MINNESOTA DEPARTMENT OF
COMMERCE

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August 31, 2015

Daniel P. Wolf
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-15-644

Dear Mr. Wolf:

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, 2015.

The filing was submitted on July 1, 2015. 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 Minnesota Public Utilities 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	/s/ ADAM J. HEINEN
Financial Analyst	Rates Analyst
651-539-1820	651-539-1825

AB/AH/lt

MINNESOTA DEPARTMENT OF
COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G008/M-15-644

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, 2015. The proposed changes do not reflect Northern Natural Gas' (Northern or NNG) 2014-2015 reallocation of units between TF-12 Base and TF-12 Variable services[3] or the final Reservation Fees cost estimate.[4]

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:

Table 1

	Proposed Changes: Increase (Decrease) (Dkt)[5]	
Type of Entitlement	**12-month**	**5-month**
Willmar	1,362	494
Pierz	336	164
St. Bonifacius	894	306
Minneapolis	11,114	8,886
Blaine	3,212	1,788
St. Michael	734	206
Anoka	1,091	1,075
Propane Peak Shaving	(7,600)	n/a

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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] 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.
[4] These items would require a supplemental filing(s) when the figures become known by the Company.
[5] Dekatherms (Dkt or DT).

CenterPoint stated that entitlements are being added to support growth in customer demand, particularly on the north side of its distribution system.[6] The effect of this change results in an overall increase in monthly Purchased Gas Adjustment (PGA) rates, as 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.

A. PROPOSED CHANGES

1. Changes to the Entitlement Level

As indicated below and in DOC Attachment 1, the Company proposed to decrease its total entitlement level from the prior year by 852 Dkt as follows:

Table 2

Previous Entitlement (Dkt)	**Proposed Entitlement (Dkt)**	**Entitlement Changes (Dkt)**	**% Change From Previous Year**
1,344,418	1,343,566	(852)	0.00%

Despite the 31,662 Dkt of added entitlements discussed above, CenterPoint's total entitlements decreased slightly. On page 1 of its *Petition*, the Company stated that of the new entitlements, 24,914 Dkt are sourced from Viking Pipeline. In a phone call with CPE,[7] the Company clarified that the entitlements sourced from Viking do not increase its overall daily entitlements; rather they increase entitlements at certain points in its system. The Company also clarified that the entitlements sourced through Viking are deliverable through Northern Natural Gas (NNG), which was a cheaper option than having NNG build out its system.

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.

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[6] *Petition*, Page 1.

[7] August 20, 2015.

2. *Changes to Non-Capacity Items*

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

In the Company's previous demand entitlement docket,[8] CPE proposed to allocate two new storage contracts 75 percent to demand and 25 percent to commodity. In its October 13, 2014 Reply Comments, CenterPoint explained that the costs represent the fixed-cost (demand) portion of the new storage services that were contracted to serve swing supplies. CPE continued:

> In the February 28, 2012 order in the G008/M-07-561 and G008/M-11-1078, this kind of cost was ordered to be split 75 percent demand and 25 percent commodity to reflect that some of the fixed-cost portion of the storage costs should be borne by dual fuel customers as they use the some [sic] of the storage supplies throughout the winter when not required for firm supply (ordering point 7).[9]

In its Briefing Papers, Commission Staff provided further context and two additional decision alternatives:[10]

- Require CenterPoint to allocate the fixed costs associated with the two new storage contracts 100% to commodity; or
- Require CenterPoint to allocate:
  - all of the new fixed storage costs associated with the annual capacity (amount) of gas that can be stored to commodity costs; and
  - all of the new fixed storage costs associated with the maximum daily quantity that can be withdrawn (peak day deliverability) like supplier reservation fees, with 75% allocated to demand costs (allocated to firm customers only) and 25% allocated to commodity costs (allocated to firm and interruptible customers).

The Commission ultimately approved CPE's proposed allocation method, but requested that Staff's proposed options be explored further in this instant docket.

