DG 05-147

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September 13, 2005

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N.H. PUBLIC UTILITIES COMMISSION

Debra A. 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 and C of the Delivery Service Terms and Conditions, 2005-2006 Winter Period Cost of Gas

Dear Ms. Howland:

Attached for filing, on behalf of Northern Utilities, Inc. ("Northern"), is Northern's Annual Update of Appendices A and C of the Delivery Service Terms and Conditions for the 2005-2006 Winter Period Cost of Gas. In support of this filing, please find the attached report prepared by and under the supervision of Joseph A. Ferro, Manager, Regulatory Policy, for Northern Utilities.

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) 836-7394 or Mr. Ferro at (508) 836-7273 if you have any questions or need additional information regarding this filing.

Thank you for your attention to this matter.

Sincerely,

Patricia M. French /SGK
Patricia M. French

cc: Joseph A. Ferro, Northern Utilities
Seth Shortlidge, Esq.
Stephen P. Frink, NHPUC
Robert Wyatt, NHPUC

ANNUAL UPDATE OF APPENDICES A AND C
OF THE DELIVERY SERVICE TERMS AND CONDITIONS
OF NORTHERN UTILTIES, INC.
FOR THE 2005-2006 WINTER PERIOD COST OF GAS

Prepared by: Joseph A. Ferro
Manager, Regulatory Policy
Northern Utilities, Inc.
September 13, 2005

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 $22.49 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 Tariff 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 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 Tariff No. 10, Northern is filing its Peaking Service Demand Charge of $22.49 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, are 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 Tariff 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.

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.77 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: **$22.49 per MMBtu** per MDPQ per month for November 2005 through April 2006.

- 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 A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.77~~5~~ per MMBtu** of Daily Imbalance Volumes C

- 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: **$22.49~~18.00~~ per MMBtu** per MDPQ per month for November 20054 through April 2006~~5~~. C

- 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, 2005 through October 31, 2006.

	Commercial and Industrial	
	High Winter Use	Low Winter Use
Pipeline:	18.26%	34.59%
Storage:	31.00%	24.81%
Peaking:	50.74%	40.60%

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, 20054 through October 31, 2006~~5~~. T

Commercial and Industrial

	High Winter Use	Low Winter Use	
Pipeline:	18.26~~19.16~~%	34.59~~42.36~~%	C
Storage:	31.00~~32.73~~%	24.81~~23.33~~%	C
Peaking:	50.74~~48.11~~%	40.60~~34.30~~%	C

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.
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

Northern Utilities, Inc. - New Hampshire Division
Calculation on Balancing Charge

Derivation of Absolute Swings
May 2000 through April 2001
Summary

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

REDACTED

Attachment II

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

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**

* Includes Granite State Transmission charge of $1.2639

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

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						

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**

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

1	C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
2	Pipeline - Base		449,392	2,267	16.52	
3	Pipeline - Remaining		1,330,189	6,709	16.52	
4	Storage		5,944,282	13,031	38.01	
5	Peaking		1,853,444	21,327	7.24	
6	Total	**63.4%**	9,577,307	43,334	18.42	
7						
8						
9	LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
10	Pipeline - Base		168,132	848	16.52	
11	Pipeline - Remaining		1,165,502	5,878	16.52	
12	Storage		5,208,338	11,418	38.01	
13	Peaking		1,623,974	18,686	7.24	
14	Total	**54.1%**	8,165,946	36,831	**18.48**	
15						
16						
17	HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
18	Pipeline - Base		281,260	1,419	16.52	
19	Pipeline - Remaining		164,687	831	16.52	
20	Storage		735,945	1,613	38.01	
21	Peaking		229,470	2,640	7.24	
22	Total	**9.3%**	1,411,361	6,503	**18.09**	
23						
24						
25	Unit Cost		Residential	LLF C&I	HLF C&I	
26						
27	Pipeline		$ 16.52	$ 16.52	$ 16.52	
28	Storage		$ 38.01	$ 38.01	$ 38.01	
29	Peaking		$ 7.24	$ 7.24	$ 7.24	
30	Total		$ 18.42	$ 18.48	$ 18.09	
31	Checktotal		$ 18.42	$ 18.48	$ 18.09	
32						
33						
34	Load Makeup		Residential	**LLF C&I**	**HLF C&I**	
35						
36	Pipeline		20.71%	**18.26%**	**34.59%**	
37	Storage		30.07%	**31.00%**	**24.81%**	
38	Peaking		49.22%	**50.74%**	**40.60%**	
39	Total		100.00%	**100.00%**	**100.00%**	
40						
41						
42	Supply Makeup		Residential	LLF C&I	HLF C&I	Total
43						
44	Pipeline		36.56%	47.54%	15.90%	100.00%
45	Storage		36.56%	55.58%	7.85%	100.00%
46	Peaking		36.56%	55.58%	7.85%	100.00%