division of energy resources
Minnesota Department of Commerce

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August 19, 2013

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G008/M-13-578

Dear Dr. Haar:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> A request by CenterPoint Energy Resources Corp., d/b/a/ CenterPoint Energy Minnesota Gas (CenterPoint, CPE, or the Company) for approval by the Minnesota Public Utilities Commission (Commission) of a change in demand units effective November 1, 2013.

The filing was submitted on July 1, 2013. The petitioner is:

> CenterPoint Energy
> 800 LaSalle Avenue
> P.O. Box 59038
> Minneapolis, MN 59459-0038

Based on its analysis, the Department recommends that the Commission approve CenterPoint's proposal, subject to supplemental filing(s) by the Company. The Department also requests that CenterPoint provide further information in its Reply Comments.

The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ ANGELA BYRNE
Financial Analyst
651-539-1820

/s/ ADAM J. HEINEN
Rates Analyst
651-539-1825

AB/AH/ja
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G008/M-13-578

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2,[1] CenterPoint Energy (CenterPoint, CPE, or the Company) filed a petition requesting a change in demand[2] units (*Petition)* on July 1, 2013.[3] The proposed changes do not reflect Northern Natural Gas' (Northern or NNG) 2012-2013 reallocation of units between TF-12 Base and TF-12 Variable services[4] or the final Reservation Fees cost estimate.[5]

In its *Petition*, CenterPoint requested that the Minnesota Public Utilities Commission (Commission) approve the following changes in the Company's overall level of contracted capacity.

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1 ***Filing by Gas Utilities:*** *Filing upon a change in demand.* Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.

2 Also called entitlement, capacity, or transportation on the pipeline.

3 At this time, CenterPoint's most recent demand entitlement filings, Docket No. G008/M-11-1078 (Docket 11-1078) and Docket No. G008/M-12-864, are pending the Commission's decision. In Docket 11-1078, the Department recommended in its June 14, 2012 Comments that the Commission request that CPE file its next annual demand entitlement filing on August 1, 2012, and by July 1 on a going forward basis, with the understanding that items would require adjustment through supplemental filings. The Company agreed to do so in its June 25, 2012 Reply Comments in Docket 11-1078.

4 On November 1, NNG annually adjusts TF-12 Base and Variable billing unit entitlements based on the utility's gas use in the previous May-through-September period.

5 These items would require a supplemental filing(s) when the figures become known by the Company.

TABLE 1

The Company's Proposed Total Entitlement Changes	
Type of Entitlement	Proposed Changes: Increase (Decrease) (Dkt)[6]
TF-12 Base – Winter	1,654
TF-12 Base – Summer	1,654
TF-12 Growth – Winter	86
TF-12 Growth – Summer	86
TF-5	811
TF-5 Growth	74
Released Capacity	1,500
Propane Peak Shaving	(9,167)
SMS	(30,000)

CPE described three factors contributing to the need for changing demand:

- increase in pipeline entitlement;
- retirement of a peak shaving station; and
- expiration of System Management Service (SMS).[7]

As discussed below, all of these items relate to a change in the level of entitlement. The effect of these changes results in an overall increase in monthly Purchased Gas Adjustment (PGA) rates, also discussed below.

II. THE DEPARTMENT'S ANALYSIS OF THE COMPANY'S PROPOSAL

The Minnesota Department of Commerce, Division of Energy Resources' (Department) analysis of the Company's request includes the following sections:

- the proposed changes to the entitlement level and to non-capacity items;
- the design-day requirement;
- the reserve margin; and
- the PGA cost recovery proposal.

[6] Dekatherms (Dkt or DT).
[7] *Petition*, pages 1-2.

A. PROPOSED CHANGES

1. Changes to the Entitlement Level

As indicated below and in DOC Attachment 1, the Company proposed to decrease its prior year total entitlement level by 5,042 Dkt as follows:

Table 2

Previous Entitlement (Dkt)	**Proposed Entitlement (Dkt)**	**Entitlement Changes (Dkt)**	**% Change From Previous Year**
1,344,981	1,339,939	(5,042)	(0.37%)

CenterPoint discussed three factors that resulted in an overall decrease in its total entitlement level. The first factor included several small adjustments to both winter and summer entitlements and capacity release, as shown in Table 1 above. The Company stated that it made these small increases to entitlements mostly "off of Northern Natural Gas's Willmar branch line where capacity is tight and some growth is expected." CPE also stated that the locations where entitlements were increased are isolated from the rest of its system, and that the only option for serving growth is through increased capacity on the upstream pipeline. Additionally, the increase from capacity release resulted from a one-year contract for CPE to release 1,500 units that was allowed to expire.

