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Minneapolis, MN 55459-0038

PUBLIC DOCUMENT
Trade Secret Information has been Excised

October 30, 2015

Mr. Dan Wolf
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 East Seventh Place, Suite 350
St. Paul, Minnesota 55101-2147

Re: CenterPoint Energy 's Request for Change in Demand Units
Docket No. G008/M-15-644- Supplemental Information

Dear Mr. Wolf:

Enclosed please find revisions to several exhibits of CenterPoint Energy's Request for Change in Demand Units. On July 1, 2015 CenterPoint Energy (CPE or the Company) filed a request for Change in Demand Units. Herein, CPE provides supplemental information that includes Northern Natural Gas' (NNG) Base/Variable unit restatement.

In the present filing, CenterPoint Energy has:

- Updated its Base/Variable split – see Exhibit C, Page 1 for NNG schedule;
- Added 1,995 DT/day units of winter entitlement on NNG to meet Carlton obligation;
- Updated the discounted winter rate with changes under the discount agreement;
- Updated the NNG commodity credits;
- Updated the Viking Pipeline rate;
- Added 10,000 additional units of three-month winter entitlement on Viking Pipeline;
- Updated the seasonal reservation schedule for the upcoming winter season in Exhibit C, page 2
- Updated the NGPL cost allocation between Firm and SVDF due to changes in sales estimates (Exhibit C, page 3).

These changes will be reflected in the Company's November 2015 PGA billing rates.

CenterPoint Energy provides additional information to support the additional proposed changes made to the demand portfolio since its initial filing in July 2015:

Additional Capacity on NNG at Carlton:

NNG filed its annual update on the Carlton Obligation in FERC Docket RP15-1192. Effective November 1, 2015, CenterPoint Energy's total Carlton flow obligation will increase to 63,945 DT; therefore, the Company needed additional incremental Carlton receipt point capacity. On August 27, 2015, NNG had an open season for firm transportation with a Carlton primary receipt point. CenterPoint Energy bid and was awarded 1,995 DT with a term of November 1, 2015 through March 31, 2019. Adding additional volumes at Carlton allows the company to have sufficient primary receipt capacity to fulfill our winter 2015-2016 Carlton obligation.

Viking Pipeline – Additional winter unit of entitlement

The decision was made after CenterPoint Energy's initial Demand Entitlement filing to purchase additional daily winter capacity on Viking for December 2015-February 2016 for 10,000 DT/day. The incremental capacity will help ensure winter peak day capacity and increase the reserve margin while the Mankato propane air plant is unavailable for winter 2015-2016.

The attached pages provide replacement pages for the original filing.

Exhibit A – Page 1 – Annual Demand Cost estimate – Nov. 1 updated
Exhibit A – Page 2 – October 2015 rate for comparison

Exhibit B – Page 2 – Updated Total Requirements plus Peak Shaving
Exhibit B – Page 3 – Updated Demand Profile, added comparisons
Exhibit B – Page 4 – Updated impact on annual customer costs

Supporting Workpapers – Exhibit C - new

Page 1 – Northern Natural Gas Entitlement Profile
Page 2 – Seasonal Reservation Costs
Page 3 – NGPL Cost Allocation – update due to sales estimate change

CenterPoint Energy will increase overall total demand costs from October 2015 by about $2.1 milllion annually, due mainly to additional Northern entitlements ($1.3 million), additional Trailblazer entitlement and changes to the mix of supplier demand services contracted. The annual effect on a typical residential heating customer using 881 therms is an increase of about $1.94 from October rates.

