Northern Utilities
Natural Gas
A NiSource Company

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September 13, 2005

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

Re: Northern Utilities, Inc., New Hampshire Division – Filing of Revised Tariff Sheets Regarding Annual Update of Appendices A, B and C of the Delivery Terms and Conditions, 2005-2006 Winter Period Cost of Gas

Dear Ms. Howland:

On March 15, 2001, the New Hampshire Public Utilities Commission ("Commission") issued Order No. 23,652 in the Gas Restructuring Docket, D.E. 98-124, essentially approving Northern Utilities, Inc.'s ("Northern" or "Company") Model Delivery Tariff, which currently is NHPUC No. 10 – Gas, Part VII. Delivery Service Terms and Conditions ("T&Cs"). Among the Supplier Charges set out in Appendix A of the T&Cs, Schedule of Administrative Fees and Charges, are the Supplier Balancing Charge and the Peaking Service Demand Charge. The Company is required to update these charges once a year, effective for the billing (calendar) month of November. Accordingly, the Company is filing herewith, the original and eight (8) copies of Fifth Revised Page 154, bearing an effective date of November 1, 2005, containing a Supplier Balancing Charge of $0.77 per MMBtu of Daily Imbalance Volumes and a monthly Peaking Service Demand Charge of $21.53 per MMBtu, per Maximum Daily Peaking Quantity ("MDPQ"), for the six months of November 2005 through April 2006.

In addition, the Company is also required to update once a year, effective every November, its Capacity Allocators contained in Appendix C of the T&Cs. Accordingly, the Company is also filing herewith, the original and eight (8) copies of Appendix C of the T&Cs, Fourth Revised Page 169, bearing an effective date of November 1, 2005.

Supplier Balancing Charge:

Pursuant to Part VII Delivery Service Terms and Conditions, Section 10.6.2 of the Company's Traiff No. 10, Northern is filing its Supplier Balancing Charge of $0.77 per MMBtu applicable for the months of November 2004 through April 2005. This charge, which is set forth in Appendix A of the T&Cs, compares to the Supplier Balancing Charge of $0.75 per MMBtu that was in effect during the last winter period of November 2004 through April 2005. As established in DE 98-124 and DG 00-046, as well as pursuant to Section 10.6.2 of the T&Cs, the calculation of the charge is based on Northern's daily dispatch activity for the twelve-month

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period May 1, 2000 through April 30, 2001. This calculation is updated each year with the current costs of the Company's balancing resources, which have been reflected in the current winter period Cost of Gas ("COG") filing. A slight increase in the annual costs of these resources as compared to last year's costs resulted in a slightly higher Supplier Balancing Charge, $0.77 per MMBtu, as the rate that was applicable during last winter ($0.75 per MMBtu).

Enclosed is Attachment I, pages 1 through 5, setting forth the Supplier Balancing Charge calculation. Page 1 is the description of the calculation by sequential step, while pages 2 through 4 present the current capacity and associated costs of the balancing resources. Page 5 is a summary of the analysis of monthly swings on Northern's system that the Company managed with its balancing resources for the "test year" period of May 2000 through April 2001. This identical schedule was also submitted last year in support of the November 2004 – April 2005 Supplier Balancing Charge.

Peaking Service Demand Charge:

Pursuant to Part VII Delivery Service Terms and Conditions, Section 14.3.1 of the Company's Traiff No. 10, Northern is filing its Peaking Service Demand Charge of $21.53 per MMBtu applicable for the months of November 2005 through April 2006. This updated Peaking Service Demand Charge compares with last winter's Demand Charge of $18.00 per MMBtu. The derivation of this charge is presented in Attachment II, enclosed, and is based on the same peaking resources and associated costs included in the Company's current Winter 2005-06 Cost of Gas. As shown on Attachment II, the first step is to identify the monthly demand costs of the peaking resources (and upstream Granite State capacity) by applying the contractual Maximum Daily Quantities ("MDQ") of each resource to the monthly demand rate. The annual costs are then calculated by multiplying these monthly costs by the number of months that Northern is assessed such monthly charge. The annual demand costs are then divided by six months to derive the monthly costs to be recovered over the six month winter period of November 2005 through April 2006. Finally, these monthly costs are divided by the quantity of each resource used to satisfy peak day requirements.