Next the Company discussed the retirement of its Coon Rapids Propane Peaking plant in June 2013. CenterPoint stated that the facility was built in the 1960s and has an estimated peak-day capacity of approximately 9,200 Dkt per day. CPE also stated that this small plant was the last in the order of plant dispatch and contained a significant amount of old manual and labor-intensive equipment. According to the Company, this plant would require an estimated $600,000 to $700,000 investment to keep the plant long term, including expenditures needed to comply with National Fire Protection (NFPA 59) Code. CenterPoint stated that, based on its current demand entitlement position, the Coon Rapids #1 Town Border Station (TBS) has sufficient capacity, so this peaking facility is not required for supply purposes. The Company is currently reviewing options for disposing of the equipment and facilities.

Finally, CenterPoint discussed an anticipated decrease of 30,000 Dkt per day in its SMS[8] contract with Northern Natural Gas effective October 31, 2013. The Company stated, "Based on recent operating experiences, the Company has decided to not renew this level of service. The Company believes it can re-subscribe in the future if it determines that it needs additional SMS service."

[8] System Management Service, or SMS, is Northern Natural Gas's no-notice service which provides additional tolerances for shippers, beyond the allowed 5% tolerance. This service protects against out-of-balance charges.

The Department concludes that the increases to capacity discussed above are reasonable. The Department also concludes that CenterPoint's decision to retire the Coon Rapids Peaking Plant is reasonable. Since the Coon Rapids TBS currently has sufficient capacity, there should be no replacement costs for fuel or facilities. The Department trusts that, if necessary, the Company will file information in compliance with Minnesota Statute § 216B.50 and Minnesota Rule 7825.1800 for the sale of the Coon Rapids Peaking Plant.[9]

Regarding the reduction of the SMS contract, the Department notes that letting this contract expire represents a large decrease in CPE's total contracted SMS service. In order to be able to confirm the reasonableness of this decision, the Department requests that CenterPoint provide, in Reply Comments, the cost/benefit analysis the Company used to arrive at the decision to allow this SMS contract to expire.

Based on its analysis, the Department concludes that CenterPoint's proposed level of demand entitlement is reasonable. The Department recommends approval subject to the supplemental filing(s) that will be submitted by the Company once the reallocation of units between TF-12 Base and TF-12 Variable services and the final Reservation Fees cost estimate are known.

2. Changes to Non-Capacity Items

As was done in the 2011 and 2012 demand entitlement filings, CenterPoint also zeroed out the Capacity Release and the Off-System Margin Sales credits. These items are adjusted on a monthly basis as credits become known.

The Department concludes that the proposed changes to non-capacity items are reasonable and recommends that the Commission accept the proposed changes to non-capacity items.

3. Design-Day Requirement

a. CPE Analysis

The design-day analysis employed by CenterPoint in this filing is similar to what was used by the Company in last year's demand entitlement filing. CenterPoint's design-day analysis is based, in large part, on the work done in its supplemental filing in Docket No. G008/M-11-1078. The Company's design day analysis is based on Ordinary Least Squares (OLS) regression and daily heating season (November through March) data over the period from November 2007 to March 2013. CPE used heating degree days (HDDs) and the squared value of HDDs (HDD^2) to

[9] Minnesota Statute §216B.50 states, in part, that "No public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $100,000, or merge or consolidate with another public utility or transmission company operating in this state, without first being authorized so to do by the commission."

estimate daily firm use per customer (UPC). The factor HDD^2 is included in the regression equation to account for non-linear relationships that may exist between HDDs and UPC. The inclusion of a squared HDD term is an appropriate method of accounting for non-linear relationships.

The Department reviewed CenterPoint's design day regression analysis, and concluded that the signs on HDD and HDD^2 are both positive and the scale of the coefficients appear to be reasonable. Further, the Department analyzed the steepness of the regression line, and the results indicate a small curvature (*i.e.,* slightly non-linear) which generally agrees with the data plot in DOC Attachment 4.

