COMMERCE DEPARTMENT

August 11, 2017

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Review of 2015-2016 Annual Automatic Adjustment Reports**
Docket No. G999/AA-16-524 and Natural Gas Utilities' 2015-2016 Purchased Gas Adjustment (PGA) True-Up Filings (see attached list)

Dear Mr. Wolf:

Minnesota Rules 7825.2800 through 7825.2830 require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports.

Attached please find the Minnesota Department of Commerce, Division of Energy Resource's (Department) *Review of the 2015-2016 Annual Automatic Adjustment Reports* (FYE16 AAA Report) for regulated natural gas utilities in Minnesota.

The Department is available should the Commission have any questions about the FYE16 AAA Report herein provided.

Sincerely,

/s/ ANGELA BYRNE
Financial Analyst
Division of Energy Resources

/s/ MICHAEL RYAN
Rate Analyst
Division of Energy Resources

AB/MR/lt
Attachments

<u>Docket Numbers for 2015-2016 Gas Utility PGA True-Up Filings:</u>

Docket No. G004/AA-16-719 -	Great Plains Natural Gas Company
Docket No. G022/AA-16-715 -	Greater Minnesota Gas
Docket No. G008/AA-16-730 -	CenterPoint Energy
Docket No. G011/AA-16-733 -	Minnesota Energy Resource Corporation (MERC) – Albert Lea PGA system
Docket No. G011/AA-16-734 -	Minnesota Energy Resource Corporation (MERC) – Consolidated PGA system
Docket No. G011/AA-16-732 -	Minnesota Energy Resource Corporation (MERC) – Northern Natural Gas PGA system
Docket No. G002/AA-16-725 -	Northern States Power d/b/a Xcel Energy

REVIEW OF THE 2015-2016

ANNUAL AUTOMATIC ADJUSTMENT REPORTS

SUBMITTED TO THE

MINNESOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. G999/AA-16-524

AUGUST 11, 2017

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EXECUTIVE SUMMARY – NATURAL GAS UTILITIES

Since 1985, Minnesota Rules 7825.2800 through 7825.2830 have required public utilities that use automatic adjustments to recover energy costs to file annual reports regarding the operation of the automatic adjustments. The reports allow verification of whether utilities are calculating their rate adjustments properly and are implementing these rates in a timely manner. In reviewing the 2015-2016 (FYE16) filings, the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) incorporated information from prior years' reports, as well as its assessment of the utilities' monthly automatic adjustment filings submitted throughout the FYE16 reporting period.

The Department's FYE16 Annual Automatic Adjustment natural gas report (FYE16 AAA Report) includes analyses of:

- FYE16 automatic adjustment charge calculations filed pursuant to Minnesota Rule 7825.2810, ANNUAL REPORT; AUTOMATIC ADJUSTMENT CHARGES;

- filings to reconcile or "true up" revenues collected by the utilities to actual gas costs incurred by the utilities, as required by Minnesota Rules 7825.2910 and 7825.2700; and

- supplemental annual reporting requirements ordered by the Minnesota Public Utilities Commission (Commission) in miscellaneous or other dockets during the reporting period.

Recovery of energy costs represents an important factor in the rates customers actually pay, particularly for ratepayers of natural gas utilities. One part of the rates that customers pay is a true-up reflecting the difference between the actual costs the utilities incur and the actual revenues they recover. True-ups are based on information from the prior year. For example, an over-recovery of costs from a certain customer class in one year would result in an offsetting decrease in the rates (compared to what would otherwise have been charged) assigned to that customer class in the following year. Since customers use different amounts of gas over time, and because some customers leave or join the utility's system over time, there is likely to be some mismatch between the amounts particular customers pay in a given year and the true-up amount assigned to these customers in subsequent years. While it is not administratively feasible to eliminate such mismatches completely, it is essential that utilities attempt to minimize both over- and under-recoveries.

All of the regulated local distribution natural gas utilities provided the information necessary to meet the filing requirements. For this reporting period, these public utilities are:

- Greater Minnesota Gas, Inc. (Greater Minnesota or GMG);
- Great Plains Natural Gas Company (Great Plains);
- Minnesota Energy Resources Corp. (MERC);
- CenterPoint Energy, a division of CenterPoint Energy Resources Corp. (CenterPoint Energy or CPE); and
- Northern States Power Company d/b/a Xcel Energy - Gas Utility (Xcel Gas).

