 High Annual-High Winter	8,485	12,749	8,007	7,848	7,771	5,421	68,002	50,282
10	**Total C&I**	**154,319**	**271,509**	**344,423**	**345,034**	**271,051**	**186,767**	**2,074,660**	**1,573,103**
11	**Total Sales**	**270,852**	**466,040**	**615,656**	**644,264**	**503,357**	**347,210**	**3,692,637**	**2,847,379**
12									
13	Residential Heat & Non Heat	116,533	194,531	271,233	299,230	232,306	160,443	1,617,977	1,274,276
14	SALES HLF CLASSES	41,608	50,788	54,848	52,542	44,722	39,247	501,347	283,757
15	SALES LLF CLASSES	112,711	220,721	289,575	292,492	226,329	147,519	1,573,312	1,289,346
16	**Total Firm Sales**	**270,852**	**466,040**	**615,656**	**644,264**	**503,357**	**347,210**	**3,692,637**	**2,847,379**
17									
18	**ESTIMATED SENDOUT BY CLASS - Therms**								
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)								
20	Normal Winter	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**TOTAL**	**Winter**
21	Res Heat	1,156,072	1,942,648	2,708,194	2,992,425	2,321,838	1,598,694	16,092,568	12,719,871
22	Res General	25,937	31,941	40,116	39,388	32,289	27,227	311,285	196,896
23	G50 Low Annual-Low Winter	133,347	163,885	185,556	178,529	161,665	118,860	1,765,906	941,841
24	G40 Low Annual-High Winter	488,976	1,092,901	1,635,492	1,648,797	1,232,426	775,028	8,119,242	6,873,621
25	G51 Med Annual-Low Winter	256,268	312,799	331,239	316,928	258,881	254,471	2,971,427	1,730,585
26	G41 Med Annual-High Winter	568,202	1,018,109	1,217,542	1,235,229	982,374	664,988	7,142,046	5,686,443
27	G52 High Annual-Low Winter	32,424	38,844	38,964	36,906	32,659	24,399	347,582	204,197
28	G42 High Annual-High Winter	86,068	129,414	81,127	79,520	78,752	54,934	689,649	509,815
29	**Subtotal**								
30	Residential	1,182,009	1,974,589	2,748,309	3,031,813	2,354,127	1,625,920	16,403,853	12,916,767
31	SALES HLF CLASSES	422,038	515,528	555,760	532,363	453,204	397,730	5,084,916	2,876,623
32	SALES LLF CLASSES	1,143,247	2,240,424	2,934,161	2,963,546	2,293,553	1,494,949	15,950,937	13,069,879
33	**Total Firm Sales**	2,747,294	4,730,540	6,238,230	6,527,721	5,100,884	3,518,599	37,439,705	28,863,270

Northern Utilities - NEW HAMPSHIRE DIVISION
Forecasted Normal Sales (Volumes in Dth)
2009 - 2010 Period

Line No.	Firm Sales	
1	Res Heat	Company Analysis
2	Res General	Company Analysis
3	**Total Residential**	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	Company Analysis
5	G40 Low Annual-High Winter	Company Analysis
6	G51 Med Annual-Low Winter	Company Analysis
7	G41 Med Annual-High Winter	Company Analysis
8	G52 High Annual-Low Winter	Company Analysis
9	G42 High Annual-High Winter	Company Analysis
10	**Total C&I**	Sum LN 4 : LN 9
11	**Total Sales**	LN 3 + LN 10
12		
13	Residential Heat & Non Heat	LN 3
14	SALES HLF CLASSES	LN 4 + LN 6 + LN 8
15	SALES LLF CLASSES	LN 5 + LN 7 + LN 9
16	**Total Firm Sales**	Sum LN 13 : LN 15
17		
18	**ESTIMATED SENDOUT BY CLASS - Therms**	
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)	
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Company Use, LAUF, BTU) x 10
22	Res General	LN 2 x Adj factor (Company Use, LAUF, BTU) x 10
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Company Use, LAUF, BTU) x 10
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Company Use, LAUF, BTU) x 10
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Company Use, LAUF, BTU) x 10
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Company Use, LAUF, BTU) x 10
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Company Use, LAUF, BTU) x 10
28	G42 High Annual-High Winter	LN 9 x Adj factor (Company Use, LAUF, BTU) x 10
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

DAILY BASE GAS ENTITLEMENT - Therms/day		
Res Heat	12,175	
Res General	555	
G50 Low Annual-Low Winter	4,419	
G40 Low Annual-High Winter	4,145	
G51 Med Annual-Low Winter	6,649	
G41 Med Annual-High Winter	4,545	
G52 High Annual-Low Winter	730	
G42 High Annual-High Winter	375	
Subtotal		
Residential	12,729	
SALES HLF CLASSES	11,798	
SALES LLF CLASSES	9,065	
Total Firm Sales	**33,592**	

BASE SENDOUT BY CLASS - Therms								
Days per Month	30	31	31	28	31	30		
	Nov-09	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**TOTAL**	**WINTER**
Res Heat	365,240	377,414	377,414	340,890	377,414	365,240	4,435,772	2,203,612
Res General	16,641	17,196	17,196	15,532	17,196	16,641	201,187	100,401
G50 Low Annual-Low Winter	132,566	136,985	136,985	123,729	136,985	118,860	1,576,846	786,111
G40 Low Annual-High Winter	124,348	128,493	128,493	116,058	128,493	124,348	1,509,675	750,233
G51 Med Annual-Low Winter	199,463	206,111	206,111	186,165	206,111	199,463	2,418,121	1,203,425
G41 Med Annual-High Winter	136,359	140,904	140,904	127,268	140,904	136,359	1,650,576	822,698
G52 High Annual-Low Winter	21,903	22,634	22,634	20,443	22,634	21,903	265,093	132,151
G42 High Annual-High Winter	11,241	11,616	11,616	10,492	11,616	11,241	136,059	67,823
Subtotal								
Residential	381,881	394,610	394,610	356,422	394,610	381,881	4,636,959	2,304,013
SALES HLF CLASSES	353,933	365,730	365,730	330,337	365,730	340,226	4,260,059	2,121,687
SALES LLF CLASSES	271,948	281,013	281,013	253,818	281,013	271,948	3,296,310	1,640,754
Total Firm Sales	1,007,761	1,041,353	1,041,353	940,577	1,041,353	994,055	12,193,328	6,066,454

REMAINING SENDOUT BY CLASS - Therms								
	Nov-09	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**TOTAL**	**WINTER**
Res Heat	790,833	1,565,234	2,330,779	2,651,535	1,944,424	1,233,454	11,656,796	10,516,259
Res General	9,296	14,745	22,920	23,856	15,093	10,585	110,098	96,496
G50 Low Annual-Low Winter	781	26,899	48,571	54,800	24,679	-	189,061	155,730
G40 Low Annual-High Winter	364,628	964,409	1,506,999	1,532,739	1,103,933	650,680	6,609,566	6,123,388
G51 Med Annual-Low Winter	56,805	106,688	125,128	130,763	52,769	55,008	553,306	527,160
G41 Med Annual-High Winter	431,843	877,205	1,076,638	1,107,960	841,470	528,629	5,491,471	4,863,745
G52 High Annual-Low Winter	10,520	16,210	16,331	16,463	10,026	2,496	82,490	72,046
G42 High Annual-High Winter	74,827	117,797	69,511	69,028	67,136	43,692	553,590	441,993
Subtotal								
Residential	800,129	1,579,979	2,353,699	2,675,391	1,959,517	1,244,040	11,766,894	10,612,754
SALES HLF CLASSES	68,106	149,798	190,029	202,026	87,474	57,504	824,857	754,936
SALES LLF CLASSES	871,299	1,959,411	2,653,148	2,709,727	2,012,540	1,223,001	12,654,627	11,429,125
Total Firm Sales	1,739,533	3,689,187	5,196,877	5,587,144	4,059,530	2,524,544	25,246,378	22,796,816

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

LN		
34		
35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	Avg (LN 21 Jul : LN 21 Aug) / 31 days
37	Res General	Avg (LN 22 Jul : LN 22 Aug) / 31 days
38	G50 Low Annual-Low Winter	Avg (LN 23 Jul : LN 23 Aug) / 31 days
39	G40 Low Annual-High Winter	Avg (LN 24 Jul : LN 24 Aug) / 31 days
40	G51 Med Annual-Low Winter	Avg (LN 25 Jul : LN 25 Aug) / 31 days
41	G41 Med Annual-High Winter	Avg (LN 26 Jul : LN 26 Aug) / 31 days
42	G52 High Annual-Low Winter	Avg (LN 27 Jul : LN 27 Aug) / 31 days
43	G42 High Annual-High Winter	Avg (LN 28 Jul : LN 28 Aug) / 31 days
44	**Subtotal**	
45	Residential	LN 36 + LN 37
46	SALES HLF CLASSES	LN 38 + LN 40 + LN 42
47	SALES LLF CLASSES	LN 39 + LN 41 + LN 43
48	**Total Firm Sales**	Sum LN 45 : LN 47
49	**BASE SENDOUT BY CLASS - Therms**	
50	Days per Month	
51		
52	Res Heat	MIN(LN 36 * LN 50, LN 21)
53	Res General	MIN(LN 37 * LN 50, LN 22)
54	G50 Low Annual-Low Winter	MIN(LN 38 * LN 50, LN 23)
55	G40 Low Annual-High Winter	MIN(LN 39 * LN 50, LN 24)
56	G51 Med Annual-Low Winter	MIN(LN 40 * LN 50, LN 25)
57	G41 Med Annual-High Winter	MIN(LN 41 * LN 50, LN 26)
58	G52 High Annual-Low Winter	MIN(LN 42 * LN 50, LN 27)
59	G42 High Annual-High Winter	MIN(LN 43 * LN 50, LN 28)
60	**Subtotal**	
61	Residential	LN 52 + LN 53
62	SALES HLF CLASSES	LN 54 + LN 56 + LN 58
63	SALES LLF CLASSES	LN 55 + LN 57 + LN 59
64	**Total Firm Sales**	Sum LN 61 : LN 63
65		
66	**REMAINING SENDOUT BY CLASS - Therms**	
67		
68	Res Heat	LN 21 - LN 52
69	Res General	LN 22 - LN 53
70	G50 Low Annual-Low Winter	LN 23 - LN 54
71	G40 Low Annual-High Winter	LN 24 - LN 55
72	G51 Med Annual-Low Winter	LN 25 - LN 56
73	G41 Med Annual-High Winter	LN 26 - LN 57
74	G52 High Annual-Low Winter	LN 27 - LN 58
75	G42 High Annual-High Winter	LN 28 - LN 59
76	**Subtotal**	
77	Residential	LN 68 + LN 69
78	SALES HLF CLASSES	LN 70 + LN 72 + LN 74
79	SALES LLF CLASSES	LN 71 + LN 73 + LN 75
80	**Total Firm Sales**	Sum LN 77 : LN 79

Attachment NUI-JDS-5

Allocation of New Hampshire Demand Costs

To New Hampshire Firm Sales Rate Classes

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

Base Capacity Costs

1	**BASE SENDOUT BY CLASS**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**WINTER**	
2	**Total Therms**								
3	Res Heat	365,240	377,414	377,414	340,890	377,414	365,240	2,203,612	Attachment NUI-JDS-4, LN 52
4	Res General	16,641	17,196	17,196	15,532	17,196	16,641	100,401	Attachment NUI-JDS-4, LN 53
5	G50 Low Annual-Low Winter	132,566	136,985	136,985	123,729	136,985	118,860	786,111	Attachment NUI-JDS-4, LN 54
6	G40 Low Annual-High Winter	124,348	128,493	128,493	116,058	128,493	124,348	750,233	Attachment NUI-JDS-4, LN 55
7	G51 Med Annual-Low Winter	199,463	206,111	206,111	186,165	206,111	199,463	1,203,425	Attachment NUI-JDS-4, LN 56
8	G41 Med Annual-High Winter	136,359	140,904	140,904	127,268	140,904	136,359	822,698	Attachment NUI-JDS-4, LN 57
9	G52 High Annual-Low Winter	21,903	22,634	22,634	20,443	22,634	21,903	132,151	Attachment NUI-JDS-4, LN 58
10	G42 High Annual-High Winter	11,241	11,616	11,616	10,492	11,616	11,241	67,823	Attachment NUI-JDS-4, LN 59
11	Total Firm Sales	1,007,761	1,041,353	1,041,353	940,577	1,041,353	994,055	6,066,454	Sum LN 3 : LN 10
12									
13	**% of Total**								
14	Res Heat	36.24%	36.24%	36.24%	36.24%	36.24%	36.74%		LN 3 / LN 11
15	Res General	1.65%	1.65%	1.65%	1.65%	1.65%	1.67%		LN 4 / LN 11
16	G50 Low Annual-Low Winter	13.15%	13.15%	13.15%	13.15%	13.15%	11.96%		LN 5 / LN 11
17	G40 Low Annual-High Winter	12.34%	12.34%	12.34%	12.34%	12.34%	12.51%		LN 6 / LN 11
18	G51 Med Annual-Low Winter	19.79%	19.79%	19.79%	19.79%	19.79%	20.07%		LN 7 / LN 11
19	G41 Med Annual-High Winter	13.53%	13.53%	13.53%	13.53%	13.53%	13.72%		LN 8 / LN 11
20	G52 High Annual-Low Winter	2.17%	2.17%	2.17%	2.17%	2.17%	2.20%		LN 9 / LN 11
21	G42 High Annual-High Winter	1.12%	1.12%	1.12%	1.12%	1.12%	1.13%		LN 10 / LN 11
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		LN 11 / LN 11
23									

24	**PIPELINE BASE DEMAND COSTS**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**WINTER**	
25	TOTAL PIPELINE BASE DEMAND COST	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 64,610	$ 387,658	Attachment NUI-JDS-3, LN 69
26	Res Heat	$ 23,416	$ 23,416	$ 23,416	$ 23,416	$ 23,416	$ 23,739	$ 140,820	LN 25 * LN 14
27	Res General	$ 1,067	$ 1,067	$ 1,067	$ 1,067	$ 1,067	$ 1,082	$ 6,416	LN 25 * LN 15
28	G50 Low Annual-Low Winter	$ 8,499	$ 8,499	$ 8,499	$ 8,499	$ 8,499	$ 7,725	$ 50,221	LN 25 * LN 16
29	G40 Low Annual-High Winter	$ 7,972	$ 7,972	$ 7,972	$ 7,972	$ 7,972	$ 8,082	$ 47,943	LN 25 * LN 17
30	G51 Med Annual-Low Winter	$ 12,788	$ 12,788	$ 12,788	$ 12,788	$ 12,788	$ 12,964	$ 76,904	LN 25 * LN 18
31	G41 Med Annual-High Winter	$ 8,742	$ 8,742	$ 8,742	$ 8,742	$ 8,742	$ 8,863	$ 52,574	LN 25 * LN 19
32	G52 High Annual-Low Winter	$ 1,404	$ 1,404	$ 1,404	$ 1,404	$ 1,404	$ 1,424	$ 8,445	LN 25 * LN 20
33	G42 High Annual-High Winter	$ 721	$ 721	$ 721	$ 721	$ 721	$ 731	$ 4,334	LN 25 * LN 21
34									
35	Residential	$ 24,483	$ 24,483	$ 24,483	$ 24,483	$ 24,483	$ 24,821	$ 147,236	LN 26 + LN 27
36	SALES HLF CLASSES	$ 22,691	$ 22,691	$ 22,691	$ 22,691	$ 22,691	$ 22,113	$ 135,570	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	$ 17,435	$ 17,435	$ 17,435	$ 17,435	$ 17,435	$ 17,676	$ 104,851	LN 29 + LN 31 + LN 33
38									

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

Remaining Capacity Costs

LN		Column A	Column B	Column C	Column D	
39		Design Day Demand (MMBtu)	Avg Daily Base Use Load (MMBtu)	Remaining Design Day Demand (MMBtu)	% of Total Remaining Design Day Demand	
40	Res Heat	17,620	1,217	16,403	46.75%	Company Analysis
41	Res General	203	55	147	0.42%	Company Analysis
42	G50 Low Annual-Low Winter	958	442	516	1.47%	Company Analysis
43	G40 Low Annual-High Winter	8,925	414	8,511	24.25%	Company Analysis
44	G51 Med Annual-Low Winter	1,839	665	1,174	3.35%	Company Analysis
45	G41 Med Annual-High Winter	8,297	455	7,842	22.35%	Company Analysis
46	G52 High Annual-Low Winter	148	73	75	0.21%	Company Analysis
47	G42 High Annual-High Winter	458	37	420	1.20%	Company Analysis
48	TOTAL	38,447	3,359	35,088	100.00%	Sum LN 40 : LN 47
49						

LN	REMAINING PIPELINE DEMAND	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER	
50	**REMAINING PIPELINE DEMAND**								
51		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER	
52	NH DIVISION TOTAL - REMAINING PIPELINE	$ 67,603	$ 193,368	$ 387,593	$ 497,111	$ 228,010	$ 111,661	$ 1,485,346	Attachment NUI-JDS-3, LN 70
53									
54	Res Heat	$ 31,602	$ 90,393	$ 181,187	$ 232,383	$ 106,587	$ 52,198	$ 694,351	LN 40 Col D * LN 52
55	Res General	$ 283	$ 811	$ 1,625	$ 2,084	$ 956	$ 468	$ 6,228	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	$ 994	$ 2,844	$ 5,701	$ 7,312	$ 3,354	$ 1,642	$ 21,848	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	$ 16,397	$ 46,901	$ 94,010	$ 120,573	$ 55,303	$ 27,083	$ 360,267	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	$ 2,262	$ 6,469	$ 12,967	$ 16,631	$ 7,628	$ 3,736	$ 49,694	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	$ 15,110	$ 43,219	$ 86,630	$ 111,108	$ 50,962	$ 24,957	$ 331,986	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	$ 145	$ 415	$ 832	$ 1,068	$ 490	$ 240	$ 3,190	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	$ 809	$ 2,315	$ 4,640	$ 5,951	$ 2,730	$ 1,337	$ 17,782	LN 47 Col D * LN 52
62	TOTAL	$ 67,603	$ 193,368	$ 387,593	$ 497,111	$ 228,010	$ 111,661	$ 1,485,346	Sum LN 54 : LN 61
63									
64	Residential	$ 31,886	$ 91,204	$ 182,812	$ 234,468	$ 107,543	$ 52,666	$ 700,579	LN 54 + LN 55
65	SALES HLF CLASSES	$ 3,401	$ 9,729	$ 19,501	$ 25,011	$ 11,472	$ 5,618	$ 74,732	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	$ 32,316	$ 92,435	$ 185,280	$ 237,632	$ 108,995	$ 53,377	$ 710,034	LN 57 + LN 59 + LN 61
67									

LN	PEAKING AND STORAGE DEMAND	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER	
68	**PEAKING AND STORAGE DEMAND**								
69		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER	
70	NH DIVISION TOTAL - PEAKING & STORAGE	$ 471,175	$ 1,347,729	$ 2,701,436	$ 3,464,753	$ 1,589,179	$ 778,253	$ 10,352,526	Attachment NUI-JDS-3, LN 73
71									
72	Res Heat	$ 220,259	$ 630,020	$ 1,262,834	$ 1,619,660	$ 742,890	$ 363,808	$ 4,839,470	LN 40 Col D * LN 70
73	Res General	$ 1,976	$ 5,651	$ 11,327	$ 14,528	$ 6,663	$ 3,263	$ 43,408	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	$ 6,931	$ 19,824	$ 39,736	$ 50,964	$ 23,376	$ 11,448	$ 152,279	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	$ 114,282	$ 326,888	$ 655,226	$ 840,366	$ 385,451	$ 188,763	$ 2,510,977	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	$ 15,764	$ 45,090	$ 90,380	$ 115,918	$ 53,168	$ 26,037	$ 346,357	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	$ 105,311	$ 301,227	$ 603,791	$ 774,397	$ 355,193	$ 173,945	$ 2,313,865	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	$ 1,012	$ 2,894	$ 5,802	$ 7,441	$ 3,413	$ 1,671	$ 22,233	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	$ 5,641	$ 16,135	$ 32,341	$ 41,479	$ 19,025	$ 9,317	$ 123,937	LN 47 Col D * LN 70
80	TOTAL	$ 471,175	$ 1,347,729	$ 2,701,436	$ 3,464,753	$ 1,589,179	$ 778,253	$ 10,352,526	Sum LN 72 : LN 79
81									
82	Residential	$ 222,235	$ 635,671	$ 1,274,161	$ 1,634,187	$ 749,553	$ 367,071	$ 4,882,879	LN 72 + LN 73
83	SALES HLF CLASSES	$ 23,706	$ 67,809	$ 135,918	$ 174,323	$ 79,957	$ 39,156	$ 520,868	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	$ 225,234	$ 644,250	$ 1,291,357	$ 1,656,243	$ 759,669	$ 372,026	$ 4,948,779	LN 75 + LN 77 + LN 79
85									

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

LN									
86	**CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**								
87		**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**WINTER**	
88	NH DIVISION - MONTHLY CAP. RELEASE	$ (98,389)	$ (250,480)	$ (485,361)	$ (617,803)	$ (292,373)	$ (151,670)	$ (1,896,076)	Attachment NUI-JDS-3, LN 76
89									
90	Res Heat	$ (45,994)	$ (117,091)	$ (226,890)	$ (288,803)	$ (136,675)	$ (70,901)	$ (886,354)	LN 40 Col D * LN 88
91	Res General	$ (413)	$ (1,050)	$ (2,035)	$ (2,590)	$ (1,226)	$ (636)	$ (7,950)	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	$ (1,447)	$ (3,684)	$ (7,139)	$ (9,087)	$ (4,301)	$ (2,231)	$ (27,890)	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	$ (23,864)	$ (60,753)	$ (117,723)	$ (149,846)	$ (70,914)	$ (36,787)	$ (459,888)	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	$ (3,292)	$ (8,380)	$ (16,238)	$ (20,669)	$ (9,782)	$ (5,074)	$ (63,436)	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	$ (21,991)	$ (55,984)	$ (108,482)	$ (138,084)	$ (65,348)	$ (33,899)	$ (423,787)	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	$ (211)	$ (538)	$ (1,042)	$ (1,327)	$ (628)	$ (326)	$ (4,072)	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	$ (1,178)	$ (2,999)	$ (5,811)	$ (7,396)	$ (3,500)	$ (1,816)	$ (22,699)	LN 47 Col D * LN 88
98	TOTAL	$ (98,389)	$ (250,480)	$ (485,361)	$ (617,803)	$ (292,373)	$ (151,670)	$ (1,896,076)	Sum LN 90 : LN 97
99									
100	Residential	$ (46,406)	$ (118,141)	$ (228,925)	$ (291,393)	$ (137,901)	$ (71,537)	$ (894,304)	LN 90 + LN 91
101	SALES HLF CLASSES	$ (4,950)	$ (12,602)	$ (24,420)	$ (31,084)	$ (14,710)	$ (7,631)	$ (95,398)	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	$ (47,033)	$ (119,736)	$ (232,015)	$ (295,326)	$ (139,762)	$ (72,502)	$ (906,374)	LN 93 + LN 95 + LN 97
103									
104	**INTERRUPTIBLE MARGINS BY CLASS**								
105		**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**WINTER**	
106	NH DIVISION - MONTHLY INTERR MARGINS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Attachment NUI-JDS-3, LN 77
107									
108	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 106
109	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 106
110	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 106
111	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 106
112	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 106
113	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 106
114	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 106
115	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 106
116	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 108 : LN 115
117									
118	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 108 + LN 109
119	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 110 + LN 112 + LN 114
120	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 111 + LN 113 + LN 115

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

LN		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER	
121									
122	**REMAINING RE-ENTRY FEE CREDIT**								
123		**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**WINTER**	
124	NH DIVISION - RE-ENTRY FEE CREDITS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Attachment NUI-JDS-3, LN 78
125									
126	Res Heat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 40 Col D * LN 124
127	Res General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 41 Col D * LN 124
128	G50 Low Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 42 Col D * LN 124
129	G40 Low Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 43 Col D * LN 124
130	G51 Med Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 44 Col D * LN 124
131	G41 Med Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 45 Col D * LN 124
132	G52 High Annual-Low Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 46 Col D * LN 124
133	G42 High Annual-High Winter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 47 Col D * LN 124
134	TOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Sum LN 126 : LN 133
135									
136	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 126 + LN 127
137	SALES HLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 128 + LN 130 + LN 132
138	SALES LLF CLASSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	LN 129 + LN 131 + LN 133
139									
140	**TOTAL NON-BASE CAPACITY COSTS**								
141		**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**WINTER**	
142	Res Heat	$ 205,868	$ 603,322	$ 1,217,131	$ 1,563,240	$ 712,802	$ 345,105	$ 4,647,467	Sum of Ln 54, 72, 90, 108, 126
143	Res General	$ 1,847	$ 5,412	$ 10,917	$ 14,022	$ 6,394	$ 3,095	$ 41,686	Sum of Ln 55, 73, 91, 109, 127
144	G50 Low Annual-Low Winter	$ 6,478	$ 18,984	$ 38,298	$ 49,189	$ 22,429	$ 10,859	$ 146,237	Sum of Ln 56, 74, 92, 110, 128
145	G40 Low Annual-High Winter	$ 106,815	$ 313,036	$ 631,513	$ 811,093	$ 369,840	$ 179,059	$ 2,411,355	Sum of Ln 57, 75, 93, 111, 129
146	G51 Med Annual-Low Winter	$ 14,734	$ 43,179	$ 87,109	$ 111,880	$ 51,015	$ 24,699	$ 332,615	Sum of Ln 58, 76, 94, 112, 130
147	G41 Med Annual-High Winter	$ 98,430	$ 288,462	$ 581,939	$ 747,422	$ 340,807	$ 165,003	$ 2,222,063	Sum of Ln 59, 77, 95, 113, 131
148	G52 High Annual-Low Winter	$ 946	$ 2,772	$ 5,592	$ 7,182	$ 3,275	$ 1,585	$ 21,351	Sum of Ln 60, 78, 96, 114, 132
149	G42 High Annual-High Winter	$ 5,272	$ 15,451	$ 31,170	$ 40,034	$ 18,255	$ 8,838	$ 119,020	Sum of Ln 61, 79, 97, 115, 133
150	TOTAL	$ 440,389	$ 1,290,617	$ 2,603,669	$ 3,344,061	$ 1,524,815	$ 738,244	$ 9,941,796	Sum LN 142 : LN 149
151									
152	Residential	$ 207,714	$ 608,733	$ 1,228,048	$ 1,577,262	$ 719,195	$ 348,201	$ 4,689,153	LN 142 + LN 143
153	SALES HLF CLASSES	$ 22,157	$ 64,935	$ 130,999	$ 168,250	$ 76,718	$ 37,143	$ 500,203	LN 144 + LN 146 + LN 148
154	SALES LLF CLASSES	$ 210,517	$ 616,949	$ 1,244,622	$ 1,598,549	$ 728,902	$ 352,900	$ 4,752,439	LN 145 + LN 147 + LN 149
155									
156	**TOTAL CAPACITY COSTS**								
157		**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**WINTER**	
158	Res Heat	$ 229,284	$ 626,738	$ 1,240,547	$ 1,586,656	$ 736,218	$ 368,844	$ 4,788,288	LN 142 + LN 26
159	Res General	$ 2,913	$ 6,478	$ 11,984	$ 15,089	$ 7,460	$ 4,177	$ 48,102	LN 143 + LN 27
160	G50 Low Annual-Low Winter	$ 14,977	$ 27,483	$ 46,797	$ 57,688	$ 30,928	$ 18,584	$ 196,458	LN 144 + LN 28
161	G40 Low Annual-High Winter	$ 114,787	$ 321,008	$ 639,485	$ 819,065	$ 377,812	$ 187,141	$ 2,459,299	LN 145 + LN 29
162	G51 Med Annual-Low Winter	$ 27,522	$ 55,967	$ 99,897	$ 124,668	$ 63,803	$ 37,663	$ 409,519	LN 146 + LN 30
163	G41 Med Annual-High Winter	$ 107,172	$ 297,205	$ 590,681	$ 756,164	$ 349,550	$ 173,866	$ 2,274,637	LN 147 + LN 31
164	G52 High Annual-Low Winter	$ 2,350	$ 4,176	$ 6,996	$ 8,586	$ 4,679	$ 3,009	$ 29,796	LN 148 + LN 32
165	G42 High Annual-High Winter	$ 5,993	$ 16,172	$ 31,891	$ 40,755	$ 18,975	$ 9,569	$ 123,354	LN 149 + LN 33
166	TOTAL	$ 607,149	$ 1,458,979	$ 2,774,601	$ 3,516,795	$ 1,697,549	$ 908,182	$ 10,963,254	Sum LN 158 : LN 165
167									
168	Residential	$ 232,197	$ 633,216	$ 1,252,531	$ 1,601,745	$ 743,678	$ 373,022	$ 4,836,390	LN 158 + LN 159
169	SALES HLF CLASSES	$ 44,849	$ 87,626	$ 153,690	$ 190,942	$ 99,410	$ 59,257	$ 635,773	LN 160 + LN 162 + LN 164
170	SALES LLF CLASSES	$ 227,953	$ 634,384	$ 1,262,057	$ 1,615,984	$ 746,337	$ 370,576	$ 4,857,290	LN 161 + LN 163 + LN 165
171									
172	% ALLOCATION BETWEEN SALES HLF AND LLF								
173	SALES HLF CLASSES							11.57%	LN 169 / (LN169 + LN 170)
174	SALES LLF CLASSES							88.43%	LN 170 / (LN 169 + LN 170)

Attachment NUI-JDS-6

Allocation of Commodity Costs to

New Hampshire and Maine Divisions

Northern Utilities, Inc.

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL	WINTER
1	**Supply Volumes - MMBtu**								
2	Total Pipeline	512,143	606,313	315,959	363,553	439,734	593,982	4,045,219	2,831,684
3	Total Storage	0	291,338	791,304	714,304	516,764	35,230	2,348,940	2,348,940
4	Total Peaking	1,350	1,395	96,171	129,294	13,157	30,838	655,808	272,204
5	Subtotal	513,493	899,046	1,203,433	1,207,151	969,655	660,050	7,049,967	5,452,828
6	Less Interruptible - Maine	4,500	0	0	0	4,500	4,500	40,500	13,500
7	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0
8	Total Firm Supply	508,993	899,046	1,203,433	1,207,151	965,155	655,550	7,009,467	5,439,328
9	Total Firm Pipeline Sendout	507,643	606,313	315,959	363,553	435,234	589,482	4,004,719	2,818,184
10	**Variable Costs**								
11	Pipeline Costs Modeled in Sendout™	$ 2,384,198	$ 3,533,738	$ 1,941,510	$ 2,253,478	$ 2,675,165	$ 3,534,706	$ 23,628,318	$ 16,322,797
12	NYMEX Price Used for Forecast	$4.726	$5.454	$5.706	$5.727	$5.672	$5.597		
13	NYMEX Price Used for Update	$4.726	$5.454	$5.706	$5.727	$5.672	$5.597		
14	Increase/(Decrease) NYMEX Price	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
15	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -		
16	Total Updated Pipeline Costs	$ 2,384,198	$ 3,533,738	$ 1,941,510	$ 2,253,478	$ 2,675,165	$ 3,534,706	$ 23,628,318	$ 16,322,797
17									
18	Total Pipeline	$ 2,384,198	$ 3,533,738	$ 1,941,510	$ 2,253,478	$ 2,675,165	$ 3,534,706	$ 23,628,318	$ 16,322,797
19	Total Storage	$ -	$ 1,222,421	$ 3,316,804	$ 3,004,009	$ 2,159,255	$ 167,343	$ 9,869,831	$ 9,869,831
20	Total Peaking	$ 12,125	$ 11,925	$ 374,173	$ 755,134	$ 53,287	$ 126,172	$ 2,814,884	$ 1,332,817
21	Subtotal	$ 2,396,323	$ 4,768,084	$ 5,632,487	$ 6,012,621	$ 4,887,708	$ 3,828,221	$ 36,313,033	$ 27,525,444
22									
23	Hedging (Gain)/Loss Estimate								
24	NYMEX NG Futures Contracts	20	24	24	23	28	30	185	149
25	Average Purchase Price	$ 7.958	$ 8.291	$ 8.423	$ 8.405	$ 8.214	$ 7.888		
26	NYMEX Price Used for Forecast	$ 4.726	$ 5.454	$ 5.706	$ 5.727	$ 5.672	$ 5.597		
27	NYMEX Price Used for Update	$ 4.726	$ 5.454	$ 5.706	$ 5.727	$ 5.672	$ 5.597		
28	Increase/(Decrease) NYMEX Price	$ -	$ -	$ -	$ -	$ -	$ -		
29	Futures Hedging (Gain)/Loss	$ 646,310	$ 680,840	$ 652,080	$ 615,970	$ 711,620	$ 687,300	$ 4,016,140	$ 3,994,120
30									
31	Interruptible Cost Estimate								
32	Variable Pipeline Costs Excld Hedges	$ 2,384,198	$ 3,533,738	$ 1,941,510	$ 2,253,478	$ 2,675,165	$ 3,534,706	$ 23,628,318	$ 16,322,797
33	Average Supply Cost ($/MMBtu)	$ 4.655	$ 5.828	$ 6.145	$ 6.198	$ 6.084	$ 5.951		
34	Interruptible Cost - Maine	$ 20,949	$ -	$ -	$ -	$ 27,376	$ 26,779	$ 237,980	$ 75,104
35	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36									
37	Firm Sales Pipeline Commodity Excld Hedge	$ 2,363,249	$ 3,533,738	$ 1,941,510	$ 2,253,478	$ 2,647,789	$ 3,507,928	$ 23,390,338	$ 16,247,692
38	Total Storage	$ -	$ 1,222,421	$ 3,316,804	$ 3,004,009	$ 2,159,255	$ 167,343	$ 9,869,831	$ 9,869,831
39	Total Peaking	$ 12,125	$ 11,925	$ 374,173	$ 755,134	$ 53,287	$ 126,172	$ 2,814,884	$ 1,332,817
40	Firm Sales Variable Costs Excld Hedge	$ 2,375,374	$ 4,768,084	$ 5,632,487	$ 6,012,621	$ 4,860,332	$ 3,801,442	$ 36,075,053	$ 27,450,340
41	Plus Hedging (Gain)/Loss	$ 646,310	$ 680,840	$ 652,080	$ 615,970	$ 711,620	$ 687,300	$ 4,016,140	$ 3,994,120
42	Total Firm Sales Variable Costs	$ 3,021,684	$ 5,448,924	$ 6,284,567	$ 6,628,591	$ 5,571,952	$ 4,488,742	$ 40,091,193	$ 31,444,460

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Attachment NUI-FXW-5
3	Total Storage	Attachment NUI-FXW-5
4	Total Peaking	Attachment NUI-FXW-5
5	Subtotal	SUM LN 2: LN 4
6	Less Interruptible - Maine	Attachment NUI-FXW-5
7	Less Interruptible - New Hampshire	Attachment NUI-FXW-5
8	Total Firm Supply	LN 5 - LN 6 - LN 7
9	Total Firm Pipeline Sendout	LN 2 - LN 6 - LN 7
10	Variable Costs	
11	Pipeline Costs Modeled in Sendout™	Attachment NUI-FXW-5
12	NYMEX Price Used for Forecast	Attachment NUI-FXW-5
13	NYMEX Price Used for Update	
14	Increase/(Decrease) NYMEX Price	LN 13 - LN 12
15	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 14
16	Total Updated Pipeline Costs	LN 15 + LN 11
17		
18	Total Pipeline	LN 16
19	Total Storage	Attachment NUI-FXW-5
20	Total Peaking	Attachment NUI-FXW-5
21	Subtotal	Sum LN 18 : LN 20
22		
23	Hedging (Gain)/Loss Estimate	
24	NYMEX NG Futures Contracts	Attachment NUI-FXW-5
25	Average Purchase Price	Attachment NUI-FXW-5
26	NYMEX Price Used for Forecast	Attachment NUI-FXW-5
27	NYMEX Price Used for Update	Company Analysis
28	Increase/(Decrease) NYMEX Price	LN 27 - LN 26
29	Futures Hedging (Gain)/Loss	(LN 25 - LN 26 - LN 28) * LN 24*10,000
30		
31	Interruptible Cost Estimate	
32	Variable Pipeline Costs Excld Hedges	LN 16
33	Average Supply Cost ($/MMBtu)	LN 32 / LN 2
34	Interruptible Cost - Maine	LN 33 * LN 6
35	Interruptible Cost - New Hampshire	LN 33 * LN 7
36		
37	Firm Sales Pipeline Commodity Excld Hedge	LN 32 - LN 34 - LN 35
38	Total Storage	LN 19
39	Total Peaking	LN 20
40	Firm Sales Variable Costs Excld Hedge	Sum LN 37 : LN 39
41	Plus Hedging (Gain)/Loss	LN 29
42	Total Firm Sales Variable Costs	LN 40 + LN 41

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL	WINTER
Maine	234,264	425,992	579,610	554,379	455,067	303,690	3,265,494	2,553,000
New Hampshire	274,729	473,054	623,823	652,772	510,088	351,860	3,743,971	2,886,327
Total	508,993	899,046	1,203,433	1,207,151	965,155	655,550	7,009,465	5,439,327

Percentage of Total								
Maine	46.02%	47.38%	48.16%	45.92%	47.15%	46.33%	46.59%	46.94%
New Hampshire	53.98%	52.62%	51.84%	54.08%	52.85%	53.67%	53.41%	53.06%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Commodity Allocation by Jurisdiction

Maine

Firm Sales Pipeline Commodity Excld Hedge	$ 1,087,683	$ 1,674,379	$ 935,090	$ 1,034,900	$ 1,248,422	$ 1,625,082	$ 10,835,041	$ 7,605,556
Hedging (Gains) Losses	$ 297,464	$ 322,600	$ 314,061	$ 282,882	$ 335,526	$ 318,398	$ 1,881,111	$ 1,870,931
Storage	$ -	$ 579,215	$ 1,597,473	$ 1,379,578	$ 1,018,080	$ 77,523	$ 4,651,870	$ 4,651,870
Peaking	$ 5,581	$ 5,650	$ 180,213	$ 346,792	$ 25,125	$ 58,450	$ 1,302,480	$ 621,811
Maine Interruptible	$ 20,949	$ -	$ -	$ -	$ 27,376	$ 26,779	$ 237,980	$ 75,104
Total Maine Commodity Costs	$ 1,411,676	$ 2,581,845	$ 3,026,838	$ 3,044,151	$ 2,654,529	$ 2,106,232	$ 18,908,482	$ 14,825,272
Maine Inventory Finance Costs	$ 7,761	$ 17,481	$ 25,383	$ 24,514	$ 18,976	$ 11,332	$ 105,447	$ 105,447
Total Maine Variable Costs	$ 1,419,437	$ 2,599,326	$ 3,052,221	$ 3,068,665	$ 2,673,505	$ 2,117,565	$ 19,013,929	$ 14,930,720