Based on Staff's discussion provided in the briefing papers in Docket 14-561, the Department sees consistency and fairness in the proposal to split the allocation of costs between those associated with annual storage capacity and maximum daily quantity. To explore this allocation in the context of CenterPoint's contracts, the Department requests

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[8] CenterPoint's *Petition* filed July 1, 2014 in Docket No. G008/M-14-561 (Docket 14-561).

[9] Order Point 7 specifically stated that reservation fees be allocated 75 percent to demand and 25 percent to commodity.

[10] Filed May 29, 2015, pages 5-8 and 12.

that CenterPoint provide in its Reply Comments the percentage breakdown of the costs associated with the two new storage contracts between annual storage capacity and maximum daily quantity.

3. *Design-Day Requirement*

a. *CPE Analysis*

The design-day analysis employed by CenterPoint Energy in this filing is similar to what was used by the Company in recent demand entitlement filings. CenterPoint Energy's design-day analysis was 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 was based on Ordinary Least Squares (OLS) regression and daily heating season (November through March) data over the period from November 2009 to March 2015. CPE used HDDs and the squared value of HDDs (HDD2) to estimate daily firm use per customer (UPC). The factor HDD2 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 Energy's design-day regression analysis, and notes that the signs on HDD and HDD^2 are both positive and the scale of the coefficients appear to be reasonable. Therefore, the Department concludes that CPE's design-day analysis method is reasonable.

As noted earlier, the Company's analysis was based on daily throughput (use per customer) and weather data over the period from November 2009 to March 2015. CenterPoint Energy's analysis resulted in a design-day estimate of 1,254,000 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 1,317,000 Dkt/day, which is 27,000 Dkt/day greater than the design-day estimate in last year's demand entitlement filing. The Company stated that it made this modification to ensure a bias toward reliability since this adjustment placed the design-day estimate at the top end of expected design-day conditions based on the regression.

This filing marks the fourth year that CenterPoint has used this design-day regression analysis. In last year's demand entitlement filing (Docket No. G008/M-14-561), the Department expressed concern that the Company's use of the upper bound of its regression model may not be appropriate going forward and may result in unnecessarily high demand costs. The Department reached this conclusion after conducting an after-the-fact review of CenterPoint's regression results relative to the 2013-2014 heating season. This analysis suggested that the Company would have had sufficient entitlement to serve firm customers on a peak using only CenterPoint's point estimate from its regression analysis.

In its Petition, CenterPoint conducted an after-the-fact analysis for the 2014-2015 heating season to demonstrate how well its model predicted sales during the past winter. After updating the model for new data, the Company's model results under-estimated usage during the 2014-2015 heating season (February 18, 2015 at 69.5 heating degree days

(HDD)) by approximately 39,400 Dkt/day, or approximately 4.1 percent. Based on this result, CenterPoint concluded that using the upper limit of its regression model confidence interval is necessary to ensure firm reliability on a peak day.

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 Energy's analysis only incorporated the impacts of weather and did not contemplate other factors including: day of the week, month, and heating season. In other words, CPE's analysis assumed 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 Energy's and included HDDs and HDD^2 along with factors that account for month, day of the week, and which heating season usage occurred (*e.g.,* 2010-2011). 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 4). 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 favor of system reliability. Using this approach, the additional regression factors decrease the projected design day by a small amount from CenterPoint Energy's 1,254,000 Dkt/day figure to approximately 1,245,406 Dkt/day as calculated using the Department's model, but the results are within the confidence interval from 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 1,375,900 Dkt/day, is higher than CenterPoint Energy's proposed total entitlement level of 1,317,000 Dkt/day. A strict interpretation of this result suggests that, based on the Department's analysis, the Company may 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. 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 Tuesday, in February, and during a heating season with usage characteristics similar to the 2014-2015 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 concludes that CPE likely has sufficient capacity to serve needs on an all-time peak day.