Estimate of Annual Demand Costs

October:	881 X $0.08282 =	$72.96 per year before "smoothing" adjustment
November:	881 X $0.08502 =	$74.90 per year before "smoothing" adjustment
Difference:		$ 1.94 per year

CenterPoint Energy has designated selected information in this document trade secret – Specifically Exhibit A, Pages 1 and 2, Exhibit B, Pages 3, Exhibit C, pages 2 and 3. The information meets the definition of trade secret in Minn. Stat. 13.37 subd.1(b) as follows: (1) the information was supplied by CenterPoint Energy, the affected organization; (2) CenterPoint Energy has taken all reasonable efforts to maintain the secrecy of the information, including protecting it from disclosure in this document; and (3) the protected information contains gas supply contract information which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Sincerely,

/s/____________
Marie M. Doyle
Regulatory Analyst

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Marie M. Doyle, being first duly sworn on oath, deposes and says she served via e filing or caused to be served on behalf of CenterPoint Energy: its supplement filing in its Request for Change in Demand Units for the 2015-2016 Heating Season on the Minnesota Public Utilities Commission; on the Department of Commerce (DOC) and; on the Office of the Attorney General - Residential Utilities Division.

/s/ ____________________________
Marie M. Doyle, Regulatory Analyst
Regulatory Services
CenterPoint Energy

Subscribed and sworn to before me
This 30th day of October, 2015

/s/ Linda Baumann
Notary Public
Term expires: 01/31/2020

Effective: 11/1/2015
Superceding: 10/2/2015

EXHIBIT A, Page 1 of 2
CenterPoint Energy - Minnesota Gas
PUBLIC DATA
Trade Secret Information has been Excised

Demand Summary

Rows marked with an "X" are considered Trade Secret	Annual Demand Cost Calculation: NORTHERN PIPELINE	UNITS (DT)	RATE	Number of Months or Days		Total Annual Cost
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
X						
			Total NNG Demand Bill			**$58,626,416**
	VIKING PIPELINE					
X						
X						
X						
			Total Viking Demand Bill		**$**	**3,121,994**
	TRAILBLAZER PIPELINE					
				Total Trailblazer Demand Bill	**$**	**608,350**
	SUPPLY DEMAND			Allocation		
X						
X						
X						
X						
X						
X						
	CAPACITY RELEASE/ ADJUSTMENTS	**UNITS**	**RATE**	**Months or Days**		
X						
X						
X						
X						

Plus: Propane Costs		$162,738
Annual Estimated Demand Expense		**$81,834,247**
Divided by: Annual Demand Volume (2013 Rate Case Sales Volume-TY End 09/2014)		962,546,190 Therms
	Rate	**0.08502** /Thm
	Change from 10/2015	0.00220
	Annual- 881 therms	$74.90
Notes:	increase from October 2015	$1.94

1 - New Base /Variable
2. Growth (12-month) - Willmar 1,362 DT; Pierz 336; St. Boni 894
2. Growth (5-month) Willmar 494 DT; St. Boni 306; ~~Pierz 164~~
3. New (since July 1 filing) - 1,995 at Carlton, plus Pierz 164 (rate)
4. Discount rate
5. Growth - Minneapolis (11,114 DT 12 month/8,886 5 month)
6. Growth - (12-month) -Blaine 3,212 DT / St. Michael 734 / Anoka 1,091)
6. Growth - (5-month) -Blaine 1,788 DT/ St. Michael 206 / Anoka 1075)
7. Leap year - additional day this year
8. Update credits for commodity
9. Viking entitlement - - rate changed
10. Viking Entitlement - additional winter months only
11. Trailblazer Pipeline - rate changed from July estimate
12. Updated Seasonal Swing Reservation
13 - New Firm / SVDF allocation based on expected Sales Volumes
15. Zero -out off system demand credit
16 - Demand smoothing

Demand Summary

Rows marked with an "X" are considered Trade Secret	Annual Demand Cost Calculation:	UNITS (DT)	RATE	Number of Months or Days		Total Annual Cost	
	NORTHERN PIPELINE						
X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
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X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
X							
			Total NNG Demand Bill			**$57,375,379**	
	VIKING PIPELINE						
X							
X							
X							
X							
			Total Viking Demand Bill		**$**	**3,096,350**	
	TRAILBLAZER PIPELINE						
X							
			Total Trailblazer Demand Bill		$	380,200	
	SUPPLY DEMAND			Allocation			
X							
X							
X							
X							
X							
X							
	CAPACITY RELEASE/ ADJUSTMENTS	**UNITS**	**RATE**	**Months or Days**			
X							
X							
X							
X							1
	Plus: Propane Costs					$162,738	
	Annual Estimated Demand Expense					**$79,718,202**	
	Divided by: Annual Demand Volume					962,546,190	
				Rate		0.08282	
	Docket G-008/M-13-728			Demand Adjust	$	(0.00491)	2
				Final Demand Rate	$	$\boxed{0.07791}$	