In this report, the Department reviews these utilities' compliances with Minnesota Rules 7825.2810 and 7825.2910, which governs the filing of annual automatic adjustment reports, and makes a number of specific recommendations to assure compliance with Commission requirements and to improve the usefulness of future annual automatic adjustment reports. These recommendations are listed in Section IV, *Summary of the Department's Recommendations*.

As noted above, several sections of the report are based on the Commission's requirements and contain information in addition to that specifically required by Minnesota Rules. The Department issued information requests and worked with all of the gas utilities to obtain these data. Based on this information, the Department developed analyses on:

- comparisons of total gas costs incurred and recovered;
- average annual residential customer bills;
- average annual gas costs;
- margins charged to residential customers;
- firm peak-day demand profiles, load factors, and reserve margins;
- penalty charges regarding daily nominations of gas supply;
- revenue from curtailment and balancing penalties;
- peak-day pipeline transportation sources and numbers of suppliers;
- variety of gas suppliers;
- revenues from releasing firm pipeline transportation capacity;
- gas utilities' annual auditor reports;
- lost-and-unaccounted-for gas for each utility;
- report on contractor main strikes and meter testing;
- Minnesota gas utilities' purchasing practices;
- cost of gas storage per unit;
- Minnesota gas utilities' hedging practices; and
- distribution planning.

The Department appreciates the utilities' cooperation in developing the data for these reports. The FYE16 AAA Report builds on the Department's experience and knowledge gained from prior years' reports and is informed by our continuing assessment of the utilities' automatic adjustment filings throughout the reporting period.

In FYE16, natural gas prices were lower than prices during FYE15. Generally, prices decreased during the reporting period due to the warmer-than-normal winter and large amount of natural gas that remained in storage. The Henry Hub price[1] began the reporting period at $2.84 per Mcf in July 2015 and ended the reporting period around $2.59 per Mcf in June 2016, but during the year pricing ranged from the high of $2.84 in July 2015 to a low of $1.73 per Mcf in March 2016 highlighting the glut of gas coming out of the heating season.[2]

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[1] The Henry Hub is a distribution hub on the natural gas pipeline system that serves as the official delivery location for futures contracts on the New York Mercantile Exchange (NYMEX).
[2] EIA Monthly Henry Hub Pricing available at https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

With the prevalence of shale gas, natural gas production has become more diversified and less reliant on any single basin or area of production. The industry still has concentration in the Gulf of Mexico making hurricanes an ongoing concern of market interruption. During FYE16 there were no major interruptions from hurricanes, and the FYE16 annual temperatures were warmer than normal. The storage inventory level reached historic heights as injections were above average due to increasing production and mild weather resulting in lower demand. Natural gas prices and weather are discussed further below.

The FYE16 AAA Report consists of the following sections:

- an overview with background information (Section I);
- an analysis of the gas utility over-/under-recoveries and true-ups (Section II);
- additional information to assist the Commission (Section III); and
- the Department's concluding comments and recommendations (Section IV).

I. BACKGROUND AND OVERVIEW

A. OVERVIEW

The Department concludes that all five[3] regulated Minnesota gas utilities met the annual filing requirements, including provision of information relating to fuel procurement and the annual true-up adjustment. As noted above, these utilities are:

- Greater Minnesota;
- Great Plains;
- MERC;
- CenterPoint Energy; and
- Xcel Gas.

The Department concludes that the annual filings are complete as originally filed. The Department's report includes the following sections:

- filing requirements;
- summaries of the gas utilities' 2015-2016 (FYE16) automatic adjustment charge calculations filed pursuant to Minnesota Rule 7825.2810;
- analyses of the gas utilities' true-up filings required by Minnesota Rule 7825.2910, subpart 4;
- supplemental reporting requirements ordered by the Commission in miscellaneous filings; and
- reports required by the Commission's previous AAA Report Orders:
    - February 26, 2008 *Order* in Docket No. E,G999/AA-06-1208;
    - December 8, 2008 *Order* in Docket No. E,G999/AA-07-1130;
    - February 12, 2010 *Order* in Docket No. G999/AA-08-1011;
    - April 7, 2011 *Order* in Docket No. G999/AA-09-896;
    - April 3, 2012 *Order* in Docket No. G999/AA-10-885;
    - October 17, 2013 *Order* in Docket No. G999/AA-11-793;
    - November 14, 2013 *Order* in Docket No. G999/AA-12-756 (Docket No. 12-756);
    - August 11, 2014 *Order* in Docket No. G999/AA-13-600;