New Hampshire

Firm Sales Pipeline Commodity Excld Hedge	$ 1,275,566	$ 1,859,359	$ 1,006,420	$ 1,218,578	$ 1,399,367	$ 1,882,846	$ 12,555,297	$ 8,642,136
Hedging (Gains) Losses	$ 348,846	$ 358,240	$ 338,019	$ 333,088	$ 376,094	$ 368,902	$ 2,135,029	$ 2,123,189
Storage	$ -	$ 643,205	$ 1,719,331	$ 1,624,431	$ 1,141,175	$ 89,819	$ 5,217,961	$ 5,217,961
Peaking	$ 6,544	$ 6,275	$ 193,960	$ 408,342	$ 28,163	$ 67,721	$ 1,512,404	$ 711,005
New Hampshire Interruptible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 1,630,956	$ 2,867,078	$ 3,257,729	$ 3,584,440	$ 2,944,799	$ 2,409,288	$ 21,420,692	$ 16,694,292
New Hampshire Inventory Finance Costs	$ 9,370	$ 19,871	$ 27,992	$ 30,094	$ 21,866	$ 13,598	$ 122,792	$ 122,792
Total New Hampshire Variable Costs	$ 1,640,326	$ 2,886,950	$ 3,285,722	$ 3,614,534	$ 2,966,665	$ 2,422,886	$ 21,543,483	$ 16,817,083

Northern Utilities

Firm Sales Pipeline Commodity Excld Hedge	$ 2,363,249	$ 3,533,738	$ 1,941,510	$ 2,253,478	$ 2,647,789	$ 3,507,928	$ 23,390,338	$ 16,247,692
Hedging (Gains) Losses	$ 646,310	$ 680,840	$ 652,080	$ 615,970	$ 711,620	$ 687,300	$ 4,016,140	$ 3,994,120
Storage	$ -	$ 1,222,421	$ 3,316,804	$ 3,004,009	$ 2,159,255	$ 167,343	$ 9,869,831	$ 9,869,831
Peaking	$ 12,125	$ 11,925	$ 374,173	$ 755,134	$ 53,287	$ 126,172	$ 2,814,884	$ 1,332,817
Northern Interruptible	$ 20,949	$ -	$ -	$ -	$ 27,376	$ 26,779	$ 237,980	$ 75,104
Total Northern Commodity Costs	$ 3,042,633	$ 5,448,924	$ 6,284,567	$ 6,628,591	$ 5,599,328	$ 4,515,521	$ 40,329,173	$ 31,519,564
Northern Inventory Finance Costs	$ 17,131	$ 37,352	$ 53,375	$ 54,608	$ 40,842	$ 24,930	$ 228,239	$ 228,239
Total Northern Variable Costs	$ 3,059,764	$ 5,486,276	$ 6,337,943	$ 6,683,200	$ 5,640,170	$ 4,540,451	$ 40,557,412	$ 31,747,803

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

LN	Description	Source
43	**Commodity Allocation Factors**	
44	Firm Sales Sendout for Normal Winter, MMBtu	
45		
46	Maine	ME Attachment NUI-JDS-4, LN 33 / 10
47	New Hampshire	NH Attachment NUI-JDS-4, LN 33 / 10
48	Total	LN 46 + LN 47
49		
50	**Percentage of Total**	
51	Maine	LN 46 / LN 48
52	New Hampshire	LN 47 / LN 48
53	Total	LN 51 + LN 52
54		
55	**Commodity Allocation by Jurisdiction**	
56	**Maine**	
57	Firm Sales Pipeline Commodity Excld Hedge	LN 37 * LN 51
58	Hedging (Gains) Losses	LN 29 * LN 51
59	Storage	LN 38 * LN 51
60	Peaking	LN 39 * LN 51
61	Maine Interruptible	LN 34
62	Total Maine Commodity Costs	Sum LN 57 : LN 61
63	Maine Inventory Finance Costs	LN 104
64	Total Maine Variable Costs	LN 62 + LN 63
65	**New Hampshire**	
66	Firm Sales Pipeline Commodity Excld Hedge	LN 37 * LN 52
67	Hedging (Gains) Losses	LN 29 * LN 52
68	Storage	LN 38 * LN 52
69	Peaking	LN 39 * LN 52
70	New Hampshire Interruptible	LN 35
71	Total New Hampshire Commodity Costs	Sum LN 66 : LN 70
72	New Hampshire Inventory Finance Costs	LN 109
73	Total New Hampshire Variable Costs	LN 71 + LN 72
74	**Northern Utilities**	
75	Firm Sales Pipeline Commodity Excld Hedge	LN 57 + LN 66
76	Hedging (Gains) Losses	LN 58 + LN 67
77	Storage	LN 59 + LN 68
78	Peaking	LN 60 + LN 69
79	Northern Interruptible	LN 61 + LN 70
80	Total Northern Commodity Costs	LN 62 + LN 71
81	Northern Inventory Finance Costs	LN 63 + LN 72
82	Total Northern Variable Costs	LN 80 + LN 81
83		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE

Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col N
Inventory Finance Charge	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**TOTAL**
Storage	$ 28,424	$ 26,799	$ 20,768	$ 12,370	$ 5,510	$ 2,538	$ 225,854
Peaking	$ 281	$ 267	$ 255	$ 216	$ 182	$ 177	$ 2,385
Total	$ 28,705	$ 27,066	$ 21,022	$ 12,586	$ 5,692	$ 2,714	$ 228,239

Inventory Finance Charge Allocation by Jurisdiction							
Maine	$ 13,211	$ 12,825	$ 10,125	$ 5,780	$ 2,684	$ 1,257	$ 105,447
New Hampshire	$ 15,493	$ 14,242	$ 10,897	$ 6,806	$ 3,008	$ 1,457	$ 122,792
Total	$ 28,705	$ 27,066	$ 21,022	$ 12,586	$ 5,692	$ 2,714	$ 228,239

Inventory Finance Charge Allocation by Month

Maine

	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
Firm Sales Normal Remaining Sendout	150,871	339,820	493,438	476,546	368,895	220,298	2,049,867	2,049,867
Monthly % Sendout of Total Winter	7.36%	16.58%	24.07%	23.25%	18.00%	10.75%	100.00%	100.00%
ME Allocated Inventory Finance Charge	$ 7,761	$ 17,481	$ 25,383	$ 24,514	$ 18,976	$ 11,332	$ 105,447	$ 105,447

New Hampshire

	Col B	Col C	Col D	Col E	Col F	Col G	Col N	Col O
Firm Sales Normal Remaining Sendout	173,953	368,919	519,688	558,714	405,953	252,454	2,279,682	2,279,682
Monthly % Sendout of Total Winter	7.63%	16.18%	22.80%	24.51%	17.81%	11.07%	100.00%	100.00%
NH Allocated Inventory Finance Charge	$ 9,370	$ 19,871	$ 27,992	$ 30,094	$ 21,866	$ 13,598	$ 122,792	$ 122,792

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

LN	Description	Source
84	**Northern Utilities**	
85	**Simplified Market Based Allocator (MBA) Calculations**	
86	**ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**	
87		
88		
89		
90	**Inventory Finance Charge**	
91	Storage	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
92	Peaking	Company Analysis, Attachment NUI-JDS-8 - 'Carrying Costs'
93	Total	Sum LN 91 : LN 92
94		
95	**Inventory Finance Charge Allocation by Jurisdiction**	
96	Maine	LN 93 * LN 51
97	New Hampshire	LN 93 * LN 52
98	Total	Sum LN 96 : LN 97
99		
100	**Inventory Finance Charge Allocation by Month**	
101	**Maine**	
102	Firm Sales Remaining Sendout	ME Attachment NUI-JDS-4, LN 80 / 10
103	Monthly % Sendout of Total Winter	LN 102 / LN 102 Col N
104	ME Allocated Inventory Finance Charge	LN 96 Col N * LN 103
105		
106	**New Hampshire**	
107	Firm Sales Remaining Sendout	NH Attachment NUI-JDS-4, LN 80 / 10
108	Monthly % Sendout of Total Winter	LN 107 / LN 107 Col N
109	NH Allocated Inventory Finance Charge	LN 97 Col N* LN 108

Attachment NUI-JDS-7

New Hampshire Division

Commodity Cost Analysis

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL	WINTER
	Supply Volumes - Therms								
1	New Hampshire Sales Pipeline	2,740,007	3,190,260	1,637,834	1,965,928	2,300,229	3,163,988	21,500,650	14,998,246
2	New Hampshire Sales Storage	0	1,532,940	4,101,879	3,862,632	2,731,121	189,094	12,417,666	12,417,666
3	New Hampshire Sales Peaking	7,287	7,340	498,520	699,162	69,533	165,518	3,521,401	1,447,360
4	Total New Hampshire Firm Sales Sendout	2,747,294	4,730,540	6,238,232	6,527,722	5,100,883	3,518,601	37,439,717	28,863,273
5									
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0
7									
8	Total Firm Sendout	2,747,294	4,730,540	6,238,232	6,527,722	5,100,883	3,518,601	37,439,717	28,863,273
9	Total Firm Sales	2,708,520	4,660,403	6,156,557	6,442,640	5,033,569	3,472,097	36,926,371	28,473,787
10	Difference (LAUF & Company Use)	38,774	70,137	81,676	85,082	67,314	46,504	513,346	389,486
11	Percent Difference	1.41%	1.48%	1.31%	1.30%	1.32%	1.32%	1.37%	1.35%
12									
13	**Variable Costs**								
14	New Hampshire Sales Pipeline Commodity	$ 1,275,566	$ 1,859,359	$ 1,006,420	$ 1,218,578	$ 1,399,367	$ 1,882,846	$ 12,555,297	$ 8,642,136
15	New Hampshire Hedging (Gains) Losses	$ 348,846	$ 358,240	$ 338,019	$ 333,088	$ 376,094	$ 368,902	$ 2,135,029	$ 2,123,189
16	New Hampshire Total Storage	$ -	$ 643,205	$ 1,719,331	$ 1,624,431	$ 1,141,175	$ 89,819	$ 5,217,961	$ 5,217,961
17	New Hampshire Total Peaking	$ 6,544	$ 6,275	$ 193,960	$ 408,342	$ 28,163	$ 67,721	$ 1,512,404	$ 711,005
18	New Hampshire Inventory Finance Charge	$ 9,370	$ 19,871	$ 27,992	$ 30,094	$ 21,866	$ 13,598	$ 122,792	$ 122,792
19	Total New Hampshire Sales Variable Costs	$ 1,640,326	$ 2,886,950	$ 3,285,722	$ 3,614,534	$ 2,966,665	$ 2,422,886	$ 21,543,483	$ 16,817,083
20	Total New Hampshire Sales Variable Costs Excld Hedges	$ 1,291,480	$ 2,528,710	$ 2,947,703	$ 3,281,446	$ 2,590,571	$ 2,053,985	$ 19,408,454	$ 14,693,895
21								$ -	$ -
22	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total New Hampshire Commodity Costs	$ 1,640,326	$ 2,886,950	$ 3,285,722	$ 3,614,534	$ 2,966,665	$ 2,422,886	$ 21,543,483	$ 16,817,083
24									
25	**Supply Cost/Therm**								
26	New Hampshire Sales Pipeline Commodity Excld Hedges	0.4655	0.5828	0.6145	0.6198	0.6084	0.5951	0.5839	0.5762
27	New Hampshire Hedging (Gains) Losses	0.1273	0.1123	0.2064	0.1694	0.1635	0.1166	0.0993	0.1416
28	New Hampshire Storage Excld Inventory Finance Costs	0.0000	0.4196	0.4192	0.4206	0.4178	0.4750	0.4202	0.4202
29	New Hampshire Peaking Excld Inventory Finance Costs	0.8981	0.8548	0.3891	0.5840	0.4050	0.4091	0.4295	0.4912
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	1.2859	0.0129	0.0061	0.0066	0.0078	0.0383	0.0077	0.0089
31	Weighted Average Cost per Dth Sendout	0.5971	0.6103	0.5267	0.5537	0.5816	0.6886	0.5754	0.5826
32									
33	New Hampshire Interruptible Cost / Therm	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
34									
35	**Commodity Costs**								
36	Base Commodity, therms	1,007,761	1,041,353	1,041,353	940,577	1,041,353	994,055	12,193,328	6,066,454
37	Base Commodity Cost Excld Hedging	$ 469,147	$ 606,925	$ 639,893	$ 583,016	$ 633,518	$ 591,548	$ 7,012,359	$ 3,524,048
38	Base Hedging Commodity Cost	$ 128,304	$ 116,935	$ 214,916	$ 159,363	$ 170,264	$ 115,901	$ 914,868	$ 905,683
39	Remaining Commodity Excld Hedging	$ 822,333	$ 1,921,784	$ 2,307,810	$ 2,698,430	$ 1,957,053	$ 1,462,437	$ 12,396,095	$ 11,169,847
40	Remaining Hedging Commodity	$ 220,542	$ 241,304	$ 123,102	$ 173,726	$ 205,830	$ 253,001	$ 1,220,162	$ 1,217,506
41	Total Commodity Excld Hedging	$ 1,291,480	$ 2,528,710	$ 2,947,703	$ 3,281,446	$ 2,590,571	$ 2,053,985	$ 19,408,454	$ 14,693,895
42	Total Hedging	$ 348,846	$ 358,240	$ 338,019	$ 333,088	$ 376,094	$ 368,902	$ 2,135,029	$ 2,123,189
43	Total Commodity (Incl Hedging)	$ 1,640,326	$ 2,886,950	$ 3,285,722	$ 3,614,534	$ 2,966,665	$ 2,422,886	$ 21,543,483	$ 16,817,083

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Attachment NUI-JDS-6, LN 9 * LN 52 * 10
2	New Hampshire Sales Storage	Attachment NUI-JDS-6, LN 3 * LN 52 * 10
3	New Hampshire Sales Peaking	Attachment NUI-JDS-6, LN 4 * LN 52 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Attachment NUI-JDS-6, LN 7 * 10
7		
8	Total Firm Sendout	LN 4
9	Total Firm Sales	Attachment NUI-JDS-4, LN 11 * 10
10	Difference (LAUF & Company Use)	LN 8 - LN 9
11	Percent Difference	LN 10 / LN 8
12		
13	**Variable Costs**	
14	New Hampshire Sales Pipeline Commodity	Attachment NUI-JDS-6, LN 66 * 10
15	New Hampshire Hedging (Gains) Losses	Attachment NUI-JDS-6, LN 67 * 10
16	New Hampshire Total Storage	Attachment NUI-JDS-6, LN 68 * 10
17	New Hampshire Total Peaking	Attachment NUI-JDS-6, LN 69 * 10
18	New Hampshire Inventory Finance Charge	Attachment NUI-JDS-6, LN 72 * 10
19	Total New Hampshire Sales Variable Costs	Sum LN 14 : LN 18
20	Total New Hampshire Sales Variable Costs Excld Hedges	LN 19 - LN 15
21		
22	New Hampshire Interruptible Commodity Costs	Attachment NUI-JDS-6, LN 70
23	Total New Hampshire Commodity Costs	LN 19
24		
25	**Supply Cost/Therm**	
26	New Hampshire Sales Pipeline Commodity Excld Hedges	LN 14 / LN 1
27	New Hampshire Hedging (Gains) Losses	LN 15 / LN 1
28	New Hampshire Storage Excld Inventory Finance Costs	LN 16 / LN 2
29	New Hampshire Peaking Excld Inventory Finance Costs	LN 17 / LN 3
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	LN 18 / Sum (LN 2 : LN 3)
31	Weighted Average Cost per Dth Sendout	LN 19 / LN 8
32		
33	New Hampshire Interruptible Cost / Therm	LN 22 / LN 6
34		
35	**Commodity Costs**	
36	Base Commodity, therms	Attachment NUI-JDS-4, LN 64
37	Base Commodity Cost Excld Hedging	Min (LN 26 * LN 36), LN 19
38	Base Hedging Commodity Cost	Min (LN 27 * LN 36), (LN 19 - LN 37)
39	Remaining Commodity Excld Hedging	LN 20 - LN 37
40	Remaining Hedging Commodity	LN 15 - LN 38
41	Total Commodity Excld Hedging	LN 37 + LN 39
42	Total Hedging	LN 38 + LN 40
43	Total Commodity (Incl Hedging)	LN 41 + LN 42

Attachment NUI-JDS-8

Northern Utilities' Inventory Activity

Northern Utilities, Inc.

Northern Utilities, Inc.
Storage Analysis

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawal Charges	Withdrawn Value plus Charges
May-10	21,450	50,635	-	72,085	$ 97,385	$ 4.54	$ 6.02	$ 304,810	$ -	$ 402,196	3.25%	$ 677	$ 402,196	$ -	$ -
Jun-10	72,085	49,002	-	121,086	$ 402,196	$ 5.58	$ 6.12	$ 299,749	$ -	$ 701,945	3.25%	$ 1,495	$ 701,945	$ -	$ -
Jul-10	121,086	50,635	-	171,721	$ 701,945	$ 5.80	$ 6.24	$ 315,967	$ -	$ 1,017,912	3.25%	$ 2,329	$ 1,017,912	$ -	$ -
Aug-10	171,721	42,776	-	214,498	$ 1,017,912	$ 5.93	$ 6.34	$ 271,182	$ -	$ 1,289,093	3.25%	$ 3,124	$ 1,289,093	$ -	$ -
Sep-10	214,498	-	-	214,498	$ 1,289,093	$ 6.01		$ -	$ -	$ 1,289,093	3.25%	$ 3,491	$ 1,289,093	$ -	$ -
Oct-10	214,498	-	-	214,498	$ 1,289,093	$ 6.01		$ -	$ -	$ 1,289,093	3.25%	$ 3,491	$ 1,289,093	$ -	$ -
Nov-09	214,498	-	-	214,498	$ 869,916	$ 4.06		$ -	$ -	$ 869,916	3.25%	$ 2,356	$ 869,916	$ -	$ -
Dec-09	214,498	-	-	214,498	$ 869,916	$ 4.06		$ -	$ -	$ 869,916	3.25%	$ 2,356	$ 869,916	$ -	$ -
Jan-10	214,498	-	66,666	147,831	$ 869,916	$ 4.06		$ -	$ 270,372	$ 599,543	3.25%	$ 1,990	$ 599,543	$ -	$ 270,372
Feb-10	147,831	-	62,231	85,600	$ 599,543	$ 4.06		$ -	$ 252,385	$ 347,159	3.25%	$ 1,282	$ 347,159	$ -	$ 252,385
Mar-10	85,600	-	42,700	42,900	$ 347,159	$ 4.06		$ -	$ 173,176	$ 173,983	3.25%	$ 706	$ 173,983	$ -	$ 173,176
Apr-10	42,900	14,651	36,100	21,450	$ 173,983	$ 4.06	$ 5.96	$ 87,304	$ 163,901	$ 97,385	3.25%	$ 367	$ 97,385	$ -	$ 163,901

Washington 10 Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawal Charges	Withdrawn Value plus Charges
May-10	199,678	424,643	-	624,320	$ 801,270	$ 4.01	$ 5.84	$ 2,478,840	$ -	$ 3,280,110	3.25%	$ 5,527	$ 3,280,110	$ -	$ -
Jun-10	624,320	410,944	-	1,035,265	$ 3,280,110	$ 5.25	$ 5.84	$ 2,398,877	$ -	$ 5,678,987	3.25%	$ 12,132	$ 5,678,987	$ -	$ -
Jul-10	1,035,265	103,095	-	1,138,360	$ 5,678,987	$ 5.49	$ 5.86	$ 604,256	$ -	$ 6,283,243	3.25%	$ 16,199	$ 6,283,243	$ -	$ -
Aug-10	1,138,360	424,643	-	1,563,003	$ 6,283,243	$ 5.52	$ 5.84	$ 2,479,841	$ -	$ 8,763,084	3.25%	$ 20,375	$ 8,763,084	$ -	$ -
Sep-10	1,563,003	410,944	-	1,973,947	$ 8,763,084	$ 5.61	$ 5.85	$ 2,405,188	$ -	$ 11,168,272	3.25%	$ 26,990	$ 11,168,272	$ -	$ -
Oct-10	1,973,947	424,643	-	2,398,590	$ 11,168,272	$ 5.66	$ 5.86	$ 2,486,870	$ -	$ 13,655,142	3.25%	$ 33,615	$ 13,655,142	$ -	$ -
Nov-09	2,398,590	-	-	2,398,590	$ 9,625,107	$ 4.01		$ -	$ -	$ 9,625,107	3.25%	$ 26,068	$ 9,625,107	$ -	$ -
Dec-09	2,398,590	-	299,001	2,099,589	$ 9,625,107	$ 4.01		$ -	$ 1,199,837	$ 8,425,270	3.25%	$ 24,443	$ 8,425,270	$ -	$ 1,199,837
Jan-10	2,099,589	-	743,563	1,356,026	$ 8,425,270	$ 4.01		$ -	$ 2,983,783	$ 5,441,487	3.25%	$ 18,778	$ 5,441,487	$ -	$ 2,983,783
Feb-10	1,356,026	-	671,605	684,421	$ 5,441,487	$ 4.01		$ -	$ 2,695,030	$ 2,746,457	3.25%	$ 11,088	$ 2,746,457	$ -	$ 2,695,030
Mar-10	684,421	-	484,743	199,678	$ 2,746,457	$ 4.01		$ -	$ 1,945,187	$ 801,270	3.25%	$ 4,804	$ 801,270	$ -	$ 1,945,187
Apr-10	199,678	-	-	199,678	$ 801,270	$ 4.01		$ -	$ -	$ 801,270	3.25%	$ 2,170	$ 801,270	$ -	$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding Carrying Costs	Withdrawal Charges	Withdrawn Value plus Charges
May-10	11,250	1,395	1,395	11,250	$ 63,919	$ 5.68	$ 5.06	$ 7,055	$ 7,830	$ 63,144	3.25%	$ 172	$ 63,144		$ 7,830
Jun-10	11,250	1,350	1,350	11,250	$ 63,144	$ 5.61	$ 5.06	$ 6,827	$ 7,497	$ 62,474	3.25%	$ 170	$ 62,474		$ 7,497
Jul-10	11,250	1,395	1,395	11,250	$ 62,474	$ 5.55	$ 5.06	$ 7,055	$ 7,670	$ 61,858	3.25%	$ 168	$ 61,858		$ 7,670
Aug-10	11,250	1,395	1,395	11,250	$ 61,858	$ 5.50	$ 5.06	$ 7,055	$ 7,602	$ 61,310	3.25%	$ 167	$ 61,310		$ 7,602
Sep-10	11,250	1,350	1,350	11,250	$ 61,310	$ 5.45	$ 5.06	$ 6,827	$ 7,300	$ 60,837	3.25%	$ 165	$ 60,837		$ 7,300
Oct-10	11,250	1,395	1,395	11,250	$ 60,837	$ 5.41	$ 5.06	$ 7,055	$ 7,490	$ 60,402	3.25%	$ 164	$ 60,402		$ 7,490
Nov-09	11,250	1,350	1,350	11,250	$ 106,343	$ 9.45	$ 5.06	$ 6,827	$ 12,125	$ 101,044	3.25%	$ 281	$ 101,044		$ 12,125
Dec-09	11,250	1,395	1,395	11,250	$ 101,044	$ 8.98	$ 5.06	$ 7,055	$ 11,925	$ 96,173	3.25%	$ 267	$ 96,173		$ 11,925
Jan-10	11,250	1,395	1,395	11,250	$ 96,173	$ 8.55	$ 5.06	$ 7,055	$ 11,388	$ 91,840	3.25%	$ 255	$ 91,840		$ 11,388
Feb-10	11,250	24,560	24,560	11,250	$ 91,840	$ 8.16	$ 5.06	$ 124,200	$ 148,169	$ 67,871	3.25%	$ 216	$ 67,871		$ 148,169
Mar-10	11,250	1,395	1,395	11,250	$ 67,871	$ 6.03	$ 5.06	$ 7,055	$ 8,266	$ 66,659	3.25%	$ 182	$ 66,659		$ 8,266
Apr-10	11,250	4,386	4,386	11,250	$ 66,659	$ 5.93	$ 5.06	$ 22,178	$ 24,918	$ 63,919	3.25%	$ 177	$ 63,919		$ 24,918

Attachment NUI-JDS-9

New Hampshire Division

Allocation of New Hampshire Variable Gas Costs

to Firm Sales Rate Classes

Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

#									
1	**BASE SENDOUT BY CLASS**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**TOTAL**	**WINTER**
2	**Total Therms**								
3	Res Heat	365,240	377,414	377,414	340,890	377,414	365,240	4,435,772	2,203,612
4	Res General	16,641	17,196	17,196	15,532	17,196	16,641	201,187	100,401
5	G50 Low Annual-Low Winter	132,566	136,985	136,985	123,729	136,985	118,860	1,576,846	786,111
6	G40 Low Annual-High Winter	124,348	128,493	128,493	116,058	128,493	124,348	1,509,675	750,233
7	G51 Med Annual-Low Winter	199,463	206,111	206,111	186,165	206,111	199,463	2,418,121	1,203,425
8	G41 Med Annual-High Winter	136,359	140,904	140,904	127,268	140,904	136,359	1,650,576	822,698
9	G52 High Annual-Low Winter	21,903	22,634	22,634	20,443	22,634	21,903	265,093	132,151
10	G42 High Annual-High Winter	11,241	11,616	11,616	10,492	11,616	11,241	136,059	67,823
11	Total Firm Sales	1,007,761	1,041,353	1,041,353	940,577	1,041,353	994,055	12,193,328	6,066,454
12	**% of Total**								
13	Res Heat	36.24%	36.24%	36.24%	36.24%	36.24%	36.74%		
14	Res General	1.65%	1.65%	1.65%	1.65%	1.65%	1.67%		
15	G50 Low Annual-Low Winter	13.15%	13.15%	13.15%	13.15%	13.15%	11.96%		
16	G40 Low Annual-High Winter	12.34%	12.34%	12.34%	12.34%	12.34%	12.51%		
17	G51 Med Annual-Low Winter	19.79%	19.79%	19.79%	19.79%	19.79%	20.07%		
18	G41 Med Annual-High Winter	13.53%	13.53%	13.53%	13.53%	13.53%	13.72%		
19	G52 High Annual-Low Winter	2.17%	2.17%	2.17%	2.17%	2.17%	2.20%		
20	G42 High Annual-High Winter	1.12%	1.12%	1.12%	1.12%	1.12%	1.13%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		
22	**BASE COMMODITY COSTS Excld Hedging**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**TOTAL**	**WINTER**
23	TOTAL BASE COMMODITY Excld Hedging	$ 469,147	$ 606,925	$ 639,893	$ 583,016	$ 633,518	$ 591,548	$ 7,012,359	$ 3,524,048
24	Res Heat	$ 170,031	$ 219,966	$ 231,914	$ 211,300	$ 229,604	$ 217,349	$ 2,551,240	$ 1,280,165
25	Res General	$ 7,747	$ 10,022	$ 10,566	$ 9,627	$ 10,461	$ 9,903	$ 115,748	$ 58,327
26	G50 Low Annual-Low Winter	$ 61,714	$ 79,838	$ 84,175	$ 76,693	$ 83,336	$ 70,732	$ 905,825	$ 456,489
27	G40 Low Annual-High Winter	$ 57,888	$ 74,889	$ 78,957	$ 71,938	$ 78,170	$ 73,998	$ 868,335	$ 435,840
28	G51 Med Annual-Low Winter	$ 92,857	$ 120,127	$ 126,652	$ 115,394	$ 125,390	$ 118,697	$ 1,390,799	$ 699,117
29	G41 Med Annual-High Winter	$ 63,480	$ 82,122	$ 86,583	$ 78,887	$ 85,720	$ 81,145	$ 949,796	$ 477,938
30	G52 High Annual-Low Winter	$ 10,197	$ 13,191	$ 13,908	$ 12,672	$ 13,769	$ 13,034	$ 152,405	$ 76,772
31	G42 High Annual-High Winter	$ 5,233	$ 6,770	$ 7,138	$ 6,503	$ 7,067	$ 6,690	$ 78,211	$ 39,401
32									
33	Residential	$ 177,778	$ 229,988	$ 242,481	$ 220,928	$ 240,065	$ 227,252	$ 2,666,988	$ 1,338,492
34	SALES HLF CLASSES	$ 164,768	$ 213,156	$ 224,735	$ 204,759	$ 222,496	$ 202,464	$ 2,449,029	$ 1,232,377
35	SALES LLF CLASSES	$ 126,601	$ 163,781	$ 172,678	$ 157,329	$ 170,957	$ 161,833	$ 1,896,342	$ 953,178
36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**								
37	TOTAL BASE HEDGING COMMODITY	$ 128,304	$ 116,935	$ 214,916	$ 159,363	$ 170,264	$ 115,901	$ 914,868	$ 905,683
38	Res Heat	$ 46,501	$ 42,381	$ 77,891	$ 57,757	$ 61,708	$ 42,585	$ 332,178	$ 328,823
39	Res General	$ 2,119	$ 1,931	$ 3,549	$ 2,632	$ 2,812	$ 1,940	$ 15,135	$ 14,982
40	G50 Low Annual-Low Winter	$ 16,878	$ 15,382	$ 28,271	$ 20,963	$ 22,398	$ 13,858	$ 118,907	$ 117,751
41	G40 Low Annual-High Winter	$ 15,831	$ 14,429	$ 26,519	$ 19,664	$ 21,009	$ 14,498	$ 113,092	$ 111,950
42	G51 Med Annual-Low Winter	$ 25,395	$ 23,145	$ 42,538	$ 31,542	$ 33,700	$ 23,256	$ 181,396	$ 179,575
43	G41 Med Annual-High Winter	$ 17,361	$ 15,822	$ 29,080	$ 21,563	$ 23,038	$ 15,899	$ 124,016	$ 122,763
44	G52 High Annual-Low Winter	$ 2,789	$ 2,542	$ 4,671	$ 3,464	$ 3,701	$ 2,554	$ 19,920	$ 19,720
45	G42 High Annual-High Winter	$ 1,431	$ 1,304	$ 2,397	$ 1,778	$ 1,899	$ 1,311	$ 10,224	$ 10,121
46									
47	Residential	$ 48,619	$ 44,311	$ 81,440	$ 60,389	$ 64,520	$ 44,525	$ 347,313	$ 343,805
48	SALES HLF CLASSES	$ 45,061	$ 41,069	$ 75,480	$ 55,969	$ 59,798	$ 39,668	$ 320,224	$ 317,045
49	SALES LLF CLASSES	$ 34,623	$ 31,555	$ 57,996	$ 43,005	$ 45,946	$ 31,707	$ 247,331	$ 244,833

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	
2	**Total Therms**	
3	Res Heat	Attachment NUI-JDS-4, LN 52
4	Res General	Attachment NUI-JDS-4, LN 53
5	G50 Low Annual-Low Winter	Attachment NUI-JDS-4, LN 54
6	G40 Low Annual-High Winter	Attachment NUI-JDS-4, LN 55
7	G51 Med Annual-Low Winter	Attachment NUI-JDS-4, LN 56
8	G41 Med Annual-High Winter	Attachment NUI-JDS-4, LN 57
9	G52 High Annual-Low Winter	Attachment NUI-JDS-4, LN 58
10	G42 High Annual-High Winter	Attachment NUI-JDS-4, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12	**% of Total**	
13	Res Heat	LN 3 / LN 11
14	Res General	LN 4 / LN 11
15	G50 Low Annual-Low Winter	LN 5 / LN 11
16	G40 Low Annual-High Winter	LN 6 / LN 11
17	G51 Med Annual-Low Winter	LN 7 / LN 11
18	G41 Med Annual-High Winter	LN 8 / LN 11
19	G52 High Annual-Low Winter	LN 9 / LN 11
20	G42 High Annual-High Winter	LN 10 / LN 11
21	Total Firm Sales	LN 11 / LN 11

22	**BASE COMMODITY COSTS Excld Hedging**	
23	TOTAL BASE COMMODITY Excld Hedging	Attachment NUI-JDS-7, LN 37
24	Res Heat	LN 23 * LN 13
25	Res General	LN 23 * LN 14
26	G50 Low Annual-Low Winter	LN 23 * LN 15
27	G40 Low Annual-High Winter	LN 23 * LN 16
28	G51 Med Annual-Low Winter	LN 23 * LN 17
29	G41 Med Annual-High Winter	LN 23 * LN 18
30	G52 High Annual-Low Winter	LN 23 * LN 19
31	G42 High Annual-High Winter	LN 23 * LN 20
32		
33	Residential	LN 24 + LN 25
34	SALES HLF CLASSES	LN 26 + LN 28 + LN 30
35	SALES LLF CLASSES	LN 27 + LN 29 + LN 31

36	**NEW HAMPSHIRE BASE HEDGING COMMODITY COSTS**	
37	TOTAL BASE HEDGING COMMODITY	Attachment NUI-JDS-7, LN 38
38	Res Heat	LN 13 * LN 37
39	Res General	LN 14 * LN 37
40	G50 Low Annual-Low Winter	LN 15 * LN 37
41	G40 Low Annual-High Winter	LN 16 * LN 37
42	G51 Med Annual-Low Winter	LN 17 * LN 37
43	G41 Med Annual-High Winter	LN 18 * LN 37
44	G52 High Annual-Low Winter	LN 19 * LN 37
45	G42 High Annual-High Winter	LN 20 * LN 37
46		
47	Residential	LN 38 + LN 39
48	SALES HLF CLASSES	LN 40 + LN 42 + LN 44
49	SALES LLF CLASSES	LN 41 + LN 43 + LN 45

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

Line	REMAINING SENDOUT BY CLASS	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL	WINTER
51	**Total Therms**								
52	Res Heat	790,833	1,565,234	2,330,779	2,651,535	1,944,424	1,233,454	11,656,796	10,516,259
53	Res General	9,296	14,745	22,920	23,856	15,093	10,585	110,098	96,496
54	G50 Low Annual-Low Winter	781	26,899	48,571	54,800	24,679	-	189,061	155,730
55	G40 Low Annual-High Winter	364,628	964,409	1,506,999	1,532,739	1,103,933	650,680	6,609,566	6,123,388
56	G51 Med Annual-Low Winter	56,805	106,688	125,128	130,763	52,769	55,008	553,306	527,160
57	G41 Med Annual-High Winter	431,843	877,205	1,076,638	1,107,960	841,470	528,629	5,491,471	4,863,745
58	G52 High Annual-Low Winter	10,520	16,210	16,331	16,463	10,026	2,496	82,490	72,046
59	G42 High Annual-High Winter	74,827	117,797	69,511	69,028	67,136	43,692	553,590	441,993
60	Total Firm Sales	1,739,533	3,689,187	5,196,877	5,587,144	4,059,530	2,524,544	25,246,378	22,796,816
61	**% of Total**								
62	Res Heat	45.46%	42.43%	44.85%	47.46%	47.90%	48.86%		
63	Res General	0.53%	0.40%	0.44%	0.43%	0.37%	0.42%		
64	G50 Low Annual-Low Winter	0.04%	0.73%	0.93%	0.98%	0.61%	0.00%		
65	G40 Low Annual-High Winter	20.96%	26.14%	29.00%	27.43%	27.19%	25.77%		
66	G51 Med Annual-Low Winter	3.27%	2.89%	2.41%	2.34%	1.30%	2.18%		
67	G41 Med Annual-High Winter	24.83%	23.78%	20.72%	19.83%	20.73%	20.94%		
68	G52 High Annual-Low Winter	0.60%	0.44%	0.31%	0.29%	0.25%	0.10%		
69	G42 High Annual-High Winter	4.30%	3.19%	1.34%	1.24%	1.65%	1.73%		
70	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

Line	REMAINING COMMODITY COSTS EXCLD HEDGING	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	TOTAL	WINTER
72	REMAINING COMMODITY Excld Hedging	$ 822,333	$ 1,921,784	$ 2,307,810	$ 2,698,430	$ 1,957,053	$ 1,462,437	$ 12,396,095	$ 11,169,847
73	Res Heat	$ 373,852	$ 815,367	$ 1,035,044	$ 1,280,615	$ 937,384	$ 714,524	$ 5,773,037	$ 5,156,787
74	Res General	$ 4,394	$ 7,681	$ 10,178	$ 11,522	$ 7,276	$ 6,132	$ 54,797	$ 47,184
75	G50 Low Annual-Low Winter	$ 369	$ 14,013	$ 21,569	$ 26,467	$ 11,898	$ -	$ 90,983	$ 74,315
76	G40 Low Annual-High Winter	$ 172,371	$ 502,383	$ 669,223	$ 740,269	$ 532,194	$ 376,931	$ 3,246,946	$ 2,993,370
77	G51 Med Annual-Low Winter	$ 26,853	$ 55,576	$ 55,566	$ 63,155	$ 25,439	$ 31,865	$ 272,894	$ 258,455
78	G41 Med Annual-High Winter	$ 204,146	$ 456,957	$ 478,109	$ 535,113	$ 405,663	$ 306,228	$ 2,680,162	$ 2,386,216
79	G52 High Annual-Low Winter	$ 4,973	$ 8,444	$ 7,252	$ 7,951	$ 4,833	$ 1,446	$ 37,679	$ 34,900
80	G42 High Annual-High Winter	$ 35,373	$ 61,363	$ 30,868	$ 33,339	$ 32,366	$ 25,310	$ 239,596	$ 218,620
81									
82	Residential	$ 378,246	$ 823,048	$ 1,045,222	$ 1,292,137	$ 944,661	$ 720,656	$ 5,827,834	$ 5,203,971
83	SALES HLF CLASSES	$ 32,196	$ 78,033	$ 84,388	$ 97,573	$ 42,170	$ 33,311	$ 401,557	$ 367,671
84	SALES LLF CLASSES	$ 411,891	$ 1,020,703	$ 1,178,200	$ 1,308,720	$ 970,222	$ 708,469	$ 6,166,704	$ 5,598,206

Line	REMAINING COMMODITY HEDGING COSTS								
86	TOTAL REMAINING COMMODITY HEDGING	$ 220,542	$ 241,304	$ 123,102	$ 173,726	$ 205,830	$ 253,001	$ 1,220,162	$ 1,217,506
87	Res Heat	$ 100,264	$ 102,380	$ 55,211	$ 82,446	$ 98,588	$ 123,612	$ 564,369	$ 562,501
88	Res General	$ 1,179	$ 964	$ 543	$ 742	$ 765	$ 1,061	$ 5,276	$ 5,254
89	G50 Low Annual-Low Winter	$ 99	$ 1,759	$ 1,151	$ 1,704	$ 1,251	$ -	$ 5,989	$ 5,964
90	G40 Low Annual-High Winter	$ 46,228	$ 63,081	$ 35,697	$ 47,659	$ 55,973	$ 65,209	$ 314,535	$ 313,847
91	G51 Med Annual-Low Winter	$ 7,202	$ 6,978	$ 2,964	$ 4,066	$ 2,676	$ 5,513	$ 29,390	$ 29,398
92	G41 Med Annual-High Winter	$ 54,750	$ 57,377	$ 25,503	$ 34,451	$ 42,665	$ 52,977	$ 268,037	$ 267,723
93	G52 High Annual-Low Winter	$ 1,334	$ 1,060	$ 387	$ 512	$ 508	$ 250	$ 4,018	$ 4,051
94	G42 High Annual-High Winter	$ 9,487	$ 7,705	$ 1,647	$ 2,146	$ 3,404	$ 4,379	$ 28,548	$ 28,767
95								$ -	$ -
96	Residential	$ 101,442	$ 103,344	$ 55,754	$ 83,188	$ 99,353	$ 124,673	$ 569,645	$ 567,755
97	SALES HLF CLASSES	$ 8,635	$ 9,798	$ 4,501	$ 6,282	$ 4,435	$ 5,763	$ 39,397	$ 39,414
98	SALES LLF CLASSES	$ 110,465	$ 128,162	$ 62,847	$ 84,256	$ 102,041	$ 122,565	$ 611,120	$ 610,337