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

c. *Testing the Design-Day Analysis Approaches*

In order to better assess the accuracy and appropriateness of these design-day analyses, the Department analyzed what firm usage may have been during the 2014-2015 heating season had a Commission peak day (*i.e.*, 90 HDD) occurred.

Using the regression coefficients from the Company's design-day model (Exhibit B, Page 1 of the Company's Petition), the Department determined that firm throughput would have been 1,187,899 Dkt on last heating season's peak day if the average temperature was 90 HDD (peak sendout during the 2014-2015 heating season occurred at 69.5 HDD). This adjusted peak day calculation results in firm throughput of 41,101 Dkt, or 3.5 percent, lower than the regression-estimated design-day figure of 1,229,000 Dkt calculated in last year's demand entitlement filing. In addition, this result is 102,101 Dkt, or 8.6 percent, lower than the upper-bound estimate used by the Company to determine its total entitlement level in last year's demand entitlement filing. This analysis shows that CenterPoint likely had sufficient entitlements to serve firm customers on a Commission peak day during the last heating season, and it is useful to consider in this docket since the design-day regressions are identical, save for updates in data, between the last year's demand entitlement and this year's demand entitlement filings.

The Department also conducted an after-the-fact analysis using the Department's alternative calculation discussed above. The predicted sales for the 2014-2015 heating season peak day are also similar to CenterPoint's results (928,751 Dkt compared to CenterPoint's 925,756 Dkt) and also suggest that the Department's alternate design-day model may under-estimate sales.[11] This result may suggest that both design-day models have a bias toward under-estimating sales on a peak day; however, it is important to note that last heating season's peak sendout occurred on a day much warmer than the 90 HDD planning objective and, as explained in the previous paragraph, it appears that the Company had sufficient entitlements to serve firm customers at 90 HDD. As such, it is unclear if the Department's alternate model or CenterPoint's design-day model would also have a bias toward under-estimating sales on an all-time peak day.

The Department's review suggests that the Company's design-day analysis is reasonable; however, as noted by CenterPoint and confirmed by the Department's alternative analysis, there may be some question regarding whether the model has some bias toward under-estimating firm sales on colder days. The Department had expressed concern in previous demand entitlement filings that CenterPoint's use of the upper-bound of its regression

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[11] Actual firm sales on the 2014-2015 peak day were 959,990 Dkt.

model may be inappropriate because it would result in the procurement of too many entitlements. After reviewing the design-day analysis and after-the-fact results, along with the reserve margin issues discussed in Section II.4., the Department concludes that the use of the upper-bound figure is not unreasonable at this time since it is biased toward firm reliability, yet not overly so, since it may under-estimate firm sales on colder days. The Department will continue to monitor this method in future demand entitlement filings.

4. *Reserve Margin*

As shown below and in DOC Attachment 2, CPE's proposed reserve margin is (0.70) percent:

Table 3

Total Entitlement (Dkt)	Design-day Estimate (Dkt)	Difference (Dkt)	Reserve Margin %	% Change From Previous Year[12]
1,343,566	1,353,000	9,434	(0.70%)	(1.47%)

The estimated design day increased, while the total entitlements declined due to the reduction of propane peaking. Both of these factors reduced reserve margin since the previous demand entitlement. However, this negative reserve margin[13] assumes that half of the 72,000 Dkt of liquefied natural gas (LNG) reserve could potentially be unavailable on a design day due to unpredictable circumstances. Assuming all of CPE's LNG physical reserve is available, the Company has an additional 36,000 Dkt to meet its design day requirements, giving CPE a reserve margin of 2 percent.

It is also worth noting that the Company reports its upper bound design day estimate, which is higher than the point estimate design day used by the Department. As discussed in Section II.3. above, the Department has concluded that this approach is reasonable, and that CenterPoint likely has sufficient capacity to serve needs on an all-time peak 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, 2015 (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 June 2015 PGA rates to its proposed November 2015 PGA which resulted in an increase of demand costs by $0.0167 per Dkt for the Residential class. As shown in DOC Attachment 3, the Department also prepared this analysis and found the same result. CenterPoint's proposed changes would result in the following annual rate impacts:

- Annual demand cost increase of $1.67, or approximately 2.02 percent, for the

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[12] As shown on DOC Attachment 2, the Company's average reserve margin since 2001-2002 is 5.66 percent.