As noted earlier, the Company's analysis is based on daily throughput (use per customer) and weather data over the period from November 2007 to March 2013. CenterPoint's analysis resulted in a design-day estimate of 1,229,000 Dkt/day; however, as explained in the CPE's filing, the Company modified the analysis such that the ultimate design-day estimate was based on the upper bound of the regression output, which resulted in a calculated design day of 1,288,000 Dkt/day. The Company stated that it made this modification to ensure a bias toward reliability since this adjustment places the design-day estimate at the top end of expected design-day conditions based on the regression. Since CenterPoint's design-day method is still new, this marks the second filing that it has been used; the Department does not oppose the Company's decision to use the upper bound of its regression analysis. This approach would place a greater emphasis on reliability, all else being equal, and provide a buffer for firm ratepayers until more actual experience with this design-day method exists.

The peak-day process is complex and can be impacted by many different factors. Although weather (HDDs) is the driving factor behind peak-day use, the ultimate result is also dependent upon the day of the week and when during a cold spell the event occurs, among other things. CenterPoint's analysis only incorporates the impacts of weather and does not contemplate other factors including: day of the week, month, and heating season. In other words, CPE's analysis assumes that all days are equal. The impact of these other factors is unclear. However, the Department conducted an alternative regression analysis to independently evaluate the impact of these other factors on CPE's design-day analysis as discussed further below.

b. Department's Alternative Design-Day Analysis

The Department's alternative analysis was based on the same time period as CenterPoint's and included HDDs and HDD^2 along with factors that account for month, day of the week, and heating season. Including these additional factors was expected to provide additional explanatory precision to the analysis, if they are relevant, and isolate characteristics specific to each heating season day. The Department conducted its regression analysis and obtained consistent results (*e.g.,* positive signs on both HDD factors) that are similar to CPE's (DOC Attachment 5). The Department identified the factors with the greatest impact, by type (*i.e.,* month, day of the week, heating season), and then added these values to the impacts related to baseload and weather. This approach is conservative and biases the calculation in the favor of system reliability. Using this approach, the additional regression factors decrease the projected design day by a small amount - from CenterPoint's 1,229,000 Dkt/day figure to approximately 1,215,156 Dkt/day - but the results are within the confidence interval associated with the Company's design-day analysis.

For comparative purposes, the Department also calculated its design-day result based on the upper bound of its regression result. Using the upper bound, the Department's estimated design day, approximately 1,339,000 Dkt/day, is higher than CenterPoint's proposed total entitlement level of 1,288,000 Dkt/day. A strict interpretation of this result suggests that, based on the Department's analysis, the Company does not have sufficient capacity to ensure firm service on a peak day (90 HDD). However, the Department believes that the upper bound result is highly unlikely and thus does not suggest that CPE has insufficient firm capacity. In addition, when the Department's upper-bound estimate is compared to CPE's upper-bound design-day estimate, inclusive of physical reserves (1,339,939 Dkt/day), the figures are roughly equal which means firm reliability should be ensured. The Department's upper bound result might happen only if peak usage were at the top of reasonable peak usage expectations on a peak day (90 HDD) that occurs on a Sunday, in February, and during a heating season with usage characteristics similar to the 2008-2009 heating season. The Department has not determined the statistical probability, but it is clear that the odds of this happening are remote. In addition, it is important to consider that all regression results are subject to error. As such, the Department believes that CPE likely has sufficient capacity to serve needs on an all-time peak day.

Given the Department's results and the similarity to CenterPoint's proposed design day, the Department concludes that the Company's design day is reasonable; however, the process is new and will continue to be reviewed over time. Thus, the Department recommends that the Commission accept the design-day level proposed by CPE.

The Department notes that a Commission-prescribed peak day has generally been interpreted as the coldest 24-hour average temperature in the past 20 years. Generally speaking, these events occurred during the 1995-1996 heating season; as such, the 20-year anniversary of the coldest day for most Minnesota natural gas utilities is approaching. In the time since the 1995-1996 heating season, there has not been a cold weather event that has equaled what occurred during that heating season. Therefore, based on the Commission peak-day definition, the design-day planning target for the natural gas utilities will change, and become less stringent, in the near future. Minnesota ratepayers will benefit from a less stringent planning objective through lower demand costs; however, if a cold weather event similar to the 1995-1996 heating season were to occur in the future, under different planning requirements, reliability could be at risk. The Department recommends that CenterPoint provide a detailed discussion, in its *Reply Comments*, explaining whether it believes the current peak-day definition (coldest temperature in the past 20 years) is appropriate or whether maintaining the 1995-1996 heating season event as the planning objective, on a going-forward basis, is more appropriate.