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

50	**REMAINING SENDOUT BY CLASS**	
51	**Total Therms**	
52	Res Heat	Attachment NUI-JDS-4, LN 68
53	Res General	Attachment NUI-JDS-4, LN 69
54	G50 Low Annual-Low Winter	Attachment NUI-JDS-4, LN 70
55	G40 Low Annual-High Winter	Attachment NUI-JDS-4, LN 71
56	G51 Med Annual-Low Winter	Attachment NUI-JDS-4, LN 72
57	G41 Med Annual-High Winter	Attachment NUI-JDS-4, LN 73
58	G52 High Annual-Low Winter	Attachment NUI-JDS-4, LN 74
59	G42 High Annual-High Winter	Attachment NUI-JDS-4, LN 75
60	Total Firm Sales	Sum LN 52 : LN 59
61	**% of Total**	
62	Res Heat	LN 52 / LN 60
63	Res General	LN 53 / LN 60
64	G50 Low Annual-Low Winter	LN 54 / LN 60
65	G40 Low Annual-High Winter	LN 55 / LN 60
66	G51 Med Annual-Low Winter	LN 56 / LN 60
67	G41 Med Annual-High Winter	LN 57 / LN 60
68	G52 High Annual-Low Winter	LN 58 / LN 60
69	G42 High Annual-High Winter	LN 59 / LN 60
70	Total Firm Sales	LN 60 / LN 60

71	**REMAINING COMMODITY COSTS EXCLD HEDGING**	
72	REMAINING COMMODITY Excld Hedging	Attachment NUI-JDS-7, LN 39
73	Res Heat	LN 72 * LN 62
74	Res General	LN 72 * LN 63
75	G50 Low Annual-Low Winter	LN 72 * LN 64
76	G40 Low Annual-High Winter	LN 72 * LN 65
77	G51 Med Annual-Low Winter	LN 72 * LN 66
78	G41 Med Annual-High Winter	LN 72 * LN 67
79	G52 High Annual-Low Winter	LN 72 * LN 68
80	G42 High Annual-High Winter	LN 72 * LN 69
81		
82	Residential	LN 73 + LN 74
83	SALES HLF CLASSES	LN 75 + LN 77 + LN 79
84	SALES LLF CLASSES	LN 76 + LN 78 + LN 80

85	**REMAINING COMMODITY HEDGING COSTS**	
86	TOTAL REMAINING COMMODITY HEDGING	Attachment NUI-JDS-7, LN 40
87	Res Heat	LN 62 * LN 86
88	Res General	LN 63 * LN 86
89	G50 Low Annual-Low Winter	LN 64 * LN 86
90	G40 Low Annual-High Winter	LN 65 * LN 86
91	G51 Med Annual-Low Winter	LN 66 * LN 86
92	G41 Med Annual-High Winter	LN 67 * LN 86
93	G52 High Annual-Low Winter	LN 68 * LN 86
94	G42 High Annual-High Winter	LN 69 * LN 86
95		
96	Residential	LN 87 + LN 88
97	SALES HLF CLASSES	LN 89 + LN 91 + LN 93
98	SALES LLF CLASSES	LN 90 + LN 92 + LN 94

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**								
100	TOTAL COMMODITY Excld Hedging	$ 1,291,480	$ 2,528,710	$ 2,947,703	$ 3,281,446	$ 2,590,571	$ 2,053,985	$ 19,408,454	$ 14,693,895
101	Res Heat	$ 543,883	$ 1,035,333	$ 1,266,958	$ 1,491,916	$ 1,166,988	$ 931,873	$ 8,324,277	$ 6,436,952
102	Res General	$ 12,141	$ 17,703	$ 20,745	$ 21,149	$ 17,737	$ 16,035	$ 170,545	$ 105,511
103	G50 Low Annual-Low Winter	$ 62,083	$ 93,851	$ 105,744	$ 103,160	$ 95,234	$ 70,732	$ 996,809	$ 530,804
104	G40 Low Annual-High Winter	$ 230,260	$ 577,272	$ 748,179	$ 812,207	$ 610,364	$ 450,928	$ 4,115,281	$ 3,429,210
105	G51 Med Annual-Low Winter	$ 119,710	$ 175,703	$ 182,218	$ 178,549	$ 150,829	$ 150,563	$ 1,663,693	$ 957,572
106	G41 Med Annual-High Winter	$ 267,626	$ 539,079	$ 564,692	$ 614,000	$ 491,383	$ 387,373	$ 3,629,958	$ 2,864,154
107	G52 High Annual-Low Winter	$ 15,170	$ 21,636	$ 21,160	$ 20,623	$ 18,603	$ 14,480	$ 190,084	$ 111,672
108	G42 High Annual-High Winter	$ 40,606	$ 68,134	$ 38,006	$ 39,842	$ 39,432	$ 32,000	$ 317,807	$ 258,020
109									
110	Residential	$ 556,025	$ 1,053,036	$ 1,287,703	$ 1,513,065	$ 1,184,726	$ 947,908	$ 8,494,822	$ 6,542,462
111	SALES HLF CLASSES	$ 196,963	$ 291,189	$ 309,122	$ 302,332	$ 264,666	$ 235,775	$ 2,850,586	$ 1,600,048
112	SALES LLF CLASSES	$ 538,492	$ 1,184,484	$ 1,350,878	$ 1,466,049	$ 1,141,179	$ 870,302	$ 8,063,046	$ 6,551,384
113	**TOTAL HEDGING COMMODITY COSTS**								
114	TOTAL HEDGING COMMODITY	$ 348,846	$ 358,240	$ 338,019	$ 333,088	$ 376,094	$ 368,902	$ 2,135,029	$ 2,123,189
115	Res Heat	$ 146,765	$ 144,760	$ 133,102	$ 140,204	$ 160,296	$ 166,197	$ 896,547	$ 891,324
116	Res General	$ 3,297	$ 2,895	$ 4,092	$ 3,373	$ 3,577	$ 3,001	$ 20,411	$ 20,236
117	G50 Low Annual-Low Winter	$ 16,977	$ 17,142	$ 29,422	$ 22,667	$ 23,649	$ 13,858	$ 124,897	$ 123,715
118	G40 Low Annual-High Winter	$ 62,060	$ 77,509	$ 62,216	$ 67,323	$ 76,982	$ 79,707	$ 427,627	$ 425,796
119	G51 Med Annual-Low Winter	$ 32,597	$ 30,123	$ 45,502	$ 35,608	$ 36,375	$ 28,769	$ 210,786	$ 208,973
120	G41 Med Annual-High Winter	$ 72,111	$ 73,199	$ 54,583	$ 56,014	$ 65,703	$ 68,876	$ 392,052	$ 390,486
121	G52 High Annual-Low Winter	$ 4,122	$ 3,602	$ 5,058	$ 3,976	$ 4,209	$ 2,804	$ 23,938	$ 23,771
122	G42 High Annual-High Winter	$ 10,918	$ 9,009	$ 4,044	$ 3,924	$ 5,303	$ 5,689	$ 38,771	$ 38,888
123									
124	Residential	$ 150,062	$ 147,656	$ 137,194	$ 143,577	$ 163,873	$ 169,198	$ 916,958	$ 911,560
125	SALES HLF CLASSES	$ 53,696	$ 50,867	$ 79,981	$ 62,251	$ 64,233	$ 45,431	$ 359,620	$ 356,459
126	SALES LLF CLASSES	$ 145,089	$ 159,718	$ 120,843	$ 127,260	$ 147,988	$ 154,272	$ 858,451	$ 855,170
127	**TOTAL COMMODITY**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**TOTAL**	**WINTER**
128	Res Heat	$ 690,648	$ 1,180,093	$ 1,400,060	$ 1,632,119	$ 1,327,284	$ 1,098,070	$ 9,220,824	$ 7,328,276
129	Res General	$ 15,439	$ 20,598	$ 24,837	$ 24,523	$ 21,314	$ 19,036	$ 190,956	$ 125,746
130	G50 Low Annual-Low Winter	$ 79,060	$ 110,993	$ 135,166	$ 125,827	$ 118,883	$ 84,590	$ 1,121,706	$ 654,519
131	G40 Low Annual-High Winter	$ 292,320	$ 654,781	$ 810,395	$ 879,530	$ 687,345	$ 530,635	$ 4,542,909	$ 3,855,006
132	G51 Med Annual-Low Winter	$ 152,307	$ 205,826	$ 227,720	$ 214,157	$ 187,205	$ 179,332	$ 1,874,479	$ 1,166,546
133	G41 Med Annual-High Winter	$ 339,737	$ 612,278	$ 619,276	$ 670,014	$ 557,087	$ 456,249	$ 4,022,010	$ 3,254,640
134	G52 High Annual-Low Winter	$ 19,293	$ 25,238	$ 26,218	$ 24,598	$ 22,812	$ 17,284	$ 214,022	$ 135,443
135	G42 High Annual-High Winter	$ 51,524	$ 77,143	$ 42,050	$ 43,766	$ 44,736	$ 37,689	$ 356,579	$ 296,908
136	Total Firm Sales	$ 1,640,326	$ 2,886,950	$ 3,285,722	$ 3,614,534	$ 2,966,665	$ 2,422,886	$ 21,543,483	$ 16,817,083
137									
138	Residential	$ 706,086	$ 1,200,692	$ 1,424,897	$ 1,656,642	$ 1,348,599	$ 1,117,106	$ 9,411,780	$ 7,454,022
139	SALES HLF CLASSES	$ 250,659	$ 342,056	$ 389,104	$ 364,583	$ 328,899	$ 281,206	$ 3,210,206	$ 1,956,507
140	SALES LLF CLASSES	$ 683,581	$ 1,344,202	$ 1,471,721	$ 1,593,310	$ 1,289,167	$ 1,024,574	$ 8,921,498	$ 7,406,555
141									
142	% ALLOCATION BETWEEN SALES HLF AND LLF								
143	SALES HLF CLASSES								20.90%
144	SALES LLF CLASSES								79.10%

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Total Commodity Costs

99	**TOTAL COMMODITY COSTS Excluding Hedging**	
100	TOTAL COMMODITY Excld Hedging	Attachment NUI-JDS-7, LN 41
101	Res Heat	LN 24 + LN 73
102	Res General	LN 25 + LN 74
103	G50 Low Annual-Low Winter	LN 26 + LN 75
104	G40 Low Annual-High Winter	LN 27 + LN 76
105	G51 Med Annual-Low Winter	LN 28 + LN 77
106	G41 Med Annual-High Winter	LN 29 + LN 78
107	G52 High Annual-Low Winter	LN 30 + LN 79
108	G42 High Annual-High Winter	LN 31 + LN 80
109		
110	Residential	LN 101 + LN 102
111	SALES HLF CLASSES	LN 103 + LN 105 + LN 107
112	SALES LLF CLASSES	LN 104 + LN 106 + LN 108
113	**TOTAL HEDGING COMMODITY COSTS**	
114	TOTAL HEDGING COMMODITY	Attachment NUI-JDS-7, LN 42
115	Res Heat	LN 38 + LN 87
116	Res General	LN 39 + LN 88
117	G50 Low Annual-Low Winter	LN 40 + LN 89
118	G40 Low Annual-High Winter	LN 41 + LN 90
119	G51 Med Annual-Low Winter	LN 42 + LN 91
120	G41 Med Annual-High Winter	LN 43 + LN 92
121	G52 High Annual-Low Winter	LN 44 + LN 93
122	G42 High Annual-High Winter	LN 45 + LN 94
123		
124	Residential	LN 115 + LN 116
125	SALES HLF CLASSES	LN 117 + LN 119 + LN 121
126	SALES LLF CLASSES	LN 118 + LN 120 + LN 122
127	**TOTAL COMMODITY**	
128	Res Heat	LN 101 + LN 115
129	Res General	LN 102 + LN 116
130	G50 Low Annual-Low Winter	LN 103 + LN 117
131	G40 Low Annual-High Winter	LN 104 + LN 118
132	G51 Med Annual-Low Winter	LN 105 + LN 119
133	G41 Med Annual-High Winter	LN 106 + LN 120
134	G52 High Annual-Low Winter	LN 107 + LN 121
135	G42 High Annual-High Winter	LN 108 + LN 122
136	Total Firm Sales	Sum LN 128 : LN 135
137		
138	Residential	LN 128 + LN 129
139	SALES HLF CLASSES	LN 130 + LN 132 + LN 134
140	SALES LLF CLASSES	LN 131 + LN 133 + LN 135
141		
142	% ALLOCATION BETWEEN SALES HLF AND LLF	
143	SALES HLF CLASSES	LN 139 / (LN 139 + LN 140)
144	SALES LLF CLASSES	LN 140 / (LN 139 + LN 140)

Attachment NUI-JDS-10

New Hampshire Proposed

2009 /2010 Winter Tariff Sheets

Unitil
Northern Utilities, Inc.

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2009 - April 30, 2010

	(Col 1)	(Col 2)	(Col 3)	(Col 4)
	ANTICIPATED DIRECT COST OF GAS			
	Purchased Gas:			
1	Demand Costs:	$ 1,873,003		Attachment NUI-JDS-3, LN 71
2	Supply Costs:	$ 8,642,136		Attachment NUI-JDS-7, LN 14
3	**Storage & Peaking Gas:**			
4	Demand, Capacity:	$ 10,352,526		Attachment NUI-JDS-3, LN 73
5	Commodity Costs:	$ 5,928,967		Attachment NUI-JDS-7, LN 16 + LN 17
6	**Hedging (Gain)/Loss**	$ 2,123,189		Attachment NUI-JDS-7, LN 15
7	**Interruptible Included Above**	$ -		
8	**Inventory Finance Charge**	$ 122,792		Attachment NUI-JDS-6, LN 97
9	**Capacity Release**	$ (1,896,076)		Attachment NUI-JDS-3, LN 76
10	**Total Anticipated Direct Cost of Gas**		$ 27,146,537	Sum LN 1 : LN 9
11	**ANTICIPATED INDIRECT COST OF GAS**			
12	**Adjustments:**			
13	Prior Period Under/(Over) Collection	$ 2,944,781		2008/09 Peak Reconciliation
14	Interest	$ 25,680		Company Analysis
15	Refunds	$ -		
16	Capacity Reserve Charge Revenue	$ (90,228)		
17	Interruptible Margins	$ -		
18	Total Adjustments		$ 2,880,233	Sum LN 13 : LN 17
19	**Working Capital:**			
20	Total Anticipated Direct Cost of Gas	$ 27,146,537		LN 10
21	Working Capital Percentage	0.190%		2nd Rev. Pg 21 IV COG Clause 6.1
22	Working Capital Allowance	$ 51,578		LN 20 * LN 21
23	Plus: Working Capital Reconciliation (Acct 182.11	$ 22,921		2nd Rev. Pg 21 IV COG Clause 6.1
24	Total Working Capital Allowance		$ 74,499	LN 22 + LN 23
25	**Bad Debt:**			
26	Total Anticipated Direct Cost of Gas	$ 27,146,537		LN 10
27	Less: Capacity Reserve Charge Revenue	$ (90,228)		LN 16
28	Plus: Prior Period Under/(Over) Collection	$ 2,944,781		2008/09 Peak Reconciliation
29	Plus: Interest	$ 25,680		LN 14
30	Plus: Total Working Capital	$ 74,499		LN 24
31	Subtotal	$ 30,101,269		Sum LN 26 : LN 30
32	Bad Debt Percentage	0.450%		2nd Rev. Pg 21 IV COG Clause 6.1
33	Bad Debt Allowance	$ 135,456		LN 32 * LN 33
34	Plus: Bad Debt Reconciliation (Acct 182.16)	$ 52,984		2nd Rev. Pg 21 IV COG Clause 6.1
35	Total Bad Debt Allowance		$ 188,440	LN 33 + LN 34
36	**Local Production and Storage Capacity**		$ 686,673	2nd Rev. Pg 21 IV COG Clause 6.1
37	**Miscellaneous Overhead-77.11% Allocated to Winter Season**		$ 95,845	2nd Rev. Pg 21 IV COG Clause 6.1
38	**Total Anticipated Indirect Cost of Gas**		$ 3,925,690	LN 18 + LN 24 + LN 35 + LN 36 + LN 37
39	**Total Cost of Gas**		$ 31,072,227	LN 10 + LN 38

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2009 - April 30, 2010

	(Col 1)	(Col 2)		(Col 3)		(Col 4)	
40	Total Anticipated Direct Cost of Gas		$	27,146,537			
41	Projected Prorated Sales (11/01/09 - 04/30/10)			28,473,787			
42	**Direct Cost of Gas Rate**				$	0.9534	per therm
43	**Demand Cost of Gas Rate**		$	10,329,453	$	0.3628	per therm
44	**Commodity Cost of Gas Rate**		$	16,817,083	$	0.5906	per therm
45	**Total Direct Cost of Gas Rate**		$	27,146,537	$	0.9534	per therm
46	Total Anticipated Indirect Cost of Gas		$	3,925,690			
47	Projected Prorated Sales (11/01/09 - 04/30/10)			28,473,787			
48	**Indirect Cost of Gas**				$	0.1379	per therm
49	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/09				$	1.0913	per therm
50	**RESIDENTIAL COST OF GAS RATE - 11/01/09**		**COGwr**		**$**	**1.0913**	per therm
51			**Maximum (COG+25%)**		**$**	**1.3641**	
52	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09**		**COGwl**		**$**	**1.0549**	**per therm**
53			**Maximum (COG+25%)**		**$**	**1.3186**	
54	C&I HLF Demand Costs Allocated per SMBA	$ 635,773					
55	PLUS: Residential Demand Reallocation to C&I HLF	$ 24,733					
56	C&I HLF Total Adjusted Demand Costs	$ 660,506					
57	C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)	2,837,571					
58	**Demand Cost of Gas Rate**	**$ 0.2328**					
59	C&I HLF Commodity Costs Allocated per SMBA	$ 1,956,507					
60	PLUS: Residential Commodity Reallocation to C&I HLF	$ (15,057)					
61	C&I HLF Total Adjusted Commodity Costs	$ 1,941,450					
62	C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)	2,837,571					
63	**Commodity Cost of Gas Rate**	**$ 0.6842**					
64	**Indirect Cost of Gas**	**$ 0.1379**					
65	**Total C&I HLF Cost of Gas Rate**	**$ 1.0549**					
66	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/09**		**COGwh**			**1.0993**	**per therm**
67			**Maximum (COG+25%)**		**$**	**1.3741**	
68	C&I LLF Demand Costs Allocated per SMBA	$ 4,857,290					
69	PLUS: Residential Demand Reallocation to C&I LLF	$ 188,959					
70	C&I LLF Total Adjusted Demand Costs	$ 5,046,250					
71	C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)	12,893,460					
72	**Demand Cost of Gas Rate**	**$ 0.3914**					
73	C&I LLF Commodity Costs Allocated per SMBA	$ 7,406,555					
74	PLUS: Residential Commodity Reallocation to C&I LLF	$ (57,000)					
75	C&I LLF Total Adjusted Commodity Costs	$ 7,349,554					
76	C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)	12,893,460					
77	**Commodity Cost of Gas Rate**	**$ 0.5700**					
78	**Indirect Cost of Gas**	**$ 0.1379**					
79	**Total C&I LLF Cost of Gas Rate**	**$ 1.0993**					

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2009 - April 30, 2010

		(Col 5) Explantion of (Col 2)	(Col 6) Explantion of (Col 3)	(Col 7) Explantion of (Col 4)
80	Total Anticipated Direct Cost of Gas		Attachment NUI-JDS-11, LN 122	
81	Projected Prorated Sales (11/01/09 - 04/30/10)		Attachment NUI-JDS-4, LN 16 * 10	
82	**Direct Cost of Gas Rate**			LN 40 / LN 41
83	**Demand Cost of Gas Rate**		Attachment NUI-JDS-3, LN 80	LN 43 / LN 42
84	**Commodity Cost of Gas Rate**		Attachment NUI-JDS-7, LN 43	LN 44 / LN 42
85	**Total Direct Cost of Gas Rate**		LN 44 + LN 45	LN 44 + LN 45
86	Total Anticipated Indirect Cost of Gas		Attachment NUI-JDS-10, LN 38	
87	Projected Prorated Sales (11/01/09 - 04/30/10)		LN 41	
88	**Indirect Cost of Gas**			LN 46 / LN 47
89	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/09			LN 45 + LN 48
90	**RESIDENTIAL COST OF GAS RATE - 11/01/09**			**LN 49**
91				LN 50 * 1.25
92	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09**			**LN 65**
93				LN 52 * 1.25
94	C&I HLF Demand Costs Allocated per SMBA	Attachment NUI-JDS-5, LN 169		
95	PLUS: Residential Demand Reallocation to C&I HLF	Attachment NUI-JDS-11, LN 16		
96	C&I HLF Total Adjusted Demand Costs	LN 54 + LN 55		
97	C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)	Attachment NUI-JDS-4, LN 14 * 10		
98	**Demand Cost of Gas Rate**	LN 56 / LN 57		
99	C&I HLF Commodity Costs Allocated per SMBA	Attachment NUI-JDS-9, LN 139		
100	PLUS: Residential Commodity Reallocation to C&I HLF	Attachment NUI-JDS-11, LN 26		
101	C&I HLF Total Adjusted Commodity Costs	LN 59 + LN 60		
102	C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)	LN 57		
103	**Commodity Cost of Gas Rate**	LN 61 / LN 62		
104	**Indirect Cost of Gas**	LN 48		
105	**Total C&I HLF Cost of Gas Rate**	LN 58 + LN 63 + LN 64		
106	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/09**			**LN 79**
107				LN 66 * 1.25
108	C&I LLF Demand Costs Allocated per SMBA	Attachment NUI-JDS-5, LN 170		
109	PLUS: Residential Demand Reallocation to C&I LLF	Attachment NUI-JDS-11, LN 17		
110	C&I LLF Total Adjusted Demand Costs	LN 68 + LN 69		
111	C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)	Attachment NUI-JDS-4, LN 15 * 10		
112	**Demand Cost of Gas Rate**	LN 70 / LN 71		
113	C&I LLF Commodity Costs Allocated per SMBA	Attachment NUI-JDS-9, LN 140		
114	PLUS: Residential Commodity Reallocation to C&I LLF	Attachment NUI-JDS-11, LN 27		
115	C&I LLF Total Adjusted Commodity Costs	LN 73 + LN 74		
116	C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)	LN 71		
117	**Commodity Cost of Gas Rate**	LN 75 / LN 76		
118	**Indirect Cost of Gas**	LN 48		
119	**Total C&I LLF Cost of Gas Rate**	LN 72 + LN 77 + LN 78		

Attachment NUI-JDS-11

Supporting Detail to the Proposed Tariff Sheets

Unitil
Northern Utilities, Inc.

Northern Utilities - NEW HAMPSHIRE DIVISION
Base & Supplemental Costs and Sendout Allocated to New Hampshire

Summary of Demand and Supply Forecast

		Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER
1	**I. Gas Volumes**							
2	**A. Firm Demand Volumes (Therms)**							
3	Firm Gas Sales (Therms)	2,708,520	4,660,403	6,156,557	6,442,640	5,033,569	3,472,097	28,473,787
4	LAUF & Company Use	38,774	70,137	81,676	85,082	67,314	46,504	389,486
5	Interruptible	0	0	0	0	0	0	0
6	Non-Grandfathered Transportation							0
7	Unbilled Therms	0	0	0	0	0	0	0
8	Total Demand Volumes	2,747,294	4,730,540	6,238,232	6,527,722	5,100,883	3,518,601	28,863,273
9								
10	**B. Supply Volumes (Net Therms)**							
11	**Pipeline Gas:**							
12	Chicago	835,180	838,978	287,408	472,158	813,374	924,701	4,171,798
13	Empress	142,668	143,715	141,584	133,404	144,352	162,053	867,775
14	Niagara	61,008	430,732	367,009	318,047	351,299	354,113	1,882,208
15	Portland Pay-Back	223,781	58,174	0	0	0	0	281,954
16	Tennessee Production	1,501,659	1,718,661	841,834	1,042,319	1,014,986	1,747,275	7,866,735
17	TETCO M3	0	0	0	0	0	0	0
18	TETCO Production	0	0	0	0	0	0	0
19	-- BLANK 1 of 1 ---	0	0	0	0	0	0	0
20	Total Pipeline	2,764,296	3,190,260	1,637,834	1,965,928	2,324,011	3,188,142	15,070,471
21	**Storage**							
22	Tennessee Storage	0	0	336,389	327,569	219,672	189,094	1,072,726
23	TETCO Storage	0	0	0	0	0	0	0
24	Washington 10	0	1,532,940	3,765,489	3,535,062	2,511,449	0	11,344,941
25	-- BLANK 1 of 2 ---	0	0	0	0	0	0	0
26	-- BLANK 2 of 2 ---	0	0	0	0	0	0	0
27	Total Storage	0	1,532,940	4,101,879	3,862,632	2,731,121	189,094	12,417,666
28	**Peaking**							
29	DOMAC	0	0	491,289	383,548	62,161	141,978	1,078,975
30	FPL Peaking / Duke	0	0	0	182,805	0	0	182,805
31	LNG	7,287	7,340	7,231	132,809	7,373	23,540	185,580
32	Propane	0	0	0	0	0	0	0
33	-- BLANK 1 of 2 ---	0	0	0	0	0	0	0
34	-- BLANK 2 of 2 ---	0	0	0	0	0	0	0
35	Total Peaking	7,287	7,340	498,520	699,162	69,533	165,518	1,447,360
36								
37	Less Interruptible Included Above	(24,289)	0	0	0	(23,783)	(24,153)	(72,225)
38								
39	Total Supply Volumes	2,747,294	4,730,540	6,238,232	6,527,722	5,100,883	3,518,601	28,863,273

Northern Utilities - NEW HAMPSHIRE DIVISION
Base & Supplemental Costs and Sendout Allocated to New Hampshire

Summary of Demand and Supply Forecast

1	I. Gas Volumes	
2	A. Firm Demand Volumes (Therms)	
3	Firm Gas Sales (Therms)	Attachment NUI-JDS-4, LN 11 * 10
4	LAUF & Company Use	Attachment NUI-JDS-7, LN 10
5	Interruptible	Attachment NUI-JDS-7, LN 6
6	Non-Grandfathered Transportation	
7	Unbilled Therms	
8	Total Demand Volumes	Sum LN 2 : LN 7
9		
10	**B. Supply Volumes (Net Therms)**	
11	Pipeline Gas:	
12	Chicago	Company Analysis
13	Empress	Company Analysis
14	Niagara	Company Analysis
15	Portland Pay-Back	Company Analysis
16	Tennessee Production	Company Analysis
17	TETCO M3	Company Analysis
18	TETCO Production	Company Analysis
19	-- BLANK 1 of 1 ---	
20	Total Pipeline	Sum LN 12 : LN 19
21	**Storage**	
22	Tennessee Storage	Company Analysis
23	TETCO Storage	Company Analysis
24	Washington 10	Company Analysis
25	-- BLANK 1 of 2 ---	
26	-- BLANK 2 of 2 ---	
27	Total Storage	Sum LN 22 : LN 26
28	**Peaking**	
29	DOMAC	Company Analysis
30	FPL Peaking / Duke	Company Analysis
31	LNG	Company Analysis
32	Propane	Company Analysis
33	-- BLANK 1 of 2 ---	
34	-- BLANK 2 of 2 ---	
35	Total Peaking	Sum LN 29 : LN 34
36		
37	Interruptible Included Above	Company Analysis
38		
39	Total Supply Volumes	LN 20 + LN 27 + LN 35 + LN 37

Northern Utilities - NEW HAMPSHIRE DIVISION
Base & Supplemental Costs and Sendout Allocated to New Hampshire

Line	II. Gas Costs	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER
40								
42	**A. Demand Costs**							
43	Pipeline/Supply Related Demand Costs							
44	Pipeline Reservation							
45	Granite							$ 134,751
46	PNGTS							$ 101,987
47	Algonquin							$ 110,692
48	Iroquois							$ 146,631
49	Tennessee							$ 876,758
50	Texas Eastern							$ 22,931
51	Trans Canada							$ 303,871
52	Vector							$ 175,382
53	---- Blank 1 of 6 ----							$ -
54	---- Blank 2 of 6 ----							$ -
55	---- Blank 3 of 6 ----							$ -
56	---- Blank 4 of 6 ----							$ -
57	---- Blank 5 of 6 ----							$ -
58	---- Blank 6 of 6 ----							$ -
59	Total Pipeline							$ 1,873,003
60	Storage							
61	TGP FS Stg							$ 48,528
62	TETCO Stg (SS1, FSS)							$ 1,157
63	Trans Canada							$ 2,203,687
64	PNGTS							$ 3,589,862
65	Confidential Supplier A							$ 1,207,705
66	Algonquin							$ 2,548
67	Granite							$ 296,482
68	Tennessee							$ 78,360
69	Vector							$ 817,698
70	---- Blank 1 of 2 ----							$ -
71	---- Blank 2 of 2 ----							$ -
72	Total Storage							$ 8,246,028
73	Peaking							
74	Confidential Supplier B							$ 1,049,339
75	Confidential Supplier C							$ 717,602
76	Granite							$ 339,556
77	---- Blank 1 of 1 ----							$ -
78	Total Peaking							$ 2,106,498
79	**Capacity Release**							$ (1,896,076)
80	**Re-Entry Fee Credits**							$ -
81	**Interruptible Margins**							$ -
82	Total Demand Costs	**$ 1,721,576**	**$ 1,721,576**	**$ 1,721,576**	**$ 1,721,576**	**$ 1,721,576**	**$ 1,721,576**	**$ 10,329,453**

Northern Utilities - NEW HAMPSHIRE DIVISION
Base & Supplemental Costs and Sendout Allocated to New Hampshire

LN		
40		
41	**II. Gas Costs**	
42	**A. Demand Costs**	
43	Pipeline/Supply Related Demand Costs	
44	Pipeline Reservation	
45	Granite	Company Analysis
46	PNGTS	Company Analysis
47	Algonquin	Company Analysis
48	Iroquois	Company Analysis
49	Tennessee	Company Analysis
50	Texas Eastern	Company Analysis
51	Trans Canada	Company Analysis
52	Vector	Company Analysis
53	---- Blank 1 of 6 ----	
54	---- Blank 2 of 6 ----	
55	---- Blank 3 of 6 ----	
56	---- Blank 4 of 6 ----	
57	---- Blank 5 of 6 ----	
58	---- Blank 6 of 6 ----	
59	Total Pipeline	Sum LN 45 : LN 58
60	Storage	
61	TGP FS Stg	Company Analysis
62	TETCO Stg (SS1, FSS)	Company Analysis
63	Trans Canada	Company Analysis
64	PNGTS	Company Analysis
65	Confidential Supplier A	Company Analysis
66	Algonquin	Company Analysis
67	Granite	Company Analysis
68	Tennessee	Company Analysis
69	Vector	Company Analysis
70	---- Blank 1 of 2 ----	
71	---- Blank 2 of 2 ----	
72	Total Storage	Sum LN 61 : LN 71
73	Peaking	
74	Confidential Supplier B	Company Analysis
75	Confidential Supplier C	Company Analysis
76	Granite	Company Analysis
77	---- Blank 1 of 1 ----	
78	Total Peaking	Sum LN 74 : LN 77
79	Capacity Release	Attachment NUI-JDS-3, - LN 76
80	Re-Entry Fee Credits	
81	Interruptible Margins	
82	Total Demand Costs	LN 59 + LN 72 + LN 78 + LN 79 + LN 80 + LN 81

Northern Utilities - NEW HAMPSHIRE DIVISION
Base & Supplemental Costs and Sendout Allocated to New Hampshire

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	WINTER
B. Supply Commodity Costs							
NH Allocation Factors	53.98%	52.62%	51.84%	54.08%	52.85%	53.67%	
Pipeline Purchases							
Chicago	$ 413,526	$ 498,225	$ 175,188	$ 292,368	$ 488,075	$ 544,885	$ 2,412,267
Empress	$ 61,959	$ 73,838	$ 76,461	$ 72,408	$ 76,581	$ 82,661	$ 443,909
Niagara	$ 31,924	$ 257,767	$ 228,956	$ 199,129	$ 218,049	$ 214,286	$ 1,150,111
Portland Pay-Back	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee Production	$ 779,463	$ 1,029,528	$ 525,814	$ 654,675	$ 631,131	$ 1,055,387	$ 4,675,998
TETCO M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TETCO Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-- BLANK 1 of 1 ---	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pipeline	$ 1,286,873	$ 1,859,359	$ 1,006,420	$ 1,218,578	$ 1,413,836	$ 1,897,219	$ 8,682,285
Storage Withdrawals							
Tennessee Storage	$ -	$ -	$ 140,153	$ 136,478	$ 91,524	$ 87,972	$ 456,127
TETCO Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington 10	$ -	$ 631,322	$ 1,546,703	$ 1,457,349	$ 1,028,039	$ -	$ 4,663,414
-- BLANK 1 of 2 ---	$ -	$ 11,883	$ 32,475	$ 30,603	$ 21,612	$ 1,847	$ 98,420
-- BLANK 2 of 2 ---	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage	$ -	$ 643,205	$ 1,719,331	$ 1,624,431	$ 1,141,175	$ 89,819	$ 5,217,961
Peaking							
DOMAC	$ -	$ -	$ 188,057	$ 146,816	$ 23,794	$ 54,347	$ 413,013
FPL Peaking / Duke	$ -	$ -	$ -	$ 181,403	$ -	$ -	$ 181,403
LNG	$ 6,544	$ 6,275	$ 5,903	$ 80,123	$ 4,369	$ 13,374	$ 116,588
Propane	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-- BLANK 1 of 2 ---	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-- BLANK 2 of 2 ---	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Peaking	$ 6,544	$ 6,275	$ 193,960	$ 408,342	$ 28,163	$ 67,721	$ 711,005
Interruptible Included above	$ (11,307)	$ -	$ -	$ -	$ (14,468)	$ (14,373)	$ (40,149)
Inventory Finance Charge	$ 9,370	$ 19,871	$ 27,992	$ 30,094	$ 21,866	$ 13,598	$ 122,792
Hedging (Gain)/Loss	$ 348,846	$ 358,240	$ 338,019	$ 333,088	$ 376,094	$ 368,902	$ 2,123,189
Total Commodity Costs	$ 1,640,326	$ 2,886,950	$ 3,285,722	$ 3,614,534	$ 2,966,665	$ 2,422,886	$ 16,817,083
Total Direct Costs	$ 3,361,902	$ 4,608,525	$ 5,007,297	$ 5,336,110	$ 4,688,241	$ 4,144,462	$ 27,146,537

Northern Utilities - NEW HAMPSHIRE DIVISION
Base & Supplemental Costs and Sendout Allocated to New Hampshire

83		
84		
85		
86	**B. Supply Commodity Costs**	
87	NH Allocation Factors	Attachment NUI-JDS-6, LN 52
88	Pipeline Purchases	
89	Chicago	Company Analysis
90	Empress	Company Analysis
91	Niagara	Company Analysis
92	Portland Pay-Back	Company Analysis
93	Tennessee Production	Company Analysis
94	TETCO M3	Company Analysis
95	TETCO Production	Company Analysis
96	-- BLANK 1 of 1 ---	
97	Total Pipeline	Sum LN 89 : LN 96
98	Storage Withdrawals	
99	Tennessee Storage	Company Analysis
100	TETCO Storage	Company Analysis
101	Washington 10	Company Analysis
102	-- BLANK 1 of 2 ---	
103	-- BLANK 2 of 2 ---	
104	Total Storage	Sum LN 99 : LN 103
105	Peaking	
106	DOMAC	Company Analysis
107	FPL Peaking / Duke	Company Analysis
108	LNG	Company Analysis
109	Propane	Company Analysis
110	-- BLANK 1 of 2 ---	
111	-- BLANK 2 of 2 ---	
112	Total Peaking	Sum LN 106 : LN 111
113		
114	Interruptible Included above	Company Analysis
115		
116	Inventory Finance Charge	Attachment NUI-JDS-7, LN 18
117		
118	Hedging (Gain)/Loss	Attachment NUI-JDS-7, LN 15
119		
120	Total Commodity Costs	LN 97 + LN 104 + LN 112 + LN 114 + LN 116 + LN 118
121		
122	Total Direct Costs	LN 82 + LN 120

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
Average Cost of Gas Calculation

		Winter	Summer	Total	
1	Demand	$ 10,329,453	$ 1,045,464	$ 11,374,918	Attachment NUI-JDS-3, LN 80
2	Commodity	$ 16,817,083	$ 4,726,400	$ 21,543,483	Attachment NUI-JDS-7, LN 0
3	Total	**$ 27,146,537**	**$ 5,771,864**	**$ 32,918,401**	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	28,473,787	8,452,584	36,926,371	Attachment NUI-JDS-4, LN 11 * 10
6	Forecasted Residential Sales (Therms)	12,742,755	3,437,017	16,179,773	Attachment NUI-JDS-4, LN 3 * 10
7	**Average Residential Rate:**	**Winter**	**Summer**	**Total**	
8	Average Demand Rate	$ 0.3628	$ 0.1237		LN 1 / LN 5
9	Average Commodity Rate	$ 0.5906	$ 0.5592		LN 2 / LN 5
10	Average Rate	$ 0.9534	$ 0.6829		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Total**	
13	Demand Costs Allocated To Residential per SMBA	$ 4,836,390	$ 457,868	$ 5,294,258	Attachment NUI-JDS-5, LN 168
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 4,622,697	$ 425,159	$ 5,047,856	LN 8 * LN 6
15	**Demand Reallocation:**	**$ 213,692**	**$ 32,709**	**$ 246,402**	LN 13 - LN 14
16	**HLF Allocation**	$ 24,733	$ 9,374	$ 34,107	LN 15 / LN 20
17	**LLF Allocation**	$ 188,959	$ 23,335	$ 212,295	LN 15 / LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	11.57%	28.66%		Attachment NUI-JDS-5, LN 173
21	LLF	88.43%	71.34%		Attachment NUI-JDS-5, LN 174
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 7,454,022	$ 1,957,758	$ 9,411,780	Attachment NUI-JDS-5, LN 138
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 7,526,079	$ 1,921,980	$ 9,448,060	LN 18 * LN 16
25	**Commodity Reallocation:**	**$ (72,058)**	**$ 35,778**	**$ (36,280)**	LN 23 - LN 24
26	**HLF Allocation**	$ (15,057)	$ 16,201	$ 1,144	LN 25 / LN 30
27	**LLF Allocation**	$ (57,000)	$ 19,577	$ (37,424)	LN 25 / LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	20.90%	45.28%		Attachment NUI-JDS-5, LN 143
31	LLF	79.10%	54.72%		Attachment NUI-JDS-5, LN 144

Attachment NUI-JDS-12

Comparison: 2009 / 2010 Winter

Compared to 2008 / 2009 Winter

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Northern Utilities, Inc.