Please note that the Company has filed, under separate letter, a Motion for Protective Order and confidential Treatment for the resource and cost information contained in this filing. Accordingly, enclosed herewith, is also an original and eight (8) copies of the redacted version of Attachment II, protecting the supplier/resource identity and associated rates and costs.

Capacity Allocators:

Pursuant to Part VII Delivery Service Terms and Conditions, Section 11.3.7 of the Company's Traiff No. 10, Northern is filing its Capacity Allocators applicable to assigned capacity for the annual period of November 2005 through October 2006. Attachment III, page 1, enclosed, provides a detailed description of the calculation determining the updated percentages of pipeline, underground storage and peaking capacity resources that make up the Total Capacity Quantity ("TCQ") assigned to suppliers. Pages 2 and 3 present the data inputs and calculation, which reflects the Company's current Design Day demands by rate class and capacity quantities and costs by resource as forecast in the current Winter 2005-06 COG filing.

Pursuant to Commission Rules 202.07 and 202.08, Northern is also filing a computer diskette version of these revised tariff sheets.

Please do not hesitate to contact me at (508) 836-7273 if you have any questions.

Thank you for your attention to this matter.

Sincerely,

Joseph A Ferro by RDG

Joseph A. Ferro
Manager, Regulatory Policy

cc: Patricia M. French, Esq., NCS
Ronald D. Gibbons, NCS
Seth Shortlidge, Esq.
Stephen P. Frink, NHPUC
Robert Wyatt, NHPUC

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

NORTHERN UTILITIES, INC. Cost of Gas Adjustment	))))	Docket DG 05-___

MOTION FOR PROTECTION FROM PUBLIC DISCLOSURE AND CONFIDENTIAL TREATMENT

NOW COMES Northern Utilities, Inc. ("Northern") and respectfully requests that the New Hampshire Public Utilities Commission ("Commission") grant a protective order for certain confidential information consistent with R.S.A. 91-A and N.H. Admin. Rules, Puc 204.07. Specifically, Northern requests that the Commission issue its order requiring that the resource, supplier identity and cost information contained in Northern's update to its Model Delivery tariff be treated as confidential commercial information and in the nature of a trade secret, and not be made part of the public record in this proceeding. Northern intends to make such information available to the Commission Staff and the Consumer Advocate under its requested protective order.

In support of its motion, Northern states the following:

1. On March 15, 2001, in Docket No. DE 98-124, the Commission approved Northern's Model Delivery Tariff, currently identified as NHPUC No. 10 – Gas, Part VII. Delivery Service Terms and Conditions ("T&Cs").

2. Among the Supplier Charges set out in Appendix A of the T&Cs, Schedule of Administrative Fees and Charges, are the Supplier Balancing Charge and the Peaking Service Demand Charge. Northern is required to update these charges once each year, effective for the billing (calendar) month of November.

3. As part of the filing of revised charges in Appendix A, Northern provides specific information about its suppliers, resource information, commodity and demand charges and related contract terms. This information constitutes a trade secret; Northern does not disclose this information outside a close circle of Northern employees with a need to know, and their representatives; release of this information is likely to result in competitive disadvantage for Northern and possibly also its suppliers; and this information is likely to be very beneficial to a competitor of Northern or NiSource, or their suppliers, who may gain a competitive edge as a result of disclosure.

4. Northern seeks to protect from disclosure on the public record this information in order to protect trade, contractual and financial secrets closely held by Northern.

5. R.S.A. 91-A:5(iv) expressly exempts from the public disclosure requirements of Chapter 91-A any records pertaining to "confidential, commercial or financial information." The Commission's rule on public records, Puc 204.07, also allows documents to be protected from public disclosure pursuant to an appropriate order of the Commission.

6. Northern requests that the Commission not disclose on the public record the confidential information on the grounds that disclosure of the confidential information would disadvantage Northern in negotiations with Suppliers or other resource providers. Public knowledge of the confidential information would impair Northern's future bargaining position and thus its ability to obtain the best cost resources for its natural gas portfolio. The Commission has recognized that supply information is sensitive commercial information in the competitive market.

7. Disclosure of this information would expose to the public and to actual and potential competitors Northern's internal, and closely held, business information. Northern does not disclose this information in any venue nor to anyone outside of its corporate affiliates with a lawful need to know and their representatives.