4. Reserve Margin

As shown below and in DOC Attachment 2, CPE's proposed reserve margin is 1.20 percent:

Table 3

Total Entitlement (Dkt)	Design-day Estimate (Dkt)	Difference (Dkt)	Reserve Margin %	% Change From Previous Year[10]
1,339,939	1,324,000	(15,939)	1.20%	(1.14%)

CenterPoint's reserve margin is reduced due to the decrease in the entitlement level as well as increases in the estimated design day.

B. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amount listed in DOC Attachment 1 represents the demand entitlements for which the Company's firm customers will be paying November 1, 2013 (excluding costs related to the reallocation of units between TF-12 Base and TF- Variable services and the final Reservation Fees cost estimate at this time). In its *Petition*, CenterPoint compared its July 2013 PGA rates to its proposed November 2013 PGA which resulted in an increase of demand costs by $0.0028 per Dkt for the Residential class. The Department also prepared this analysis and found the same result as shown in DOC Attachment 3.[11] CenterPoint's proposed changes would result in the following annual rate impacts:

- Annual demand cost increase of $0.28, or approximately 0.37 percent, for the average Residential customer consuming 100 Dkt annually;
- Annual demand cost increase of $0.22, or approximately 0.37 percent, for the average Commercial/Industrial Firm - A customer consuming 80 Dkt annually;
- Annual demand cost increase of $8.01, or approximately 0.37 percent, for the average Commercial/Industrial Firm - B customer consuming 2,860 Dkt annually; and
- Annual demand cost increase of $40.04, or approximately 0.37 percent, for the average Commercial/Industrial Firm - C customer consuming 14,300 Dkt annually.

Based on its analysis, the Department recommends that the Commission approve the proposed demand costs with an effective date of November 1, 2013.

[10] As shown on DOC Attachment 2, the Company's average reserve margin since 2001-2002 is 6.48 percent.
[11] CPE's footnote 1 states that demand costs do not include demand smoothing, which is incorrect for CenterPoint's column titled Last Demand Change. The DOC's Attachment 3 corrected this figure.

III. THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission:

- approve CenterPoint's proposed level of demand entitlement subject to supplemental filing(s) by the Company related to the reallocation of units between TF-12 Base and TF-12 Variable services and the final Reservation Fees cost estimate;
- accept the proposed changes to non-capacity items;
- accept the design-day level proposed by CPE; and
- approve the proposed demand costs with an effective date of November 1, 2013.

The Department requests that, in its Reply Comments, CenterPoint provide:

- the cost/benefit analysis the Company used to arrive at the decision to allow 30,000 units of SMS service to expire; and
- a detailed discussion explaining whether it believes the current peak-day definition (coldest temperature in the past 20 years) is appropriate or whether maintaining the 1995-1996 heating season event as the planning objective, on a going-forward basis, is more appropriate.