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: November 1, 2009 - April 30, 2010

1	Total Anticipated Direct Cost of Gas		$ 27,146,537		
2	Projected Prorated Sales (11/01/09 - 04/30/10)		28,473,787		
3	**Direct Cost of Gas Rate**			**$ 0.9534**	**per therm**
4					
5	**Demand Cost of Gas Rate**		**$ 10,329,453**	**$ 0.3628**	**per therm**
6	**Commodity Cost of Gas Rate**		**$ 16,817,083**	**$ 0.5906**	**per therm**
7	**Total Direct Cost of Gas Rate**		**$ 27,146,537**	**$ 0.9534**	**per therm**
8					
9	Total Anticipated Indirect Cost of Gas		$ 3,925,690		
10	Projected Prorated Sales (11/01/09 - 04/30/10)		28,473,787		
11	Indirect Cost of Gas			$ 0.1379	per therm
12					
13					
14	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/09			$ 1.0913	per therm
15					
16	**RESIDENTIAL COST OF GAS RATE - 11/01/09**		**COGwr**	**$ 1.0913**	**per therm**
17			**Maximum (COG+25%)**	**$ 1.3641**	
18					
19	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/09**		**COGwl**	**$ 1.0549**	**per therm**
20			**Maximum (COG+25%)**	**$ 1.3186**	
21	C&I HLF Demand Costs Allocated per SMBA	$ 635,773			
22	PLUS: Residential Demand Reallocation to C&I HLF	$ 24,733			
23	C&I HLF Total Adjusted Demand Costs	$ 660,506			
24	C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)	2,837,571			
25	**Demand Cost of Gas Rate**	**$ 0.2328**			
26					
27	C&I HLF Commodity Costs Allocated per SMBA	$ 1,956,507			
28	PLUS: Residential Commodity Reallocation to C&I HLF	$ (15,057)			
29	C&I HLF Total Adjusted Commodity Costs	$ 1,941,450			
30	C&I HLF Projected Prorated Sales (11/01/09 - 04/30/10)	2,837,571			
31	**Commodity Cost of Gas Rate**	**$ 0.6842**			
32					
33	**Indirect Cost of Gas**	**$ 0.1379**			
34					
35	**Total C&I HLF Cost of Gas Rate**	**$ 1.0549**			
36					
37	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/09**		**COGwh**	**$ 1.0993**	**per therm**
38			**Maximum (COG+25%)**	**$ 1.3741**	
39	C&I LLF Demand Costs Allocated per SMBA	$ 4,857,290			
40	PLUS: Residential Demand Reallocation to C&I LLF	$ 188,959			
41	C&I LLF Total Adjusted Demand Costs	$ 5,046,250			
42	C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)	12,893,460			
43	**Demand Cost of Gas Rate**	**$ 0.3914**			
44					
45	C&I LLF Commodity Costs Allocated per SMBA	$ 7,406,555			
46	PLUS: Residential Commodity Reallocation to C&I LLF	$ (57,000)			
47	C&I LLF Total Adjusted Commodity Costs	$ 7,349,554			
48	C&I LLF Projected Prorated Sales (11/01/09 - 04/30/10)	12,893,460			
49	**Commodity Cost of Gas Rate**	**$ 0.5700**			
50					
51	**Indirect Cost of Gas**	**$ 0.1379**			
52					
53	**Total C&I LLF Cost of Gas Rate**	**$ 1.0993**			

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2008 - April 30, 2009

54	Total Anticipated Direct Cost of Gas		$ 37,570,662		
55	Projected Prorated Sales (11/01/08 - 04/30/09)		29,889,150		
56	**Direct Cost of Gas Rate**			**$ 1.2570**	**per therm**
57					
58	**Demand Cost of Gas Rate**		**$ 9,681,096**	**$ 0.3239**	**per therm**
59	**Commodity Cost of Gas Rate**		**$ 27,889,566**	**$ 0.9331**	**per therm**
60	**Total Direct Cost of Gas Rate**		**$ 37,570,662**	**$ 1.2570**	**per therm**
61					
62	Total Anticipated Indirect Cost of Gas		$ 197,268		
63	Projected Prorated Sales (11/01/08 - 04/30/09)		29,889,150		
64	**Indirect Cost of Gas**			$ 0.0066	per therm
65					
66					
67	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/08			$ 1.2636	per therm
68					
69	**RESIDENTIAL COST OF GAS RATE - 11/01/08**		**COGwr**	**$ 1.2636**	**per therm**
70			**Maximum (COG+25%)**	**$ 1.5795**	
71					
72	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/08**		**COGwl**	**$ 1.0608**	**per therm**
73			**Maximum (COG+25%)**	**$ 1.3260**	
74	C&I HLF Demand Costs Allocated per SMBA	$ 776,207			
75	PLUS: Residential Demand Reallocation to C&I HLF	$ 54,377			
76	C&I HLF Total Adjusted Demand Costs	$ 830,584			
77	C&I HLF Projected Prorated Sales (11/01/08 - 04/30/09)	3,366,290			
78	**Demand Cost of Gas Rate**	**$ 0.2467**			
79					
80	C&I HLF Commodity Costs Allocated per SMBA	$ 2,665,602			
81	PLUS: Residential Commodity Reallocation to C&I HLF	$ 52,579			
82	C&I HLF Total Adjusted Commodity Costs	$ 2,718,181			
83	C&I HLF Projected Prorated Sales (11/01/08 - 04/30/09)	3,366,290			
84	**Commodity Cost of Gas Rate**	**$ 0.8075**			
85					
86	**Indirect Cost of Gas**	**$ 0.0066**			
87					
88	**Total C&I HLF Cost of Gas Rate**	**$ 1.0608**			
89					
90	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/08**		**COGwh**	**$ 1.3948**	**per therm**
91			**Maximum (COG+25%)**	**$ 1.7435**	
92	C&I LLF Demand Costs Allocated per SMBA	$ 4,989,888			
93	PLUS: Residential Demand Reallocation to C&I LLF	$ 349,566			
94	C&I LLF Total Adjusted Demand Costs	$ 5,339,454			
95	C&I LLF Projected Prorated Sales (11/01/08 - 04/30/09)	13,525,770			
96	**Demand Cost of Gas Rate**	**$ 0.3948**			
97					
98	C&I LLF Commodity Costs Allocated per SMBA	$ 13,177,345			
99	PLUS: Residential Commodity Reallocation to C&I LLF	$ 259,923			
100	C&I LLF Total Adjusted Commodity Costs	$ 13,437,268			
101	C&I LLF Projected Prorated Sales (11/01/08 - 04/30/09)	13,525,770			
102	**Commodity Cost of Gas Rate**	**$ 0.9935**			
103					
104	**Indirect Cost of Gas**	**$ 0.0066**			
105					
106	**Total C&I LLF Cost of Gas Rate**	**$ 1.3948**			

N.H.P.U.C No.10
NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE

VARIANCE BETWEEN PEAK 2009 / 2010 and PEAK 2008 / 2009

107	Total Anticipated Direct Cost of Gas		$ (10,424,125)		
108	Projected Prorated Sales		(1,415,363)		
109	Direct Cost of Gas Rate			$ (0.3036)	per therm
110					
111	**Demand Cost of Gas Rate**		**$ 648,358**	**$ 0.0389**	**per therm**
112	**Commodity Cost of Gas Rate**		**$ (11,072,482)**	**$ (0.3425)**	**per therm**
113	**Total Direct Cost of Gas Rate**		**$ (10,424,125)**	**$ (0.3036)**	**per therm**
114					
115	Total Anticipated Indirect Cost of Gas		$ 3,728,422		
116	Projected Prorated Sales		(1,415,363)		
117	Indirect Cost of Gas			$ 0.1313	per therm
118					
119					
120	TOTAL PERIOD AVERAGE COST OF GAS			$ (0.1723)	per therm
121					
122	**RESIDENTIAL COST OF GAS RATE**		**COGwr**	**$ (0.1723)**	**per therm**
123			**Maximum (COG+25%)**	**$ (0.2154)**	
124					
125	**COM/IND LOW WINTER USE COST OF GAS RATE**		**COGwl**	**$ (0.0059)**	**per therm**
126			**Maximum (COG+25%)**	**$ (0.0074)**	
127	C&I HLF Demand Costs Allocated per SMBA				
128	PLUS: Residential Demand Reallocation to C&I HLF				
129	C&I HLF Total Adjusted Demand Costs				
130	C&I HLF Projected Prorated Sales				
131	**Demand Cost of Gas Rate**	**$ (0.0140)**			
132					
133	C&I HLF Commodity Costs Allocated per SMBA				
134	PLUS: Residential Commodity Reallocation to C&I HLF				
135	C&I HLF Total Adjusted Commodity Costs				
136	C&I HLF Projected Prorated Sales				
137	**Commodity Cost of Gas Rate**	**$ (0.1233)**			
138					
139	Indirect Cost of Gas	$ 0.1313			
140					
141	Total C&I HLF Cost of Gas Rate	$ (0.0059)			
142					
143	**COM/IND HIGH WINTER USE COST OF GAS RATE**		**COGwh**	**$ (0.2955)**	**per therm**
144			**Maximum (COG+25%)**	**$ (0.3694)**	
145	C&I LLF Demand Costs Allocated per SMBA				
146	PLUS: Residential Demand Reallocation to C&I LLF				
147	C&I LLF Total Adjusted Demand Costs				
148	C&I LLF Projected Prorated Sales				
149	**Demand Cost of Gas Rate**	**$ (0.0034)**			
150					
151	C&I LLF Commodity Costs Allocated per SMBA				
152	PLUS: Residential Commodity Reallocation to C&I LLF				
153	C&I LLF Total Adjusted Commodity Costs				
154	C&I LLF Projected Prorated Sales				
155	**Commodity Cost of Gas Rate**	**$ (0.4235)**			
156					
157	**Indirect Cost of Gas**	**$ 0.1313**			
158					
159	**Total C&I LLF Cost of Gas Rate**	**$ (0.2955)**			

Attachment NUI-JDS-13

New Hampshire Division Typical Bill Analyses

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 1,250 therms/year

Comparison of Winter 2009-10 vs. Winter 2008-09

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2009 - 2010																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.0913	$118.95						$118.95								
	CGA 2	$1.0913		$163.70					$163.70								
	CGA 3	$1.0913			$204.07				$204.07								
	CGA 4	$1.0913				$205.16			$205.16								
	CGA 5	$1.0913					$181.16		$181.16								
	CGA 6	$1.0913						$144.05	$144.05								
	LDAC	$0.0303	$3.30	$4.55	$5.67	$5.70	$5.03	$4.00	$28.24								
Summer 2009																	
Customer Charge	units @	$ 9.50								$ 9.50	$9.50	$9.50	$9.50	$ 9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$0.7385								$66.47						$66.47	
	CGA 2	$0.7385									$40.62					$40.62	
	CGA 3	$0.7385										$22.16				$22.16	
	CGA 4	$0.7385											$22.16			$22.16	
	CGA 5	$0.7385												$31.02		$31.02	
	CGA 6	$0.7385													$52.43	$52.43	
	LDAC	$ 0.0255								$2.30	$1.40	$0.77	$0.77	$1.07	$1.81	$8.11	
		TOTAL	$169.91	$228.15	$280.71	$282.13	$250.88	$202.58	$1,414.36	$110.73	$73.53	$44.73	$44.73	$58.82	$90.53	$423.06	$1,837.42

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
	Typical Usage: therms		109	150	187	188	166	132	932	90	55	30	30	42	71	318	1,250
Winter 2008 - 2009																	
Customer Charge	units @	$ 9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00								
First	50 units @	$0.4102	$20.51	$20.51	$20.51	$20.51	$20.51	$20.51	$123.06								
Over	50 units @	$0.2990	$17.64	$29.90	$40.96	$41.26	$34.68	$24.52	$188.97								
	CGA 1	$1.2636	$137.73						$137.73								
	CGA 2	$1.2636		$189.54					$189.54								
	CGA 3	$1.2636			$236.29				$236.29								
	CGA 4	$1.2636				$237.56			$237.56								
	CGA 5	$1.0540					$174.96		$174.96								
	CGA 6	$1.0540						$139.13	$139.13								
	LDAC	$ 0.0255	$2.78	$3.83	$4.77	$4.79	$4.23	$3.37	$23.77								
Summer 2008																	
Customer Charge	units @	$ 9.50								$9.50	$9.50	$9.50	$9.50	$9.50	$9.50	$57.00	
First	50 units @	$0.4102								$20.51	$20.51	$12.31	$12.31	$17.23	$20.51	$103.37	
Over	50 units @	$0.2990								$11.96	$1.50	$0.00	$0.00	$0.00	$6.28	$19.73	
	CGA 1	$1.1315								$101.84						$101.84	
	CGA 2	$1.3231									$72.77					$72.77	
	CGA 3	$1.3231										$39.69				$39.69	
	CGA 4	$1.2050											$36.15			$36.15	
	CGA 5	$0.9305												$39.08		$39.08	
	CGA 6	$0.9305													$66.07	$66.07	
	LDAC	$ 0.0194								$1.75	$1.07	$0.58	$0.58	$0.81	$1.38	$6.17	
		TOTAL	$188.16	$253.28	$312.03	$313.62	$243.89	$197.02	$1,508.01	$145.55	$105.34	$62.08	$58.54	$66.62	$103.73	$541.87	$2,049.88
		Change	($18.26)	($25.13)	($31.32)	($31.49)	$6.99	$5.56	($93.65)	($34.82)	($31.82)	($17.36)	($13.81)	($7.81)	($13.20)	**($118.81)**	($212.46)
		% Chg	-9.70%	-9.92%	-10.04%	-10.04%	2.87%	2.82%	-6.21%	-23.92%	-30.20%	-27.96%	-23.59%	-11.72%	-12.72%	**-21.93%**	-10.36%

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Winter 200910 vs. Actual Winter 2008-09

Residential Heating

	Winter 2008-09	Winter 2009-10
Customer Charge	$9.50	$9.50
First 50 Therms	$0.4102	$0.4102
Over 50 therms	$0.2990	$0.2990
LDAC	$0.0255	$0.0303
CGA	$1.1937	$1.0913

	Usage (Therms)	Winter 08-09 Bill Amount	Winter 09-10 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$17.65	$17.16	($0.49)	-2.8%	$0.00	0.0%	($0.51)	-2.9%	$0.02	0.1%
	10	$25.79	$24.82	($0.98)	-3.8%	$0.00	0.0%	($1.02)	-4.0%	$0.05	0.2%
	20	$42.09	$40.14	($1.95)	-4.6%	$0.00	0.0%	($2.05)	-4.9%	$0.10	0.2%
	25	$50.24	$47.80	($2.44)	-4.9%	$0.00	0.0%	($2.56)	-5.1%	$0.12	0.2%
	30	$58.38	$55.45	($2.93)	-5.0%	$0.00	0.0%	($3.07)	-5.3%	$0.14	0.2%
	45	$82.82	$78.43	($4.39)	-5.3%	$0.00	0.0%	($4.61)	-5.6%	$0.22	0.3%
	50	$90.97	$86.09	($4.88)	-5.4%	$0.00	0.0%	($5.12)	-5.6%	$0.24	0.3%
	75	$143.88	$136.56	($7.32)	-5.1%	$0.00	0.0%	($7.68)	-5.3%	$0.36	0.3%
	125	$219.79	$207.59	($12.20)	-5.6%	$0.00	0.0%	($12.80)	-5.8%	$0.60	0.3%
Average Monthly	150	$257.75	$243.10	($14.65)	-5.7%	$0.00	0.0%	($15.37)	-6.0%	$0.72	0.3%
	200	$333.66	$314.13	($19.53)	-5.9%	$0.00	0.0%	($20.49)	-6.1%	$0.96	0.3%

Attachment NUI-JDS-14
Supplier Balancing Charge

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Northern Utilities, Inc.

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

November 2009 through October 2010

		MDQ		Max Swing	% MDQ	
1	New Hampshire Underground	16,962		3,532	20.82%	
2	LNG	4,746		0	0.00%	
3	Propane	1,898		0	0.00%	
4						
5		% MDQ	Costs	Balancing Costs	% Allocated to Balancing	Allocated Costs
6	New Hampshire Underground					
7	Del., Res., and Transp.	20.82%	$8,004,845	$1,666,853	0.20%	$3,330
8	Capacity	20.82%	$1,399,290	$291,375	35.42%	$103,211
9						
10	LNG	0.00%	$109,007	$0	145.28%	$0
11						
12	Propane	0.00%	$119,113	$0	0.00%	$0
13						
14	Total		$9,632,254	$1,958,228		$106,541
15						
16	Annual Sum of Absolute Swings					142,624
17	Balancing Rate Per MMBtu Swing					**$0.75**

Note: LNG and LP MDQ allocated based on New Hampshire's current PR-Allocator percentage. 47.46%

Northern Utilities, Inc.
Calculation of Balancing Charge
Costs of Balancing Resources
November 2009 through October 2010

Line	Maine	Type	Northern Capacity	Division Allocated	Rate	Months	Costs
3	**El Paso FS Storage**						
4	Capacity	Cap	259,337	136,252	$0.0185	12	$30,248
5	Deliverability	Del	4,243	2,229	$1.1500	12	$30,763
6	Firm Transportation-Tenn	Trans	2,653	1,394	$5.8900	12	$98,517
7	Firm Transportation-GSGT	Trans	2,653	1,394	$1.6666	12	$27,876
8	Total						$187,404
9	**Texas Eastern Storage**						
10	Space - SS-1	Cap	1,470	772	$0.1293	1	$100
11	Reservation - SS-1	Res	21	11	$5.5370	12	$733
12	Space - FSS-1	Cap	320	168	$0.1293	12	$261
13	Reservation - FSS-1	Res	64	34	$0.8950	12	$361
14	TETCO Reservation	Res	64	34	$5.2930	12	$2,136
15	Firm Transportation-GSGT	Trans	64	34	$1.6666	12	$672
16	Firm Transportation-GSGT	Trans	21	11	$1.6666	12	$221
17	Total						$4,484
18	**W-10 Storage**						
19	W-10	Cap	34,000	17,863	$ 7.0833	12	$1,518,361
20	PNGTS	Trans	20,000	10,508	$ 52.0632	5	$2,735,319
21	PNGTS	Trans	13,000	6,830	$ 52.0632	12	$4,267,098
22	Vector - In	Trans	17,172	9,022	$ 7.6042	12	$823,252
23	Vector -Out	Trans	17,086	8,977	$ 4.5625	5	$204,781
24	TCPL	Trans	33,000	17,338	$ 13.3166	12	$2,770,538
25	Firm Transportation-GSGT	Trans	33,000	17,338	$ 1.6666	12	$346,740
26	Total						$12,666,088
27	LNG						
28	ME		10,000	5,254			$229,674
29	Total						$229,674
29	Propane						
30	Capacity						
31	ME		4,000	2,102			$250,967
34	Total						$250,967
32	Maine Summary						
35		Del	4,243	2,229			$30,763
33		Res	149	78			$3,230
36		Trans	138,649	72,844			$11,275,014
34		Cap	295,127	155,055			$1,548,969
37		Total	438,168	230,207			$12,857,976
35		Gate Station Delivery	35,738	18,776			

Northern Utilities, Inc.
Calculation of Balancing Charge
Analysis of Swings

Division	UGS Maximum Swings	UGS Sum Positive Swings	Northern UGS Withdrawals	Allocated UGS Withdrawals	Positive UGS Swings as a % of UGS Withdrawals
NH	3,532	3,811	4,019,426	1,907,683	0.20%
ME	7,580	1,635	4,019,426	2,111,743	0.08%

Division	LP Max. Swing	LP Sum Positive Swings	LP Tank Capacity	LP Allocated Tank Capacity	LP Swings as a % of Tank Capacity
NH	0	0	25,733	12,213	0.00%
ME	0	0	25,733	13,520	0.00%

Division	LNG Max. Swing	LNG Sum Positive Swings	LNG Tank Capacity	LNG Allocated Tank Capacity	LNG Swings as a % of Tank Capacity
NH	0	(9,481)	13,750	6,526	145.28%
ME	1,418	(26,271)	13,750	7,224	363.66%

Division	UGS Absolute Value All Swings	UGS Total Absolute Value All Swings	Northern UGS Capacity	Allocated UGS Capacity	Positive UGS Swings as a % of UGS Withdrawals
NH	45,999	36,518	295,127	140,072	32.84%
ME	94,294	68,023	295,127	155,055	60.81%
Total	140,292	104,540		295,127	35.42%

Division		UGS Max Abs Cum. All Swings		Allocated UGS Capacity	
NH		49,355		140,072	
ME		34,012		155,055	52.54%
Total		83,367		295,127	**28.25%**

Northern Utilities, Inc.
Calculation of Suppliler Balancing Charge

Derivation of Absolute Swings
May 2000 through April 2001
Summary

		Sum Positive Swings		Sum Negative Swings		Sum LP / LNG Swings		ABS all Swings		Total
		Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	ABS Swings
1	May	1,060	1,484	8,125	1,162	0	0	9,185	2,646	11,832
2	June	0	28	1,213	5,553	0	0	1,213	5,582	6,794
3	July	1,125	0	0	0	0	0	1,125	0	1,125
4	Aug	45	0	99	1,027	0	0	145	1,027	1,172
5	Sept	0	0	301	11,279	0	0	301	11,279	11,580
6	Oct	1,196	123	2,821	26,853	0	0	4,017	26,976	30,993
7	Nov	384	0	3,976	7,620	(2,382)	(2,539)	6,743	10,159	16,901
8	Dec	0	0	7,956	12,177	0	0	7,956	12,177	20,133
9	Jan	0	0	1,873	174	(423)	(13,355)	2,296	13,530	15,826
10	Feb	0	0	2,807	542	(4,431)	(4,339)	7,238	4,880	12,118
11	March	0	0	1,048	0	(2,245)	(6,038)	3,293	6,038	9,331
12	April	0	0	2,487	0	0	0	2,487	0	2,487
13	Total	3,811	1,635	32,707	66,387	(9,481)	(26,271)	45,999	94,294	140,292
14				add back 10% of the scheduled deliveries=				96,625	97,195	193,819
15						Total ABS Swings =		**142,624**	**191,488**	334,112

Prefiled Testimony of Francis X. Wells

Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2009/2010
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
FRANCIS X. WELLS

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Francis X. Wells. I am Senior Energy Trader for Unitil Service Corp. ("Unitil"). My business address is 6 Liberty Lane West, Hampton, NH.

Q. Please describe your relevant educational and work experience.

A. I received my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined Unitil in September 1996, assisting in the planning and operation of both electric power and natural gas supply portfolios. Since January 2001, I have worked as a Senior Energy Trader in the Energy Contracts Department. I have responsibilities in the areas of (1) energy supply acquisition, including natural gas supply procurement, electric default service purchasing; (2) regulatory testimony and reporting; (3) budgeting for both natural gas and electric supply, and (4) long-term supply planning.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I have testified before the New Hampshire Public Utilities Commission in Docket No. DG 08-048, the joint petition by Unitil and NiSource for the approval of the acquisition of

Northern Utilities, Inc. ("Northern" or the "Company") by Unitil Corporation and in Docket No. DG 09-052, Northern's 2009 Summer Cost of Gas Adjustment.

Q. Please explain the purpose of your prepared direct testimony in this proceeding.

A. First, I will provide an overview of Northern's gas supply activity for the 2008/2009 Winter period. Next, I will provide an overview of the supply plan for the upcoming 2009/2010 Winter period, including Northern's forecast of gas demand and the resulting forecasted gas sendout and estimated gas supply costs that I have developed for the Maine and New Hampshire Divisions. I also provide a review of Northern's portfolio and a supply plan to cover the forecasted sendout requirements over the 2009/2010 Winter period.

I also provide the impact of the Company's current hedging program for the 2009/2010 Winter period on Northern's projected supply costs. On August 4, 2009, the Company proposed modifications to its hedging program in Docket No. DG 09-141 to be implemented for the 2010/2011 Winter period. Northern believes that it would be appropriate for the ongoing discussion of the 2010/2011 hedging plan to continue in DG 09-141 rather than in the instant docket. However for purposes of this filing and my testimony, when I refer to the Company's hedging program, I am referring to the program currently in place and previously approved by this Commission.

James Simpson, Vice President of Concentric Energy Advisors, describes and explains the calculation of the Cost of Gas rates ("COG") that Northern proposes to bill from November 1, 2009 to April 30, 2010. He also discusses the impact that the proposed COG will have on the bills of the Company's typical customers.

II. OVERVIEW OF 2008 / 2009 PEAK PERIOD GAS SUPPLY

Q. Please provide a summary of Northern's natural gas supply requirements for the 2008/2009 Winter period and its sources of gas supply used to meet these requirements.

A. Please refer to Attachment NUI-FXW-1, titled, "Dispatch Data." Pages 1 through 6 provide daily Effective Degree Days and the Total Receipts. Subsequent columns, End User Transport, W10 Storage, FS-MA Storage, TETCO Storage, Propane, LNG Boil-Off, LNG Vapor, and Pipeline Supplies show the supply source for each day's Total Receipts. Page 7 of Attachment NUI-FXW-1 provides a monthly and seasonal subtotal for all columns. I have also summarized the seasonal totals and percentages in the table below.

Table 1. 2008/2009 Resources Utilized

Supply Source	City Gate Volume (Dth)	Percentage
End-User Transport	5,874,853	52.1%
W10 Storage	3,034,650	26.9%
FS-MA Storage	235,540	2.1%
Texas Eastern Storage	4,361	0.0%
Propane	-	0.0%
LNG Boil-Off	5,827	0.1%
LNG Vapor	23,114	0.2%
Pipeline Supplies	2,105,301	18.7%
Total Season Receipts	11,283,646	100.0%

Table 1 indicates that the majority of the 2008/2009 seasonal receipts were attributable to End-User Transport to Northern's transportation-only customers. To provide an understanding of the gas supply sources used to serve Northern' Sales Service customers, I have prepared Table 2, below, which shows Sources of Gas Supply, excluding End-Use Transport.

Table 2. 2008/2009 Resources Utilized for Sales Service Supply		
Supply Source	City Gate Volume (Dth)	Percentage
W10 Storage	3,034,650	56.1%
FS-MA Storage	235,540	4.4%
Texas Eastern Storage	4,361	0.1%
Propane	-	0.0%
LNG Boil-Off	5,827	0.1%
LNG Vapor	23,114	0.4%
Pipeline Supplies	2,105,301	38.9%
Total Season	5,408,793	100.0%

Northern sourced approximately 60% of Northern's total city-gate receipts for Sales Service customers from its Washington 10 and FS-MA Storage contracts. Various pipeline supplies combined to provide the majority of the remaining 40% of 2008/2009 Peak period supplies. Pipeline supplies were sourced from Chicago Hub; Alberta, Canada, Tennessee Production Area, and the Distrigas and FPL Peaking contracts.

III. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast billed distribution deliveries[1] for the Company's residential, small commercial and larger industrial/commercial classes, the Company has utilized time-series techniques to develop two forecast models: use-per-meter and the number of meters. The growth rates for customers (meters) and use-per-meter from these models are applied to the most recent data normalized for weather; the forecast monthly billed deliveries for each customer class was calculated by multiplying forecast customers times forecast use-per-customer. Forecast demand for the large commercial customers with special contracts was developed separately for each of these customers.

Q. Have you prepared a schedule to compare the forecasted deliveries for the 2009/2010 Winter COG period to actual weather-normalized normalized deliveries for the 2008/2009 Peak COG period?

A. Yes, I have prepared Attachment NUI-FXW-2 for that purpose. Attachment NUI-FXW-2 compares Northern's total monthly distribution metered deliveries forecast for the 2009/ 2010 gas year to weather-normalized total distribution metered deliveries. I compare the 2009/2010 total monthly distribution metered deliveries forecast to 2008/2009 actual weather-normalized total monthly distribution metered deliveries through June 2009; the latest actual data available at the time the deliveries forecast was prepared. I also compare the deliveries forecast to weather-normalized actual data for the 2007/2008 gas year for

[1] In my testimony I use the term "deliveries" to refer to the volumes or quantities of gas that are distributed to the premises of sales customers and transportation customers. I use the term "sales customer" to refer to a gas customer that receives bundled distribution and gas supply service from Northern. Finally I use the term "transportation customer" to refer to a gas customer that receives distribution service from Northern and gas supply service from a competitive retail supplier.

which a complete year of actual data are available. I have prepared Table 3, below, which provides a summary of the company's forecast of total billed distribution deliveries.

Table 3.
2009 / 2010 New Hampshire Division Billed Deliveries Forecast Compared to Prior Years

Month	2009-2010[1]	Change over Prior Year	Percent Change	2008-2009[2]	Change over Prior Year	Percent Change	2007-2008[3]
Nov	509,893	-39,556	-7.2%	549,450	-12,927	-2.3%	562,377
Dec	781,265	-10,742	-1.4%	792,007	15,725	2.0%	776,282
Jan	979,765	-10,471	-1.1%	990,236	-21,605	-2.1%	1,011,841
Feb	949,163	-41,924	-4.2%	991,088	-58,432	-5.6%	1,049,520
Mar	846,205	-47,903	-5.4%	894,108	-42,101	-4.5%	936,209
Apr	657,301	-21,653	-3.2%	678,954	-99,303	-12.8%	778,257
May	432,762	-4,893	-1.1%	437,655	-99,986	-18.6%	537,641
Jun	342,189	24,952	7.9%	317,236	-70,969	-18.3%	388,205
Jul	284,559	3,121	1.1%	281,438	-100,384	-26.3%	381,822
Aug	270,037	3,042	1.1%	266,995	-3,916	-1.4%	270,911
Sep	310,686	3,099	1.0%	307,587	17,192	5.9%	290,395
Oct	352,562	3,199	0.9%	349,364	-8,233	-2.3%	357,596
Peak	4,723,592	-172,250	-3.5%	4,895,842	-218,643	-4.3%	5,114,485
Off-Peak	1,992,795	32,521	1.7%	1,960,274	-266,297	-12.0%	2,226,571
Total	6,716,387	-139,729	-2.0%	6,856,116	-484,940	-6.6%	7,341,056

Note 1: 2010 Company Forecast.
Note 2: Actual Weather-Normalized Data through June 2009. Forecast Data begins July 2009.
Note 3: Actual Weather-Normalized Data.

Q. How does the Company forecast firm sendout?

A. First, the total firm distribution forecasted delivery quantities are allocated between sales and transportation services based upon Northern's recent history of actual deliveries to transportation customers as a percentage of total deliveries to sales and transportation customers. As I explain in this testimony, the estimated gas supply costs that I provided to

Mr. Simpson for this filing are based on the gas supply costs to Northern's sales customers only.

Second, I converted from billing month deliveries to calendar month city-gate receipts, based on the recent historical company use requirements and ratios of billing month deliveries to calendar month city-gate receipts.

Q. Have you prepared a schedule that converts the metered distribution deliveries to sendout requirements?

A. Yes. I have prepared Attachment NUI-FXW-3 for this purpose. First, I determine the monthly metered distribution deliveries that will be served through Northern's Sales Service. I multiply the monthly distribution deliveries forecast by an estimate of the percentage of total deliveries to be served through Sales Service. I provide these calculations on page 1 of Attachment NUI-FXW-3. Second, I determine the monthly city-gate receipts required to meet the Sales Service deliveries forecast, which are provided on page 2 of Attachment NUI-FXW-3. I have summarized this data in Table 4, below.

Table 4. Required City-Gate Receipts Summary			
Month	Total Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-09	509,893	259,755	274,729
Dec-09	781,265	451,329	473,054
Jan-10	979,765	631,824	623,823
Feb-10	949,163	625,692	652,772
Mar-10	846,205	525,469	510,088
Apr-10	657,301	390,952	351,860
May-10	432,762	232,685	232,872
Jun-10	342,189	156,509	166,077
Jul-10	284,559	109,067	105,222
Aug-10	270,037	96,763	103,049
Sep-10	310,686	116,545	108,369
Oct-10	352,562	136,291	142,055
Peak	4,723,592	2,885,021	2,886,327
Off-Peak	1,992,795	847,861	857,644
Annual	6,716,387	3,732,881	3,743,971

IV. ESTIMATED GAS SUPPLY COSTS

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its sales customers.

A. Northern has access to gas supply markets in the Gulf of Mexico, the northeastern and mid-continental United States, and both western and eastern Canada through its portfolio of natural gas transportation contracts. Transportation contracts with Tennessee Gas Pipeline provide access to the Gulf of Mexico and to the northeastern United States, while contracts with Vector Pipeline, the TransCanada Pipelines, Iroquois Gas Pipeline, Algonquin Gas Transmission and the Portland Natural Gas Transmission System ("PNGTS") provide access to western Canada and the mid-continental United States.

Northern has storage contracts with Washington 10 Storage Corporation, Tennessee, and Texas Eastern. Northern has peaking supply contracts with FPL Energy Power Marketing, Inc ("FPL") [2] and Distrigas of Massachusetts Corporation ("Distrigas"). Under the FPL peaking contract, Northern has the right to call on a daily basis for natural gas, delivered to Granite State Gas Transmission ("Granite"). Under the Distrigas peaking contract, Northern has the right to call on a daily basis for either Liquefied Natural Gas ("LNG"), which can be trucked to its LNG facility in Lewiston, Maine or on natural gas delivered to Granite.

With the exception of its long-term peaking contracts, Northern's current practice is to secure its gas supply commodity contracts through seasonal requests-for-proposal ("RFP"). Northern issued an RFP to procure the actual supplies necessary to meet its projected peak season requirements on September 9, 2009. Supplies injected into inventory for use in the upcoming peak period were procured through an RFP at prices based upon first of month indexes plus applicable transportation and storage variable charges.

All pipeline supplies are delivered through the Company's affiliate pipeline, Granite, with the exception of deliveries to Northern's city gate with the Maritimes & Northeast Pipeline, located in Lewiston.

Q. What changes have been made to Northern's gas supply portfolio since the 2009 Summer COG filing?

[2] Effective November 1, 2008, Northern consented to the assignment of the peaking supply contract with Duke Energy Trading & Marketing ("DETM") to FPL.

A. In order to better match Northern's gas supply with its needs, Northern has recently entered into capacity release agreements for portions of its Texas Eastern Transmission and Algonquin capacity. The Company has found that these transportation resources were not highly utilized by Northern and are highly valued in the market-place. Northern was able to recover 100% of the demand costs associated with these contracts, resulting in projected savings of $175,000 for the upcoming gas year. The majority of these contracts have been released on a permanent basis, reducing the fixed cost liability to Northern's customers.

Northern has also released a portion of its Washington 10 storage capacity from May 1, 2009 through March 31, 2010. Prior to the capacity release, Northern held 3,400,000 Dth of Washington 10 storage and 34,000 Dth of withdrawal capacity. Northern has released 500,000 Dth and 5,000 Dth of withdrawal capacity, leaving Northern with 2,900,000 Dth and 29,000 Dth of withdrawal capacity for Washington 10. This release benefits customers through increased asset management credits for its Washington 10 summer injection asset management contract.

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Simpson to calculate the 2009/2010 Winter COG.

A. I have prepared demand and commodity cost forecasts for the gas year beginning November 1, 2009 and ending October 31, 2010. Please refer to the Table 5 below, titled, "Summary of Estimated Gas Supply Costs." The table provides a summary of annual Northern demand and commodity gas supply estimates for the period November 2009 through October 2010.

Table 5. Summary of Estimated Gas Supply Costs November 1, 2009 through October 31, 2010			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 6,642,704	Attachment NUI-FXW-4, Page 2 - Pipeline Allocated Cost
2.	Storage	$ 19,732,486	Attachment NUI-FXW-4, Page 2 - Storage Allocated Cost plus Page 3 - Annual Fixed Charges
3.	Peaking	$ 5,040,783	Attachment NUI-FXW-4, Page 2 – Peaking Allocated Cost plus Attachment NUI-FXW-4, Page 4 - Annual Fixed Charges
4.	Capacity Release	$ (4,335,643)	Attachment NUI-FXW-4, Page 5 - Total Projected Capacity Releases
5.	PNGTS Litigation Rate Case Costs	$ 434,116	Attachment NUI-FXW-9
6.	Subtotal Demand Costs	$ 27,514,446	Sum Lines 1 through 5.
7.	NH Division Capacity Assignment	$ (1,683,859)	Attachment NUI-FXW-5, NH Division Capacity Assignment Demand Revenue, Page 1
8.	ME Division Capacity Assignment	$ (3,344,887)	Attachment NUI-FXW-5, ME Division Capacity Assignment Demand Revenue, Page 1
9.	Net Demand Costs	$ 22,485,700	Sum Lines 6 through 8.
10.	Peak Commodity Cost	$ 27,525,445	Attachment NUI-FXW-6, Page 1, Nov - Apr, Total Variable Supply Costs
11.	Peak Hedging (Profit)/Loss	$ 3,994,120	Attachment NUI-FXW-6, Page 1, Nov - Apr, Futures (Profit) or Loss
12.	Off-Peak Commodity Cost	$ 8,787,590	Attachment NUI-FXW-6, Page 1, May - Oct, Total Variable Supply Costs
13.	Off-Peak Hedging (Profit)/Loss	$ 22,020	Attachment NUI-FXW-6, Page 1, May - Oct, Futures (Profit) or Loss
14.	Subtotal Commodity Cost	$ 40,329,175	Sum Lines 10 through 13.
15.	Total Gas Supply Costs	$ 62,814,875	Sum Line 9 and Line 14.

Q. Please provide the detailed calculations of the Company's demand cost forecast.

A. I present the demand cost forecast in Attachment NUI-FXW-4. On page 1 of the Attachment, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 2 of Attachment NUI-FXW-4, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 3 and 4 of Attachment NUI-FXW-4 provide my calculations of demand costs for storage and peaking supply contracts. On page 5 of Attachment NUI-FXW-4, I forecast the capacity release and asset management revenue the Company expects to receive for the 2009/2010 gas year.

Q. Please provide the detailed calculations of the Company's projections of Capacity Assignment demand revenue.

A. I have prepared Attachment NUI-FXW-5 to estimate projected Capacity Assignment demand revenue for both the New Hampshire and Maine Divisions. I summarize the Capacity Assignment demand revenue on page 1 of Attachment NUI-FXW-5. Pages 2 through 4 provide the detailed calculations of the Capacity Assignment demand revenue for pipeline, storage, and peaking resources for the New Hampshire Division. I calculate the amount of the Company's Capacity Release revenue, which will be shared with retail marketers through Company-Managed capacity assignments on page 5. I calculate the impact of the Company's proposed inclusion of legal and consulting costs to oppose PNGTS' proposed rate increase on page 6, which I discuss in further detail later in my testimony. On Pages 7 and 8, I also provide the detailed capacity assignment calculations for the Maine Division.

Q. Please present the Company's detailed calculations of the Company's commodity cost forecast.

A. I prepared Attachment NUI-FXW-6 to show the monthly forecasted commodity cost detail, by supply option. Page 1 of Attachment NUI-FXW-6 provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 1 also provides the calculation of the hedging gains or losses. Page 2 of the Attachment provides delivered volumes (Dth) by supply source. Finally, Page 3 provides delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

I based the Company's commodity cost forecast on the supplies available to Northern based upon its portfolio of transportation, storage, and peaking contracts, current commodity prices, variable transportation and fuel retention rates, base load gas commitments and LNG boil-off. I utilized the Sendout® natural gas supply cost optimization model to provide an optimal cost result, based on the economic and operational parameters that reasonably modeled Northern's current gas supply portfolio. I have also calculated the gains or losses of the NYMEX natural gas contracts purchased by the Company in accordance with its hedging program.

Q. Has the Company accounted for retail migration[3] in its gas supply budget?

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[3] Retail migration refers to customers switching from bundled sales service to unbundled distribution service, with a competitive retail supplier providing the gas supplies.

A. Yes, it has. I have reduced Northern's projected sendout requirement by the amount it expects will be served by retail suppliers. The commodity costs included in the cost summary table exclude costs to serve customers electing transportation-only service from the Company.

While the demand charges presented in the cost summary table include total Company demand costs, I have also estimated the amount of revenue offset to the demand costs that the Company expects to receive from retail suppliers through its New Hampshire Division capacity assignment program. This amount is approximately $1.7 million and the detailed calculations of that amount are contained in Attachment NUI-FXW-5. As discussed by Mr. Simpson, this amount is deducted from the annual demand charges allocated to the New Hampshire Division to be recovered through the proposed COG.