[3] In Docket No. G011,007/GR-10-977, the Commission approved consolidation of MERC's two operating divisions, MERC-PNG and MERC-NMU, into MERC effective January 1, 2013. In that same order, the Commission approved the consolidation of MERC's four PGA systems into two systems effective July 1, 2013. In Docket No. G011/PA-14-107, the Commission approved a new PGA system (MERC-Albert Lea or MERC AL) related to MERC's purchase of Interstate Power and Light's assets.

- o August 24, 2015 *Order* in Docket No. G999/AA-14-580; and
- o February 6, 2017 *Order* in Docket No. G999/AA-15-612.

B. FILING REQUIREMENTS

Minnesota Rule 7825.2810, subparts 1 and 2 contain the following filing requirements for gas utilities:

<u>Subpart 1</u>

- Paragraph A – Commission-approved base cost of gas;
- Paragraph B – billing amounts in Mcf, Ccf, or Btu for each type of energy cost (*e.g.*, purchased gas, peak shaving, and manufactured gas);
- Paragraph C – billing adjustment amounts;
- Paragraph D – total cost of gas;
- Paragraph E – revenues collected;
- Paragraph F – supplier refunds received; and
- Paragraph G – refunds credited to customers.

<u>Subpart 2</u>

- Paragraph A – a listing of all variances in effect or requested;
- Paragraph B – identification of all changes in demand contracted;
- Paragraph C – the level of customer-owned gas volumes delivered through the utility's system; and
- Paragraph D – a brief explanation of deviations between gas-cost recovery and actual cost.

In addition to reviewing the basic data, the Department investigated and developed additional data to provide more detailed information to assist the Commission in its review of each individual gas utility's annual automatic adjustment report.

C. NATURAL GAS PRICES AND WEATHER

1. Gas Prices in FYE16

As noted above, in FYE16, natural gas prices were lower than prices during FYE15. Overall, Henry Hub prices decreased during the reporting period, beginning the reporting period (July 2015) at $2.84 per Mcf and ending at $2.59 per Mcf in June 2016, with the lowest price at $1.73 per Mcf in March 2016 and the highest price at $2.84 in July 2015. In FYE16, the price of residential propane in Minnesota was lower than the previous year but still high (approximately $13-$18/Mcf) compared to the cost of natural gas.[4]

2. *Weather in FYE16*

Compared to 30-year normal weather,[5] the weather in the Minnesota area for the entire year of FYE16 was warmer than normal. The warmer-than-normal annual weather ranged from approximately 12.0 percent warmer at the Rochester and International Falls weather stations to approximately 18.5 percent warmer in Fargo, North Dakota. Natural gas storage inventory was at record level, as a result of these warmer-than-average weather and high levels of domestic natural gas production.

The heating season (November 2015 through March 2016) was warmer than normal compared to 30-year normal weather. The warmer-than-normal weather ranged from approximately 11.55 percent at the Rochester weather station to approximately 24.13 percent warmer in Fargo, North Dakota.

According to Northern Natural Gas Company's (NNG) March 2016 *Northern Notes*, the 2015-2016 heating season has been warmer than normal in all five winter months (November through March). The 2015-2016 heating season was 10 percent warmer than normal. The warmer-than-average heating season comes after two consecutive years of colder-than-average weather. When compared to normal temperatures, January and February 2016 were the closest to an average winter with system weighted temperatures 1 and 3 percent above average, respectively. This average weather was followed by the warmer-than-normal month of March 2016, which was 19% above average. November and December 2015 were also in the range of 14 to 17 percent above average. Even with January 2016 being warmer than average, NNG experienced two of its top five market area peak days.

On January 18, 2016, market area delivery averaged 5.158 Bcf, which is NNG's highest market area delivery average recorded. NNG experienced 13 days of market area deliveries of 4.0 Bcf/day or greater during the 2015-2016 heating season. This amount compares to 36 days of market area deliveries in 2014-2015 and 49 days in the 2013-2014 heating season.