/ja

Heating Season Services	{1} CenterPoint Energy 12-864 (Aug 2012) Quantity (Dkt)	{2} CenterPoint Energy 12-864 (Dec 2012) Quantity (Dkt)	{3} CenterPoint Energy 12-864 (Jan 2013) Quantity (Dkt)	{4} CenterPoint Energy 13-578 (July 2013) Quantity (Dkt)	{5} TOTAL Change (Jan. 2013 - Jul. 2013)
[TRADE SECRET DATA BEGINS					
					TRADE SECRET DATA ENDS]
Total NNG Demand Winter	979,172	979,032	978,872	981,497	2,625
Total NNG Demand Summer	551,883	551,673	551,673	553,413	1,740
[TRADE SECRET DATA BEGINS					
					TRADE SECRET DATA ENDS]
Total Viking Demand	56,809	56,809	56,809	56,809	0
Supply Demand					
[TRADE SECRET DATA BEGINS					
					TRADE SECRET DATA ENDS]
NOTE: Reflects total volumes contracted and does not reflect any cost allocation.					
Released Capacity	0	(1,500)	(1,500)	0	1,500
Underground Storage	50,000	50,000	50,000	50,000	0
LNG Peak Shaving	72,000	72,000	72,000	72,000	0
Propane Peak Shaving	188,800	188,800	188,800	179,633	(9,167)
Total Propane	310,800	310,800	310,800	301,633	(9,167)
Total Capacity	1,346,781	1,345,141	1,344,981	1,339,939	(5,042)
Total Peak-Shaving Capacity/On-line Storage	310,800	310,800	310,800	301,633	(9,167)
Total Annual Transportation	608,692	608,556	608,482	610,222	1,740
Total Seasonal Transportation	1,035,981	1,034,267	1,034,181	1,038,306	4,125
Peak Shaving as % of Total Capacity	23.1%	23.1%	23.1%	22.5%	-0.6%
Annual Transportation as % of Total Capacity	45.2%	45.2%	45.2%	45.5%	0.3%
Seasonal Transportation as % of Total Capacity	76.9%	76.9%	76.9%	77.5%	0.6%
Annual and Seasonal Transportation as % of Total Transportation	63.0%	63.0%	63.0%	63.0%	0.0%

CenterPoint Energy

		Number of Firm Customers				Design Day Requirement			Total Entitlement + On-line Storage + Peak Shaving				Reserve Margin	
		(1 A)	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)	(10.5)
Docket No.	Heating Season	Actual Number of Jan. Customers	Projected DD Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dk)	Change from Previous Year	% Change From Previous Year	Total Entitlement (Dk)		Entitlement Change from Previous Year	% Change From Previous Year	Corrected Reserve Margin [(7)-(4)]/(4)	As Reported Reserve Margin
13-578	2013-2014*	n/a	823,790	12,651	1.56%	1,324,000	8,000	0.61%	1,339,939		-6,842	-0.51%	1.20%	1.20%
12-864	2012-2013	813,605	811,139	3,212	0.40%	1,316,000	100,000	8.22%	1,346,781		-32,900	-2.38%	2.34%	2.34%
11-1078	2011-2012	807,922	807,927	3,647	0.45%	1,216,000	3,000	0.25%	1,379,681		0	0.00%	13.46%	13.46%
10-1162	2010-2011	804,703	804,280	3,104	0.39%	1,213,000	2,000	0.17%	1,379,681		40,000	2.99%	13.74%	13.74%
09-1260	2009-2010	801,286	801,176	4,031	0.51%	1,211,000	-24,000	-1.94%	1,339,681	1/	9,615	0.72%	**10.63%**	9.78%
08-1307	2008-2009	797,228	797,145	-10,815	-1.34%	1,235,000	-11,000	-0.88%	1,330,066	1/	873	0.07%	**7.70%**	6.87%
07-561	2007-2008	792,950	807,960	15,025	1.89%	1,246,000	14,000	1.14%	1,329,193	1/	26,891	2.06%	**6.68%**	5.63%
06-1533	2006-2007	787,326	792,935	16,585	2.14%	1,232,000	12,000	0.98%	1,302,302		2,000	0.15%	5.71%	5.71%
05-1736	2005-2006	777,424	776,350	17,129	2.26%	1,220,000	-44,000	-3.48%	1,300,302		4,500	0.35%	6.58%	6.58%
	2004-2005	762,835	759,221	14,710	1.98%	1,264,000	21,000	1.69%	1,295,802		0	0.00%	2.52%	2.52%
	2003-2004**	745,890	744,511	18,603	2.56%	1,243,000	29,300	2.41%	1,295,802		34,400	2.73%	4.25%	4.25%
	2002-2003**	728,005	725,908	16,524	2.33%	1,213,700	30,092	2.54%	1,261,402		12,500	1.00%	3.93%	3.93%
	2001-2002		709,384			1,183,608			1,248,902				5.52%	5.52%
	Average Per Year:		781,671	9,534	1.26%	1,239,793	11,699	0.98%	1,319,195		7,586	0.60%	6.48%	