Q. Please discuss the status of the PNGTS meter error in-kind payback.

A. In January 2008 Northern filed a letter with the Commission and the Office of the Consumer Advocate stating that an investigation of unaccounted-for gas in its New Hampshire Division had uncovered a metering problem on the Northern system. It was determined that Northern had been overcharged for 758,502 Dth due to this metering error. PNGTS began paying back this volume with in-kind gas on November 1, 2008. According to the agreement with PNGTS, Northern was to receive 1,382 Dth daily on a best-efforts basis at no cost until PNGTS has provided the full 758,502 Dth. The pay-back could be at a higher daily amount with mutual agreement by the PNGTS and Northern. For the purpose of estimating the cost of gas for the Peak period, I assumed that PNGTS would deliver

1,382 each day. Based on this schedule, the PNGTS meter pay-back should be completed in early December, 2009.

Q. Please provide the documentation for the gas supply rate inputs used to generate the gas supply cost estimates.

A. Please refer to Attachment NUI-FXW-7, which provides the NYMEX prices, negotiated transportation rates, transportation tariff sheets and Canadian dollar exchange rate used to generate the gas supply estimates for the COG. The NYMEX prices reflect the NYMEX settlement on August 10, 2009. The Company intends to revise its commodity cost estimates to reflect NYMEX prices closer to the effective date of the proposed COG.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2009 through October 2010.

A. Page 1 of Attachment NUI-FXW-8 provides this information. The results are based upon the Company's Sendout® analysis. Page 2 of Attachment NUI-FXW-8 is Northern's second semi-annual report of in-kind volumes received from PNGTS as required by Commission Order 24,912, issued October 31, 2008 in Docket DG 08-115.

Q. How has the Company taken advantage of the decrease in natural gas prices?

A. The Company has purchased replacement storage supplies at dramatically lower prices for the upcoming winter than for last winter. The average inventory cost for the Company's largest underground storage, Washington 10, was approximately $10.07 per Dth for last winter. This winter, the Company projects average Washington 10 inventory costs to decrease to approximately $4.01 per Dth. Also, the Company has continued to implement its hedging plan for the 2010 Off-Peak period, as provided to the Commission in the 2009 Off-Peak COG filing.

V. HEDGING

Q. Please provide the results of the hedging program related to the Company's proposed COG rates.

A. Based upon the August 10, 2009 NYMEX natural gas settlement price data, Northern projects hedging losses of approximately $4 million. Actual results will be determined as financial positions are liquidated on the final day trading for each month.

Q. Has Northern developed a plan for hedging the 2010/2011 Winter period?

A. On August 7, 2009, the Company proposed modifications to its hedging program in Docket No. DG 09-141 to be implemented for the 2010/2011 Peak Period and requests that the ongoing discussions of 2010/2011 hedging plan continue in that docket.

VI. PNGTS Rate Case Litigation Costs

Q. Does Northern propose to recover extraordinary external legal and consulting costs incurred opposing proposed rate increases at the Federal Energy Regulatory Commission ("FERC") in the interests of its cost of gas customers during the coming peak season?

A. Yes. Northern has actively opposed proposed rate increases by Portland Natural Gas Transmission System ("PNGTS") before the FERC in order to defend the interests of its cost of gas customers and has incurred extraordinary costs in the process. By "extraordinary," I am referring to reasonably and prudently incurred costs that are not likely to arise on an annual basis but nonetheless are costs that the Company periodically incurs in the conduct of its business. Northern has participated in the proceedings described below as a member of an ad hoc group of companies, who each hold long-term (20 year) firm transportation agreements with PNGTS, known as the PNGTS Shippers' Group ("PSG"). By virtue of jointly opposing the proposed rate increases, individual members of PSG, including Northern, were able to reduce cost, retain highly qualified counsel and expert witnesses, and leverage each others' professional expertise.

Q. Please identify the proceedings in which Northern is participating in opposing rate increases proposed by PNGTS.

A. Northern is participating in FERC Docket No. RP08-306-000, which is a rate proceeding filed by PNGTS on April 1, 2008, pursuant to the terms of settlement in FERC RP02-13. In addition, Northern is participating in FERC Docket No. 09-1029, an appeal by PSG of FERC orders 123 FERC 61,275 (2008), "Order Granting Petition for Declaratory Order," and 125 FERC 61,198 (2008), "Order Denying Rehearing," which would reduce the capacity on PNGTS outside of an application for abandonment and in turn significantly reduce protection for shippers under the "at risk" provision associated with PNGTS' certificate proceedings. Lastly, Northern also participated in FERC Docket No. RP09-2-001, a proceeding in which PNGTS sought to pass through fuel costs it anticipated from Maritimes and Northeast Pipeline ("Maritimes") associated with Maritimes' Phase IV expansion. FERC ultimately rejected PNGTS' filing in RP09-2-001.

Q. For what future costs would customers be at risk if Northern had not opposed proposed rate increases by PNGTS?

A. There are many issues currently being disputed with PNGTS in the proceedings described above including the appropriate cost of service levelization methodology, treatment of bankruptcy proceeds (Androscoggin and Rumford) received by PNGTS, depreciation rate on transmission plant, system capacity for purposes of the "at risk" condition and rate design, treatment of revenues for short term services, return on equity and cost of debt. As initially filed, the proposed rates in FERC Docket RP08-306 would increase Northern's prior average transportation rates by 8.5 percent or $700,000 per year. Subsequent changes sought by PNGTS during the proceeding and in the orders being contested by PSG in FERC Docket No. 09-1029 would increase costs over Northern's prior average transportation rates by as much as 66 percent or $5,500,000 per year. Clearly, these cumulative proposed increases, if allowed, would have a material and adverse impact on our customers.

Q. Please identify the costs incurred to oppose PNGTS proposed rate increases that Northern proposes to recover.

A. Northern proposes to recover costs of $206,028.50, which is the New Hampshire division's share of the $434,095.14 in external legal and consulting costs that Northern has incurred opposing PNGTS proposed rate increases since December 1, 2008. The proposed fixed proportional responsibility allocators were used to assign these costs by state. Northern is not proposing to recover costs for expenses that were paid before December 1, 2008 or the costs of internal resources. In this Cost of Gas filing, Northern has reflected these costs as a deduction from Asset Management revenues. I have prepared Attachment NUI-FXW-9 to provide an overview of these expenses.

Q. Does the Company propose that a pro-rated share of these legal and consulting costs be passed through to retail marketers, who are assigned a share of Northern's transportation contracts with PNGTS?

A. Yes. On page 6 of Attachment NUI-FXW-5, I have calculated an estimate of the PNGTS litigation costs, which would be passed through to retail marketers as costs pertaining to Washington 10 and Empress Company-Managed supplies. Any benefits that Northern may receive as a result of its opposition to PNGTS' proposed rate increase will be passed along to retail marketers in the form of lower company-managed supply costs. As such, the Company is proposing that retail marketers pay a pro-rated share of these costs.

Q: In making this request for inclusion of these extraordinary legal and consulting costs in the cost of gas rates for the coming peak season, does Northern intend to establish any precedent for such future treatment?

A: No. With this request, Northern intends to recover the costs that have been incurred from December 1, 2008 through August 31, 2009 and does not intend to establish any precedent with regard to the manner of recovery of similar costs in the future. Northern would address the recovery of similar future costs, should they occur, at such future time. In addition, if recovery is allowed in the proposed cost of gas rates as requested, Northern would exclude these costs from revenue requirements proposed in any future Northern base rate case.

Q. Does this conclude your testimony?

A. Yes it does.

Attachment NUI-FXW-1

Dispatch Data

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
Daily Dispatch Data
2008-2009 Peak Period

Month	Day	Effective Degree Days	Total Received by Granite	End-User Transport	W10 Storage	FS-MA Storage	Tetco Storage	Propane	LNG Boil-Off	LNG Vapor	Pipeline Supplies
Nov	1	30	46,470	24,421	15,000	-	-	-	45	-	7,004
Nov	2	32	53,115	26,940	15,000	-	-	-	-	-	11,175
Nov	3	22	47,756	27,756	5,000	-	-	-	59	-	14,941
Nov	4	14	37,703	25,354	-	-	-	-	54	-	12,295
Nov	5	10	35,016	25,027	-	-	-	-	2	-	9,987
Nov	6	9	33,190	25,426	-	-	-	-	2	-	7,762
Nov	7	10	27,915	23,675	-	-	-	-	55	-	4,185
Nov	8	12	27,063	21,104	-	-	-	-	52	-	5,907
Nov	9	18	34,741	25,160	-	-	-	-	12	-	9,569
Nov	10	26	47,744	30,359	15,000	2,555	-	-	25	-	(195)
Nov	11	29	52,494	31,840	10,000	-	-	-	52	-	10,602
Nov	12	31	54,681	30,847	15,000	-	-	-	-	-	8,834
Nov	13	18	45,380	28,668	5,000	-	-	-	44	-	11,668
Nov	14	13	32,527	25,188	5,000	-	-	-	54	-	2,285
Nov	15	8	26,794	19,704	-	-	-	-	52	-	7,038
Nov	16	26	42,837	26,739	5,000	-	-	-	31	-	11,067
Nov	17	33	56,519	31,627	15,000	2,555	-	-	-	-	7,337
Nov	18	40	65,559	34,553	30,000	2,555	-	-	45	-	(1,594)
Nov	19	46	76,409	35,886	30,000	2,555	-	-	54	-	7,914
Nov	20	44	76,417	35,129	30,000	2,555	-	-	46	-	8,687
Nov	21	45	74,830	36,312	30,000	2,555	-	-	-	-	5,963
Nov	22	49	77,783	32,273	30,000	2,555	-	-	13	-	12,942
Nov	23	43	75,804	31,570	32,000	-	-	-	55	-	12,179
Nov	24	28	60,430	31,175	15,000	-	-	-	11	-	14,244
Nov	25	24	52,624	30,107	15,000	2,555	-	-	-	-	4,962
Nov	26	33	55,478	30,510	15,000	2,555	-	-	-	-	7,413
Nov	27	30	50,457	28,054	15,000	2,555	-	-	8	-	4,840
Nov	28	32	54,557	27,910	15,000	2,555	-	-	11	-	9,081
Nov	29	36	56,911	28,307	15,000	2,555	-	-	14	-	11,035
Nov	30	31	57,877	31,200	15,000	2,555	-	-	17	-	9,105
Nov Total		822	1,537,081	862,821	392,000	33,215	-	-	813	-	248,232

Northern Utilities, Inc.
Daily Dispatch Data
2008-2009 Peak Period

Month	Day	Effective Degree Days	Total Received by Granite	End-User Transport	W10 Storage	FS-MA Storage	Tetco Storage	Propane	LNG Boil-Off	LNG Vapor	Pipeline Supplies
Dec	1	27	55,842	34,763	20,000	332	-	-	56	-	691
Dec	2	32	60,212	32,910	15,000	332	-	-	11	-	11,959
Dec	3	31	61,712	32,777	15,000	332	-	-	56	-	13,547
Dec	4	28	57,439	33,026	15,000	332	-	-	12	-	9,069
Dec	5	39	67,277	35,291	20,000	332	-	-	52	-	11,602
Dec	6	35	62,507	31,782	15,000	332	-	-	32	-	15,361
Dec	7	47	76,914	32,599	15,000	332	-	-	48	-	28,935
Dec	8	53	93,497	37,262	23,000	332	-	-	64	-	32,839
Dec	9	24	61,633	30,027	24,000	332	-	-	60	-	7,214
Dec	10	26	50,840	29,588	25,000	332	-	-	26	-	(4,106)
Dec	11	36	64,006	35,529	25,000	2,601	-	-	44	-	832
Dec	12	41	62,556	37,089	25,000	2,601	-	-	49	-	(2,183)
Dec	13	49	80,284	38,560	30,000	2,601	-	-	55	-	9,068
Dec	14	31	65,175	31,813	14,236	332	-	-	-	3,275	15,519
Dec	15	16	45,866	31,092	12,953	332	-	-	70	-	1,419
Dec	16	41	72,051	35,556	18,092	332	-	-	54	-	18,017
Dec	17	46	81,567	36,007	26,515	332	-	-	-	160	18,553
Dec	18	41	74,813	36,304	31,515	332	-	-	-	-	6,662
Dec	19	60	90,557	39,825	25,721	2,532	-	-	6	-	22,473
Dec	20	60	93,327	40,254	33,000	2,532	-	-	15	-	17,526
Dec	21	56	87,759	37,650	33,000	2,532	-	-	-	3,291	11,286
Dec	22	57	93,155	44,645	33,000	2,532	-	-	21	-	12,957
Dec	23	44	80,242	37,531	33,000	2,532	-	-	-	-	7,179
Dec	24	27	54,322	27,139	25,000	332	-	-	56	-	1,795
Dec	25	40	62,387	29,117	30,000	332	-	-	-	-	2,938
Dec	26	34	61,385	27,882	25,000	332	-	-	-	-	8,171
Dec	27	25	50,697	26,059	20,000	332	-	-	-	-	4,306
Dec	28	21	44,823	27,398	20,000	332	-	-	26	-	(2,933)
Dec	29	34	58,763	31,230	15,000	332	-	-	22	-	12,179
Dec	30	44	72,157	32,142	17,500	332	-	-	-	-	22,183
Dec	31	63	91,774	36,438	30,000	2,532	-	-	-	2,222	20,582
Dec Total		1,208	2,135,539	1,049,285	710,532	30,299	-	-	835	8,948	335,640

Northern Utilities, Inc.
Daily Dispatch Data
2008-2009 Peak Period

Month	Day	Effective Degree Days	Total Received by Granite	End-User Transport	W10 Storage	FS-MA Storage	Tetco Storage	Propane	LNG Boil-Off	LNG Vapor	Pipeline Supplies
Jan	1	60	94,559	35,938	33,000	2,532	-	-	48	-	23,041
Jan	2	45	80,359	33,602	33,000	332	-	-	61	-	13,364
Jan	3	48	78,694	35,240	33,000	2,532	-	-	57	-	7,865
Jan	4	40	71,020	33,125	33,000	2,532	-	-	56	-	2,307
Jan	5	38	71,652	35,132	28,000	2,532	-	-	49	-	5,939
Jan	6	38	70,891	37,169	23,000	2,532	-	-	-	-	8,190
Jan	7	44	77,284	36,381	23,000	2,532	-	-	-	-	15,371
Jan	8	45	78,378	37,880	30,000	2,532	-	-	8	-	7,958
Jan	9	53	86,103	39,418	26,000	2,532	-	-	8	-	18,145
Jan	10	47	75,920	34,255	23,000	2,532	-	-	28	-	16,105
Jan	11	52	82,466	36,344	23,000	2,532	-	-	32	-	20,558
Jan	12	52	86,092	39,018	23,000	2,532	-	-	13	-	21,529
Jan	13	39	75,496	36,270	15,000	2,532	-	-	56	-	21,638
Jan	14	60	96,385	46,531	33,000	2,532	-	-	11	-	14,311
Jan	15	66	105,541	47,527	33,000	2,532	-	-	-	625	21,857
Jan	16	62	104,065	47,191	33,000	2,532	-	-	-	5,212	16,130
Jan	17	52	88,679	38,192	23,000	2,532	-	-	-	-	24,955
Jan	18	50	82,142	35,300	23,000	332	-	-	56	-	23,454
Jan	19	45	78,817	38,013	18,000	332	-	-	1	-	22,471
Jan	20	49	82,801	40,612	23,000	332	-	-	1	-	18,856
Jan	21	50	85,215	41,503	28,000	332	-	-	-	-	15,380
Jan	22	41	76,555	37,155	18,000	332	-	-	16	-	21,052
Jan	23	38	69,030	34,783	10,000	332	-	-	-	-	23,915
Jan	24	61	85,159	38,471	33,000	2,532	-	-	-	-	11,156
Jan	25	56	90,079	39,675	33,000	2,532	-	-	18	-	14,854
Jan	26	56	94,390	45,007	33,000	2,532	-	-	21	-	13,830
Jan	27	50	87,252	41,252	27,500	2,532	-	-	12	-	15,956
Jan	28	41	79,038	37,210	22,500	332	-	-	51	-	18,945
Jan	29	45	77,023	37,922	17,500	332	-	-	27	-	21,242
Jan	30	43	72,519	36,525	17,500	332	-	-	31	-	18,131
Jan	31	51	77,826	34,341	17,500	332	-	-	53	-	25,600
Jan Total		1,517	2,561,430	1,186,982	789,500	54,292	-	-	714	5,837	524,105

Northern Utilities, Inc.
Daily Dispatch Data
2008-2009 Peak Period

Month	Day	Effective Degree Days	Total Received by Granite	End-User Transport	W10 Storage	FS-MA Storage	Tetco Storage	Propane	LNG Boil-Off	LNG Vapor	Pipeline Supplies
Feb	1	43	73,911	32,744	23,000	332	-	-	48	-	17,787
Feb	2	32	65,767	33,522	14,000	332	-	-	3	-	17,910
Feb	3	47	82,999	40,282	28,000	2,532	-	-	41	-	12,144
Feb	4	57	92,256	41,755	24,000	2,532	-	-	33	-	23,936
Feb	5	61	100,179	48,484	33,000	2,532	-	-	-	3,209	12,954
Feb	6	53	85,423	36,921	23,000	2,532	-	-	10	-	22,960
Feb	7	30	60,867	29,207	16,000	332	-	-	38	-	15,290
Feb	8	40	66,999	34,121	26,000	332	-	-	46	-	6,500
Feb	9	45	77,632	40,184	16,000	332	-	-	6	-	21,110
Feb	10	35	70,349	35,651	16,000	332	-	-	28	-	18,338
Feb	11	26	53,929	31,566	8,000	332	-	-	41	-	13,990
Feb	12	32	60,008	34,214	16,000	332	-	-	-	557	8,905
Feb	13	48	76,396	37,774	33,000	332	-	-	2	-	5,288
Feb	14	39	63,688	32,261	23,000	332	-	-	5	-	8,090
Feb	15	39	63,951	32,151	23,000	332	-	-	8	-	8,460
Feb	16	41	70,500	36,968	20,000	332	-	-	9	-	13,191
Feb	17	42	74,194	37,858	23,000	332	-	-	11	-	12,993
Feb	18	35	65,412	35,584	15,000	332	-	-	31	-	14,465
Feb	19	39	68,284	35,544	15,000	332	-	-	40	-	17,368
Feb	20	46	75,705	36,886	23,000	332	-	-	31	-	15,456
Feb	21	39	65,996	31,620	20,000	332	-	-	32	-	14,012
Feb	22	37	63,157	33,667	20,000	332	-	-	49	-	9,109
Feb	23	49	80,230	42,804	33,000	393	-	-	38	-	3,995
Feb	24	47	81,412	43,209	33,000	2,532	-	-	32	-	2,639
Feb	25	41	74,562	36,288	23,000	332	-	-	47	-	14,895
Feb	26	32	65,004	33,034	23,000	332	-	-	42	-	8,596
Feb	27	23	46,537	28,916	14,000	332	-	-	47	-	3,242
Feb	28	44	64,783	30,886	23,000	332	-	-	47	-	10,518
Feb Total		1,142	1,990,130	1,004,101	607,000	20,357	-	-	765	3,766	354,141

Northern Utilities, Inc.
Daily Dispatch Data
2008-2009 Peak Period

Month	Day	Effective Degree Days	Total Received by Granite	End-User Transport	W10 Storage	FS-MA Storage	Tetco Storage	Propane	LNG Boil-Off	LNG Vapor	Pipeline Supplies
Mar	1	48	78,524	33,260	33,000	2,555	-	-	47	-	9,662
Mar	2	51	86,471	38,722	33,000	2,555	-	-	46	-	12,148
Mar	3	54	88,690	43,327	33,000	2,555	-	-	-	2,506	7,302
Mar	4	49	84,641	42,895	22,780	2,555	1,143	-	-	2,057	13,211
Mar	5	34	65,947	36,021	22,780	2,555	1,143	-	6	-	3,442
Mar	6	25	53,663	29,530	10,000	2,702	989	-	11	-	10,431
Mar	7	22	39,584	25,834	-	2,555	-	-	29	-	11,166
Mar	8	26	47,042	28,328	4,000	2,555	-	-	37	-	12,122
Mar	9	39	69,291	33,284	10,000	2,555	-	-	35	-	23,417
Mar	10	30	58,752	32,635	10,000	2,555	-	-	41	-	13,521
Mar	11	30	63,750	32,615	17,000	2,555	-	-	38	-	11,542
Mar	12	44	73,579	38,312	22,780	2,555	-	-	42	-	9,890
Mar	13	41	67,599	36,018	15,780	2,555	-	-	46	-	13,200
Mar	14	29	52,436	29,904	10,000	2,555	-	-	46	-	9,931
Mar	15	29	49,413	31,140	10,000	2,555	-	-	44	-	5,674
Mar	16	36	60,243	32,292	10,000	2,555	-	-	44	-	15,352
Mar	17	32	55,582	32,617	5,000	2,555	-	-	48	-	15,362
Mar	18	18	44,125	27,612	-	2,555	-	-	48	-	13,910
Mar	19	29	56,305	33,983	7,500	2,555	-	-	45	-	12,222
Mar	20	38	62,614	34,612	8,000	2,555	1,086	-	45	-	16,316
Mar	21	33	56,113	31,250	7,999	2,555	-	-	49	-	14,260
Mar	22	38	61,190	30,973	7,999	2,555	-	-	48	-	19,615
Mar	23	46	77,761	36,056	10,000	2,555	-	-	46	-	29,104
Mar	24	32	62,220	35,282	27,000	2,555	-	-	42	-	(2,659)
Mar	25	29	55,087	32,737	10,000	2,555	-	-	50	-	9,745
Mar	26	26	49,062	30,996	10,000	2,555	-	-	48	-	5,463
Mar	27	26	46,121	30,044	10,000	2,555	-	-	51	-	3,471
Mar	28	29	46,677	25,343	-	2,555	-	-	51	-	18,728
Mar	29	27	50,876	27,273	7,500	2,555	-	-	51	-	13,497
Mar	30	27	54,973	31,419	10,000	2,555	-	-	49	-	10,950
Mar	31	28	52,813	31,646	5,000	2,555	-	-	43	-	13,569
Mar Total		1,045	1,871,144	1,015,960	390,118	79,352	4,361	-	1,226	4,563	375,564

Northern Utilities, Inc.
Daily Dispatch Data
2008-2009 Peak Period

Month	Day	Effective Degree Days	Total Received by Granite	End-User Transport	W10 Storage	FS-MA Storage	Tetco Storage	Propane	LNG Boil-Off	LNG Vapor	Pipeline Supplies
Apr	1	29	55,834	31,138	12,000	-	-	-	47	-	12,649
Apr	2	22	42,600	27,868	2,500	-	-	-	51	-	12,181
Apr	3	20	42,434	26,378	7,500	-	-	-	51	-	8,505
Apr	4	23	40,657	23,581	7,500	-	-	-	51	-	9,525
Apr	5	21	40,565	24,711	7,500	-	-	-	51	-	8,303
Apr	6	24	47,671	28,804	8,000	2,575	-	-	51	-	8,241
Apr	7	28	51,502	29,745	13,000	2,575	-	-	-	-	6,182
Apr	8	27	55,241	30,994	8,000	2,575	-	-	50	-	13,622
Apr	9	19	42,668	30,046	3,000	-	-	-	49	-	9,573
Apr	10	19	37,335	26,750	3,000	-	-	-	45	-	7,540
Apr	11	30	44,759	26,404	14,000	2,575	-	-	52	-	1,728
Apr	12	33	51,554	26,229	18,000	2,575	-	-	52	-	4,698
Apr	13	24	49,180	29,121	13,000	-	-	-	51	-	7,008
Apr	14	24	46,199	29,804	4,000	-	-	-	47	-	12,348
Apr	15	25	46,123	30,392	-	-	-	-	49	-	15,682
Apr	16	24	44,805	28,416	-	-	-	-	49	-	16,340
Apr	17	9	31,604	23,780	-	-	-	-	51	-	7,773
Apr	18	18	32,776	23,838	-	-	-	-	51	-	8,887
Apr	19	25	38,340	25,501	10,000	2,575	-	-	51	-	213
Apr	20	23	42,864	27,369	8,000	-	-	-	51	-	7,444
Apr	21	17	40,267	26,657	-	-	-	-	52	-	13,558
Apr	22	18	36,280	25,791	-	-	-	-	53	-	10,436
Apr	23	18	38,251	24,518	-	-	-	-	50	-	13,683
Apr	24	11	28,701	17,125	-	-	-	-	52	-	11,524
Apr	25	3	19,901	12,842	-	-	-	-	52	-	7,007
Apr	26	4	22,424	13,545	-	-	-	-	22	-	8,857
Apr	27	15	29,215	17,458	4,000	2,575	-	-	67	-	5,115
Apr	28	1	27,298	19,735	-	-	-	-	61	-	7,502
Apr	29	18	33,162	24,653	2,500	-	-	-	58	-	5,951
Apr	30	10	28,112	22,511	-	-	-	-	57	-	5,544
Apr Total		582	1,188,322	755,704	145,500	18,025	-	-	1,474	-	267,619

Northern Utilities, Inc.
Daily Dispatch Data
2008-2009 Peak Period
Monthly and Seasonal Summary Data

Month	Effective Degree Days	Total Received by Granite	End-User Transport	W10 Storage	FS-MA Storage	Tetco Storage	Propane	LNG Boil-Off	LNG Vapor	Pipeline Supplies
Nov	822	1,537,081	862,821	392,000	33,215	-	-	813	-	248,232
Dec	1,208	2,135,539	1,049,285	710,532	30,299	-	-	835	8,948	335,640
Jan	1,517	2,561,430	1,186,982	789,500	54,292	-	-	714	5,837	524,105
Feb	1,142	1,990,130	1,004,101	607,000	20,357	-	-	765	3,766	354,141
Mar	1,045	1,871,144	1,015,960	390,118	79,352	4,361	-	1,226	4,563	375,564
Apr	582	1,188,322	755,704	145,500	18,025	-	-	1,474	-	267,619
Season	6,316	11,283,646	5,874,853	3,034,650	235,540	4,361	-	5,827	23,114	2,105,301

Attachment NUI-FXW-2

Billed Distribution Deliveries & Meter Counts

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Deliveries and Meter Counts by Rate Class

	Total Division Billed Deliveries (Dth)										
	2009-2010	Compared to 2008-2009					Compared to 2007-2008				
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	509,893	549,450	-39,556	-7.2%	20,238	-59,795	562,377	-52,483	-9.3%	13,191	-65,675
Dec	781,265	792,007	-10,742	-1.4%	6,779	-17,521	776,282	4,983	0.6%	24,015	-19,032
Jan	979,765	990,236	-10,471	-1.1%	6,369	-16,840	1,011,841	-32,076	-3.2%	17,680	-49,756
Feb	949,163	991,088	-41,924	-4.2%	6,365	-48,290	1,049,520	-100,356	-9.6%	18,699	-119,055
Mar	846,205	894,108	-47,903	-5.4%	5,720	-53,623	936,209	-90,004	-9.6%	13,954	-103,959
Apr	657,301	678,954	-21,653	-3.2%	4,351	-26,005	778,257	-120,956	-15.5%	11,279	-132,235
May	432,762	437,655	-4,893	-1.1%	2,820	-7,713	537,641	-104,879	-19.5%	9,253	-114,132
Jun	342,189	317,236	24,952	7.9%	6,037	18,915	388,205	-46,017	-11.9%	10,288	-56,304
Jul	284,559	281,438	3,121	1.1%	1,839	1,282	381,822	-97,263	-25.5%	10,835	-108,098
Aug	270,037	266,995	3,042	1.1%	1,748	1,294	270,911	-874	-0.3%	7,701	-8,575
Sep	310,686	307,587	3,099	1.0%	2,016	1,083	290,395	20,291	7.0%	7,983	12,308
Oct	352,562	349,364	3,199	0.9%	2,292	907	357,596	-5,034	-1.4%	9,823	-14,857
Peak	4,723,592	4,895,842	-172,250	-3.5%	57,371	-229,621	5,114,485	-390,894	-7.6%	101,349	-492,243
Off-Peak	1,992,795	1,960,274	32,521	1.7%	16,852	15,669	2,226,571	-233,775	-10.5%	57,682	-291,458
Annual	6,716,387	6,856,116	-139,729	-2.0%	69,605	-209,334	7,341,056	-624,669	-8.5%	167,800	-792,469

Note 1 Forecast approved by Company on July 14, 2009. Page 2 - 4; Sum of Column 1 of Billed Deliveries table.
Note 2 Actual Data is weather normalized through June 2009. Forecast Data begins July 2009. Pages 2 - 4; Sum of Column 2 of Billed Deliveries table.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Pages 2 - 4; Sum of Column 7 of Billed Deliveries Table. Actual Data provided is weather normalized.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	28,081	27,083	998	3.7%	27,437	644	2.3%	27,083	27,437	-354	-1.3%
Dec	28,113	27,874	239	0.9%	27,269	844	3.1%	27,874	27,269	605	2.2%
Jan	28,101	27,921	180	0.6%	27,618	483	1.7%	27,921	27,618	303	1.1%
Feb	28,140	27,960	180	0.6%	27,647	493	1.8%	27,960	27,647	313	1.1%
Mar	28,093	27,914	179	0.6%	27,680	413	1.5%	27,914	27,680	234	0.8%
Apr	28,042	27,863	179	0.6%	27,641	401	1.4%	27,863	27,641	222	0.8%
May	28,050	27,870	180	0.6%	27,575	475	1.7%	27,870	27,575	295	1.1%
Jun	28,282	27,754	528	1.9%	27,552	730	2.7%	27,754	27,552	202	0.7%
Jul	28,272	28,089	184	0.7%	27,492	780	2.8%	28,089	27,492	597	2.2%
Aug	28,223	28,040	184	0.7%	27,443	780	2.8%	28,040	27,443	597	2.2%
Sep	28,189	28,006	184	0.7%	27,435	754	2.7%	28,006	27,435	571	2.1%
Oct	28,170	27,987	184	0.7%	27,417	753	2.7%	27,987	27,417	570	2.1%
Peak	28,095	27,769	325	1.2%	27,549	546	2.0%	27,769	27,549	221	0.8%
Off-Peak	28,198	27,957	240	0.9%	27,486	712	2.6%	27,957	27,486	472	1.7%
Annual	28,146	27,863	283	1.0%	27,517	629	2.3%	27,863	27,517	346	1.3%

Note 1 Forecast approved by Company on July 14, 2009. Page 2 - 4; Sum of Column 1 of Meter Counts table.
Note 2 Actual Data through June 2009. Forecast Data begins July 2009. Page 2 - 4; Sum of Column 2 of Meter Counts table.
Note 3 Actual Data. Page 2 - 4; Sum of Column 5 of Meter Counts table.

	Total Division Use Per Meter										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	18.16	20.29	-2.13	-10.5%	20.50	-2.34	-11.4%	20	20	0	-1.0%
Dec	27.79	28.41	-0.62	-2.2%	28.47	-0.68	-2.4%	28	28	0	-0.2%
Jan	34.87	35.47	-0.60	-1.7%	36.64	-1.77	-4.8%	35	37	-1	-3.2%
Feb	33.73	35.45	-1.72	-4.8%	37.96	-4.23	-11.1%	35	38	-3	-6.6%
Mar	30.12	32.03	-1.91	-6.0%	33.82	-3.70	-10.9%	32	34	-2	-5.3%
Apr	23.44	24.37	-0.93	-3.8%	28.16	-4.72	-16.7%	24	28	-4	-13.5%
May	15.43	15.70	-0.27	-1.8%	19.50	-4.07	-20.9%	16	19	-4	-19.5%
Jun	12.10	11.43	0.67	5.9%	14.09	-1.99	-14.1%	11	14	-3	-18.9%
Jul	10.06	10.02	0.05	0.5%	13.89	-3.82	-27.5%	10	14	-4	-27.9%
Aug	9.57	9.52	0.05	0.5%	9.87	-0.30	-3.1%	10	10	0	-3.5%
Sep	11.02	10.98	0.04	0.3%	10.58	0.44	4.1%	11	11	0	3.8%
Oct	12.52	12.48	0.03	0.3%	13.04	-0.53	-4.0%	12	13	-1	-4.3%
Peak	168.13	176.30	-8.17	-4.6%	185.65	-17.43	-9.4%	176	186	-2	-0.9%
Off-Peak	70.67	70.12	0.56	0.8%	81.01	-10.28	-12.7%	70	81	-2	-2.2%
Annual	238.63	246.06	-7.44	-3.0%	266.78	-27.71	-10.4%	246	267	-2	-0.6%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Deliveries and Meter Counts by Rate Class

	Residential Non-Heat Billed Deliveries (Dth)										
	2009-2010	Compared to 2008-2009					Compared to 2007-2008				
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	2,452	2,542	-89	-3.5%	-61	-28	2,292	161	7.0%	-173	334
Dec	3,047	3,151	-104	-3.3%	-115	11	3,014	34	1.1%	-170	204
Jan	4,063	4,430	-367	-8.3%	-162	-205	3,670	394	10.7%	-245	638
Feb	3,775	3,922	-147	-3.7%	-144	-3	3,346	430	12.8%	-214	644
Mar	3,326	3,543	-217	-6.1%	-131	-86	3,057	269	8.8%	-215	484
Apr	3,025	3,029	-4	-0.1%	-110	106	2,681	344	12.8%	-160	504
May	2,456	2,562	-106	-4.1%	-92	-14	2,343	113	4.8%	-137	250
Jun	2,046	2,457	-412	-16.8%	-85	-327	2,185	-139	-6.4%	-152	13
Jul	1,748	1,811	-63	-3.5%	-66	2	1,874	-126	-6.7%	-131	5
Aug	1,646	1,706	-59	-3.5%	-62	3	1,736	-90	-5.2%	-122	32
Sep	1,688	1,751	-63	-3.6%	-65	2	1,814	-126	-6.9%	-129	3
Oct	1,728	1,793	-65	-3.6%	-67	2	1,858	-130	-7.0%	-134	4
Peak	19,689	20,618	-928	-4.5%	-712	-216	18,059	1,631	9.0%	-1,184	2,815
Off-Peak	11,312	12,080	-769	-6.4%	-437	-331	11,811	-499	-4.2%	-810	311
Annual	31,001	32,698	-1,697	-5.2%	-1,157	-540	29,870	1,132	3.8%	-2,003	3,135

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data provided is weather normalized through June 2009. Forecast Data begins July 2009. Forecast approved by Company on July 14, 2009.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual Data provided is weather normalized.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Residential Non-Heat Meter Counts										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	1,592	1,631	-39	-2.4%	1,722	-130	-7.6%	1,631	1,722	-91	-5.3%
Dec	1,593	1,653	-60	-3.6%	1,688	-95	-5.6%	1,653	1,688	-35	-2.1%
Jan	1,583	1,643	-60	-3.7%	1,696	-113	-6.7%	1,643	1,696	-53	-3.1%
Feb	1,580	1,640	-60	-3.7%	1,688	-108	-6.4%	1,640	1,688	-48	-2.8%
Mar	1,573	1,633	-60	-3.7%	1,692	-119	-7.0%	1,633	1,692	-59	-3.5%
Apr	1,593	1,653	-60	-3.6%	1,694	-101	-6.0%	1,653	1,694	-41	-2.4%
May	1,614	1,674	-60	-3.6%	1,714	-100	-5.8%	1,674	1,714	-40	-2.3%
Jun	1,610	1,667	-57	-3.4%	1,730	-120	-7.0%	1,667	1,730	-63	-3.6%
Jul	1,600	1,660	-60	-3.6%	1,720	-120	-7.0%	1,660	1,720	-60	-3.5%
Aug	1,596	1,656	-60	-3.6%	1,716	-120	-7.0%	1,656	1,716	-60	-3.5%
Sep	1,574	1,634	-60	-3.7%	1,694	-120	-7.1%	1,634	1,694	-60	-3.6%
Oct	1,550	1,610	-60	-3.7%	1,670	-120	-7.2%	1,610	1,670	-60	-3.6%
Peak	1,585	1,642	-57	-3.5%	1,697	-111	-6.6%	1,642	1,697	-55	-3.2%
Off-Peak	1,590	1,650	-60	-3.6%	1,707	-117	-6.9%	1,650	1,707	-57	-3.4%
Annual	1,588	1,646	-58	-3.5%	1,702	-114	-6.7%	1,646	1,702	-56	-3.3%

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data through June 2009. Forecast Data begins July 2009. Forecast approved by Company on July 14, 2009.
Note 3 Actual Data.

	Residential Non-Heat Use Per Meter										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	1.54	1.56	-0.02	-1.1%	1.33	0.21	15.8%	2	1	0	17.1%
Dec	1.91	1.91	0.01	0.4%	1.79	0.13	7.2%	2	2	0	6.8%
Jan	2.57	2.70	-0.13	-4.8%	2.16	0.40	18.6%	3	2	1	24.6%
Feb	2.39	2.39	0.00	-0.1%	1.98	0.41	20.6%	2	2	0	20.7%
Mar	2.11	2.17	-0.05	-2.5%	1.81	0.31	17.0%	2	2	0	20.1%
Apr	1.90	1.83	0.07	3.6%	1.58	0.32	20.0%	2	2	0	15.8%
May	1.52	1.53	-0.01	-0.6%	1.37	0.15	11.3%	2	1	0	11.9%
Jun	1.27	1.47	-0.20	-13.8%	1.26	0.01	0.6%	1	1	0	16.7%
Jul	1.09	1.09	0.00	0.1%	1.09	0.00	0.3%	1	1	0	0.1%
Aug	1.03	1.03	0.00	0.2%	1.01	0.02	2.0%	1	1	0	1.8%
Sep	1.07	1.07	0.00	0.1%	1.07	0.00	0.2%	1	1	0	0.1%
Oct	1.12	1.11	0.00	0.1%	1.11	0.00	0.2%	1	1	0	0.1%
Peak	12.42	12.56	-0.14	-1.1%	10.64	1.77	16.7%	13	11	0	3.0%
Off-Peak	7.11	7.32	-0.21	-2.8%	6.92	0.19	2.7%	7	7	0	1.0%
Annual	19.52	19.86	-0.34	-1.7%	17.55	1.96	11.2%	20	18	0	1.1%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Deliveries and Meter Counts by Rate Class

	Residential Heat Billed Deliveries (Dth)										
	2009-2010	Compared to 2008-2009					Compared to 2007-2008				
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	109,306	106,140	3,166	3.0%	3,885	-719	100,621	8,685	8.6%	3,064	5,621
Dec	185,343	181,356	3,987	2.2%	2,102	1,885	190,962	-5,619	-2.9%	7,498	-13,117
Jan	274,293	285,999	-11,706	-4.1%	2,735	-14,441	290,916	-16,623	-5.7%	7,139	-23,762
Feb	286,828	284,338	2,490	0.9%	2,714	-224	277,913	8,916	3.2%	6,937	1,979
Mar	239,185	242,924	-3,739	-1.5%	2,318	-6,057	242,611	-3,426	-1.4%	5,877	-9,303
Apr	177,631	169,833	7,798	4.6%	1,627	6,171	183,389	-5,758	-3.1%	4,049	-9,807
May	107,209	106,345	865	0.8%	1,018	-154	102,985	4,224	4.1%	2,687	1,537
Jun	63,043	37,302	25,741	69.0%	853	24,888	59,578	3,465	5.8%	2,132	1,332
Jul	39,947	39,588	359	0.9%	376	-17	37,086	2,862	7.7%	1,329	1,533
Aug	34,690	34,380	310	0.9%	327	-17	31,431	3,259	10.4%	1,128	2,131
Sep	40,548	40,187	361	0.9%	382	-21	37,534	3,014	8.0%	1,344	1,669
Oct	47,867	47,440	427	0.9%	451	-23	44,954	2,913	6.5%	1,610	1,304
Peak	1,272,586	1,270,590	1,996	0.2%	18,169	-16,173	1,286,411	-13,825	-1.1%	35,444	-49,269
Off-Peak	333,305	305,241	28,063	9.2%	3,579	24,485	313,568	19,737	6.3%	10,726	9,011
Annual	1,605,891	1,575,832	30,059	1.9%	20,497	9,562	1,599,979	5,912	0.4%	49,401	-43,490

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data provided is weather normalized through June 2009. Forecast Data begins July 2009. Forecast approved by Company on July 14, 2009.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual Data provided is weather normalized.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Residential Heat Meter Counts										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	20,136	19,425	711	3.7%	19,541	595	3.0%	19,425	19,541	-116	-0.6%
Dec	20,169	19,938	231	1.2%	19,407	762	3.9%	19,938	19,407	531	2.7%
Jan	20,168	19,977	191	1.0%	19,685	483	2.5%	19,977	19,685	292	1.5%
Feb	20,206	20,015	191	1.0%	19,714	492	2.5%	20,015	19,714	301	1.5%
Mar	20,213	20,022	191	1.0%	19,735	478	2.4%	20,022	19,735	287	1.5%
Apr	20,138	19,947	191	1.0%	19,703	435	2.2%	19,947	19,703	244	1.2%
May	20,140	19,949	191	1.0%	19,628	512	2.6%	19,949	19,628	321	1.6%
Jun	20,318	19,864	454	2.3%	19,616	702	3.6%	19,864	19,616	248	1.3%
Jul	20,298	20,107	191	1.0%	19,596	702	3.6%	20,107	19,596	511	2.6%
Aug	20,257	20,066	191	1.0%	19,555	702	3.6%	20,066	19,555	511	2.6%
Sep	20,303	20,112	191	0.9%	19,601	702	3.6%	20,112	19,601	511	2.6%
Oct	20,307	20,116	191	0.9%	19,605	702	3.6%	20,116	19,605	511	2.6%
Peak	20,172	19,887	284	1.4%	19,631	541	2.8%	19,887	19,631	257	1.3%
Off-Peak	20,271	20,036	235	1.2%	19,600	670	3.4%	20,036	19,600	436	2.2%
Annual	20,221	19,962	260	1.3%	19,616	606	3.1%	19,962	19,616	346	1.8%

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data through June 2009. Forecast Data begins July 2009. Forecast approved by Company on July 14, 2009.
Note 3 Actual Data.