8. Northern is not requesting non-disclosure protection from Staff or the Office of the Consumer Advocate. Northern has filed its motion for a protective order to allow it to make available its trade secrets and confidential information to Staff and the Consumer Advocate during this proceeding subject to the requested order from the Commission that such information should be accorded confidential treatment.

9. The Commission has granted protected treatment to similar financially-sensitive information that is held as a trade secret, finding that the benefits of non-disclosure in similar cost of gas proceedings outweigh the benefits to the public of

disclosure. Northern Utilities, Inc., *Order Approving the Cost of Gas Rate, Local Distribution Adjustment Clause Rates and Other* Rates, Order No. 24,389 (October 29, 2004); See also, Northern Utilities, Inc., Order No. 24, 228 (October 30, 2003); EnergyNorth Natural Gas, Inc., *Order Granting Motion for Protective Order and Confidential Treatment*, Order No. 23,950, Docket No. DG 02-045 (Apr. 12, 2002) citing Union Leader Corp. v. New Hampshire Housing Finance Authority, 142 N.H. 540 (1997); Re NET (Auditel), 80 NHPUC 437 (1995); Re Eastern Utilities Assoc., 76 NHPUC 236 (1991); EnergyNorth Natural Gas, Order No. 23,559,. Docket No. 00-193 (Sept. 25, 2000).

WHEREFORE, Northern Utilities, Inc. respectfully requests that the Commission grant its protective order over Northern's confidential and trade secret information as described herein, and that the Commission.

Respectfully submitted,

NORTHERN UTILITIES, INC.

By its attorney,

Patricia M. French
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DATED: September 9, 2005

Calculation Steps for Supplier Balancing Charge

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

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

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

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

November 2005 through October 2006

	MDQ		Max Swing	% MDQ	
New Hampshire Underground	20,364		3,532	17.34%	
LNG	5,698		0	0.00%	
Propane	2,279		0	0.00%	

	% MDQ	Costs	Balancing Costs	% Allocated (to Balancing)	Allocated Costs
New Hampshire Underground					
Del., Res., and Transp.	17.34%	$7,553,165	$1,310,065	0.17%	$2,180
Capacity	17.34%	$1,742,687	$302,262	35.49%	$107,278
LNG	0.00%	$130,868	$0	121.01%	$0
Propane	0.00%	$143,001	$0	0.00%	$0
Total		$9,569,721	$1,612,327		$109,458
Annual Sum of Absolute Swings					142,624
Balancing Rate Per MMBtu Swing					**$0.77**

Northern Utilities, Inc.-Maine
Calculation of Balancing Charge

	MDQ		Max Swing	% MDQ	
Maine Underground	15,374		7,580	49.30%	
LNG	4,302		1,418	32.97%	
Propane	1,721		0	0.00%	

	% MDQ	Costs	Balancing Costs	% Allocated	Allocated Costs
Maine Underground					
Del., Res., and Transp.	49.30%	$5,702,651	$2,811,499	0.09%	$2,659
Capacity	49.30%	$1,191,622	$587,489	35.49%	$208,511
LNG	32.97%	$98,806	$32,578	0.00%	$0
Propane	0.00%	$107,966	$0	0.00%	$0
Total		$7,101,045	$3,431,566		$211,170
Annual MMBtu Throughput					4,723,297
Balancing Rate per MMBtu Throughput					$0.0447
Annual Sum of Absolute Swings					191,488
Balancing Rate Per MMBtu Swing					$1.10

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

	Maximum Swing	Sum of Positive Swings	Total Utilization	Ratio Pos. Swings to Tot. Utilization	Sum of Absolute Swings	Total Capacity	Ratio Abs. Swings to Capacity
New Hampshire Underground	3,532	3,811	2,290,269	0.1664%	36,518	168,163	21.72%
Maine Underground	7,580	1,635	1,729,157	0.09%	68,023	126,384	53.82%
Total Northern					104,540	294,547	**35.49%**
	Maximum Swing	Sum of Swings	Tank Capacity	Ratio Swings to Tank Capacity			
LNG	0	(9,481)	7,835	121.01%			
Propane	0	0	14,663	0.00%			

Northern Utilities, Inc.
Calculation of Balancing Charge
Costs of Balancing Resources
November 2005 through October 2006