	Firm Peak Day Sendout			Amounts per Customer				
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Firm Peak Day Sendout (Dk)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak Day Sendout per DD # Customer (11)/(1)	Peak Day Sendout per Actual Customers (11)/(1 A)
2013-2014*	n/a	n/a	n/a	0.0193	1.6072	1.6266	n/a	n/a
2012-2013	961,134	130,690	15.74%	0.0379	1.6224	1.6604	1.1849	1.1813
2011-2012	830,444	(42,328)	-4.85%	0.2026	1.5051	1.7077	1.0279	1.0279
2010-2011	872,772	(21,153)	-2.37%	0.2072	1.5082	1.7154	1.0852	1.0846
2009-2010	893,925	(130,839)	-12.77%	0.1606	1.5115	1.6721	1.1158	1.1156
2008-2009	1,024,764	21,335	2.13%	0.1193	1.5493	1.6685	1.2855	1.2854
2007-2008	1,003,429	5,627	0.56%	0.1030	1.5422	1.6451	1.2419	1.2654
2006-2007	997,802	140,866	16.44%	0.0887	1.5537	1.6424	1.2584	1.2673
2005-2006	856,936	(87,406)	-9.26%	0.1034	1.5715	1.6749	1.1038	1.1023
2004-2005	944,342	(69,052)	-6.81%	0.0419	1.6649	1.7068	1.2438	1.2379
2003-2004	1,013,394	97,281	10.62%	0.0709	1.6696	1.7405	1.3612	1.3586
2002-2003	916,113	122,670	15.46%	0.0657	1.6720	1.7377	1.2620	1.2584
2001-2002	793,443			0.0920	1.6685	1.7605	1.1185	
Average Per Year:	925,708	15,245	2.26%	0.1010	1.5881	1.6891	1.1907	1.1986

All the numbers reflected in the above tables are consolidated for the Company's previous Northern and Viking service areas.
* = Projected Values
** = From CenterPoint's Exh. B, page 3 in Docket No. G008/M-08-1307.
1/ Corrected total entitlement amounts for peak-shaving output. See Docket No. G008/M-10-1162.

Residential	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-12-864) (Dec 2012)	July PGA (7/1/13) before proposed demand entitlement change	Nov. 2013 PGA with Proposed Demand Entitlement Change	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)	$6.0690	$3.9277	$3.8208	$3.8208	-37.04%	-2.72%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7282	$0.7483	**$0.7511**	**-10.59%**	**3.14%**	**0.37%**	**$0.0028**
Commodity Margin (2)	$1.6637	$1.7344	$1.8075	$1.8075	8.64%	4.21%	0.00%	$0.0000
Total Cost of Gas	$8.5728	$6.3903	$6.3766	$6.3794	-25.59%	-0.17%	0.04%	$0.0028
Average Annual Usage (Dk)	100	100	100	100				
Average Annual Total Cost of Gas	$857.28	$639.03	$637.66	$637.94	-25.59%	-0.17%	0.04%	$0.28
Average Annual Total Demand Cost of Gas								**$0.28**

Commercial/Industrial Firm - A	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-12-864) (Dec 2012)	July PGA (7/1/13) before proposed demand entitlement change	Nov. 2013 PGA with Proposed Demand Entitlement Change	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)	$6.0690	$3.9277	$3.8208	$3.8208	-37.04%	-2.72%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7282	$0.7483	**$0.7511**	**-10.59%**	**3.14%**	**0.37%**	**$0.0028**
Commodity Margin	$1.4680	$1.5700	$1.6926	$1.6926	15.30%	7.81%	0.00%	$0.0000
Total Cost of Gas	$8.3771	$6.2259	$6.2617	$6.2645	-25.22%	0.62%	0.04%	$0.0028
Average Annual Usage (Dk)	80	80	80	80				
Average Annual Total Cost of Gas	$670.17	$498.07	$500.94	$501.16	-25.22%	0.62%	0.04%	$0.22
Average Annual Total Demand Cost of Gas								**$0.22**