	Residential Heat Use Per Meter										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	5.43	5.46	-0.04	-0.7%	5.15	0.28	5.4%	5	5	0	6.1%
Dec	9.19	9.10	0.09	1.0%	9.84	-0.65	-6.6%	9	10	-1	-7.6%
Jan	13.60	14.32	-0.72	-5.0%	14.78	-1.18	-8.0%	14	15	0	-3.1%
Feb	14.20	14.21	-0.01	-0.1%	14.10	0.10	0.7%	14	14	0	0.8%
Mar	11.83	12.13	-0.30	-2.5%	12.29	-0.46	-3.7%	12	12	0	-1.3%
Apr	8.82	8.51	0.31	3.6%	9.31	-0.49	-5.2%	9	9	-1	-8.5%
May	5.32	5.33	-0.01	-0.1%	5.25	0.08	1.5%	5	5	0	1.6%
Jun	3.10	1.88	1.22	65.2%	3.04	0.07	2.2%	2	3	-1	-38.2%
Jul	1.97	1.97	0.00	0.0%	1.89	0.08	4.0%	2	2	0	4.0%
Aug	1.71	1.71	0.00	0.0%	1.61	0.11	6.5%	2	2	0	6.6%
Sep	2.00	2.00	0.00	-0.1%	1.91	0.08	4.3%	2	2	0	4.3%
Oct	2.36	2.36	0.00	0.0%	2.29	0.06	2.8%	2	2	0	2.8%
Peak	63.09	63.89	-0.80	-1.3%	65.53	-2.40	-3.7%	64	66	0	-0.4%
Off-Peak	16.44	15.23	1.21	7.9%	16.00	0.47	2.9%	15	16	0	-0.8%
Annual	79.42	78.94	0.47	0.6%	81.57	-1.93	-2.4%	79	82	0	-0.3%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Deliveries and Meter Counts by Rate Class

	Total Division C&I Billed Deliveries (Dth)										
	2009-2010	Compared to 2008-2009					Compared to 2007-2008				
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	Actual	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	398,135	440,768	-42,633	-9.7%	23,822	-66,455	459,464	-61,329	-13.3%	13,302	-74,631
Dec	592,874	607,499	-14,625	-2.4%	6,550	-21,175	582,306	10,568	1.8%	16,669	-6,102
Jan	701,409	699,807	1,602	0.2%	5,413	-3,811	717,256	-15,847	-2.2%	12,965	-28,812
Feb	658,559	702,827	-44,268	-6.3%	5,433	-49,701	768,261	-109,702	-14.3%	13,377	-123,079
Mar	603,693	647,641	-43,947	-6.8%	4,940	-48,887	690,540	-86,847	-12.6%	5,935	-92,782
Apr	476,645	506,092	-29,447	-5.8%	3,858	-33,304	592,188	-115,543	-19.5%	6,330	-121,872
May	323,097	328,748	-5,651	-1.7%	2,565	-8,216	432,312	-109,215	-25.3%	4,352	-113,567
Jun	277,100	277,477	-377	-0.1%	5,863	-6,239	326,443	-49,342	-15.1%	7,810	-57,153
Jul	242,864	240,039	2,825	1.2%	2,003	823	342,862	-99,998	-29.2%	11,019	-111,017
Aug	233,701	230,909	2,791	1.2%	1,928	864	237,744	-4,043	-1.7%	7,645	-11,689
Sep	268,450	265,649	2,801	1.1%	2,238	563	251,047	17,403	6.9%	7,052	10,351
Oct	302,967	300,131	2,836	0.9%	2,528	308	310,785	-7,817	-2.5%	8,677	-16,494
Peak	3,431,316	3,604,634	-173,317	-4.8%	56,464	-229,781	3,810,016	-378,699	-9.9%	71,189	-449,888
Off-Peak	1,648,179	1,642,952	5,226	0.3%	17,079	-11,853	1,901,192	-253,013	-13.3%	48,833	-301,847
Annual	5,079,495	5,247,586	-168,091	-3.2%	68,340	-236,431	5,711,208	-631,712	-11.1%	126,634	-758,347

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data provided is weather normalized through June 2009. Forecast Data begins July 2009. Forecast approved by Company on July 14, 2009.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual Data provided is weather normalized.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division C&I Meter Counts										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	6,353	6,027	326	5.4%	6,174	179	2.9%	6,027	6,174	-147	-2.4%
Dec	6,351	6,283	68	1.1%	6,174	177	2.9%	6,283	6,174	109	1.8%
Jan	6,350	6,301	49	0.8%	6,237	113	1.8%	6,301	6,237	64	1.0%
Feb	6,354	6,305	49	0.8%	6,245	109	1.7%	6,305	6,245	60	1.0%
Mar	6,307	6,259	48	0.8%	6,253	54	0.9%	6,259	6,253	6	0.1%
Apr	6,311	6,263	48	0.8%	6,244	67	1.1%	6,263	6,244	19	0.3%
May	6,296	6,247	49	0.8%	6,233	63	1.0%	6,247	6,233	14	0.2%
Jun	6,354	6,223	131	2.1%	6,206	148	2.4%	6,223	6,206	17	0.3%
Jul	6,374	6,322	53	0.8%	6,176	198	3.2%	6,322	6,176	146	2.4%
Aug	6,370	6,318	53	0.8%	6,172	198	3.2%	6,318	6,172	146	2.4%
Sep	6,312	6,260	53	0.8%	6,140	172	2.8%	6,260	6,140	120	2.0%
Oct	6,313	6,261	53	0.8%	6,142	171	2.8%	6,261	6,142	119	1.9%
Peak	6,337	6,240	98	1.6%	6,221	116	1.9%	6,240	6,221	19	0.3%
Off-Peak	6,337	6,272	65	1.0%	6,178	159	2.6%	6,272	6,178	93	1.5%
Annual	6,337	6,256	81	1.3%	6,200	137	2.2%	6,256	6,200	56	0.9%

Note 1 Forecast approved by Company on July 14, 2009.
Note 2 Actual Data through June 2009. Forecast Data begins July 2009. Forecast approved by Company on July 14, 2009.
Note 3 Actual Data.

	Total Division C&I Use Per Meter										
	2009-2010	Compared to 2008-2009			Compared to 2007-2008			2008-2009 Compared to 2007-2008			
	Forecast	8 Actual 4 Forecast	Change	Percent Change	Actual	Change	Percent Change	8 Actual 4 Forecast	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	Column 2	Column 5	(8-9)	(10/9)
Nov	62.67	73.13	-10.46	-14.3%	74.42	-11.75	-15.8%	73	74	-1	-1.7%
Dec	93.36	96.69	-3.33	-3.4%	94.32	-0.96	-1.0%	97	94	2	2.5%
Jan	110.46	111.06	-0.60	-0.5%	115.00	-4.54	-3.9%	111	115	-4	-3.4%
Feb	103.65	111.47	-7.82	-7.0%	123.02	-19.37	-15.7%	111	123	-12	-9.4%
Mar	95.72	103.47	-7.75	-7.5%	110.43	-14.71	-13.3%	103	110	-7	-6.3%
Apr	75.53	80.81	-5.28	-6.5%	94.84	-19.31	-20.4%	81	95	-14	-14.8%
May	51.32	52.62	-1.31	-2.5%	69.36	-18.04	-26.0%	53	69	-17	-24.1%
Jun	43.61	44.59	-0.98	-2.2%	52.60	-8.99	-17.1%	45	53	-8	-15.2%
Jul	38.10	37.97	0.13	0.3%	55.52	-17.42	-31.4%	38	56	-18	-31.6%
Aug	36.68	36.55	0.14	0.4%	38.52	-1.83	-4.8%	37	39	-2	-5.1%
Sep	42.53	42.44	0.09	0.2%	40.89	1.64	4.0%	42	41	2	3.8%
Oct	47.99	47.94	0.05	0.1%	50.60	-2.61	-5.2%	48	51	-3	-5.3%
Peak	541.44	577.70	-36.26	-6.3%	612.43	-70.64	-11.5%	578	612	-6	-1.0%
Off-Peak	260.09	261.96	-1.87	-0.7%	307.73	-47.26	-15.4%	262	308	-8	-2.5%
Annual	801.54	838.85	-37.31	-4.4%	921.21	-117.90	-12.8%	839	921	-7	-0.7%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Attachment NUI-FXW-3

Sales Service Deliveries & City Gate Receipts

Northern Utilities, Inc.

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Sales Service Deliveries (Dth)
(Total Forecast Deliveries times Sales Service Percentage)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-09	2,452	109,306	46,232	12,608	53,723	24,230	8,138	3,066	0	259,755
Dec-09	3,047	185,343	104,271	15,636	97,135	29,843	12,347	3,706	0	451,329
Jan-10	4,063	274,293	165,647	18,794	123,316	33,549	8,217	3,946	0	631,824
Feb-10	3,775	286,828	158,040	17,112	118,398	30,378	7,622	3,538	0	625,692
Mar-10	3,326	239,185	126,959	16,654	101,200	26,669	8,113	3,364	0	525,469
Apr-10	3,025	177,631	86,113	13,207	73,887	28,274	6,104	2,711	0	390,952
May-10	2,456	107,209	41,697	14,400	41,600	20,281	2,792	2,249	0	232,685
Jun-10	2,046	63,043	22,795	14,237	29,706	20,996	1,388	2,299	0	156,509
Jul-10	1,748	39,947	13,653	13,402	15,482	21,472	1,130	2,232	0	109,067
Aug-10	1,646	34,690	11,763	13,585	12,437	19,256	1,158	2,228	0	96,763
Sep-10	1,688	40,548	14,275	13,924	17,890	20,968	4,916	2,337	0	116,545
Oct-10	1,728	47,867	18,873	12,034	26,470	19,945	6,545	2,830	0	136,291
Peak	19,689	1,272,586	687,262	94,010	567,659	172,943	50,540	20,331	0	2,885,021
Off-Peak	11,312	333,305	123,056	81,583	143,584	122,918	17,929	14,174	0	847,861
Annual	31,001	1,605,891	810,318	175,593	711,243	295,861	68,469	34,505	0	3,732,881
	100%	100%	88%	74%	65%	68%	15%	4%	0%	61%
	100%	100%	86%	88%	69%	69%	15%	4%	0%	43%

Total Forecast Deliveries (Dth)
(Company Approved Deliveries Forecast as of July 14, 2009)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-09	2,452	109,306	52,628	17,014	82,993	35,769	52,991	75,649	81,091	509,893
Dec-09	3,047	185,343	118,696	21,100	150,056	44,056	80,401	91,450	87,114	781,265
Jan-10	4,063	274,293	188,563	25,362	190,501	49,526	53,506	97,383	96,569	979,765
Feb-10	3,775	286,828	179,903	23,093	182,904	44,845	49,634	87,292	90,888	949,163
Mar-10	3,326	239,185	144,523	22,474	156,335	39,370	52,828	83,020	105,144	846,205
Apr-10	3,025	177,631	98,026	17,822	114,142	41,740	39,746	66,898	98,271	657,301
May-10	2,456	107,209	48,502	16,317	60,457	29,238	18,182	54,536	95,865	432,762
Jun-10	2,046	63,043	26,515	16,132	43,172	30,269	9,038	55,749	96,226	342,189
Jul-10	1,748	39,947	15,881	15,186	22,500	30,955	7,361	54,142	96,840	284,559
Aug-10	1,646	34,690	13,682	15,393	18,074	27,761	7,537	54,042	97,211	270,037
Sep-10	1,688	40,548	16,605	15,777	25,999	30,228	32,014	56,676	91,152	310,686
Oct-10	1,728	47,867	21,953	13,636	38,468	28,753	42,617	68,623	88,916	352,562
Peak	19,689	1,272,586	782,339	126,866	876,930	255,307	329,105	501,692	559,077	4,723,592
Off-Peak	11,312	333,305	143,139	92,440	208,670	177,203	116,750	343,768	566,209	1,992,795
Annual	31,001	1,605,891	925,478	219,307	1,085,600	432,510	445,855	845,460	1,125,286	6,716,387

Sales Service Percentage
(Company Approved Forecast as of)

	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-09	100.0%	100.0%	87.8%	74.1%	64.7%	67.7%	15.4%	4.1%	0.0%	51%
Dec-09	100.0%	100.0%	87.8%	74.1%	64.7%	67.7%	15.4%	4.1%	0.0%	58%
Jan-10	100.0%	100.0%	87.8%	74.1%	64.7%	67.7%	15.4%	4.1%	0.0%	64%
Feb-10	100.0%	100.0%	87.8%	74.1%	64.7%	67.7%	15.4%	4.1%	0.0%	66%
Mar-10	100.0%	100.0%	87.8%	74.1%	64.7%	67.7%	15.4%	4.1%	0.0%	62%
Apr-10	100.0%	100.0%	87.8%	74.1%	64.7%	67.7%	15.4%	4.1%	0.0%	59%
May-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	54%
Jun-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	46%
Jul-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	38%
Aug-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	36%
Sep-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	38%
Oct-10	100.0%	100.0%	86.0%	88.3%	68.8%	69.4%	15.4%	4.1%	0.0%	39%

Northern Utilities, Inc.
New Hampshire Division
Estimation of Northern City-Gate Receipts Required to Meet Sales Service Deliveries Forecast

	Total Deliveries (Dth)	Estimated Company Use Factor	Estimated Company Use (Dth)	Sales Service Deliveries (Dth)	Sales Service plus Company Use (Dth)	Estimated Receipts to Deliveries Ratio	Estimated Division City-Gate Receipts (Dth)
Nov-09	509,893	0.08%	392	259,755	260,147	1.06	274,729
Dec-09	781,265	0.13%	1,009	451,329	452,337	1.05	473,054
Jan-10	979,765	0.03%	299	631,824	632,124	0.99	623,823
Feb-10	949,163	0.03%	259	625,692	625,951	1.04	652,772
Mar-10	846,205	0.04%	305	525,469	525,774	0.97	510,088
Apr-10	657,301	0.04%	234	390,952	391,186	0.90	351,860
May-10	432,762	0.02%	101	232,685	232,786	1.00	232,872
Jun-10	342,189	0.11%	383	156,509	156,892	1.06	166,077
Jul-10	284,559	0.06%	172	109,067	109,239	0.96	105,222
Aug-10	270,037	0.11%	300	96,763	97,063	1.06	103,049
Sep-10	310,686	0.12%	371	116,545	116,916	0.93	108,369
Oct-10	352,562	0.07%	234	136,291	136,525	1.04	142,055
Peak	4,723,592	0.1%	2,499	2,885,021	2,887,519	1.000	2,886,327
Off-Peak	1,992,795	0.2%	1,561	847,861	849,421	1.010	857,644
Annual	6,716,387	0.1%	4,059	3,732,881	3,736,940	1.002	3,743,971

Attachment NUI-FXW-4

Demand Costs

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.

Pipeline Contract Demand Cost Estimates

November 1, 2009 through October 31, 2010

Pipeline	Contract ID	Rate	Negotiated Rate	Contract Ends	MDQ	Dth / GJ	Receipt Zone	Delivery Zone	Demand Rate ($/MDQ)	Currency	Months Per Year	Annual Demand
Algonquin	93200F	AFT-1 (AFT-2)	No[1]	10/31/2012	4,211	Dth	Mendon, MA	Brockton, MA	$ 6.1138	USD	12	$ 308,943
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes[1]	10/31/2012	286	Dth	Centerville, NJ	Taunton, MA	$ 5.9771	USD	12	$ 20,513
Algonquin	93201A1C	AFT-1 (F-2/F-3)	Yes[1]	10/31/2012	965	Dth	Lambertville, NJ	Taunton, MA	$ 5.9771	USD	12	$ 69,215
Granite	08-003-FT-NN	FT-NN	Yes[2]	10/31/2009	100,000	Dth	See Note 3.	See Note 3.	$ 1.6666	USD	12	$ 1,999,920
Iroquois	R181001	RTS-1	No	10/31/2013	6,569	Dth	Zone 1	Zone 1	$ 6.5971	USD	12	$ 520,036
PNGTS	1997-003	FT	No	3/31/2019	1,100	Dth	Pittsburgh	Westbrook	$ 27.4017	USD	12	$ 361,702
PNGTS	1997-004	FT	Yes[3]	3/31/2019	15,100	Dth	Pittsburgh	Westbrook	$ 52.0632	USD	5	$ 3,930,772
PNGTS	1997-004	FT	Yes[3]	3/31/2019	4,900	Dth	Pittsburgh	Eliot	$ 52.0632	USD	5	$ 1,275,548
PNGTS	1997-004	FT	Yes[3]	3/31/2019	13,000	Dth	Pittsburgh	Newington	$ 52.0632	USD	5	$ 3,384,108
Tennessee	5083	FT-A	No	10/31/2013	4,605	Dth	Zone 0	Zone 6	$ 16.5900	USD	12	$ 916,763
Tennessee	5083	FT-A	No[5]	10/31/2013	8,550	Dth	Zone L	Zone 6	$ 15.1500	USD	12	$ 1,554,390
Tennessee	5265	FT-A	No	10/31/2013	2,653	Dth	Zone 4	Zone 6	$ 5.8900	USD	12	$ 187,514
Tennessee	5292	FT-A	No	3/31/2015	1,406	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 83,179
Tennessee	31861	NET	No	10/31/2012	1,382	Dth	3	3	$ 5.0700	USD	12	$ 84,081
Tennessee	31861	NET[6]	No	10/31/2012	844	Dth	3	4	$ 10.6100	USD	12	$ 107,458
Tennessee	39735	FT-A	No	3/31/2015	929	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 54,960
Tennessee	41099	FT-A	No	10/31/2012	4,267	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 252,436
Tennessee	46314	FT-A	No	2/13/2012	950	Dth	Zone 5	Zone 6	$ 4.9300	USD	12	$ 56,202
Texas Eastern	800384	FT-1	Yes[1]	10/31/2009	965	Dth	M3	M3	$ 5.7300	USD	12	$ 66,353
Texas Eastern	800436	CDS	No[1]	10/31/2012	64	Dth	M3	M3	$ 5.2930	USD	12	$ 4,065
Texas Eastern	800464	CDS	No[1]	10/31/2012	33	Dth	ELA	M1	$ 2.3750	USD	12	$ 941
Texas Eastern	800464	CDS	No[1]	10/31/2012	9	Dth	ETX	M1	$ 2.1890	USD	12	$ 236
Texas Eastern	800464	CDS	No[1]	10/31/2012	16	Dth	STX	M1	$ 6.8040	USD	12	$ 1,306
Texas Eastern	800464	CDS	No[1]	10/31/2012	18	Dth	WLA	M1	$ 2.8250	USD	12	$ 610
Texas Eastern	800464	CDS	No[1]	10/31/2012	59	Dth	M1	M3	$ 11.0360	USD	12	$ 7,813
TransCanada	29594	FT	No[8]	10/31/2016	6,264	GJ	Dawn	Iroquois	$ 8.2913	CAD	12	$ 573,068
TransCanada	29833	FT	No[9]	10/31/2010	1,196	GJ	Empress	E. Hereford	$ 38.2391	CAD	12	$ 504,628
TransCanada	33322	FT	No[10]	3/31/2018	35,872	GJ	Dawn	E. Hereford	$ 13.3229	CAD	12	$ 5,273,355
Vector	CRL-NUI-0725	FT	Yes	3/31/2018	17,172	Dth	Alliance	Dawn	$ 7.6042	USD	12	$ 1,566,952
Vector	CRL-NUI-0727	FT	Yes	3/31/2018	17,086	Dth	W-10	Dawn	$ 4.5625	USD	5	$ 389,774
Vector	FT-1-NUI-0122	FT	Yes	3/31/2016	6,070	Dth	Alliance	St. Clair	$ 8.0908	USD	12	$ 589,334
Vector	FT-1-NUI-C0122	FT	Yes	3/31/2016	6,404	GJ	St. Clair	Dawn	$ 0.4623	CAD	12	$ 32,667

Total Annual Demand Costs $ 24,178,843

Exchange Rate (CAD/USD) = 0.9195

1. Capacity released. Please refer to the Capacity Release Estimates worksheet for details.
3. Granite only has one zone
3. Rate = 1.9 times the recourse reservation rate
5. The demand rate applied for Zone L to Zone 6 transportation capacity Zone 1 to Zone 6 demand rate.
6. The rate is the Segment 3 demand rate of $5.07 per Dth plus the Segment 4 demand rate of $5.54 per Dth.
7. Rate is expressed in the tariff sheet as as a Delivery Zone of AAB ("Access Area Boundary"). The AAB is the border between the Access Areas (ETX, ELA, WLA, and STX) and the M1 Zone.
8. Rate is the Delivery Pressure Toll for deliveries into Iroquois of $CAD 0.56297 plus the FT Toll for Union Dawn to Iroquois of $CAD 7.72830.
9. Rate is the Delivery Pressure Toll for deliveries into E. Hereford of $CAD 1.41498 plus the FT Toll for Empress to E. Hereford of $CAD 36.82407.
10. Rate is the Delivery Pressure Toll for deliveries into E. Hereford of $CAD 1.41498 plus the FT Toll for Union Dawn to E. Hereford of $CAD 11.90791.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2009 through October 31, 2010

Pipeline	Contract ID	MDQ	Dth / GJ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Pipeline %	Storage %	Peaking %	Annual Demand	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost
Algonquin	93200F	4,211	Dth	4,211			100%	0%	0%	$ 308,943	$ 308,943	$ -	$ -
Algonquin	93201A1C	286	Dth	286			100%	0%	0%	$ 20,513	$ 20,513	$ -	$ -
Algonquin	93201A1C	965	Dth	880	85		91%	9%	0%	$ 69,215	$ 63,118	$ 6,097	$ -
Granite	08-003-FT-NN	100,000	Dth	23,896	35,475	40,629	24%	35%	41%	$ 1,999,920	$ 477,901	$ 709,472	$ 812,547
Iroquois	R181001	6,569	Dth	6,569			100%	0%	0%	$ 520,036	$ 520,036	$ -	$ -
PNGTS	1997-003	1,100	Dth	1,100			100%	0%	0%	$ 361,702	$ 361,702	$ -	$ -
PNGTS	1997-004	15,100	Dth		15,100		0%	100%	0%	$ 3,930,772	$ -	$ 3,930,772	$ -
PNGTS	1997-004	4,900	Dth		4,900		0%	100%	0%	$ 1,275,548	$ -	$ 1,275,548	$ -
PNGTS	1997-004	13,000	Dth		13,000		0%	100%	0%	$ 3,384,108	$ -	$ 3,384,108	$ -
Tennessee	5083	4,605	Dth	4,605			100%	0%	0%	$ 916,763	$ 916,763	$ -	$ -
Tennessee	5083	8,550	Dth	8,550			100%	0%	0%	$ 1,554,390	$1,554,390	$ -	$ -
Tennessee	5265	2,653	Dth		2,653		0%	100%	0%	$ 187,514	$ -	$ 187,514	$ -
Tennessee	5292	1,406	Dth	1,406	-		100%	0%	0%	$ 83,179	$ 83,179	$ -	$ -
Tennessee	31861	1,382	Dth	1,382			100%	0%	0%	$ 84,081	$ 84,081	$ -	$ -
Tennessee	31861	844	Dth	844			100%	0%	0%	$ 107,458	$ 107,458	$ -	$ -
Tennessee	39735	929	Dth	929	-		100%	0%	0%	$ 54,960	$ 54,960	$ -	$ -
Tennessee	41099	4,267	Dth	4,267	-		100%	0%	0%	$ 252,436	$ 252,436	$ -	$ -
Tennessee	46314	950	Dth	950	-		100%	0%	0%	$ 56,202	$ 56,202	$ -	$ -
Texas Eastern	800384	965	Dth	965	-		100%	0%	0%	$ 66,353	$ 66,353	$ -	$ -
Texas Eastern	800436	64	Dth	64	-		100%	0%	0%	$ 4,065	$ 4,065	$ -	$ -
Texas Eastern	800464	33	Dth	33			100%	0%	0%	$ 941	$ 941	$ -	$ -
Texas Eastern	800464	9	Dth	9			100%	0%	0%	$ 236	$ 236	$ -	$ -
Texas Eastern	800464	16	Dth	16			100%	0%	0%	$ 1,306	$ 1,306	$ -	$ -
Texas Eastern	800464	18	Dth	18			100%	0%	0%	$ 610	$ 610	$ -	$ -
Texas Eastern	800464	59	Dth	59			100%	0%	0%	$ 7,813	$ 7,813	$ -	$ -
TransCanada	29594	6,264	GJ	6,264	-		100%	0%	0%	$ 573,068	$ 573,068	$ -	$ -
TransCanada	29833	1,196	GJ	1,196	-		100%	0%	0%	$ 504,628	$ 504,628	$ -	$ -
TransCanada	33322	35,872	GJ		35,872		0%	100%	0%	$ 5,273,355	$ -	$ 5,273,355	$ -
Vector	CRL-NUI-0725	17,172	Dth		17,172		0%	100%	0%	$ 1,566,952	$ -	$ 1,566,952	$ -
Vector	CRL-NUI-0727	17,086	Dth		17,086		0%	100%	0%	$ 389,774	$ -	$ 389,774	$ -
Vector	FT-1-NUI-0122	6,070	Dth	6,070	-		100%	0%	0%	$ 589,334	$ 589,334	$ -	$ -
Vector	FT-1-NUI-C0122	6,404	GJ	6,404	-		100%	0%	0%	$ 32,667	$ 32,667	$ -	$ -
Annual Total Demand Costs										$24,178,843	$6,642,704	$16,723,592	$ 812,547

Northern Utilities, Inc.

Storage Contract Demand Cost Estimates

November 1, 2009 through October 31, 2010

Vendor	Contract ID	Rate	Negotiated	MSQ	Space Charge Billing Determinant	MDWQ	Space Rate	Demand Rate	Months Per Year	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	259,337	4,243	$ 0.0185	$ 1.1500	12	$ 57,573	$ 58,553	$ 116,126
Texas Eastern	400215	SS-1	No	1,470	122	21	$ 0.1293	$ 5.5370	12	$ 189	$ 1,395	$ 1,585
Texas Eastern	400513	FSS-1	No	3,840	320	64	$ 0.1293	$ 0.8950	12	$ 497	$ 687	$ 1,184
W-10	01052	Storage	Yes	3,400,000		34,000			12	$ -	$ -	$ 2,890,000

Total Annual Fixed Charges $ 3,008,895

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.

Peaking Resources Demand Cost Estimates

November 1, 2009 through October 31, 2010

Resource	Contract Quantity	Maximum Daily Quantity	Contract Quantity Demand Rate	MDQ Demand Rate	Months Per Year	Annual CQ Demand Cost	Annual MDQ Demand Cost	Annual Fixed Charges
FPL Energy	1,272,000	53,000	$ 1.3500	$ -	5	$ 1,717,200	$ -	$ 1,717,200
Distrigas	755,000	5,000	$ -	$ 41.8506	12	$ -	$ 2,511,036	$ 2,511,036

Total Annual Demand Costs $ 4,228,236

Northern Utilities, Inc.

Asset Management and Capacity Release Revenue Projections

November 2009 through October 2010

Asset Management Agreeement Revenue		
Resources	Term	Annual Value
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	Nov 2009 - Apr 2010	$ (370,000)
Empress via TCPL, PNGTS	Nov 2009 - Oct 2010	$ (100,000)
Wash 10 via Vector, TCPL, PNGTS	Nov 2009 - Apr 2010	$ (1,000,000)
Tennessee Long-Haul	Nov 2009 - Apr 2010	$ (1,300,000)
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	May 2010 - Oct 2010	$ (250,000)
Wash 10 via Vector, TCPL, PNGTS	May 2010 - Oct 2010	$ (750,000)
Total Asset Management	Nov 2009 - Oct 2010	$ (3,770,000)

Capacity Release Revenue		
Resources	Term	Annual Value
Tennessee Long-Haul	May 2010 - Oct 2010	$ (348,566)
Tetco	May 2009 - Oct 2017	$ (66,353)
Tetco	May 2009 - Mar 2010	$ (8,360)
AGT	May 2009 - Oct 2012	$ (98,860)
Tennessee Z4-Z6	Apr 2010 - Oct 2010	$ (16,275)
Tennessee Niagara Z5 - Z6	Apr 2010 - Oct 2010	$ (27,229)
Total Capacity Release	Nov 2009 - Oct 2010	$ (565,644)

Total Asset Management and Capacity Release Revenue		$ (4,335,643)

Attachment NUI-FXW-5
Capacity Assignment Revenue

Northern Utilities, Inc.

Northern Utilities, Inc. Retail Marketer Capacity Assignment Revenue Projections November 2009 through October 2010		
Item	Amount	Reference
NH Division Pipeline Contract Capacity Assignment	$ (1,377,384)	Page 2
NH Division Storage Contract Capacity Assignment	$ (166,174)	Page 3
NH Division Peaking Contract Capacity Assignment Estimates	$ (268,437)	Page 4
NH Division Asset Management and Capacity Release Revenue Assigned to Retail Suppliers	$ 152,441	Page 5
NH Division PNGTS Litigation Costs Assigned to Retail Suppliers	$ (24,307)	Page 6
NH Division Capacity Assignment Demand Revenue	$ (1,683,859)	

ME Division Capacity Assignment Revenue	$ (3,344,887)	Page 7

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 1, 2009 through October 31, 2010

Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost	Capacity Assigned? (Y/N)	Pipeline Allocated MDQ	Storage Allocated MDQ	Peaking Allocated MDQ	Assigned Pipeline MDQ	Assigned Storage MDQ	Assigned Peaking MDQ	NH Annual Cap Assign Credit
Algonquin	93200F	$ 308,943	$ -	$ -	Y	4,211	-	-	(326)	-	-	$ (23,917)
Algonquin	93201A1C	$ 20,513	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Algonquin	93201A1C	$ 63,118	$ 6,097	$ -	N	NA	NA	NA	-	-	-	$ -
Granite	08-003-FT-NN	$ 477,901	$ 709,472	$ 812,547	Y	23,896	35,475	40,629	(1,849)	(1,961)	(2,219)	$ (120,575)
Iroquois	R181001	$ 520,036	$ -	$ -	Y	6,569	-	-	(508)	-	-	$ (40,216)
PNGTS	1997-003	$ 361,702	$ -	$ -	Y	1,100	-	-	(85)	-	-	$ (27,950)
PNGTS	1997-004	$ -	$ 3,930,772	$ -	Y	-	15,100	-	-	(835)	-	$ (217,364)
PNGTS	1997-004	$ -	$ 1,275,548	$ -	Y	-	4,900	-	-	(271)	-	$ (70,546)
PNGTS	1997-004	$ -	$ 3,384,108	$ -	Y	-	13,000	-	-	(719)	-	$ (187,167)
Tennessee	5083	$ 916,763	$ -	$ -	Y	4,605	-	-	(356)	-	-	$ (70,872)
Tennessee	5083	$ 1,554,390	$ -	$ -	Y	8,550	-	-	(661)	-	-	$ (120,170)
Tennessee	5265	$ -	$ 187,514	$ -	Y	-	2,653	-	-	(147)	-	$ (10,390)
Tennessee	5292	$ 83,179	$ -	$ -	Y	1,406	-	-	(109)	-	-	$ (6,448)
Tennessee	31861	$ 84,081	$ -	$ -	Y	1,382	-	-	(107)	-	-	$ (6,510)
Tennessee	31861	$ 107,458	$ -	$ -	Y	844	-	-	(65)	-	-	$ (8,276)
Tennessee	39735	$ 54,960	$ -	$ -	Y	929	-	-	(72)	-	-	$ (4,260)
Tennessee	41099	$ 252,436	$ -	$ -	Y	4,267	-	-	(330)	-	-	$ (19,523)
Tennessee	46314	$ 56,202	$ -	$ -	Y	950	-	-	(73)	-	-	$ (4,319)
Texas Eastern	800384	$ 66,353	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800436	$ 4,065	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 941	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 236	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 1,306	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 610	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Texas Eastern	800464	$ 7,813	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
TransCanada	29594	$ 573,068	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
TransCanada	29833	$ 504,628	$ -	$ -	Y	1,196	-	-	(93)	-	-	$ (39,239)
TransCanada	33322	$ -	$ 5,273,355	$ -	Y	-	35,872	-	-	(1,983)	-	$ (291,510)
Vector	CRL-NUI-0725	$ -	$ 1,566,952	$ -	Y	-	17,172	-	-	(949)	-	$ (86,597)
Vector	CRL-NUI-0727	$ -	$ 389,774	$ -	Y	-	17,086	-	-	(944)	-	$ (21,535)
Vector	FT-1-NUI-0122	$ 589,334	$ -	$ -	N	NA	NA	NA	-	-	-	$ -
Vector	FT-1-NUI-C0122	$ 32,667	$ -	$ -	N	NA	NA	NA	-	-	-	$ -

Total NH Capacity Assignment Credits $ (1,377,384)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 1, 2009 through October 31, 2010

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Storage Assigned NH	Assigned MSQ	Assigned MDWQ	NH Annual Cap Assign Credit
Tennessee	5195	$ 116,126	Y	N	5.53%	(14,336)	(235)	$ (6,419)
W-10	01052	$ 2,890,000	Y	Y	5.53%	(187,946)	(1,879)	$ (159,754)

Total NH Division Storage Capacity Assignment $ (166,174)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
New Hampshire Division Peaking Contract Capacity Assignment Estimates
November 1, 2009 through October 31, 2010

Resource	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Peaking Assigned NH	NH Annual Cap Assign Credit
FPL Energy	$ 1,717,200	Y	Y	5.46%	$ (93,788)
Distrigas	$ 2,511,036	Y	Y	5.46%	$ (137,145)
Peaking Plants	$ 686,673	Y	Y	5.46%	$ (37,504)

Total NH Division Peaking Capacity Assignment $ (268,437)

Asset Management and Capacity Release Revenue Assigned to Retail Suppliers

November 2009 through October 2010

Asset Management Agreeement Revenue						
Resources	Term	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	Nov 2009 - Apr 2010	$ (370,000)	Yes	Pipeline	7.74%	$ 28,626
Empress via TCPL, PNGTS	Nov 2009 - Oct 2010	$ (100,000)	Yes	Pipeline	7.74%	$ 7,737
Wash 10 via Vector, TCPL, PNGTS	Nov 2009 - Apr 2010	$ (1,000,000)	Yes	Storage	5.53%	$ 55,278
Tennessee Long-Haul	Nov 2009 - Apr 2010	$ (1,300,000)	No	Pipeline	7.74%	$ -
Chicago via Vector, TCPL, Iroquois, TGP, Algonquin	May 2010 - Oct 2010	$ (250,000)	Yes	Pipeline	7.74%	$ 19,342
Wash 10 via Vector, TCPL, PNGTS	May 2010 - Oct 2010	$ (750,000)	Yes	Storage	5.53%	$ 41,459
Total Asset Management	Nov 2009 - Oct 2010	$ (3,770,000)				$ 152,441

Capacity Release Revenue						
Resources	Term	Annual Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to NH Retail Marketers
Tennessee Long-Haul	May 2010 - Oct 2010	$ (348,566)	No	Pipeline	7.74%	$ -
Tetco	May 2009 - Oct 2017	$ (66,353)	No	Pipeline	7.74%	$ -
Tetco	May 2009 - Mar 2010	$ (8,360)	No	Pipeline	5.53%	$ -
AGT	May 2009 - Oct 2012	$ (98,860)	No	Pipeline	7.74%	$ -
Tennessee Z4-Z6	Apr 2010 - Oct 2010	$ (16,275)	No	Storage	7.74%	$ -
Tennessee Niagara Z5 - Z6	Apr 2010 - Oct 2010	$ (27,229)	No	Pipeline	5.53%	$ -
Total Capacity Release	Nov 2009 - Oct 2010	$ (565,644)				$ -

Total Asset Management and Capacity Release Revenue	$ (4,335,643)	$ 152,441

Northern Utilities, Inc.
New Hampshire Division
PNGTS Litigation Costs - Assigned to Retail Suppliers
November 2009 through October 2010

PNGTS Litigation Costs	$ 434,116

PNGTS Contract	MDQ	Percentage MDQ	Allocated Litigation Costs	Resource Type	Percentage Capacity Assigned	Capacity Assignment Revenue
PNGTS Contract 1997-003	1,100	3%	$ 14,004	Pipeline	7.74%	$ (1,083)
PNGTS Contract 1997-004	33,000	97%	$ 420,112	Storage	5.53%	$ (23,223)
PNGTS Total	34,100	100%	$ 434,116			$ (24,307)

Northern Utilities, Inc.
Maine Division Capacity Assignment Demand Revenue Estimates
November 2009 through March 2010

	Retail Supplier 1	Retail Supplier 2	Retail Supplier 3	Retail Supplier 4	Retail Supplier 5	Total	Rate	Demand Revenue
Nov-09	3,765	5,671	3,267	1,703	314	14,720	$ 45.45	$ (668,977)
Dec-09	3,765	5,671	3,267	1,703	314	14,720	$ 45.45	$ (668,977)
Jan-10	3,765	5,671	3,267	1,703	314	14,720	$ 45.45	$ (668,977)
Feb-10	3,765	5,671	3,267	1,703	314	14,720	$ 45.45	$ (668,977)
Mar-10	3,765	5,671	3,267	1,703	314	14,720	$ 45.45	$ (668,977)