New Hampshire			
El Paso FS Storage	MMBtu	Rate	Costs
Capacity	147,770	$0.0185	$32,805
Deliverability	2,418	$1.1500	$33,364
Firm Transportation-Tenn	1,512	$5.8900	$106,845
Firm Transportation-GSGT	1,512	$1.2639	$22,927
Total			$195,942
Texas Eastern Storage	MMBtu	Rate	Costs
Space - SS-1	838	$0.1293	$108
Reservation - SS-1	12	$5.5010	$790
Space - FSS-1	182	$0.1293	$283
Reservation - FSS-1	36	$0.8970	$393
TETCO Reservation	36	$5.6800	$2,486
Firm Transportation-GSGT	36	$1.2639	$553
Firm Transportation-GSGT	12	$1.2639	$181
Total			$4,794
MCN Storage	MMBtu	Rate	Costs
MCN	19,373	$ 17.6480	$ 1,709,491
PNGTS	11,396	$ 49.1229	$ 2,799,024
PNGTS	7,407	$ 49.1229	$ 1,819,365
CoEnergy/Trans Canada	18,803	$ 11.0000	$ 2,482,049
Firm Transportation-GSGT	18,803	$ 1.2639	$ 285,187
Total			$ 9,095,117
Maine			
El Paso FS Storage	MMBtu	Rate	Costs
Capacity	111,567	$0.0185	$24,768
Deliverability	1,825	$1.1500	$25,190
Firm Transportation-Tenn	1,141	$5.8900	$80,669
Firm Transportation-GSGT	1,141	$1.2639	$17,310
Total			$147,936
Texas Eastern Storage			
Space - SS-1	53	$0.1293	$7
Reservation - SS-1	9	$5.4880	$595
Space - FSS-1	138	$0.1293	$214
Reservation - FSS-1	28	$0.8970	$296
TETCO Reservation	28	$5.6800	$1,877
Firm Transportation-GSGT	28	$1.2639	$418
Firm Transportation-GSGT	9	$1.2639	$137
Total			$3,543
MCN Storage	MMBtu	Rate	Costs
MCN	14,627	$ 17.6480	$ 1,166,634
PNGTS	8,604	$ 49.1229	$ 2,113,268
PNGTS	5,593	$ 49.1229	$ 1,373,624
CoEnergy/TransCanada	14,197	$ 11.0000	$ 1,873,951
Firm Transportation-GSGT	14,197	$ 1.2639	$ 215,317
Total			$ 6,742,794
LNG	MMBtu		Costs
Capacity	10,000		$229,674
Total			$229,674
Propane	MMBtu		Costs
Capacity	4,000		$250,967
Total			$250,967

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
PEAKING SERVICE DEMAND CHARGE
WINTER PERIOD - NOV. 2005 to APRIL 2006

Attachment II

Resource	MDQ	D1 Rate	No. of Months	Annual Cost			Monthly Cost for 6 Months	Peak Day Requirement (MMBtu)	Mo. Peaking Service Demand Chg. for 6 Mos.
Resource 1								5,000	
Resource 2								0	
Resource 3								20,310	
LNG & LP (Prod&Storage in CGA)								14,000	
TOTAL				$4,622,405			$884,152	39,310	**$ 22.49**

Description of Calculation of Capacity Allocators

This brief report summarizes the method used to assign capacity costs to customers migrating from bundled sales to delivery service. The method is designed to be consistent with the gas cost allocation method implicit in the Company's COGC. This method is the basis for the development of the figures shown on Appendix C, Capacity Allocators, set out on **Fourth** Revised Page 169, of the Delivery Service Terms and Conditions of the Northern Utilities' NHPUC Tariff No. 10.

As part of its settlement in docket number DG 00-046, the Company implemented a gas cost recovery method that recovered average seasonal gas costs from the residential classes and recovered the remaining gas costs using the simplified Market Based Allocation method (MBA). Under this method capacity costs are assigned to classes on the basis of their contribution to the system's design day load. The assignment is performed in two steps:

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

The following pages of this Attachment detail the development of capacity assignment allocators. Page 2 of 3 lists the major assumptions behind the calculations and tabulates the input data. Base use and remaining design day demand are shown by class. Beginning on line 27, the system pipeline capacity is assigned to the base use and remaining categories using the class base use load data above. Then on line 34, the residential allocation of supplies is performed. Since this class is assigned average costs, their assignment is simply computed as their proportion of the design day demand, irrespective of the supplies used to serve their loads.