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[4] http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPLLPA_PRS_SMN_DPG&f=W

[5] Based on weather data from 1981 through 2010.

D. GAS UTILITIES SUMMARY

The Department reviewed the gas utilities' filings to:

- identify systematic patterns of over- or under-recoveries that may be occurring over time;
- identify any incorrect calculations of annual true-up adjustment factors;
- identify additional issues that may warrant Commission attention; and
- assess the utilities' compliance with additional annual automatic adjustment report filing requirements, as ordered by the Commission in miscellaneous filings.

As discussed further in Section II, the Department categorized each gas utility's estimated revenue recovery by pipeline system and customer class to allow for full verification of the actual annual fuel costs and the related annual true-up adjustments. The Department reviewed the reasonableness of the utilities' explanations of differences between actual gas costs and gas-cost recovery based on estimated gas costs, as required in Minnesota Rule 7825.2810, subpart 2, paragraph D. Further, since Minnesota Rule 7825.2910 requires that gas utilities "true up" all over- or under-recoveries of gas costs, the Department also verified the accuracy of each utility's annual true-up adjustments.

Gas-cost recovery generally represents the largest component in the rates and bills that customers pay. Further, as noted above, there can be mismatches in the over- or under-charges in a given year and the true-up amounts in the subsequent year. These mismatches affect rates in subsequent years such that an over-recovery for a certain customer class in one year results in an offsetting decrease in the rates (compared to what would otherwise have been charged) assigned to that customer class in the following year. Likewise, an under-recovery in one year increases rates in the subsequent year, compared to rates that would otherwise have been charged. Thus, it is essential that utilities attempt to minimize both over- and under-recoveries.[6] Section II below provides analyses of the true-ups for individual utilities. Table G1 below summarizes the fuel-cost recovery during the FYE16 reporting period for gas utilities.

[6] As discussed further in the individual gas utility evaluations, Section II, CenterPoint Energy and Xcel Gas have received Commission approval to add a monthly demand adjustment to their demand cost recovery rate in order to match costs better within the true-up year.

Table G1:[7] Summary of Gas Utilities' Annual Demand & Commodity Cost Recovery[8]

July 1, 2015 - June 30, 2016

Utility/System	Gas Cost Recovered ($)	Incurred Cost of Gas ($)	Over(Under) Recovery ($)	Over(Under) Recovery (%)
Greater Minnesota	$3,975,174	$3,923,221	$51,953	1.32%
Great Plains				
North	$5,077,612	$5,163,189	$(85,577)	(1.66%)
South	$5,610,225	$5,752,732	$(142,507)	(2.48%)
MERC				
CON	$19,154,988	$19,018,750	$136,238	0.72%
NNG	$92,150,994	$94,613,319	$(2,462,325)	(2.60%)
AL	$5,275,747	$5,465,133	$(189,386)	(3.47%)
CenterPoint Energy	$372,764,107	$383,527,681	$(10,763,574)	(2.81%)
Xcel Gas	$208,493,362	$213,484,094	$(4,990,732)	(2.34%)
MN TOTAL	**$712,502,209**	**$730,948,119**	**$(18,445,910)**	**(2.52)%**

As shown above, six of the eight PGA systems[9] under-recovered gas costs (demand and commodity), ranging from negative 1.66 percent for Great Plains' North PGA to negative 3.47 percent for MERC's AL PGA.[10] By contrast, MERC's CON and Greater Minnesota Gas' PGAs over-recovered gas costs by 0.72 and 1.32 percent, respectively. The weighted average for all

[7] The information for Table G1 can be found in each of the utilities' true-ups, which have been included as Department Attachments G5 through G11.

[8] Except for CenterPoint Energy, the recovery in Table G1 includes credits or revenues related to gas costs. CenterPoint Energy's revenues related to annual credits were $1,044,351 in FYE16. As shown on DOC Attachment G10, CenterPoint Energy's under-recovery including these revenues was $9,719,223, or approximately 2.53 percent.

[9] The Department notes that "gas utility" and "PGA system" are, at times, interchangeable in this Report.

[10] MERC purchased Interstate Gas on April 30, 2015. This is the first full year of data for MERC-AL.