Total ME Division Capacity Assignment $ (3,344,887)

Northern Utilities, Inc.
Maine Division Capacity Assignment Demand Rate Estimate
November 2009 through March 2010

Line	Description	Northern	ME Division
1	Capacity Allocation Factor		52.54%
2	Pipeline	23,896	12,555
3	Storage	35,475	18,638
4	Peaking Contracts	51,740	27,183
5	Peaking Plants	14,000	7,355
6	Total	125,111	65,731
7	Subtotal Capacity Costs	$ 27,514,446	$ 14,455,659
8	Peaking Plants		$ 480,642
9	Capacity Costs (Before Cap Assignment)		$ 14,936,301
10	ME Division Capacity Assignment Rate		$ 45.446

Attachment NUI-FXW-6

Supply Source Costs and Volumes

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
Supply Source Costs
November 2009 through October 2010

Description	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Pipeline												
Chicago	$ 766,143	$ 946,884	$ 337,960	$ 540,666	$ 923,502	$1,015,174	$1,059,139	$1,013,621	$ 983,303	$ 393,616	$ 243,009	$ 659,385
Empress	$ 114,792	$ 140,331	$ 147,503	$ 133,901	$ 144,902	$ 154,006	$ 160,981	$ 156,995	$ 168,565	$ 171,773	$ 168,757	$ 178,619
Niagara	$ 59,146	$ 489,890	$ 441,685	$ 368,242	$ 412,578	$ 399,236	$ 176,918	$ 277,480	$ -	$ -	$ -	$ -
Portland Pay-Back	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee Production	$1,444,116	$1,956,634	$1,014,361	$1,210,669	$1,194,183	$1,966,290	$1,146,763	$ 346,596	$ -	$ -	$ -	$ -
TETCO M3												
TETCO Production												
Storage												
Tennessee Storage	$ -	$ -	$ 276,713	$ 258,303	$ 177,237	$ 167,343	$ -	$ -	$ -	$ -	$ -	$ -
TETCO Storage												
Washington 10 Storage	$ -	$1,222,421	$3,040,091	$2,745,706	$1,982,018	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking												
Distrigas	$ -	$ -	$ 362,785	$ 271,501	$ 45,021	$ 101,254	$ 9,392	$ -	$ 21,227	$ 367,779	$ 485,480	$ 552,801
FPL Peaking	$ -	$ -	$ -	$ 335,464	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG	$ 12,125	$ 11,925	$ 11,388	$ 148,169	$ 8,266	$ 24,918	$ 7,830	$ 7,497	$ 7,670	$ 7,602	$ 7,300	$ 7,490
Propane												
Total Variable Costs	$2,396,323	$4,768,084	$5,632,488	$6,012,621	$4,887,708	$3,828,221	$2,561,024	$1,802,189	$1,180,765	$ 940,770	$ 904,547	$1,398,294
As of 8/10/2009												
NYMEX NG Futures Contracts	20	24	24	23	28	30	18					18
Average Purchase Price	$ 7.958	$ 8.291	$ 8.423	$ 8.405	$ 8.214	$ 7.888	$ 5.738					$ 6.170
Current NYMEX Price	$ 4.726	$ 5.454	$ 5.706	$ 5.727	$ 5.672	$ 5.597	$ 5.654	$ 5.746	$ 5.861	$ 5.954	$ 6.017	$ 6.132
Futures (Profit) or Loss	$ 646,310	$ 680,840	$ 652,080	$ 615,970	$ 711,620	$ 687,300	$ 15,180					$ 6,840
Total Commodity Costs	$3,042,633	$5,448,924	$6,284,568	$6,628,591	$5,599,328	$4,515,521	$2,576,204	$1,802,189	$1,180,765	$ 940,770	$ 904,547	$1,405,134

Northern Utilities, Inc.
Supply Source Volumes
November 2009 through October 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Pipeline												
Chicago	154,734	159,449	55,445	87,315	153,901	172,281	178,024	168,440	158,805	64,004	38,971	102,742
Empress	26,432	27,313	27,313	24,670	27,313	30,192	31,127	30,294	31,112	31,279	30,003	31,074
Niagara	11,303	81,861	70,801	58,815	66,471	65,975	28,990	44,788	0	0	0	0
Portland Pay-Back	41,460	11,056	0	0	0	0	0	0	0	0	0	0
Tennessee Production	278,213	326,634	162,400	192,753	192,049	325,535	187,976	55,908	0	0	0	0
TETCO M3												
TETCO Production												
Storage												
Tennessee Storage	0	0	64,894	60,576	41,565	35,230	0	0	0	0	0	0
TETCO Storage												
Washington 10 Storage	0	291,338	726,410	653,728	475,200	0	0	0	0	0	0	0
Peaking												
Distrigas	0	0	94,776	70,928	11,762	26,452	2,454	0	5,545	96,080	126,829	144,416
FPL Peaking	0	0	0	33,806	0	0	0	0	0	0	0	0
LNG	1,350	1,395	1,395	24,560	1,395	4,386	1,395	1,350	1,395	1,395	1,350	1,395
Propane												
Total Delivered	513,493	899,046	1,203,433	1,207,151	969,655	660,050	429,965	300,779	196,857	192,758	197,153	279,627
ME Firm	234,264	425,992	579,610	554,379	455,067	303,690	192,593	130,202	87,135	85,209	84,284	133,072
ME Interruptible	4,500	0	0	0	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500
NH Firm	274,729	473,054	623,823	652,772	510,088	351,860	232,872	166,077	105,222	103,049	108,369	142,055
NH Interuptible	0	0	0	0	0	0	0	0	0	0	0	0
Total Required Volumes	513,493	899,046	1,203,433	1,207,151	969,655	660,050	429,965	300,779	196,857	192,758	197,153	279,627

Northern Utilities, Inc.
Delivered Cost per Dth
November 2009 through October 2010

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
Pipeline												
Chicago	$ 4.9513	$ 5.9385	$ 6.0955	$ 6.1922	$ 6.0006	$ 5.8926	$ 5.9494	$ 6.0177	$ 6.1919	$ 6.1499	$ 6.2356	$ 6.4179
Empress	$ 4.3429	$ 5.1378	$ 5.4004	$ 5.4277	$ 5.3052	$ 5.1009	$ 5.1717	$ 5.1825	$ 5.4180	$ 5.4916	$ 5.6248	$ 5.7483
Niagara	$ 5.2328	$ 5.9844	$ 6.2384	$ 6.2610	$ 6.2069	$ 6.0514	$ 6.1028	$ 6.1955				
Portland Pay-Back	$ -	$ -										
Tennessee Production	$ 5.1907	$ 5.9903	$ 6.2461	$ 6.2809	$ 6.2181	$ 6.0402	$ 6.1006	$ 6.1994				
TETCO M3												
TETCO Production												
Storage												
Tennessee Storage			$ 4.2641	$ 4.2641	$ 4.2641	$ 4.7500						
TETCO Storage												
Washington 10 Storage		$ 4.1959	$ 4.1851	$ 4.2001	$ 4.1709							
Peaking												
Distrigas			$ 3.8278	$ 3.8278	$ 3.8278	$ 3.8278	$ 3.8278		$ 3.8278	$ 3.8278	$ 3.8278	$ 3.8278
FPL Peaking				$ 9.9233								
LNG	$ 8.9817	$ 8.5487	$ 8.1635	$ 6.0329	$ 5.9253	$ 5.6817	$ 5.6128	$ 5.5533	$ 5.4985	$ 5.4498	$ 5.4077	$ 5.3690
Propane												
Total Variable Costs	$ 4.6667	$ 5.3035	$ 4.6803	$ 4.9808	$ 5.0407	$ 5.7999	$ 5.9564	$ 5.9917	$ 5.9981	$ 4.8806	$ 4.5880	$ 5.0006
Total Commodity Costs	$ 5.9254	$ 6.0608	$ 5.2222	$ 5.4911	$ 5.7746	$ 6.8412	$ 5.9917	$ 5.9917	$ 5.9981	$ 4.8806	$ 4.5880	$ 5.0250

Attachment NUI-FXW-7

Supplier Rates

Unitil

Northern Utilities, Inc.

NYMEX Natural Gas Futures Contract
As of August 10, 2009

Month	Year	Settlement Price
Nov	2009	$ 4.726
Dec	2009	$ 5.454
Jan	2010	$ 5.706
Feb	2010	$ 5.727
Mar	2010	$ 5.672
Apr	2010	$ 5.597
May	2010	$ 5.654
Jun	2010	$ 5.746
Jul	2010	$ 5.861
Aug	2010	$ 5.954
Sep	2010	$ 6.017
Oct	2010	$ 6.132

Algonquin Gas Transmission, LLC
5400 Westheimer Court
Houston, TX 77056-5310
713.627.5400 main

Mailing Address:
P.O. Box 1642
Houston, TX 77251-1642

Energy

December 4, 2008

Chico Dafonte
Director of Gas Supply
NORTHERN UTILITIES, INC.
300 Friberg Parkway
Westborough, MA 01581

Re: Algonquin Gas Transmission, LLC
Contract No. 93201A1C

Dear Mr. Dafonte:

As you may be aware, the term of your 2005 negotiated rate agreement applicable to Contract No. 93201A1C for firm transportation on Algonquin Gas Transmission, LLC ("Algonquin") ends on December 31, 2008. Algonquin is willing to offer you a discounted rate, for all points available under the existing negotiated rate, equivalent to the prior negotiated rate commencing on January 1, 2009 through October 31, 2010. Attached is a schedule reflecting the contemplated discount from the currently effective maximum recourse rate ("Discounted Rate") that is available commencing on January 1, 2009. If you are interested in this Discounted Rate for Contract No. 93201A1C, please submit a request for such Discounted Rate electronically on the LINK® System by December 15, 2008, and Algonquin will grant this request.

Additionally, Algonquin notes that the Federal Energy Regulatory Commission approved a revision to Algonquin's tariff to be effective as of December 5, 2008, which provides a right of first refusal ("ROFR") to any firm Part 284 service agreement, notwithstanding the fact the customer has paid a discounted rate or negotiated rate pursuant to said firm service agreement, if the customer (i) was charged and has paid a rate no less than the effective maximum recourse rate during the 12 consecutive months immediately prior to the latest applicable date that customer or Algonquin is required to provide notice of termination (notice deadline) and (ii) will pay a rate no less than the effective maximum recourse rate from such notice deadline to the termination date of the firm service agreement. In conjunction with this tariff modification, Algonquin is granting all of its Part 284 customers the opportunity to extend, in annual increments of their choice, not to exceed October 31, 2018, their current firm service agreements if they notify Algonquin of such request no later than April 1, 2009. This opportunity will allow the extension of any of your existing firm service agreements that will not have at least two years remaining on the term after the date on which the Discounted Rate will no longer apply in order to qualify as ROFR Agreements.

If you have any questions regarding the process for electronically requesting the Discounted Rate or the process for extending the term of your firm service agreement, please contact Andrew Moreno at (713) 627-5322.

Very truly yours,

William C. Penney
Vice President
Marketing & Business Development

ALGONQUIN GAS TRANSMISSION, LLC
DISCOUNTED RATE LETTER - SCHEDULE

Customer Name	Contract No.	Contract Term	Rate Schedule	Discounted Rate	Recourse Reservation Rate	Recourse Usage Rate
NORTHERN UTILITIES, INC.	93201A1C	12/1/1997 - 10/31/2012	AFT-12	5.97710	6.58540	0.01120

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Proposed Rates Effective 12/01/2008

•RATE SCHEDULE AFT-1

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(F-2/F-3)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(F-4)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(STB/SS-3)	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(FTP)	$11.8368	$0.0017	$0.0017	$0.3909	$0.0017	$0.3892
(PSS-T)	$ 9.7854	$0.0017	$0.0017	$0.3234	$0.0017	$0.3217
(AFT-2)	$ 6.1138	$0.0017	$0.0017	$0.2027	$0.0017	$0.2010
(AFT-3)	$10.7554	$0.0017	$0.0017	$0.3553	$0.0017	$0.3536
(AFT-5)	$12.6265	$0.0017	$0.0017	$0.4168	$0.0017	$0.4151
(ITP)	$13.0110	$0.0017	$0.0017	$0.4295	$0.0017	$0.4278
(X-35)	$10.2027	$0.0017	$0.0017	$0.3371	$0.0017	$0.3354
X-39	$13.2089	$0.0017	$0.0017	$0.4360	$0.0017	$0.4343
Incremental Surcharges						
Hubline	$ 1.8607	$0.0000	$0.0000	$0.0000	$0.0000	$0.0612
Secondary 1/		$0.0612	$0.0000			
Tiverton	$ 1.6424	$0.0000	$0.0000	$0.0000	$0.0000	$0.0540

•RATE SCHEDULE AFT-1S

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
(F-1/WS-1)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(F-2/F-3)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(F-4)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0029	$0.0866
(STB/SS-3)	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(Hubline) 1/		$0.0612	$0.0000			

•OTHER FIRM RATE SCHEDULES

		Commodity		Authorized Overrun		Capacity Release
	Reservation	Max	Min	Max	Min	Vol Res
AFT-E	$ 6.5854	$0.0129	$0.0129	$0.2294	$0.0129	$0.2165
(Hubline) 1/		$0.0612	$0.0000			
AFT-ES	$ 2.6342	$0.2294	$0.0129	$0.2294	$0.0129	$0.0866
(Hubline) 1/		$0.0612	$0.0000			
T-1	$ 1.6480	$0.0056		$0.0598		
AFT-4	$ 3.5211	$0.0030		$0.1188		
AFT-CL:						
Canal	$ 2.0858	$0.0017	$0.0017	$0.0703	$0.0017	$0.0686
Middletown	$ 3.2764	$0.0017	$0.0017	$0.1094	$0.0017	$0.1077
Cleary	$ 1.4529	$0.0017	$0.0017	$0.0495	$0.0017	$0.0478
Lake Road	$ 0.6476	$0.0017	$0.0017	$0.0230	$0.0017	$0.0213
Brayton Pt.	$ 1.2700	$0.0017	$0.0017	$0.0435	$0.0017	$0.0418
Manchester	$ 2.4500	$0.0017	$0.0017	$0.0822	$0.0017	$0.0805
Bellingham	$ 0.9714	$0.0017	$0.0017	$0.0336	$0.0017	$0.0319
Phelps Dodge	$ 0.0000	$0.0183	$0.0017	$0.0183	$0.0017	$0.0000
Cape Cod	$ 9.0501	$0.0019	$0.0017	$0.2992	$0.0017	$0.2975
Northeast Gateway	$ 4.3449	$0.0019	$0.0017	$0.1445	$0.0017	$0.1428
X-33	$ 3.0873	$0.0412		$0.1427		

•INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun	
	Max	Min	Max	Min
AIT-1	$0.2442	$0.0093	$0.2442	$0.0093
(Hubline 1/)	$0.0612	$0.0000		
AIT-2				
Brayton Pt.	$0.0435	$0.0017	$0.0435	$0.0017
Manchester	$0.0822	$0.0017	$0.0822	$0.0017
Canal	$0.0703	$0.0017	$0.0703	$0.0017
Cape Cod	$0.2992	$0.0017	$0.2992	$0.0017
Northeast Gateway	$0.1445	$0.0017	$0.1445	$0.0017
PAL	$0.2442	$0.0000	$0.0000	$0.0000

•TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Commodity rates include ACA Charges of $0.0017 and applicable GRI Commodity Surcharge.

GRI Max Surcharges:

Reservation Surcharge	
High Load Factor	$0.0000
Low Load Factor	$0.0000
Commodity Surcharge	$0.0000
Small Customer Commodity Surcharge	$0.0000

•FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
Winter	Dec 1 - Mar 31	1.44%
Spring, Summer and Fall	Apr 1 - Nov 30	1.02%

1/ Hubline Surcharge applicable to all customers utilizing secondary receipt points between and including Beverly and Weymouth and/or utilizing secondary delivery points between Beverly and Weymouth,including Beverly and excluding Weymouth,and in addition to other applicable charges.

•The Summary of Rates serves as a handy reference and does not replace Algonquin's Tariff. The rates are subject to commission approval.

Granite State Gas Transmission, Inc.
FERC Gas Tariff
Third Revised Volume No. 1

Thirty-Fourth Revised Sheet No. 22 : Effective
Thirty-Third Revised Sheet No. 22

Rate Schedule FT-NN

Firm Transportation Service

$/Dth

Base Total

Tariff ACA Current

Rate Adj. Rate

1/

Reservation Charge:

Maximum $1.6666 $1.6666

Minimum $0.0000 $0.0000

Commodity Charge:

Maximum $0.0000 $0.0017 $0.0017

Minimum $0.0000 $0.0017 $0.0017

Authorized Overrun

Commodity Charge:

Maximum $0.0548 $0.0017 $0.0565

Minimum $0.0000 $0.0017 $0.0017

Fuel and Losses

Percentage 0.5%

Volumetric

Reservation Charge

Maximum $0.0548 $0.0548

Minimum $0.0000 $0.0000

1/ The Base Tariff Rate is the effective rate on file with the Commission, excluding adjustment approved

by the Commission.

Issued by:
Issue date: 10/01/08 **Effective date: 10/01/08**

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Iroquois Gas Transmission System, L.P. Thirty First Revised Sheet No. 4

FERC Gas Tariff Superseding

FIRST REVISED VOLUME NO. 1 Thirtieth Revised Sheet No. 4

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

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

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

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

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

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

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

Issued on: Jan 26, 2009 Effective: Jan 27, 2009

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Portland Natural Gas Transmission System

FERC Gas Tariff

Second Revised Volume No. 1

Sixth Revised Sheet No. 100 : Effective

Fourth Revised Sheet No. 100

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/	Current Rate
FT	Recourse Reservation Rate			
	-- Maximum	$27.4017	---------	$27.4017
	-- Minimum	$00.0000	---------	$00.0000
	Seasonal Recourse Reservation Rate			
	-- Maximum	$52.0632	---------	$52.0632
	-- Minimum	$00.0000	---------	$00.0000
	Recourse Usage Rate			
	-- Maximum	$00.0000	$00.0017	$00.0017
	-- Minimum	$00.0000	$00.0017	$00.0017
FT-FLEX	Recourse Reservation Rate			
	--Maximum	$18.3920	-------	$18.3920
	--Minimum	$00.0000	-------	$00.0000
	Recourse Usage Rate			
	--Maximum	$00.2962	$00.0017	$00.2979
	--Minimum	$00.0000	$00.0017	$00.0017

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

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

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 17 of the General Terms and Conditions at such time that initial and successive
ACA assessments are made.

ATTACHMENT 1
TO GAS TRANSPORTATION CONTRACT
FOR NEGOTIATED FIRM TRANSPORTATION SERVICE

Statement of Negotiated Firm Transportation Rates
For The Period November 1 Through March 31
(Rates per MMBTU)

1. Following are the reservation rate and usage rate (which are negotiated rates and are subject to change as set forth below):

- The negotiated reservation rate shall equal 1.9 times the Recourse Reservation Rate listed on Sheet No. 6 of the Tariff, as that Recourse Reservation Rate may be revised from time to time.
- The negotiated usage rate shall equal the currently effective Usage Rate under Transporter's Rate Schedule FT, as that Usage Rate may be revised from time to time.

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TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Twenty-Sixth Revised Sheet No. 23
Superseding
Twenty-Fifth Revised Sheet No. 23

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

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

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
L		$0.00						
1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

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

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

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

Issued by: Patrick A. Johnson, Vice President
Issued on: May 30, 2008 Effective on: July 1, 2008

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TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Thirtieth Revised Sheet No. 26
Superseding
Twenty-Ninth Revised Sheet No. 26

RATES PER DEKATHERM

RATE SCHEDULE NET

Rate Schedule and Rate	Base Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 6/	Rate After Current Adjustments
Demand Rate 1/, 5/					
Segment U	$9.65			$0.00	$9.65
Segment 1	$1.33			$0.00	$1.33
Segment 2	$8.08			$0.00	$8.08
Segment 3	$5.07			$0.00	$5.07
Segment 4	$5.54			$0.00	$5.54
Commodity Rate 2/, 7/					
Segments U, 1, 2, 3 & 4		$0.0017			$0.0017

Notes:

1/ A specific customer's Monthly Demand Rate is dependent upon the location of its points of receipt and delivery, and is to be determined by summing the Monthly Demand Rate components for those pipeline segments connecting said points.
2/ The applicable surcharges for ACA and TCSM will be assessed on actual quantities delivered and are not dependent upon the location of points of receipt and delivery.
3/ Reserved for future use.
4/ Reserved for future use.
5/ Rates are subject to negotiation pursuant to the terms of the Rate Schedule for NET.
6/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2010 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
7/ The applicable fuel retention percentages are listed on Sheet Nos. 180 and 181.

Issued by: Patrick A. Johnson, Vice President
Issued on: August 29, 2008 Effective on: October 1, 2008

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TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

Currently Effective Rates 2/01/2009

•RESERVATION CHARGES

	CDS	FT-1	SCT
STX-AAB	6.8040	6.5810	2.7220
WLA-AAB	2.8250	2.6020	1.1300
ELA-AAB	2.3750	2.1520	0.9500
ETX-AAB	2.1890	1.9660	0.8760
STX-STX	5.7340	5.5110	2.2920
STX-WLA	5.8930	5.6700	2.3560
STX-ELA	6.8090	6.5860	2.7220
STX-ETX	6.8090	6.5860	2.7220
WLA-WLA	2.0570	1.8340	0.8220
WLA-ELA	2.8300	2.6070	1.1300
WLA-ETX	2.8300	2.6070	1.1300
ELA-ELA	2.3780	2.1550	0.9500
ETX-ETX	2.1920	1.9690	0.8760
ETX-ELA	2.3780	2.1550	0.9500
M1-M1	4.5310	4.3080	1.8100
M1-M2	8.3970	8.1740	3.3560
M1-M3	11.0360	10.8130	4.4110
M2-M2	6.5210	6.2980	2.6060
M2-M3	9.2960	9.0730	3.7160
M3-M3	5.2930	5.0700	2.1150

7(C) RATE	SCHEDULES
FTS	5.3500
FTS-2	7.9590
FTS-4	7.7160
FTS-5	5.1790
FTS-7	6.5760
FTS-8	6.8640
X-127	7.7060
X-129	7.5430
X-130	7.5430
X-135	1.6030
X-137	4.0100

SCT DEMAND	CHARGES
Access Area	0.0020
M1-M1	0.0020
M1-M2	0.0030
M1-M3	0.0040

•USAGE CHARGES

CDS & FT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0021	0.0024	0.0041	0.0041	0.0173	0.0442	0.0623
from WLA		0.0009	0.0027	0.0027	0.0159	0.0428	0.0609
from ELA			0.0021	0.0021	0.0153	0.0422	0.0603
from ETX				0.0021	0.0153	0.0422	0.0603
from M1					0.0132	0.0401	0.0582
from M2						0.0270	0.0452
from M3							0.0184

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.0088						
from WLA	0.0096	0.0059					
from ELA	0.0140	0.0103	0.0087				
from ETX	0.0140	0.0103	0.0087	0.0087			
from M1	0.0336	0.0299	0.0283	0.0283	0.0196		
from M2	0.0652	0.0615	0.0599	0.0599	0.0512	0.0359	
from M3	0.0870	0.0833	0.0817	0.0817	0.0730	0.0576	0.0258

SCT USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1832	0.1887	0.2205	0.2205	0.3751	0.5291	0.6339
from WLA		0.0611	0.0883	0.0883	0.2429	0.3968	0.5016
from ELA			0.0729	0.0729	0.2275	0.3815	0.4863
from ETX				0.0667	0.2214	0.3753	0.4801
from M1					0.1547	0.3086	0.4134
from M2						0.2339	0.3433
from M3							0.1849

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1899						
from WLA	0.1959	0.0661					
from ELA	0.2304	0.0959	0.0795				
from ETX	0.2304	0.0959	0.0795	0.0733			
from M1	0.3914	0.2569	0.2405	0.2344	0.1611		
from M2	0.5501	0.4155	0.3992	0.3930	0.3197	0.2428	
from M3	0.6586	0.5240	0.5077	0.5015	0.4282	0.3557	0.1923

IT-1 USAGE-1

Forward Haul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1833	0.1888	0.2207	0.2207	0.3756	0.5295	0.6344
from WLA		0.0612	0.0884	0.0884	0.2433	0.3972	0.5021
from ELA			0.0730	0.0730	0.2279	0.3818	0.4867
from ETX				0.0668	0.2217	0.3756	0.4805
from M1					0.1549	0.3088	0.4137
from M2						0.2341	0.3434
from M3							0.1851

Backhaul	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.1900						

from WLA	0.1960	0.0662					
from ELA	0.2306	0.0960	0.0796				
from ETX	0.2306	0.0960	0.0796	0.0734			
from M1	0.3919	0.2573	0.2409	0.2347	0.1613		
from M2	0.5505	0.4159	0.3995	0.3933	0.3199	0.2430	
from M3	0.6591	0.5245	0.5081	0.5019	0.4285	0.3558	0.1925

•OTHER TRANSPORTATION SERVICES

	Reservation	Usage-1	Shrinkage	
			In Path	Out-of-Path
LLFT	3.3400	0.0023	0.43%	
	3.3400 1/			
LLIT		0.1121	0.43%	
		0.1121 1/	0.43%	
VKFT	0.0945		0.00%	
VKIT		0.0945	0.00%	
FT-1/FTS	0.6600		0.00%	
FT-1/FTS-4	3.0110		0.00%	
FT-1/M1	7.8849		0.40%	
FT-1/NC	6.5590		0.00%	
FT-1/RIV	10.4380		0.00%	
FT-1/PLP	1.9410		0.00%	
FT-1/L1A	1.5830		0.00%	
FT-1/LEP	4.4610		0.00%	
FT-1/IRW	1.2690 2/		0.00%	
FT-1/TME	11.2878		4.03%	4.80%
FT-1/TME2	26.5849		3.20%	4.80%
MLS-1/FH	0.6247		0.01%	
MLS-1/FA	0.8690	0.0286 3/	0.00%	
MLS-1/HR	1.1120	0.0366 3/	0.01%	
MLS-1/CB	0.9270		0.01%	

1/ Pursuant to Section 26 of the General Terms and Conditions
2/ Effective May 1 through September 30
3/ Per Section 3.3 of MLS-1 Rate Schedule

•STORAGE SERVICES

	RES.	SPACE	INJ.	WITH.
SS	5.4400	0.1293	0.0280	0.0437
SS-1	5.5370	0.1293	0.0280	0.0436
X-28	4.8410	0.1293	0.0280	0.0394
FSS-1	0.8950	0.1293	0.0280	0.0280
ISS-1		0.0323	0.1837	0.0280

•SHRINKAGE PERCENTAGES (December 1 through March 31)

TRANSPORTATION

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.20%	2.39%	3.41%	3.41%	5.46%	7.35%	8.59%
from WLA	1.64%	1.50%	2.54%	2.54%	4.59%	6.48%	7.72%
from ELA	2.16%	2.16%	2.16%	2.16%	4.21%	6.10%	7.34%
from ETX	2.20%	2.16%	2.16%	2.16%	4.21%	6.10%	7.34%
from M1					2.05%	3.94%	5.18%
from M2						3.03%	4.30%
from M3							2.43%

•SHRINKAGE PERCENTAGES (April 1 through November 30)

TRANSPORTATION

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	2.25%	2.39%	3.15%	3.16%	5.29%	6.69%	7.63%
from WLA	1.73%	1.73%	2.50%	2.50%	4.64%	6.04%	6.98%
from ELA	2.22%	2.22%	2.22%	2.22%	4.36%	5.76%	6.70%
from ETX	2.25%	2.22%	2.22%	2.22%	4.36%	5.76%	6.70%
from M1					2.14%	3.54%	4.48%
from M2						2.87%	3.81%
from M3							2.42%

NON-ASA RATE SCHEDULES

FTS-4 LEIDY	
(Apr 1-Nov 14)	1.00%
(Nov 15-Mar 31)	4.89%
FTS-4 CHMSBG	0.00%
FTS-5	0.00%
FTS-7 M3	2.00%
FTS-7 M1 & M2	0.00%
FTS-8 M3	1.50%
FTS-8 M1 & M2	0.00%

FTS	1.29%
FTS-2	0.00%
X-127	0.00%
X-129	0.00%
X-130	0.00%
X-135	0.00%
X-137	1.30%

STORAGE SERVICE	12/01-3/31	04/01-11/30
WITHDRAWALS:		
SS,SS-1,X-28	3.49%	3.53%
FSS-1,ISS-1	1.27%	1.27%
INJECTIONS	1.27%	1.27%
INVENTORY LEVEL	0.08%	0.08%

•SURCHARGES

ACA Surcharge
Commodity 0.0017

•The Summary of Rates serves as a handy reference and does not replace Texas Eastern's Tariff.

TransCanada
In business to deliver

Transportation Tolls
2009 Final Tolls Effective May 1st

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

Storage Transportation Service

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)
	(a)	(b)	(c)
2	Centra Gas Manitoba - MDA	2.34500	0.00462
3	Union Gas - WDA	16.66667	0.04509
4	Union Gas - NDA	6.45333	0.01622
5	Union Gas - EDA	4.22833	0.00964
6	Kingston PUC	4.06250	0.00908
7	Gaz Metropolitain - EDA	7.51000	0.01911
8	Enbridge - CDA	0.93583	0.00015
9	Enbridge - EDA	2.58833	0.00499
10	Cornwall	5.76167	0.01393
11	Philipsburg	7.58917	0.01914

Enhanced Capacity Release

Line No	Particulars	Commodity Toll ($/GJ)
	(a)	(b)
12	ECR Surcharge	0.029

Delivery Pressure

Line No	Particulars	Demand Toll ($/GJ/mo)	Commodity Toll ($/GJ)	Daily Equivalent *(1) ($/GJ)
	(a)	(b)	(c)	(d)
13	Emerson - 1 (Viking)	0.06426	0.00000	0.00211
14	Emerson - 2 (Great Lakes)	0.08446	0.00000	0.00278
15	Dawn	0.06286	0.00000	0.00207
16	Niagara Falls	0.10558	0.00000	0.00347
17	Iroquois	0.56297	0.00000	0.01851
18	Chippawa	0.61730	0.00000	0.02029
19	East Hereford	1.41498	0.02139	0.06791

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

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
2009 Final Tolls Effective May 1st
* These tolls will become effective on November 1, 2009

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	STFT Minimum Tolls (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% LF FT Tolls) ($/GJ)
1	Empress	Empress	0.87529	0.00000	0.0288	0.0317
2	Empress	Saskatchewan Zone	4.88397	0.01347	0.1741	0.1915
3	* *Empress*	*Saskatchewan Zone*	4.40283	0.01208	0.1569	0.1726
4	Empress	Manitoba Zone	10.38858	0.02678	0.3683	0.4051
5	Empress	Western Zone	16.70445	0.04506	0.5943	0.6537
6	Empress	Northern Zone	25.63374	0.07038	0.9132	1.0045
7	Empress	Eastern Zone	33.37571	0.09272	1.1900	1.3090
8	Empress	North Bay Junction	27.99976	0.07732	0.9978	1.0976
9	Empress	Southwest Zone	28.08670	0.07751	1.0009	1.1010
10	Empress	Spruce	11.38556	0.02996	0.4043	0.4447
11	Empress	Emerson 1	11.60683	0.03059	0.4122	0.4534
12	Empress	Emerson 2	11.60683	0.03059	0.4122	0.4534
13	Empress	St. Clair	28.03227	0.07741	0.9990	1.0989
14	Empress	Dawn Export	28.28112	0.07812	1.0079	1.1087
15	Empress	Kirkwall	30.25966	0.08376	1.0786	1.1865
16	Empress	Niagara Falls	31.43397	0.08711	1.1205	1.2326
17	Empress	Chippawa	31.45904	0.08718	1.1215	1.2337
18	Empress	Iroquois	32.51411	0.09019	1.1592	1.2751
19	Empress	Cornwall	33.05670	0.09174	1.1785	1.2964
20	Empress	Napierville	34.70134	0.09642	1.2373	1.3610
21	Empress	Philipsburg	34.88444	0.09695	1.2439	1.3683
22	Empress	East Hereford	36.82407	0.10247	1.3132	1.4445
23	* *Empress*	*Welwyn*	7.28893	0.01828	0.2579	0.2837
24	Bayhurst 1	Empress	1.19357	0.00000	0.0392	0.0431
25	Bayhurst 1	Saskatchewan Zone	4.56569	0.01256	0.1627	0.1790
26	* *Bayhurst 1*	*Saskatchewan Zone*	4.08452	0.01117	0.1455	0.1601
27	Bayhurst 1	Manitoba Zone	10.07031	0.02587	0.3570	0.3927
28	Bayhurst 1	Western Zone	16.38618	0.04415	0.5829	0.6412
29	Bayhurst 1	Northern Zone	25.31546	0.06947	0.9018	0.9920
30	Bayhurst 1	Eastern Zone	33.05691	0.09182	1.1786	1.2965
31	Bayhurst 1	North Bay Junction	27.68149	0.07641	0.9865	1.0852
32	Bayhurst 1	Southwest Zone	27.76842	0.07660	0.9895	1.0885
33	Bayhurst 1	Spruce	11.06729	0.02905	0.3930	0.4323
34	Bayhurst 1	Emerson 1	11.28856	0.02968	0.4008	0.4409
35	Bayhurst 1	Emerson 2	11.28856	0.02968	0.4008	0.4409
36	Bayhurst 1	St. Clair	27.71400	0.07651	0.9876	1.0864
37	Bayhurst 1	Dawn Export	27.96285	0.07721	0.9965	1.0962
38	Bayhurst 1	Kirkwall	29.94139	0.08285	1.0673	1.1740
39	Bayhurst 1	Niagara Falls	31.11570	0.08620	1.1092	1.2201
40	Bayhurst 1	Chippawa	31.14076	0.08627	1.1101	1.2211
41	Bayhurst 1	Iroquois	32.19584	0.08928	1.1478	1.2626
42	Bayhurst 1	Cornwall	32.73842	0.09083	1.1671	1.2838
43	Bayhurst 1	Napierville	34.38307	0.09552	1.2259	1.3485
44	Bayhurst 1	Philipsburg	34.56616	0.09604	1.2324	1.3556
45	Bayhurst 1	East Hereford	36.50580	0.10157	1.3018	1.4320
46	* *Bayhurst 1*	*Welwyn*	6.97062	0.01738	0.2466	0.2713
47	Bayhurst 2	Empress	1.19357	0.00000	0.0392	0.0431
48	Bayhurst 2	Saskatchewan Zone	4.56569	0.01256	0.1627	0.1790
49	* *Bayhurst 2*	*Saskatchewan Zone*	4.08452	0.01117	0.1455	0.1601
50	Bayhurst 2	Manitoba Zone	10.07031	0.02587	0.3570	0.3927
51	Bayhurst 2	Western Zone	16.38618	0.04415	0.5829	0.6412
52	Bayhurst 2	Northern Zone	25.31546	0.06947	0.9018	0.9920
53	Bayhurst 2	Eastern Zone	33.05691	0.09182	1.1786	1.2965
54	Bayhurst 2	North Bay Junction	27.68149	0.07641	0.9865	1.0852
55	Bayhurst 2	Southwest Zone	27.76842	0.07660	0.9895	1.0885
56	Bayhurst 2	Spruce	11.06729	0.02905	0.3930	0.4323
57	Bayhurst 2	Emerson 1	11.28856	0.02968	0.4008	0.4409
58	Bayhurst 2	Emerson 2	11.28856	0.02968	0.4008	0.4409
59	Bayhurst 2	St. Clair	27.71400	0.07651	0.9876	1.0864
60	Bayhurst 2	Dawn Export	27.96285	0.07721	0.9965	1.0962
61	Bayhurst 2	Kirkwall	29.94139	0.08285	1.0673	1.1740
62	Bayhurst 2	Niagara Falls	31.11570	0.08620	1.1092	1.2201
63	Bayhurst 2	Chippawa	31.14076	0.08627	1.1101	1.2211
64	Bayhurst 2	Iroquois	32.19584	0.08928	1.1478	1.2626
65	Bayhurst 2	Cornwall	32.73842	0.09083	1.1671	1.2838

TransCanada
In business to deliver

FT, STFT and Interruptible Transportation Tolls
2009 Final Tolls Effective May 1st
* These tolls will become effective on November 1, 2009

Line No.	Receipt Point	Delivery point	Demand Toll ($/GJ/MO)	Commodity Toll ($/GJ)	STFT Minimum Tolls (100% LF FT Tolls) ($/GJ)	(1) IT Bid Floor (110% LF FT Tolls) ($/GJ)
1	Emerson 2	Napierville	25.40156	0.06991	0.9050	0.9955
2	Emerson 2	Philipsburg	25.58592	0.07044	0.9116	1.0028
3	Emerson 2	East Hereford	27.52555	0.07597	0.9809	1.0790
4	Union Dawn	Empress	28.28112	0.00000	0.9298	1.0228
5	Union Dawn	Transgas SSDA	24.33086	0.00000	0.7999	0.8799
6	* *Union Dawn*	*Transgas SSDA*	24.82353	0.00000	0.8161	0.8977
7	Union Dawn	Centram SSDA	21.86751	0.00000	0.7189	0.7908
8	Union Dawn	Centram MDA	19.03032	0.05218	0.6779	0.7457
9	Union Dawn	Centrat MDA	19.03776	0.05177	0.6777	0.7455
10	Union Dawn	Union WDA	18.74224	0.05102	0.6672	0.7339
11	Union Dawn	Nipigon WDA	16.73298	0.04520	0.5953	0.6548
12	Union Dawn	Union NDA	8.83255	0.02300	0.3134	0.3447
13	Union Dawn	Calstock NDA	13.26448	0.03532	0.4714	0.5185
14	Union Dawn	Tunis NDA	10.53372	0.02753	0.3738	0.4112
15	Union Dawn	GMIT NDA	8.49698	0.02156	0.3010	0.3311
16	Union Dawn	Union SSMDA	7.25587	0.01819	0.2567	0.2824
17	Union Dawn	Union NCDA	5.18095	0.01233	0.1826	0.2009
18	Union Dawn	Union CDA	3.30151	0.00680	0.1153	0.1268
19	Union Dawn	Enbridge CDA	3.98389	0.00880	0.1398	0.1538
20	Union Dawn	Union EDA	6.95563	0.01711	0.2458	0.2704
21	Union Dawn	Enbridge EDA	8.17713	0.02087	0.2897	0.3187
22	Union Dawn	GMIT EDA	9.88931	0.02589	0.3510	0.3861
23	Union Dawn	KPUC EDA	6.44157	0.01587	0.2277	0.2505
24	Union Dawn	North Bay Junction	7.02348	0.01753	0.2484	0.2732
25	Union Dawn	Enbridge SWDA	0.87529	0.00000	0.0288	0.0317
26	Union Dawn	Union SWDA	1.09017	0.00000	0.0358	0.0394
27	Union Dawn	Spruce	19.03776	0.05177	0.6777	0.7455
28	Union Dawn	Emerson 1	17.54958	0.00000	0.5770	0.6347
29	Union Dawn	Emerson 2	17.54958	0.00000	0.5770	0.6347
30	Union Dawn	St. Clair	1.12519	0.00000	0.0370	0.0407
31	Union Dawn	Dawn Export	0.87529	0.00000	0.0288	0.0317
32	Union Dawn	Kirkwall	2.85383	0.00564	0.0994	0.1093
33	Union Dawn	Niagara Falls	4.02646	0.00898	0.1414	0.1555
34	Union Dawn	Chippawa	4.05153	0.00905	0.1423	0.1565
35	Union Dawn	Iroquois	7.72830	0.01953	0.2736	0.3010
36	Union Dawn	Cornwall	8.14221	0.02071	0.2884	0.3172
37	Union Dawn	Napierville	9.78381	0.02539	0.3471	0.3818
38	Union Dawn	Philipsburg	9.96827	0.02592	0.3536	0.3890
39	Union Dawn	East Hereford	11.90791	0.03145	0.4230	0.4653
40	Enbridge CDA	Empress	31.70810	0.08792	1.1304	1.2434
41	Enbridge CDA	Transgas SSDA	27.83218	0.07467	0.9897	1.0887
42	* *Enbridge CDA*	*Transgas SSDA*	28.32485	0.07609	1.0073	1.1080
43	Enbridge CDA	Centram SSDA	24.85939	0.06833	0.8856	0.9742
44	Enbridge CDA	Centram MDA	22.42153	0.06187	0.7990	0.8789
45	Enbridge CDA	Centrat MDA	21.14728	0.05781	0.7531	0.8284
46	Enbridge CDA	Union WDA	16.43683	0.04444	0.5848	0.6433
47	Enbridge CDA	Nipigon WDA	14.65020	0.03987	0.5216	0.5738
48	Enbridge CDA	Union NDA	6.39952	0.01609	0.2265	0.2492
49	Enbridge CDA	Calstock NDA	11.34823	0.03072	0.4038	0.4442
50	Enbridge CDA	Tunis NDA	8.74845	0.02352	0.3111	0.3422
51	Enbridge CDA	GMIT NDA	6.37278	0.01463	0.2241	0.2465
52	Enbridge CDA	Union SSMDA	10.36446	0.02699	0.3677	0.4045
53	Enbridge CDA	Union NCDA	2.74487	0.00541	0.0956	0.1052
54	Enbridge CDA	Union CDA	1.87122	0.00258	0.0641	0.0705
55	Enbridge CDA	Enbridge CDA	0.87529	0.00000	0.0288	0.0317
56	Enbridge CDA	Union EDA	3.93145	0.00878	0.1381	0.1519
57	Enbridge CDA	Enbridge EDA	5.65768	0.01371	0.1997	0.2197
58	Enbridge CDA	GMIT EDA	7.19001	0.01822	0.2546	0.2801
59	Enbridge CDA	KPUC EDA	3.74248	0.00819	0.1312	0.1443
60	Enbridge CDA	North Bay Junction	4.58363	0.01060	0.1613	0.1774
61	Enbridge CDA	Enbridge SWDA	3.98389	0.00880	0.1398	0.1538
62	Enbridge CDA	Union SWDA	4.11969	0.00929	0.1447	0.1592
63	Enbridge CDA	Spruce	21.08017	0.05763	0.7506	0.8257
64	Enbridge CDA	Emerson 1	20.65724	0.05633	0.7354	0.8089
65	Enbridge CDA	Emerson 2	20.65724	0.05633	0.7354	0.8089

**CAPACITY RELEASE TRANSACTIONS
CONFIRMATION LETTER**

1. Replacement Shipper's Name: Northern Utilities, Inc.

2. a. Master Service Agreement for Capacity Release Agreement No.: CRT-NUI-0079
   b. Underlying Rate Schedule No.: FT-1

3. Replacement Shipper's Firm Transportation Agreement No.: **CRL-NUI-0725**
   Temporary Assignment of Canadian portion Agreement No.: **CRL-NUI-C0725**

4. Releasing Shipper's Firm Transportation Agreement No.: FT1-DTE-0425

5. Commencement Date: **04/01/2008**
   Termination Date: **10/31/2017**

6. Reservation Quantity: **17,172 Dth/d**

7. Primary Receipt Point(s):

	Maximum Daily Reservation Quantity Dth
Alliance Interconnect	**17,172**

8. Primary Delivery Point(s):

	Maximum Daily Reservation Quantity Dth
St. Clair (US) Interconnect	**17,172**

9. Reservation Rate: **$7.6042/Dth ($0.2500 per Dth on a 100% load factor basis), exclusive of ACA and fuel reimbursement.**

10. Usage Rate: $0.00/Dth

11. Special Terms and Conditions of Release (if any):

Replacement shipper will receive corresponding Vector-Canada capacity from St. Clair (International Border) to Dawn at no additional cost.