[13] *Petition,* page 2.

average Residential customer consuming 100 Dkt annually;
- Annual demand cost increase of $1.34, or approximately 2.02 percent, for the average Commercial/Industrial Firm - A customer consuming 80 Dkt annually;
- Annual demand cost increase of $47.76, or approximately 2.02 percent, for the average Commercial/Industrial Firm - B customer consuming 2,860 Dkt annually; and
- Annual demand cost increase of $238.81, or approximately 2.02 percent, for the average Commercial/Industrial Firm - C customer consuming 14,300 Dkt annually.

The increase in demand costs is driven by the increase in entitlements and the additional capacity on the Trailblazer Pipeline. Based on its analysis, the Department recommends that the Commission approve the proposed demand costs with an effective date of November 1, 2015.

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; and
- accept the design-day level proposed by CPE.

Also, the Department requests that, in its *Reply Comments*, CenterPoint provide the percentage breakdown of the costs associated with the two new storage contracts between annual storage capacity and maximum daily quantity.

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Heating Season Services	{1} CenterPoint Energy 13-578 (July 2013) Quantity (Dkt)	{2} CenterPoint Energy 13-578 (Jan 2014) Quantity (Dkt)	{3} CenterPoint Energy 14-561 (July 2014) Quantity (Dkt)	{4} CenterPoint Energy 15-644 (Jan 2015) Quantity (Dkt)	{5} CenterPoint Energy 15-644 (July 2015) Quantity (Dkt)	{6} TOTAL Change (Jan. 2015 - Jul. 2015)
	[TRADE SECRET DATA BEGINS					**{5}-{4}**
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						
TFX-Winter 5 mo. (non-discounted)						
TFX-Summer 7 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]
NNG Demand Winter	981,497	981,657	987,009	987,009	1,018,671	31,662
NNG entitlements sources from Viking					(24,914)	
Total NNG Demand Winter					993,757	
Total NNG Demand Summer	553,413	553,531	555,729	555,729	574,472	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.)						
						TRADE SECRET DATA ENDS]
Total Viking Demand	56,809	56,809	56,809	56,809	56,809	0
Trailblazer (FTS Backhaul)				50,000	100,000	50,000
Supply Demand						
	[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	0	0	0	0	0
Underground Storage	50,000	50,000	50,000	50,000	50,000	0
LNG Peak Shaving	72,000	72,000	72,000	72,000	72,000	0
Propane Peak Shaving	179,633	179,633	178,600	178,600	171,000	(7,600)
Total Propane	301,633	301,633	300,600	300,600	293,000	(7,600)
Total Capacity	1,339,939	1,340,099	1,344,418	1,344,418	1,343,566	(852)
Total Peak-Shaving Capacity/On-line Storage	301,633	301,633	300,600	300,600	293,000	(7,600)
Total Annual Transportation	610,222	610,340	612,538	612,538	631,281	18,743
Total Seasonal Transportation	1,038,306	1,038,466	1,043,818	1,043,818	1,050,566	6,748
Peak Shaving as % of Total Capacity	22.5%	22.5%	22.4%	22.4%	21.8%	-0.6%
Annual Transportation as % of Total Capacity	45.5%	45.5%	45.6%	45.6%	47.0%	1.4%
Seasonal Transportation as % of Total Capacity	77.5%	77.5%	77.6%	77.6%	78.2%	0.6%
Annual and Seasonal Transportation as % of Total Transportation	63.0%	63.0%	63.0%	63.0%	62.5%	-0.6%