Notes:
1. Offsystem sales credit
2. Demand Adjustment - not in effect June - September

CENTERPOINT ENERGY

ADDITIONAL INFORMATION REQUEST FROM THE DOC

2. Provide Heating Degree Day (HDD) data for the most recent 12 month period, ending March 31 or October 30.

		Peak Season (Nov-Mar)	Off Peak (Apr-Oct)	Total Actual
Total Heating Degree Day (April 2014 - March 2015)	Actual	6,195	1,541	7,736
	Normal (20 yr) (1995-2014)	6,018	1,401	7,419
Total Annual Firm Sales (In Dekatherms (April 2014 - March 2015)				121,150,874
Average Annual Firm Customers (April 2014 - March 2015)				815,953
Use per Firm Customer				148.5
Projected Peak Day HDD (Typical) (-12 degrees F.)				77
Projected Design Day HDD (-25 degrees F.)				90

3. **Historical and Projected Design Day and Peak Day Requirements**

Heating Season	Firm Customers (January)	Design Day Dekatherms	Total Requirements plus Peak Shaving	Firm Peak Day Sendout
2015/2016 P	841,135	1,317,000	**1,355,561**	na
2014/2015	830,377	1,290,000	1,344,418	959,990
2013/2014	821,220	1,288,000	1,340,099	1,086,330
2012/2013	813,605	1,280,000	1,346,781	961,134
2011/2012	807,922	1,216,000	1,379,681	830,444