The Term of the FT1-DTE-0425 contract underlying this release is subject to the June 30, 2005 Precedent Agreement between DTE Energy Trading, Inc. and Vector Pipeline L.P.

Authorized Signature of Replacement Shipper: DT

Name: DON TULCHINSKY

Title: ANALYST

Telephone: (508) 836-7259

Fax: ( ) 508 - 870 - 2294

CAPACITY RELEASE TRANSACTIONS CONFIRMATION LETTER

1. Replacement Shipper's Name: Northern Utilities, Inc.

2. a. Master Service Agreement for Capacity Release Agreement No.: CRT-NUI-0079
   b. Underlying Rate Schedule No.: FT-1

3. Replacement Shipper's Firm Transportation Agreement No.: CRL-NUI-0727
   Temporary Assignment of Canadian portion Agreement No.: CRL-NUI-C0727

4. Releasing Shipper's Firm Transportation Agreement No.: FT1-DTE-0426

5. Commencement Date: **11/01/2008** Winter Only (November 1 thru March 31 on an annual basis)
   Termination Date: **03/31/2017**

6. Reservation Quantity: **17,086 Dth/d**

7. Primary Receipt Point(s): Maximum Daily Reservation Quantity Dth

   Washington 10 Interconnect **17,086**

8. Primary Delivery Point(s): Maximum Daily Reservation Quantity Dth

   St. Clair (US) Interconnect **17,086**

9. Reservation Rate: $4.5625/Dth ($0.1500 per Dth on a 100% load factor basis), exclusive of ACA and fuel reimbursement.

10. Usage Rate: $0.00/Dth

11. Special Terms and Conditions of Release (if any):

    Replacement shipper will receive corresponding Vector-Canada capacity from St. Clair (International Border) to Dawn at no additional cost.

    The Term of the FT1-DTE-0425 contract underlying this release is subject to the June 30, 2005 Precedent Agreement between DTE Energy Trading, Inc. and Vector Pipeline L.P.

Authorized Signature of Replacement Shipper: DTC

Name: DON TULCHINSKY

Title: ANALYST

Telephone: ( ) 508-836 7257

Fax: ( ) 508-870-2244

Exhibit A
To
Firm Transportation Agreement No. FT1-NUI-0122
Under Rate Schedule FT-1
Between
Vector Pipeline L.P. and Northern Utilities, Inc.

Primary Term	05/01/2006 - 03/31/2016
Contracted Capacity:	6,070 Dth/day
Primary Receipt Points:	Alliance Interconnect
Primary Delivery Points:	St. Clair (US) Interconnect
Rate Election Recourse:	

The Reservation Charge applicable to this service is $8.0908/Dth/month ($0.2660 per Dth on a 100% load factor basis), exclusive of fuel reimbursement, Annual Charge Adjustment ("ACA") and any other future surcharges. Secondary points within the primary path and out of path secondary backhauls are subject to the same rate as the primary path.

Exhibit A
To
FT-1 Firm Transportation Agreement No. FT1-NUI-C0122
Under Toll Schedule FT-1
Between
Vector Pipeline Limited Partnership and Northern Utilities, Inc.

Primary Term:	05/01/2006 – 03/31/2016
Contracted Capacity:	6,404 GJ/d
Primary Receipt Points:	St. Clair (Canada) Interconnect
Primary Delivery Points:	Dawn Interconnect

Toll Election Negotiated:
The Reservation Charge applicable to this service is $0.4623/GJ/month ($0.0152 per GJ on a 100% load factor basis). Secondary points within the primary path and out of secondary from Dawn Interconnect to St. Clair (Canada) Interconnect are subject to the same rate as the primary path.

Bank of Canada

Rates and Statistics

Exchange Rates

Daily currency converter

SEE ALSO:

10-Year Currency Converter

Using rates for: 12 Aug 2009

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

Currency:	U.S. dollar
Amount:	1.00
Convert:	(•) **from $Can** ( ) **to $Can**
Use the:	(•) Nominal rate HELP ( ) Cash rate (4%) HELP
Answer:	**0.92** CONVERT
Exchange rate:	0.9195

Summary:

On 12 Aug 2009, 1.00 Canadian dollar(s) = 0.92 U.S. dollar(s), at an exchange rate of 0.9195 (using nominal rate.)

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

SEE ALSO:

10-Year Currency Converter

FREQUENTLY ASKED:

Why is the currency I'm looking for not listed here?

The Bank currently collects data for over 50 foreign currencies. These data are intended primarily for individuals with a research interest in foreign exchange markets and represent only a sampling of currencies.

More comprehensive currency converters include **CanadianForex**, **HiFX**, or **OANDA.com**.

Are the exchange rates shown here accepted by the Canada Revenue Agency?

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

Attachment NUI-FXW-8

Storage Inventory and PNGTS Meter Pay-Back

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.

Storage Analysis

Washington 10 Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value
Nov-09	2,398,590	-	-	2,398,590	$ 9,625,107	NA	$ -	$ 4.01	$ -	$ 9,625,107
Dec-09	2,398,590	-	299,001	2,099,589	$ 9,625,107	NA	$ -	$ 4.01	$ 1,199,837	$ 8,425,270
Jan-10	2,099,589	-	743,563	1,356,026	$ 8,425,270	NA	$ -	$ 4.01	$ 2,983,784	$ 5,441,487
Feb-10	1,356,026	-	671,605	684,421	$ 5,441,487	NA	$ -	$ 4.01	$ 2,695,030	$ 2,746,457
Mar-10	684,421	-	484,743	199,678	$ 2,746,457	NA	$ -	$ 4.01	$ 1,945,187	$ 801,270
Apr-10	199,678	-	-	199,678	$ 801,270	NA	$ -	$ 4.01	$ -	$ 801,270
May-10	199,678	424,643	-	624,320	$ 801,270	$ 5.84	$ 2,478,840	$ 5.25	$ -	$ 3,280,110
Jun-10	624,320	410,944	-	1,035,265	$ 3,280,110	$ 5.84	$ 2,398,877	$ 5.49	$ -	$ 5,678,987
Jul-10	1,035,265	103,095	-	1,138,360	$ 5,678,987	$ 5.86	$ 604,256	$ 5.52	$ -	$ 6,283,243
Aug-10	1,138,360	424,643	-	1,563,003	$ 6,283,243	$ 5.84	$ 2,479,841	$ 5.61	$ -	$ 8,763,084
Sep-10	1,563,003	410,944	-	1,973,947	$ 8,763,084	$ 5.85	$ 2,405,188	$ 5.66	$ -	$ 11,168,272
Oct-10	1,973,947	424,643	-	2,398,590	$ 11,168,272	$ 5.86	$ 2,486,870	$ 5.69	$ -	$ 13,655,142

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value
Nov-09	214,498	-	-	214,498	$ 869,916	NA	$ -	$ 4.06	$ -	$ 869,916
Dec-09	214,498	-	-	214,498	$ 869,916	NA	$ -	$ 4.06	$ -	$ 869,916
Jan-10	214,498	-	66,666	147,831	$ 869,916	NA	$ -	$ 4.06	$ 270,372	$ 599,543
Feb-10	147,831	-	62,231	85,600	$ 599,543	NA	$ -	$ 4.06	$ 252,385	$ 347,159
Mar-10	85,600	-	42,700	42,900	$ 347,159	NA	$ -	$ 4.06	$ 173,176	$ 173,983
Apr-10	42,900	14,651	36,100	21,450	$ 173,983	$ 5.96	$ 87,304	$ 4.54	$ 163,901	$ 97,385
May-10	21,450	50,635	-	72,085	$ 97,385	$ 6.02	$ 304,810	$ 5.58	$ -	$ 402,196
Jun-10	72,085	49,002	-	121,086	$ 402,196	$ 6.12	$ 299,749	$ 5.80	$ -	$ 701,945
Jul-10	121,086	50,635	-	171,721	$ 701,945	$ 6.24	$ 315,967	$ 5.93	$ -	$ 1,017,912
Aug-10	171,721	42,776	-	214,498	$ 1,017,912	$ 6.34	$ 271,182	$ 6.01	$ -	$ 1,289,093
Sep-10	214,498	-	-	214,498	$ 1,289,093	NA	$ -	$ 6.01	$ -	$ 1,289,093
Oct-10	214,498	-	-	214,498	$ 1,289,093	NA	$ -	$ 6.01	$ -	$ 1,289,093

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value
Nov-09	11,250	1,350	1,350	11,250	$ 106,343	$ 5.06	$ 6,827	$ 8.98	$ 12,125	$ 101,044
Dec-09	11,250	1,395	1,395	11,250	$ 101,044	$ 5.06	$ 7,055	$ 8.55	$ 11,925	$ 96,173
Jan-10	11,250	1,395	1,395	11,250	$ 96,173	$ 5.06	$ 7,055	$ 8.16	$ 11,388	$ 91,840
Feb-10	11,250	24,560	24,560	11,250	$ 91,840	$ 5.06	$ 124,200	$ 6.03	$ 148,169	$ 67,871
Mar-10	11,250	1,395	1,395	11,250	$ 67,871	$ 5.06	$ 7,055	$ 5.93	$ 8,266	$ 66,659
Apr-10	11,250	4,386	4,386	11,250	$ 66,659	$ 5.06	$ 22,178	$ 5.68	$ 24,918	$ 63,919
May-10	11,250	1,395	1,395	11,250	$ 63,919	$ 5.06	$ 7,055	$ 5.61	$ 7,830	$ 63,144
Jun-10	11,250	1,350	1,350	11,250	$ 63,144	$ 5.06	$ 6,827	$ 5.55	$ 7,497	$ 62,474
Jul-10	11,250	1,395	1,395	11,250	$ 62,474	$ 5.06	$ 7,055	$ 5.50	$ 7,670	$ 61,858
Aug-10	11,250	1,395	1,395	11,250	$ 61,858	$ 5.06	$ 7,055	$ 5.45	$ 7,602	$ 61,310
Sep-10	11,250	1,350	1,350	11,250	$ 61,310	$ 5.06	$ 6,827	$ 5.41	$ 7,300	$ 60,837
Oct-10	11,250	1,395	1,395	11,250	$ 60,837	$ 5.06	$ 7,055	$ 5.37	$ 7,490	$ 60,402

Northern Utilities, Inc.
Portland Natural Gas Transmission System, Inc. Meter Error Pay-Back
November 2008 through September 2009

Month	Beginning Month Remaining Volume	Volume Received		NH Allocator	NH Allocated	
		Monthly	Cumulative		Monthly	Cumulative
Nov-08	758,502	114,000	114,000	51.74%	58,985	58,985
Dec-08	644,502	111,600	225,600	52.57%	58,668	117,652
Jan-09	532,902	42,842	268,442	54.96%	23,544	141,196
Feb-09	490,060	38,696	307,138	55.03%	21,294	162,490
Mar-09	451,364	42,842	349,980	52.44%	22,466	184,956
Apr-09	408,522	102,210	452,190	58.84%	60,138	245,094
May-09	306,312	42,842	495,032	52.22%	22,371	267,465
Jun-09	263,470	41,460	536,492	56.97%	23,619	291,083
Jul-09	222,010	42,842	579,334	48.09%	20,602	311,685
Aug-09	179,168	42,842	622,176	59.21%	25,368	337,053
Sep-09	136,326	41,460	663,636		-	337,053

Attachment NUI-FXW-9

Expenses Incurred to Oppose PNGTS Rate Increase

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.
Expenses Incurred to Oppose Proposed PNGTS Rate Increases

Service Provider	Description of Services	Expense
Bates White, LLC	Consulting	$ 43,257.93
Benjamin Schlesinger and Associates, Inc.	Consulting	$ 13,126.80
Hall Estill Attorneys at Law	Legal Services	$ 349,343.71
Jeffry L. Fink	Consulting	$ 16,687.47
Snake Hill Energy Resources, Inc.	Consulting	$ 11,679.23
Total Expenses Paid Since December 1, 2008		$ 434,095.14

	Fixed PR Allocators	Share of Cost
Maine	52.54%	$ 228,066.64
New Hampshire	47.46%	$ 206,028.50

Prefiled Testimony of Todd M. Bohan

Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2009 / 2010 PROPOSED
COST OF GAS ADJUSTMENT
PREFILED TESTIMONY OF
TODD M. BOHAN

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Todd M. Bohan. My business address is 6 Liberty Lane West, Hampton, New Hampshire. I am a Senior Regulatory Analyst for Unitil Service Corp. ("Unitil").

Q. Please describe your relevant educational and work experience.

A. I graduated *magna cum laude* from Saint Anselm College, Manchester, New Hampshire in 1987 with a Bachelor of Arts degree in Financial Economics. I earned a Masters in Economics from Clark University, Worcester, Massachusetts in May 1990. In September 1995, I earned a Ph.D. in Economics from Clark University. Before joining Unitil, I worked for Bay State Gas Company ("Bay State") as a Rate Analyst. Prior to working for Bay State, I was employed as a Utility Analyst and an Economist in the Economics Department of the New Hampshire Public Utilities Commission ("NHPUC" or "Commission"). I joined Unitil in November 1998, and have been involved in various regulatory proceedings since then. Most recently, my efforts have been focused on the integration of Northern Utilities, Inc.'s ("Northern" or the "Company") regulatory reporting requirements since the acquisition of Northern by Unitil.

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes, I have testified before the Commission on various regulatory matters.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to introduce and describe Northern's proposed changes to its Local Delivery Adjustment Clause tariff (Page No. 56). Northern is proposing changes to its rates for effect November 1, 2009 for the following items: Residential Low Income Assistance Program ("RLIAP") rate; Demand Side Management ("DSM") rate and Environmental Response Costs ("ERC") rate.

Q. Please describe the proposed change to the RLIAP rate.

A. Northern is proposing to increase the RLIAP rate from $0.0039 to $0.0052 per therm effective November 1, 2009.

Q. Could you describe the reason for the proposed change to the RLIAP rate?

A. Yes. The Residential Low-Income Assistance Program has been in effect since 2005. Northern is not proposing any program changes at this time; however, Northern is proposing to change the RLIAP rate in order to eliminate a currently projected under-collected balance as of October 31, 2009 of $76,009, as shown on Attachment NUI-TMB-1, Schedule 1. Estimated program costs and recoveries are provided in Attachment NUI-TMB-1, Schedule 2 and are based on actual results for the 12-month period ending August 2009. Changing the RLIAP rate from $0.0039 to $0.0052 per therm eliminates a projected under-collection balance as of October 2010.

Q. What changes are being proposed for the DSM charges?

A. The Company is proposing to increase the DSM charge for the residential classes from $0.0113 to $0.0200 per therm, and decrease the charge for the commercial and industrial customer classes from $0.0069 to $0.0062 per therm effective November 1, 2009.

Q. Please describe the reason for these proposed changes to the DSM rates.

A. The proposed changes to the DSM rates are necessitated by the implementation of Northern's current energy efficiency program budget. On March 17, 2009, Northern filed its Energy Efficiency Plan for the period May 1, 2009 to December 31, 2010, which the Commission docketed as DG 09-053. By Order No. 21,968, dated May 21, 2009, the Commission approved Northern's proposed energy efficiency program budget. That budget is provided in Attachment NUI-TMB-2, Schedule 3. Information regarding the development of the proposed DSM rate, $0.0020 per therm, for the residential classes is provided in Attachment NUI-TMB-2, Schedule 1. Attachment NUI-TMB-2, Schedule 2 provides the support for the proposed DSM rate of $0.0062 per therm for the commercial and industrial classes.

Q. Please describe the change to Northern's ERC rate that is proposed for effect November 1, 2009.

A. The current ERC rate is $0.0103 per therm. Northern proposes to decrease this charge to $0.0051 per therm.

Q. Please explain the calculation of the proposed ERC rate.

A. During the period July 1, 2008 through June 30, 2009, ERC expenses totaled $127,728. Northern is allowed to recover one-seventh of the actual response costs incurred by the Company in a twelve-month period ending June 30 of each year until fully amortized, plus any insurance and third-party expenses for the year. Any insurance and third-party recoveries, or other benefits for the year, are used to reduce the unamortized balance. The $372,043 shown on Schedule 1 in the Environmental Response Cost filing is comprised of the following:

1/7th ERC costs incurred July 2008 - June 2009	$ 18,247
1/7th ERC costs incurred July 2007 - June 2008	$ 33,280
1/7th ERC costs incurred July 2006 - June 2007	$ 26,686
1/7th ERC costs incurred July 2005 - June 2006	$ 90,352
1/7th ERC costs incurred July 2004 - June 2005	$129,871
1/7th ERC costs incurred July 2003 - June 2004	$ 41,661
1/7th ERC costs incurred July 2002 - June 2003	$ 31,946
Total	$372,043

The prior period reconciliation of ERC costs, an over collection of $51,347, is added to the annual ERC costs resulting in total ERC costs to be recovered from customers in the period of November 2009 through October 2010 of $320,696. Dividing these recoverable ERC costs by total annual sales of 62,313,300 therms yields an ERC rate of $0.0051 per therm.

III. CONCLUSION

Q. Would you please summarize the overall changes in the LDAC rates?

A. As shown on the red line version of Tariff Page No. 56, the LDAC rate for residential customers is increasing from $0.0255 per therm to $0.0303 per therm, and the LDAC rate for general service customers is decreasing from $0.0211 per therm to $0.0165 per therm.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment NUI-TMB-1

RLIAP Component of the LDAC

Unitil
Northern Utilities, Inc.

Northern Utilities--New Hampshire Division

Residential Low Income Assistance Program (RLIAP)

Estimated Balance: November 2009 through October 2010

	Estimate Nov-09	Estimate Dec-09	Estimate Jan-10	Estimate Feb-10	Estimate Mar-10	Estimate Apr-10	Estimate May-10	Estimate Jun-10	Estimate Jul-10	Estimate Aug-10	Estimate Sep-10	Estimate Oct-10
Beginning Balance	$ 76,009	$ 69,823	$ 46,798	$ 13,639	$ (463)	$ (6,907)	$ 1,233	$ 6,067	$ 5,186	$ 1,733	$ 8,362	$ 5,614
Plus: Program Costs	$ 17,349	$ 26,687	$ 36,219	$ 39,356	$ 36,669	$ 35,916	$ 21,376	$ 16,113	$ 8,869	$ 9,061	$ 8,093	$ 9,403
Less: Revenues	$ (23,732)	$ (38,278)	$ (52,840)	$ (46,416)	$ (39,886)	$ (31,842)	$ (18,964)	$ (16,561)	$ (10,600)	$ (5,754)	$ (9,476)	$ (13,911)
Month Activity	$ (6,383)	$ (11,591)	$ (16,620)	$ (7,060)	$ (3,217)	$ 4,074	$ 2,412	$ (448)	$ (1,731)	$ 3,307	$ (1,383)	$ (4,508)
Ending Bal w/o interest	$ 69,626	$ 46,640	$ 13,557	$ (481)	$ (6,897)	$ 1,240	$ 6,057	$ 5,171	$ 1,724	$ 8,348	$ 5,595	$ (3,402)
Average Balance	$ 72,817	$ 58,231	$ 30,177	$ 6,579	$ (3,680)	$ (2,833)	$ 3,645	$ 5,619	$ 3,455	$ 5,040	$ 6,978	$ 1,106
Monthly Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Monthly Interest	$ 197.21	$ 157.71	$ 81.73	$ 17.82	$ (9.97)	$ (7.67)	$ 9.87	$ 15.22	$ 9.36	$ 13.65	$ 18.90	$ 3.00

Northern Utilities--New Hampshire Division
Residential Low Income Assistance Program (RLIAP)
Estimated Program Costs and Recoveries: November 2009 through October 2010

	Estimate Nov-09	Estimate Dec-09	Estimate Jan-10	Estimate Feb-10	Estimate Mar-10	Estimate Apr-10	Estimate May-10	Estimate Jun-10	Estimate Jul-10	Estimate Aug-10	Estimate Sep-10	Estimate Oct-10
Customer Count (1)												
Actual / Projected No. of Customers:												
LIHEAP	868	1,071	1,075	1,258	1,303	1,492	1,302	1,350	839	978	789	756
Non-LIHEAP	15	21	20	20	20	21	21	22	17	23	10	18
Total	883	1,092	1,094	1,278	1,323	1,513	1,323	1,372	856	1,001	799	774
RLIAP Recoveries (1)												
Actual / Projected												
Therm Sales-Total Firm Throughput	4,563,784	7,361,235	10,161,499	8,926,074	7,670,462	6,123,536	3,646,887	3,184,871	2,038,468	1,106,516	1,822,336	2,675,191
RLIAP Rate Per Therm	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052	$ 0.0052
Total	$ 23,732	$ 38,278	$ 52,840	$ 46,416	$ 39,886	$ 31,842	$ 18,964	$ 16,561	$ 10,600	$ 5,754	$ 9,476	$ 13,911
Program Costs (1)												
Actual & Projected Costs												
IT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admin.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Education	$ 1,230	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest	$ 194	$ 156	$ 120	$ 114	$ 147	$ 141	$ 172	$ 180	$ 193	$ 202	$ 102	$ 110
Discounts-LIHEAP	$ 15,774	$ 26,597	$ 36,128	$ 39,269	$ 36,585	$ 35,828	$ 21,288	$ 16,025	$ 8,805	$ 8,981	$ 7,923	$ 9,184
Discounts -Non-LIHEAP	$ 345	$ 90	$ 91	$ 87	$ 85	$ 88	$ 88	$ 88	$ 63	$ 81	$ 170	$ 219
Total Costs	$ 17,543	$ 26,843	$ 36,339	$ 39,470	$ 36,816	$ 36,057	$ 21,548	$ 16,293	$ 9,062	$ 9,263	$ 8,195	$ 9,513
Avg Monthly Residential Customer Bill	$ 98	$ 152	$ 241	$ 227	$ 176	$ 143	$ 68	$ 43	$ 34	$ 29	$ 35	$ 37
Avg Monthly Residential Low Income Customer Bill	$ 80	$ 128	$ 206	$ 194	$ 146	$ 117	$ 50	$ 30	$ 23	$ 19	$ 24	$ 26
Avg Monthly RLIAP Customer Discount	$ 18	$ 25	$ 35	$ 33	$ 30	$ 26	$ 18	$ 13	$ 11	$ 10	$ 11	$ 11
Avg. Monthly RLIAP Customer Discount as a % to Avg. Monthly Residential Customer Bill	19%	16%	14%	15%	17%	18%	26%	30%	32%	34%	32%	31%
Gross Monthly Revenues	$ 6,171,278	$ 8,273,087	$ 12,286,166	$ 11,047,195	$ 8,807,586	$ 6,012,278	$ 3,116,915	$ 2,253,950	$ 1,427,445	$ 1,326,914	$ 1,624,179	$ 3,151,318
Total Costs as a percent of Gross Monthly Revenues	0.28%	0.32%	0.30%	0.36%	0.42%	0.60%	0.69%	0.72%	0.63%	0.70%	0.50%	0.30%

(1) Forecast based on actual results for the 12-month period ended August 2009.

Attachment NUI-TMB-2

DSM Component of the LDAC

Unitil
Northern Utilities, Inc.

Northern Utilities, Inc.

New Hampshire Division

Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge

To Be Effective November 1, 2009 through October 31, 2010

Residential Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Expenditures	Allocated Low Income Expenditures	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
June-09	Actual										(42,649)		
July-09	Forecast	(42,649)	$0.0113	4,832	11,574	2,104	(33,803)	(38,226)	3.25%	(106)	(33,909)	427,593	31
August-09	Forecast	(33,909)	$0.0113	4,005	26,350	4,790	(6,775)	(20,342)	3.25%	(56)	(6,831)	354,435	31
September-09	Forecast	(6,831)	$0.0113	4,259	14,037	2,551	5,498	(666)	3.25%	(2)	5,496	376,903	30
October-09	Forecast	5,496	$0.0113	6,202	14,037	2,551	15,882	10,689	3.25%	30	15,912	548,861	31
November-09	Forecast	15,912	$0.0200	20,999	14,037	2,551	11,502	13,707	3.25%	37	11,539	1,052,495	30
December-09	Forecast	11,539	$0.0200	38,625	60,827	11,055	44,796	28,167	3.25%	78	44,874	1,935,901	31
January-10	Forecast	44,874	$0.0200	60,146	14,037	2,551	1,316	23,095	3.25%	64	1,380	3,014,580	31
February-10	Forecast	1,380	$0.0200	56,612	16,500	2,999	(35,733)	(17,177)	3.25%	(43)	(35,776)	2,837,442	28
March-10	Forecast	(35,776)	$0.0200	48,772	18,962	3,446	(62,140)	(48,958)	3.25%	(135)	(62,275)	2,444,499	31
April-10	Forecast	(62,275)	$0.0200	37,452	18,962	3,446	(77,319)	(69,797)	3.25%	(186)	(77,505)	1,877,140	30
May-10	Forecast	(77,505)	$0.0200	21,470	14,037	2,551	(82,387)	(79,946)	3.25%	(221)	(82,608)	1,076,103	31
June-10	Forecast	(82,608)	$0.0200	11,366	43,589	7,922	(42,463)	(62,536)	3.25%	(167)	(42,630)	569,668	30
July-10	Forecast	(42,630)	$0.0200	8,583	11,574	2,104	(37,536)	(40,083)	3.25%	(111)	(37,647)	430,203	31
August-10	Forecast	(37,647)	$0.0200	7,113	26,350	4,790	(13,620)	(25,633)	3.25%	(71)	(13,691)	356,504	31
September-10	Forecast	(13,691)	$0.0200	7,563	14,037	2,551	(4,666)	(9,178)	3.25%	(25)	(4,691)	379,073	30
October-10	Forecast	(4,691)	$0.0200	11,023	14,037	2,551	874	(1,908)	3.25%	(5)	869	552,504	31

Northern Utilities, Inc.

New Hampshire Division

Calculation of the DSM Charge, a Component of the Local Distribution Adjustment Charge

To Be Effective November 1, 2009 through October 31, 2010

General Service Customers

		Beginning Balance (Over)/Under	DSM Rate per Therm	DSM Collections	DSM Expenditures	Allocated Low Income Expenditures	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
June-09	Actual										(281,693)		
July-09	Forecast	(281,693)	$0.0069	13,849	18,299	2,279	(274,964)	(278,329)	3.25%	(768)	(275,732)	2,007,036	31
August-09	Forecast	(275,732)	$0.0069	13,034	49,580	5,188	(233,998)	(254,865)	3.25%	(703)	(234,701)	1,888,992	31
September-09	Forecast	(234,701)	$0.0069	13,871	49,580	2,764	(196,228)	(215,465)	3.25%	(576)	(196,804)	2,010,293	30
October-09	Forecast	(196,804)	$0.0069	17,290	26,119	2,764	(185,211)	(191,008)	3.25%	(527)	(185,738)	2,505,835	31
November-09	Forecast	(185,738)	$0.0062	22,058	33,939	2,764	(171,093)	(178,416)	3.25%	(477)	(171,570)	3,541,866	30
December-09	Forecast	(171,570)	$0.0062	30,454	33,939	11,977	(156,108)	(163,839)	3.25%	(452)	(156,560)	4,889,960	31
January-10	Forecast	(156,560)	$0.0062	41,814	26,119	2,764	(169,491)	(163,026)	3.25%	(450)	(169,941)	6,713,881	31
February-10	Forecast	(169,941)	$0.0062	39,299	33,939	3,249	(172,052)	(170,997)	3.25%	(426)	(172,478)	6,310,171	28
March-10	Forecast	(172,478)	$0.0062	35,432	26,119	3,734	(178,057)	(175,268)	3.25%	(484)	(178,541)	5,689,170	31
April-10	Forecast	(178,541)	$0.0062	29,502	41,760	3,734	(162,549)	(170,545)	3.25%	(456)	(163,005)	4,737,128	30
May-10	Forecast	(163,005)	$0.0062	20,450	26,119	2,764	(154,572)	(158,789)	3.25%	(438)	(155,010)	3,283,548	31
June-10	Forecast	(155,010)	$0.0062	13,559	57,400	8,583	(102,586)	(128,798)	3.25%	(344)	(102,930)	2,177,160	30
July-10	Forecast	(102,930)	$0.0062	12,550	18,299	2,279	(94,902)	(98,916)	3.25%	(273)	(95,175)	2,015,170	31
August-10	Forecast	(95,175)	$0.0062	11,808	49,580	5,188	(52,215)	(73,695)	3.25%	(203)	(52,418)	1,895,983	31
September-10	Forecast	(52,418)	$0.0062	12,570	49,580	2,764	(12,644)	(32,531)	3.25%	(87)	(12,731)	2,018,374	30
October-10	Forecast	(12,731)	$0.0062	15,662	26,119	2,764	490	(6,121)	3.25%	(17)	473	2,514,778	31

Northern Utilities, Inc. -- New Hampshire Division

Energy Efficiency Budget
as Approved by Order No. 21,968
Issued May 21, 2009 in Docket DG 09-053

	Residential	Low-Income	Gen Service	Total
July-09	$11,574	$4,383	$18,299	$34,256
August-09	$26,350	$9,978	$49,580	$85,908
September-09	$14,037	$5,315	$49,580	$68,932
October-09	$14,037	$5,315	$26,119	$45,472
November-09	$14,037	$5,315	$33,939	$53,292
December-09	$60,827	$23,032	$33,939	$117,799
January-10	$14,037	$5,315	$26,119	$45,472
February-10	$16,500	$6,248	$33,939	$56,687
March-10	$18,962	$7,180	$26,119	$52,262
April-10	$18,962	$7,180	$41,760	$67,902
May-10	$14,037	$5,315	$26,119	$45,472
June-10	$43,589	$16,505	$57,400	$117,494
July-10	$11,574	$4,383	$18,299	$34,256
August-10	$26,350	$9,978	$49,580	$85,908
September-10	$14,037	$5,315	$49,580	$68,932
October-10	$14,037	$5,315	$26,119	$45,472
15-Month Budget	$332,950	$126,071	$566,492	$1,025,513

Approved Budget with Low-Income Costs Allocated
to Residential and General Service Classes

	Residential	Low-Income	Gen Service	Total
July-09	$13,678	0	$20,578	$34,256
August-09	$31,140	0	$54,768	$85,908
September-09	$16,588	0	$52,344	$68,932
October-09	$16,588	0	$28,883	$45,472
November-09	$16,588	0	$36,703	$53,292
December-09	$71,883	0	$45,916	$117,799
January-10	$16,588	0	$28,883	$45,472
February-10	$19,499	0	$37,188	$56,687
March-10	$22,409	0	$29,853	$52,262
April-10	$22,409	0	$45,493	$67,902
May-10	$16,588	0	$28,883	$45,472
June-10	$51,511	0	$65,982	$117,494
July-10	$13,678	0	$20,578	$34,256
August-10	$31,140	0	$54,768	$85,908
September-10	$16,588	0	$52,344	$68,932
October-10	$16,588	0	$28,883	$45,472
15-Month Budget	$393,464	$0	$632,049	$1,025,513

Attachment NUI-TMB-3

ERC Component of the LDAC

Northern Utilities, Inc.

Attachment NUI-TMB-3
Schedule 1

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE

November 1, 2009 through October 31, 2010

Total ERC Costs for the Period	$372,043
Less Current (Over) Collection (Estimated)	($51,347)
Total ERC Cost to be Recovered	$320,696
Forcasted Firm Sales & Firm Transportation Volumes	62,313,300
ERC Recovery Rate	**$0.0051**

Attachment NUI-TMB-3
Schedule 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
REMEDIATION ADJUSTMENT CLAUSE COMPLIANCE FILING
2008 - 2009 ENVIRONMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES

Line	Description	Total	11/06 - 10/07	11/07 - 10/08	11/08 - 10/09	11/09 - 10/10	11/10 - 10/11	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14 10/15	11/15-10/16
-	-	------	------	------	------	------	------	------	------	------	------	
	ENVIRONMENTAL RESPONSE COST (ERC)											
	-											
2	July 02 - June 03 Expenses Amortization (1/7)	$ 223,620	$ 31,946	$ 31,946	$ 31,946	$ 31,946						
3	July 03 - June 04 Expenses Amortization (1/7)	$ 291,630	$ 41,661	$ 41,661	$ 41,661	$ 41,661	$ 41,661					
	July 04 - June 05 Expenses Amortization (1/7)	$ 909,099	$ 129,871	$ 129,871	$ 129,871	$ 129,871	$ 129,871	$ 129,871				
4	July 05 - June 06 Expenses Amortization (1/7)	$ 632,461	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352	$ 90,352			
5	July 06 - June 07 Expenses Amortization (1/7)	$ 186,804	$ -	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686	$ 26,686		
6	July 07 - June 08 Expenses Amortization (1/7)	$ 232,960	$ -	$ -	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	$ 33,280	
7	July 08 - June 09 Expenses Amortization (1/7)	$ 127,728	$ -	$ -	$ -	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247	$ 18,247
8	Subtotal (Line 1 through Line 5)	$ 1,179,953	$ 441,746	$ 468,432	$ 501,712	$ 372,043	$ 340,097	$ 298,436	$ 168,565	$ 78,213	$ 51,527	$ 18,247
9	Add: Excess amortization from prior years (from schedule 5, Line 10)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Less: Excess amortization to be deferred (from schedule 5, Line 9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total Enviromental Response cost to be recovered (ERC)	$ 1,179,953	$ 441,746	$ 468,432	$ 501,713	$ 372,043	$ 340,097	$ 298,436	$ 168,565	$ 78,213	$ 51,527	$ 18,247
	UNAMORTIZED ENVIRONMENTAL RESPONSE COST											
9	July 2003 - June 2004 Unamortized beginning balanc		$ 159,729	$ 127,783	$ 95,837	$ 63,891	$ 31,946	$ 31,946	$ 31,946	$ 31,946		
10	July 2004 - June 2005 Unamortized beginning balance		$ 249,969	$ 208,307	$ 166,646	$ 124,984	$ 83,323	$ 41,661	$ 41,661	$ 41,661		
11	July 2005 - June 2006 Unamortized beginning balance		$ 632,461	$ 542,109	$ 451,758	$ 361,406	$ 271,055	$ 180,703	$ 90,352	$ -		
12	July 2006 - June 2007 Unamortized beginning balance			$ 186,804	$ 160,118	$ 133,431	$ 106,745	$ 80,059	$ 53,373	$ 26,686	$ -	
13	July 2007 - June 2008 Unamortized beginning balance				$ 232,960	$ 199,680	$ 166,400	$ 133,120	$ 99,840	$ 66,560	$ 33,280	
14	July 2008 - June 2009 Unamortized beginning balance					$ 127,728	$ 109,481	$ 91,234	$ 72,987	$ 54,741	$ 36,494	$ 18,247
15	Total Unamortized beginning balance		$ 1,042,158	$ 1,065,003	$ 1,107,318	$ 1,011,121	$ 768,949	$ 558,723	$ 390,159	$ 221,594	$ 69,774	$ 18,247
16	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)		$ -	$ -	$ -							
17	INSURANCE/3RD PARTY RECOVERIES (IR)											
18	UNDER/OVER Recovery from previous year											
19	**Total of Lines 15, 16, 17, 18**		$ 1,042,158	$ 1,065,003	$ 1,107,318	$ 1,011,121	$ 768,949	$ 558,723	$ 390,159	$ 221,594	$ 69,774	$ 18,247