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
15-644	2015-2016*	n/a	841,135	11,133	1.34%	1,353,000	27,000	2.04%	1,343,566		-852	-0.06%	-0.70%	-0.07%
14-561	2014-2015	830,377	830,002	6,212	0.75%	1,326,000	2,000	0.15%	1,344,418		4,479	0.33%	1.39%	1.40%
13-578	2013-2014	821,220	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:		788,858	9,411	1.23%	1,253,087	12,099	0.99%	1,322,501		6,762	0.53%	5.66%	

	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)
2015-2016*	n/a	n/a	n/a	-0.0112	1.6085	1.5973	n/a	n/a
2014-2015	959,990	(126,340)	-11.63%	0.0222	1.5976	1.6198	1.1566	1.1561
2013-2014	1,086,330	125,196	13.03%	0.0193	1.6072	1.6266	1.3187	1.3228
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:	939,630	12,811	2.02%	0.0882	1.5901	1.6784	1.1974	1.2049

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-13-316)	Last Demand Change (G008/M-14-561) (Jan 2015)	June 2015 PGA before proposed demand entitlement change	Nov. 2015 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)	$4.0048	$4.2198	$2.8942	$2.8942	-27.73%	-31.41%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.7692	$0.8292	$0.8282	**$0.8449**	**9.84%**	**1.89%**	**2.02%**	**$0.0167**
Commodity Margin (2) (3)	$1.8458	$1.9640	$1.9341	$1.9341	4.78%	-1.52%	0.00%	$0.0000
Total Cost of Gas	$6.6198	$7.0130	$5.6565	$5.6732	-14.30%	-19.10%	0.30%	$0.0167
Average Annual Usage (Dk)	100	100	100	100				
Average Annual Total Cost of Gas	$661.98	$701.30	$565.65	$567.32	-14.30%	-19.10%	0.30%	$1.67
Average Annual Total Demand Cost of Gas								**$1.67**

Commercial/Industrial Firm - A	Last Rate Case (G008/GR-13-316)	Last Demand Change (G008/M-14-561) (Jan 2015)	June 2015 PGA before proposed demand entitlement change	Nov. 2015 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)	$4.0181	$4.2198	$2.8942	$2.8942	-27.97%	-31.41%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.7692	$0.8292	$0.8282	**$0.8449**	**9.84%**	**1.89%**	**2.02%**	**$0.0167**
Commodity Margin	$1.4129	$1.2870	$1.3197	$1.3197	-6.60%	2.54%	0.00%	$0.0000
Total Cost of Gas	$6.2002	$6.3360	$5.0421	$5.0588	-18.41%	-20.16%	0.33%	$0.0167
Average Annual Usage (Dk)	80	80	80	80				
Average Annual Total Cost of Gas	$496.02	$506.88	$403.37	$404.70	-18.41%	-20.16%	0.33%	$1.34
Average Annual Total Demand Cost of Gas								**$1.34**

Commercial/Industrial Firm - B	Last Rate Case (G008/GR-13-316)	Last Demand Change (G008/M-14-561) (Jan 2015)	June 2015 PGA before proposed demand entitlement change	Nov. 2015 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)	$4.0181	$4.2198	$2.8942	$2.8942	-27.97%	-31.41%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.7692	$0.8292	$0.8282	**$0.8449**	**9.84%**	**1.89%**	**2.02%**	**$0.0167**
Commodity Margin	$1.3329	$1.2840	$1.3689	$1.3689	2.70%	6.61%	0.00%	$0.0000
Total Cost of Gas	$6.1202	$6.3330	$5.0913	$5.1080	-16.54%	-19.34%	0.33%	$0.0167
Average Annual Usage (Dk)	2,860	2,860	2,860	2,860				
Average Annual Total Cost of Gas	$17,503.77	$18,112.38	$14,561.12	$14,608.88	-16.54%	-19.34%	0.33%	$47.76
Average Annual Total Demand Cost of Gas								**$47.76**