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

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2005-2006
Derivation of Class Assignments and Weightings

Attachment III

Basic assumptions:

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

		Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total	Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	1,900	216	0.3%	74	142
2	RATE B-Resi Htg	218,200	24,759	36.2%	1,123	23,636
3	RATE G-40 (R)	117,200	13,299	19.5%	280	13,018
4	RATE G-50 (Q)	11,600	1,316	1.9%	430	886
5	RATE G-41 (T)	120,400	13,662	20.0%	411	13,251
6	RATE G-51 (S)	27,600	3,132	4.6%	843	2,289
7	RATE G-42 (V)	38,400	4,357	6.4%	134	4,223
8	RATE G-52a (U)	13,000	1,475	2.2%	278	1,197
9	RATE G-52b (Y)					
10	RATE T-40	3,400	386	0.6%	26	360
11	RATE T-50	600	68	0.1%	7	61
12	RATE T-41	34,000	3,858	5.6%	118	3,740
13	RATE T-51	5,600	635	0.9%	94	542
14	RATE T-42	9,300	1,055	1.5%	39	1,017
15	RATE T-52	800	91	0.1%	34	57
16	Total	602,000	68,308	100.0%	3,573	58,642
17						-
18	Residential Total	220,100	24,974	**36.6%**	1,197	23,777
19	LLF Total	322,700	36,616	53.6%	1,008	35,609
20	HLF Total	59,200	6,717	9.8%	1,686	5,032
21	Total	602,000	68,308	100.0%	3,891	64,418
22						
23						

		Capacity Cost	MDQ, Dt	$/Dt-Mo.
24		Capacity Cost	MDQ, Dt	$/Dt-Mo.
25	Pipeline	2,805,205	14,149	16.52
26	Storage	9,370,144	20,541	38.01
27	Peaking	2,921,637	33,618	7.24
28	Total	15,096,986	68,308	18.42
29				
30				
31				

32		Capacity Cost	MDQ, Dt	$/Dt-Mo.
33	Pipeline - Baseload	708,390	3,573	16.52
34	Pipeline - Remaining	2,096,815	10,576	16.52
35	Storage	9,370,144	20,541	38.01
36	Peaking	2,921,637	33,618	7.24
37	Total	15,096,986	68,308	18.42
38				
39				

40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
41	Pipeline - Base	**36.6%**	258,998	1,306	16.52
42	Pipeline - Remaining	**36.6%**	766,626	3,867	16.52
43	Storage	**36.6%**	3,425,862	7,510	38.01
44	Peaking	**36.6%**	1,068,193	12,291	7.24
45	Total	**36.6%**	5,519,679	24,974	**18.42**

Attachment III

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2005-2006
Derivation of Class Assignments and Weightings

C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		449,392	2,267	16.52
Pipeline - Remaining		1,330,189	6,709	16.52
Storage		5,944,282	13,031	38.01
Peaking		1,853,444	21,327	7.24
Total	**63.4%**	9,577,307	43,334	18.42

LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		168,132	848	16.52
Pipeline - Remaining		1,165,502	5,878	16.52
Storage		5,208,338	11,418	38.01
Peaking		1,623,974	18,686	7.24
Total	**54.1%**	8,165,946	36,831	**18.48**

HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
Pipeline - Base		281,260	1,419	16.52
Pipeline - Remaining		164,687	831	16.52
Storage		735,945	1,613	38.01
Peaking		229,470	2,640	7.24
Total	**9.3%**	1,411,361	6,503	**18.09**

Unit Cost	Residential	LLF C&I	HLF C&I
Pipeline	$ 16.52	$ 16.52	$ 16.52
Storage	$ 38.01	$ 38.01	$ 38.01
Peaking	$ 7.24	$ 7.24	$ 7.24
Total	$ 18.42	$ 18.48	$ 18.09
Checktotal	$ 18.42	$ 18.48	$ 18.09

Load Makeup	Residential	**LLF C&I**	**HLF C&I**
Pipeline	20.71%	**18.26%**	**34.59%**
Storage	30.07%	**31.00%**	**24.81%**
Peaking	49.22%	**50.74%**	**40.60%**
Total	100.00%	**100.00%**	**100.00%**

Supply Makeup	Residential	LLF C&I	HLF C&I	Total
Pipeline	36.56%	47.54%	15.90%	100.00%
Storage	36.56%	55.58%	7.85%	100.00%
Peaking	36.56%	55.58%	7.85%	100.00%