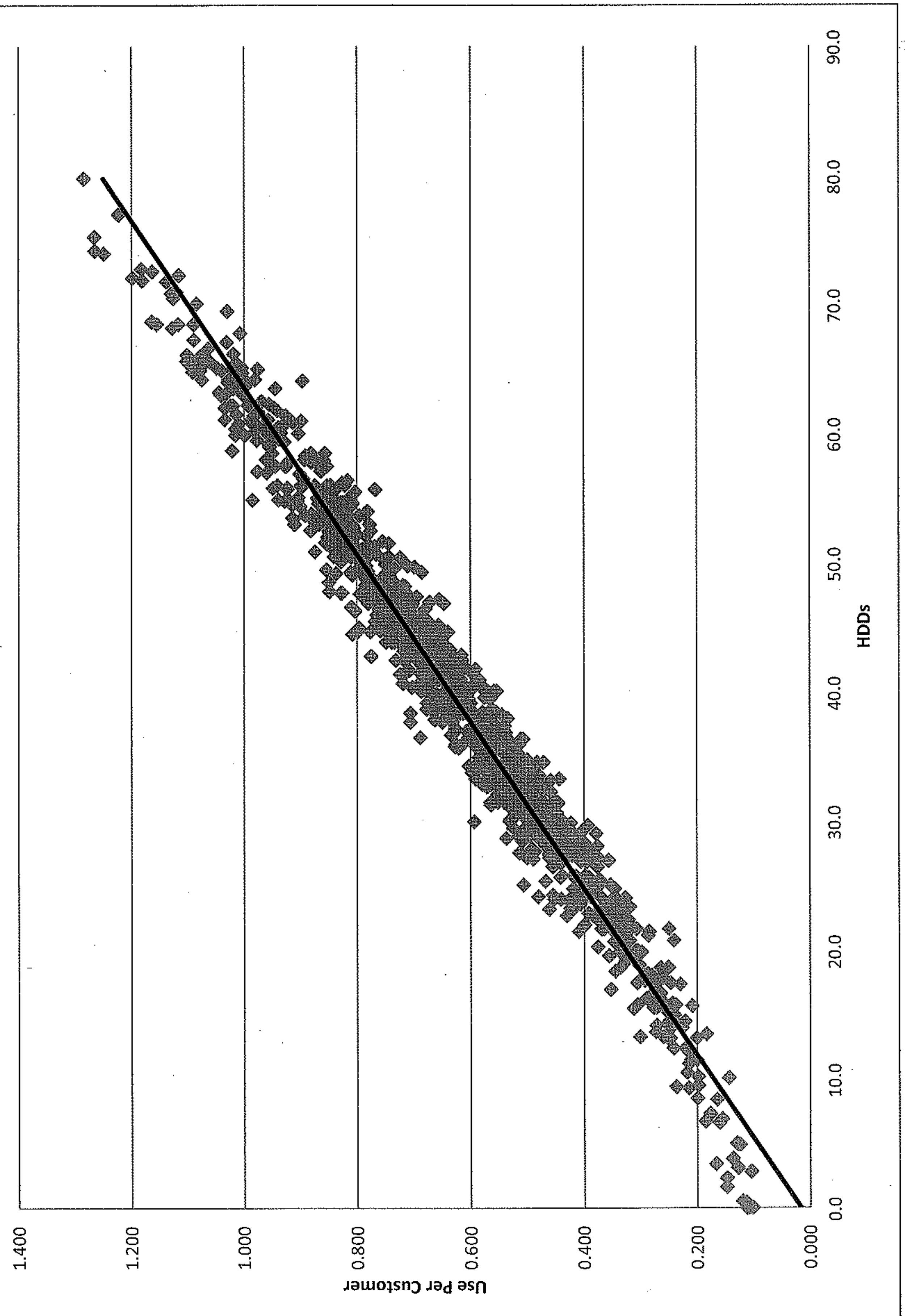
Commercial/Industrial Firm - B	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-12-864) (Dec 2012)	July PGA (7/1/13) before proposed demand entitlement change	Nov. 2013 PGA with Proposed Demand Entitlement Change	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$6.0690	$3.9277	$3.8208	$3.8208	-37.04%	-2.72%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7282	$0.7483	**$0.7511**	**-10.59%**	**3.14%**	**0.37%**	**$0.0028**
Commodity Margin	$1.4422	$1.4090	$1.4861	$1.4861	3.04%	5.47%	0.00%	$0.0000
Total Cost of Gas	$8.3513	$6.0649	$6.0552	$6.0580	-27.46%	-0.11%	0.05%	$0.0028
Average Annual Usage (Dk)	2,860	2,860	2,860	2,860				
Average Annual Total Cost of Gas	$23,884.72	$17,345.61	$17,317.87	$17,325.88	-27.46%	-0.11%	0.05%	$8.01
Average Annual Total Demand Cost of Gas								**$8.01**