P = projected

CenterPoint Energy Demand Profile
2015-2016

Heating Season Services	{1} 10-1162 (Dec. 2010) Quantity (Dkt)	{2} 11-1078(Dec 2011) Quantity (Dkt)	{3} 11-1078(April 2012) Quantity (Dkt)	{4} 12-864(Jan 2013) Quantity (Dkt)	{5} 13-578(Jan 2014) Quantity (Dkt)	{6} 14-561(Jan 2015) Quantity (Dkt)	{7} FILED July 2015 (Nov 2015) Quantity (Dkt)	{8} UPDATED Nov 2015 15-644 (Nov 2015) Quantity (Dkt)	{9} TOTAL Change fr July ({8}-{7})	{10} TOTAL Change Last Demand ({8}-{6})
	[TRADE SECRET DATA BEGINS…									
NNG TF-12 Base Winter										
NNG TF-12 Base Summer										
NNG TF-12 Variable Winter										
NNG TF-12 Variable Summer										
NNG TF-12 -Growth-Winter										
NNG TF-12 Growth Summer										
NNG TF-5										
NNG TF-5 Growth										
NNG TF-5 Growth										
TFX-5 mo (non-discounted)										
TFX-12 mo (non-discounted)										
TFX-A1-winter										
TFX-A1-summer										
TFX-A2-winter										
TFX-A2-summer										
TFX-B1-winter										
TFX-B1-summer										
TFX-B2-winter										
TFX-B2-summer										
TFX-C1-winter										
TFX-C1-summer										
TFX-C2-winter										
TFX-C2-summer										
									...TRADE SECRET DATA ENDS]	
Total NNG Demand Winter	979,172	979,172	979,172	978,872	981,657	987,009	1,018,671	1,020,666 **	**1,995**	**33,657**
Total NNG Demand Summer	551,883	551,883	551,883	551,673	553,531	555,729	574,472	574,472	**0**	**18,743**
	[TRADE SECRET DATA BEGINS									
Reservation - Waterville (151 days)										
Waterville - SBA										
SMS										
Viking										
FT-A - 12 month										
FT-A - 5 month (5,000 5 mo.)										
FT-A - 3 month										
									...TRADE SECRET DATA ENDS]	
Total Viking Demand	76,809	76,809	76,809	56,809	56,809	56,809	**56,809**	**66,809**	**10,000**	**10,000**
Trailblazer (FTS Backhaul)						50,000	100,000	100,000	**0**	**50,000**
Supply Demand	**1/**						**** - 24,914 of NNG sources off of Viking**			
	[TRADE SECRET DATA BEGINS									
Seasonal Reservation										
Storage NGPL										
Storage Tennaska										
Storage BP Canada										
Storage Northern Natural FDD										
									...TRADE SECRET DATA ENDS]	
NOTE: Reflects Total volumes contracted and does not reflect any cost allocation.										
Released Capacity			**0**	(1,500)	0	0	0	0	**0**	**0**
Underground Storage	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	**0**	**0**
LNG Peak Shaving	72,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000	**0**	**0**
Propane Peak Shaving	201,700	201,700	201,700	188,800	179,633	178,600	171,000	171,000	**0**	**(7,600)**
Total Peaking	323,700	323,700	323,700	310,800	301,633	300,600	293,000	293,000	**0**	**(7,600)**
Total Capacity	1,379,481	1,379,481	1,379,681	1,344,981	1,340,099	1,344,418	1,343,566	1,355,561 **	**11,995**	**11,143**
Total Peak-Shaving Capacity/On-line Storage	323,700	323,700	323,700	310,800	301,633	300,600	293,000	293,000	**0**	**(7,600)**
Total Annual Transportation	608,692	608,692	608,692	608,482	610,340	612,538	631,281	631,281	**0**	**18,743**
Total Seasonal Transportation	1,055,981	1,055,981	1,055,981	1,034,181	1,038,466	1,043,818	1,050,566	1,062,561 **	**11,995**	**18,743**
Peak Shaving as % of Total Capacity	23.5%	23.5%	23.5%	23.1%	22.5%	22.4%	21.8%	21.6%		
Annual Transportation as % of Total Capacity	44.1%	44.1%	44.1%	45.2%	45.5%	45.6%	47.0%	46.6%		
Seasonal Transportation as % of Total Capacity	76.5%	76.5%	76.5%	76.9%	77.5%	77.6%	78.2%	78.4%		
Annual and Seasonal Transportation as % of Total Transportation	63.4%	63.4%	63.4%	63.0%	63.0%	63.0%	62.5%	62.7%		

Residential	Last Rate Case (G008/MR-15-728 and GR-14-424)	Last Demand Change (G008/M-14-561) (01/2015)	October 2015 PGA	November 2015 PGA (M-15-644)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$3.4897	$4.2198	$2.7831	$2.8243	-19.07%	-33.07%	1.48%	$0.0412
Demand Cost of Gas (1)	$0.7646	$0.8292	$0.8282	$0.8502	**11.20%**	**2.53%**	**2.66%**	**$0.0220**
Commodity Margin (2)	$1.8458	$1.9640	$1.9341	$1.9341	4.78%	-1.52%	0.00%	$0.0000
Total Cost of Gas	$6.1001	$7.0130	$5.5454	$5.6086	-8.06%	-20.03%	1.14%	$0.0632
Average Annual Usage (Dk)	100	100	100	100				
Average Annual Total Cost of Gas	$610.01	$701.30	$554.54	$560.86	-8.06%	-20.03%	1.14%	$6.32
Average Annual Total Demand Cost of Gas								**$2.20**

Commercial/Industrial Firm - A	Last Rate Case (G008/MR-15-728 and GR-14-424)	Last Demand Change (G008/M-14-561) (01/2015)	October 2015 PGA	November 2015 PGA (M-15-644)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$3.5019	$4.2198	$2.7831	$2.8243	-19.35%	-33.07%	1.48%	$0.0412
Demand Cost of Gas (1)	$0.7646	$0.8292	$0.8282	$0.8502	**11.20%**	**2.53%**	**2.66%**	**$0.0220**
Commodity Margin	$1.4129	$1.2870	$1.5012	$1.5012	6.25%	16.64%	0.00%	$0.0000
Total Cost of Gas	$5.6794	$6.3360	$5.1125	$5.1757	-8.87%	-18.31%	1.24%	$0.0632
Average Annual Usage (Dk)	80	80	80	80				
Average Annual Total Cost of Gas	$454.35	$506.88	$409.00	$414.06	-8.87%	-18.31%	1.24%	$5.06
Average Annual Total Demand Cost of Gas								**$1.76**