Minnesota gas utilities was an under-recovery of 2.52 percent.[11] The Minnesota total cost of gas for FYE16 was $730,948,119 (about $731 million) and for FYE15 was $1,140,929,250 (about $1.1 billion), which represents a decrease in gas costs of $409,981,131 (about $410 million), or approximately 36 percent from the level in FYE15. Table G1a below presents a comparison of FYE16 gas costs to the nominal gas costs in past reporting periods.

Table G1a: Summary of Gas Utilities' Annual Fuel Cost Recovery

Report Period	Total Cost of Gas	FYE15 Increase/ (Decrease) Compared to Prior Years
FYE16	$730,948,119	
FYE15	$1,140,929,250	(36)%
FYE14	$1,659,257,488	(56)%
FYE13	$1,063,629,628	(31)%
FYE12	$899,685,483	(19)%
FYE11	$1,228,496,903	(41)%
FYE10	$1,290,861,146	(43)%
FYE09	$1,667,839,793	(56)%
FYE08	$2,183,027,141	(67)%
FYE07	$1,904,701,880	(62)%

Table G1a indicates that the total cost of gas including demand and commodity costs for FYE16 was the lowest cost of natural gas in the last ten years.

Table G2 below summarizes the over- and under-recoveries for each utility over the past ten years, including a ten-year non-weighted average, and the cumulative balance percentage over- or under-recovery.

[11] The Minnesota weighted-average amount is calculated by dividing the total under-recovery amount by the total cost of gas.

Table G2: Percent Over-Recovery/(Under-Recovery)

FYE07-FYE16[12]

Utility/System	Greater Minnesota	Great Plains		Interstate Gas[13]	MERC			CenterPoint Energy	Xcel Gas
		North	South		CON	NNG	AL[14]		
2006-2007	(6.44)	(4.37)	(3.47)	(1.20)	(2.22)	(4.39)		0.06	0.32
2007-2008	3.25	0.67	(1.56)	1.67	1.94	1.21		(0.44)	(1.75)
2008-2009	(4.96)	(0.36)	(3.34)	5.42	3.85	1.21		1.17	(0.23)
2009-2010	(5.18)	(3.57)	(2.62)	(5.17)	(2.09)	(1.25)		(3.96)	(1.26)
2010-2011	(3.92)	0.45	(1.95)	(0.65)	2.00	2.58		(0.66)	(0.50)
2011-2012	0.58	(7.83)	(4.73)	(5.61)	(2.15)	(6.19)		(4.68)	(3.15)
2012-2013	1.46	(3.66)	(1.86)	3.76	2.82	0.08		(0.84)	(0.36)
2013-2014	(0.27)	(12.09)	(13.57)	5.92	(9.25)	(6.45)		(6.88)	(10.47)
2014-2015	0.98	1.57	(3.00)	(0.21)	(3.91)	1.90	(27.03)	1.19	(2.24)
2015-2016	1.32	(1.66)	(2.48)	0.00	0.72	(2.60)	(3.47)	(2.81)	(2.34)
10-Yr. Avg.	**(1.32)**	**(3.09)**	**(3.86)**	**0.39**	**(0.83)**	**(1.39)**	**(15.25)**	**(1.79)**	**(2.20)**
Cumulative[15]	**1.55**	**0.45**	**(4.40)**	**(0.00)**	**(1.36)**	**(1.70)**	**(4.20)**	**(2.42)**	**(1.59)**

As shown in Table G2, all of the PGA systems except GMG and Great Plains North experienced cumulative under-recoveries during FYE16.

The ten-year average from FYE07 through FYE16 shows an under-recovery for all of the gas utilities except for Interstate Gas. The Department's analysis of the over- or under-recovery for each utility is presented below in Section II.

12 See Department Attachment G2 graph comparing historical true-up adjustments.
13 MERC purchased Interstate Gas on April 30, 2015. In Table G2 for 2014-2015, Interstate Gas includes ten months of data.
14 MERC purchased Interstate Gas on April 30, 2015. In Table G2 for 2014-2015, MERC-AL includes two months of data.
15 The figures for this column are included in Department Attachment G5 through G11 in each of the utility's true-ups. The cumulative over- or under-recovery is a calculation based on prior years' true-ups and the present year's true-up.

Table G3 below provides a summary of the current period's over- or under-recoveries. This table illustrates over- or under-recoveries for firm and interruptible classes as a whole and by pipeline system for equivalent PGA systems during the FYE16 true-up period.