Commercial/Industrial Firm - C	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-12-864) (Dec 2012)	July PGA (7/1/13) before proposed demand entitlement change	Nov. 2013 PGA with Proposed Demand Entitlement Change	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)	$6.0690	$3.9277	$3.8208	$3.8208	-37.04%	-2.72%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7282	$0.7483	**$0.7511**	**-10.59%**	**3.14%**	**0.37%**	**$0.0028**
Commodity Margin	$1.3362	$1.3114	$1.3465	$1.3465	0.77%	2.68%	0.00%	$0.0000
Total Cost of Gas	$8.2453	$5.9673	$5.9156	$5.9184	-28.22%	-0.82%	0.05%	$0.0028
Average Annual Usage (Dk)	14,300	14,300	14,300	14,300				
Average Annual Total Cost of Gas	$117,907.79	$85,332.39	$84,593.08	$84,633.12	-28.22%	-0.82%	0.05%	$40.04
Average Annual Total Demand Cost of Gas								**$40.04**

Summary Change from most recent PGA Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	$0.0000	0.00%	$0.0028	0.37%	$0.28	$0.28	0.04%
Commercial/Industrial Firm A	$0.0000	0.00%	$0.0028	0.37%	$0.22	$0.22	0.04%
Commercial/Industrial Firm B	$0.0000	0.00%	$0.0028	0.37%	$8.01	$8.01	0.05%
Commercial/Industrial Firm C	$0.0000	0.00%	$0.0028	0.37%	$40.04	$40.04	0.05%

(1) The "Last Demand Change" column includes demand smoothing.
(2) Reflects Decoupling Factor and CIPR. Does not reflect IBR Adjustment, GAP or GRC Factors.

DOC Attachment 4: CenterPoint Firm UPC vs. HDDs Heating Seasons 2007-2013



Data Prepared by CenterPoint Energy and Trendline added by the Minnesota Department of Commerce

Untitled

```
. regress upc hdd HDD_2 Nov Dec Jan Feb Mar Sun Mon Tue Wed Thu Fri Sat HS0708
HS0809 HS0910 HS1011 HS1112 HS1213
note: Jan omitted because of collinearity
note: Wed omitted because of collinearity
note: HS0708 omitted because of collinearity
```

Source	SS	df	MS
Model	44.136641	17	2.596273
Residual	.799378304	890	.000898178
Total	44.9360193	907	.049543571

Number of obs	=	908
F(17, 890)	=	2890.60
Prob > F	=	0.0000
R-squared	=	0.9822
Adj R-squared	=	0.9819
Root MSE	=	.02997

upc	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
hdd	.0116468	.0003095	37.63	0.000	.0110393	.0122543
HDD_2	.0000373	3.70e-06	10.09	0.000	.0000301	.0000446
Nov	-.0528681	.0038007	-13.91	0.000	-.0603275	-.0454087
Dec	-.0215077	.0031707	-6.78	0.000	-.0277306	-.0152847
Jan	0	(omitted)				
Feb	-.0140746	.0032661	-4.31	0.000	-.0204847	-.0076645
Mar	-.0352462	.0036544	-9.64	0.000	-.0424184	-.0280739
Sun	.0081461	.0037276	2.19	0.029	.0008301	.0154621
Mon	.0061684	.0037253	1.66	0.098	-.0011429	.0134797
Tue	.007756	.0037249	2.08	0.038	.0004455	.0150665
Wed	0	(omitted)				
Thu	-.0047442	.0037276	-1.27	0.203	-.0120601	.0025717
Fri	-.0087891	.0037356	-2.35	0.019	-.0161206	-.0014576
Sat	-.0100806	.0037255	-2.71	0.007	-.0173925	-.0027687
HS0708	0	(omitted)				
HS0809	-.0102935	.0034497	-2.98	0.003	-.0170639	-.003523
HS0910	-.0298762	.0034816	-8.58	0.000	-.0367094	-.023043
HS1011	-.0252166	.0034453	-7.32	0.000	-.0319785	-.0184547
HS1112	-.0273916	.0036185	-7.57	0.000	-.0344933	-.0202898
HS1213	-.0223331	.0034617	-6.45	0.000	-.0291271	-.0155391
_cons	.1409598	.0081666	17.26	0.000	.1249317	.1569879

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. G008/M-13-578

Dated this **19th** day of **August, 2013**

/s/Sharon Ferguson

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