Commercial/Industrial Firm - B	Last Rate Case (G008/MR-15-728 and GR-14-424)	Last Demand Change (G008/M-14-561) (01/2015)	October 2015 PGA	November 2015 PGA (M-15-644)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$3.5019	$4.2198	$2.7831	$2.8243	-19.35%	-33.07%	1.48%	$0.0412
Demand Cost of Gas (1)	$0.7646	$0.8292	$0.8282	$0.8502	**11.20%**	**2.53%**	**2.66%**	**$0.0220**
Commodity Margin	$1.3329	$1.2840	$1.4232	$1.4232	6.77%	10.84%	0.00%	$0.0000
Total Cost of Gas	$5.5994	$6.3330	$5.0345	$5.0977	-8.96%	-19.51%	1.26%	$0.0632
Average Annual Usage (Dk)	2,860	2,860	2,860	2,860				
Average Annual Total Cost of Gas	$16,014.28	$18,112.38	$14,398.67	$14,579.42	-8.96%	-19.51%	1.26%	$180.75
Average Annual Total Demand Cost of Gas								**$62.92**

Commercial/Industrial Firm - C	Last Rate Case (G008/MR-15-728 and GR-14-424)	Last Demand Change (G008/M-14-561) (01/2015)	October 2015 PGA	November 2015 PGA (M-15-644)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$3.4688	$4.2198	$2.7831	$2.8243	-18.58%	-33.07%	1.48%	$0.0412
Demand Cost of Gas (1)	$0.7646	$0.8292	$0.8282	$0.8502	**11.20%**	**2.53%**	**2.66%**	**$0.0220**
Commodity Margin	$1.3969	$1.4852	$1.4852	$1.4852	6.32%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.6303	$6.5342	$5.0965	$5.1597	-8.36%	-21.04%	1.24%	$0.0632
Average Annual Usage (Dk)	14,300	14,300	14,300	14,300				
Average Annual Total Cost of Gas	$80,513.29	$93,439.06	$72,879.95	$73,783.71	-8.36%	-21.04%	1.24%	$903.76
Average Annual Total Demand Cost of Gas								**$314.60**

Summary **Change from most recent PGA** Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Total Change ($/Dk)	Total Change (Percent)
Residential	$0.0412	1.48%	$0.0220	2.66%	$6.32	1.14%
Commercial/Industrial Firm A	$0.0412	1.48%	$0.0220	2.66%	$5.06	1.24%
Commercial/Industrial Firm B	$0.0412	1.48%	$0.0220	2.66%	$180.75	1.26%
Commercial/Industrial Firm C	$0.0412	1.48%	$0.0220	2.66%	$903.76	1.24%

(1) Does not include Demand Smoothing
(2) Reflects CCRA, Decoupling. Does not reflect GAP, Interim or GCR Factors.
(4) WACOG value in the Jan 2014 is Jan 2014 (Last Demand change)

27-Oct-15

NORTHERN NATURAL GAS COMPANY
EFFECTIVE NOVEMBER 1, 2015
THROUGHPUT ENTITLEMENT PROFILE

Business Development & Marketing
Commercial Support

Exhibit C - Page 1

Utility: **CENTERPOINT ENERGY MINNESOTA GAS**

Actual May through September 2015 Throughput (MMBTU)

ACCT MO	TF	TI	FDD/IDD	OTHER	TOTAL
MAY	2,941,977	-	50,000	729,130	3,721,107
JUN	2,746,837	-	78,420	912,279	3,737,536
JUL	2,691,314	-	83,624	1,051,226	3,826,164
AUG	2,814,099	3,425	110,005	1,062,223	3,989,752
SEPT	3,011,871	-	66,352	1,109,476	4,187,699
TOTAL:	14,206,098	3,425	388,401	4,864,334	19,462,258
				average day =	127,204