Commercial/Industrial Firm - C	Last Rate Case (G008/GR-13-316)	Last Demand Change (G008/M-14-561) (Jan 2015)	June 2015 PGA before proposed demand entitlement change	Nov. 2015 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)	$3.9806	$4.2198	$2.8942	$2.8942	-27.29%	-31.41%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.7692	$0.8292	$0.8282	**$0.8449**	**9.84%**	**1.89%**	**2.02%**	**$0.0167**
Commodity Margin	$1.3969	$1.4852	$1.3453	$1.3453	-3.69%	-9.42%	0.00%	$0.0000
Total Cost of Gas	$6.1467	$6.5342	$5.0677	$5.0844	-17.28%	-22.19%	0.33%	$0.0167
Average Annual Usage (Dk)	14,300	14,300	14,300	14,300				
Average Annual Total Cost of Gas	$87,897.81	$93,439.06	$72,468.11	$72,706.92	-17.28%	-22.19%	0.33%	$238.81
Average Annual Total Demand Cost of Gas								**$238.81**

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%	$0.0167	2.02%	$1.67	$1.67	0.30%
Commercial/Industrial Firm A	$0.0000	0.00%	$0.0167	2.02%	$1.34	$1.34	0.33%
Commercial/Industrial Firm B	$0.0000	0.00%	$0.0167	2.02%	$47.76	$47.76	0.33%
Commercial/Industrial Firm C	$0.0000	0.00%	$0.0167	2.02%	$238.81	$238.81	0.33%

(1) Does not include Demand Smoothing.

(2) Reflects Decoupling Factor and CCRA. Does not reflect GAP, Interim or GCR Factors.

(3) Reflects decrease in CCRA of ($0.0767 per DT effective November 1, 2013 (Docket No. G008/M-13-373).

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regress upc hdd HDDs_2 Nov Dec Feb Mar Sun Mon Tue Thu Fri Sat HS0910 HS1011
HS1213 HS1314

      Source         SS         df        MS              Number of obs =      907
---------------------------------------------             F( 17,    889) = 2843.38
       Model    47.2418481     17  2.77893224             Prob > F      =  0.0000
    Residual     .86884998    889  .000977334             R-squared     =  0.9819
---------------------------------------------             Adj R-squared =  0.9816
       Total    48.1106981    906  .053102316             Root MSE      =  .03126

------------------------------------------------------------------------------
         upc |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
         hdd |   .0119953   .0003266    36.73   0.000     .0113543    .0126364
      HDDs_2 |   .0000339   3.83e-06     8.84   0.000     .0000264    .0000414
         Nov |  -.0516694   .0037612   -13.74   0.000    -.0590513   -.0442875
         Dec |  -.0249751   .0032918    -7.59   0.000    -.0314357   -.0185145
         Feb |  -.0177215   .0033408    -5.30   0.000    -.0242782   -.0111647
         Mar |  -.0375281   .0037211   -10.09   0.000    -.0448314   -.0302249
         Sun |   .0041281   .0038864     1.06   0.288    -.0034994    .0117556
         Mon |   .0023771   .0038862     0.61   0.541    -.0052501    .0100043
         Tue |   .0063498   .0038859     1.63   0.103    -.0012767    .0139763
         Thu |  -.0046846   .0038947    -1.20   0.229    -.0123284    .0029593
         Fri |  -.0082881   .0038964    -2.13   0.034    -.0159353   -.0006409
         Sat |  -.0133623    .003886    -3.44   0.001    -.0209891   -.0057356
      HS0910 |  -.0029481   .0036455    -0.81   0.419    -.0101029    .0042067
      HS1011 |   .0011763   .0037449     0.31   0.754    -.0061735    .0085261
      HS1213 |   .0041498   .0037002     1.12   0.262    -.0031122    .0114119
      HS1314 |     .02576   .0038777     6.64   0.000     .0181494    .0333706
      HS1415 |   .0279336   .0037129     7.52   0.000     .0206466    .0352206
       _cons |   .1098961    .007756    14.17   0.000     .0946739    .1251183
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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-15-644

Dated this 31st day of August 2015

/s/Sharon Ferguson

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