APPROVED TFX:	878,044
APPROVED TF5:	93,761
APPROVED TF12:	148,861
TOTAL:	1,120,666

ALLOCATED TF12B:	127,204
INCREMENTAL TF12B:	2,592
ALLOCATED TF12V:	19,065
TOTAL:	148,861

CNP Deliveries		
Transport	14,206,098	
Odgen	338,401	
3rd Party Storage - Glenwood	50,000	
	14,594,499	
Other		
Alternate Points / Interruptible	118,511	
Temporary Releases	4,749,248	
	4,867,759	
Total		19,462,258
3rd Party Activity CNP does not get credit		
Primary Delivery	2,379,811	
AMA	0	
OSE	0	
		2,379,811
		21,842,069

CONTRACT	TFX ENTLMNT	TF5 ENTLMNT	TF12V ENTLMNT	TF12B ENTLMNT	TOTAL ENTLMNT	
111463	**-**	**90,496**	**19,065**	**125,505**	**235,066**	
111463	-	800	-	2,256	3,056	Eff 11/01/2015 3056 increases
127357		**2301**	**-**	**1,699**	**4,000**	
127357		164	0	336	500	MDQ eff 11/01/2015 is 4,500
111461	50,000				50,000	
111464	819,549				819,549	
111697	6,500				6,500	
129533	1,995				1,995	
TOTAL:	878,044	93,761	19,065	129,796	1,120,666	

2014	847,943	92,797	33,651	110,919	1,085,310
Diff. (2015 -2014)	30,101	964	(14,586)	18,877	35,356

CenterPoint Energy Minnesota Gas
Natural Gas Swing Supplies - Reservation Fees
November 2015 - March 2016

PUBLIC INFORMATION
Trade Secret Information has been Excised

			Demand	Term /	Total	Nov-15			Dec-15			Jan-16			Feb-16			Mar-16			Total
Supplier	Pipeline	Pricing	Rate	Description	MMBtu	Days	MMBtu	$$	Days	MMBtu	$$	Days	MMBtu	$$	Days	MMBtu	$$	Days	MMBtu	$$	$$
[TRADE SECRET DATA BEGINS…																					

... TRADE SECRET DATA ENDS]

CenterPoint Energy Minnesota Gas
NGPL Storage Costs: "Fixed" Contract Allocation

Exhibit C - Page 3
PUBLIC INFORMATION
Trade Secret Information has been Excised

EFFECTIVE NOVEMBER 1, 2015

ALLOCATION	**[TS Begins…**	Percent Allocation
Total Storage		1.0000
Allocate to Firm and SVDF based on sales volume		#DIV/0!
Allocate to All customers Based on Sales Volume		#DIV/0!
	... TS Ends]	

Based on Winter Sales Volumes

	Annual (DT)	Winter (DT)	New Allocation**	Commodity	Total	Change
			[Trade Secret Data Begins…			
SV - Firm	**106,256,000**	**75,331,100**				
SV - Dual Fuel	**11,878,600**	**8,336,300**				
LV - Dual Fuel	**4,208,100**	**2,230,900**				
Total	**122,342,700**	**85,898,300**				

** - Firm to Demand - See Exhibit A - NGPL Storage total dollars
- SVDF Winter only. Billed as Per-Unit commodity adjustment: Exhibits D and E

PER-UNIT RATE

	Annual (DT)	**Winter (DT)**
SV - Firm	**106,256,000**	**75,331,100**
SV - Dual Fuel	**11,878,600**	**8,336,300**
LV - Dual Fuel	**4,208,100**	**2,230,900**
Total	122,342,700	85,898,300

Annual Bill Impact:	UPC-annual (DT	UPC-Winter (DT)
Residential	88.10	65.56
Com-A	72.40	57.46
C/I-B	271.40	209.49
C/I-C	1,378.40	962.67
SV-Dual Fuel-A	4,559.00	3,250.00
SV-Dual Fuel-B	16,491.00	10,650.00

...Trade Secret Data Ends]

NOTE: Sales volumes: Matches Sales volumes used in the Company's AAA filing - G-008/AA-15-800, Page 11