Table G3: Percent Over-Recovery/(Under-Recovery) FYE16 by Firm and Interruptible Classes

Utility/System	**Firm [16]**	**Interruptible**	**Total**
Greater Minnesota	1.58%	(1.35)%	1.32%
Great Plains			
North	(3.41)%	4.85%	(1.66)%
South	(2.36)%	(3.13)%	(2.48)%
MERC			
CON	0.84%	(0.07)%	0.72%
NNG	(1.99)%	(8.99)%	(2.60)%
AL	(3.17)%	(5.15)%	(3.47)%
CenterPoint Energy	(2.74)%	(3.46)%	(2.81)%
Xcel Gas	(2.09)%	(3.94)%	(2.34)%
MN Weighted Avg.	**(2.35)%**	**(4.01)%**	**(2.25)%**

Table G3 shows that the MERC-NNG and MERC-AL PGA systems experienced an under-recovery of interruptible costs in excess of five percent.[17] The remaining PGA systems experienced an under-recovery of interruptible costs of less than five percent, except Great Plains North, which had an over-recovery.

The following two sections include the Department's detailed analysis of the significant factors causing the over- and under-recoveries reported in the above tables, as well as summaries of each utility's annual fuel reports, utility-specific reporting requirements, and other items the Department notes for the Commission.

[16] MERC's interruptible figures include the Joint customers' firm requirements since the Joint customers are not considered firm on the peak day.
[17] The Department specifies the five percent threshold per Minnesota Rule 7825.2920, subpart 2, concerning adjustment errors.

E. IMPACTS ON GAS COSTS AND THE RECOVERY OF GAS COSTS

It is normal for utilities to over- or under-recover gas costs. Factors that commonly lead to gas cost over- or under-recovery include:

- weather varying from "normal" weather;
- calculation of the volumetric demand-cost recovery rate;
- capacity release credits;
- deviations between forecasted and actual sales volumes and prices;
- prorating of customer bills; and
- the "three-cent rule" from Minnesota Rule 7825.2700, subp. 3.

Each of these factors is discussed below.

1. **Weather Variance** – Weather is typically the largest factor affecting firm natural gas sales volumes. Therefore, changes in weather can significantly affect the recovery of both demand and commodity gas costs.[18]

   There are seven area weather stations used for Minnesota data.[19] The Department compiled weather data from each of those stations as summarized below and in more detail in Attachment G1. Compared to 30-year normal weather from 1981 to 2010,[20] the weather in Minnesota for FYE16 as a whole was warmer than normal across the state. For the reporting period, the warmer-than-normal weather ranged from approximately 12.0 percent warmer at the Rochester and International Falls stations to approximately 18.5 percent warmer in Fargo, North Dakota. The FYE16 weather in Minnesota was as follows:

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[18] Demand gas costs represent the cost of pipeline capacity to transport firm gas supplies. Commodity gas costs represent the cost of the physical natural gas product.
[19] Of the seven National Weather Service stations in our area, five are located in Minnesota (Minneapolis/St. Paul, Rochester, Duluth, International Falls, and St. Cloud), one is located in Fargo, North Dakota (representing Moorhead and other parts of northwestern Minnesota), and one is located in Sioux Falls, South Dakota (representing southwestern Minnesota).
[20] Comparing the reported weather to "normal" weather varies depending on whether a utility uses a thirty-year (1981-2010) average from the National Oceanic and Atmospheric Administration (NOAA) for normal weather data calculations or some other basis to estimate normal weather data calculations.

Table G4 FYE16 Weather in Minnesota	
Weather Station	**Change from normal***
Duluth	**-13.32%**
International Falls	**-11.99%**
Fargo, ND	**-18.52%**
St. Cloud	**-15.96%**
Minneapolis/St. Paul	**-17.11%**
Rochester	**-11.99%**
Sioux Falls, SD	**-17.21%**

** Negative indicates warmer than normal (fewer heating degree days)*

The weather in Minnesota for the heating season November to March was also warmer than normal compared to 30-year normal weather for all weather stations. The warmer-than-normal weather ranged from approximately 11.55 percent warmer at the Rochester weather station to approximately 24.13 percent warmer in Fargo, North Dakota as follows:

Table G5 2015-2016 Winter Weather in Minnesota	
Weather Station	**Change from normal**
Duluth	**-13.03%**
International Falls	**-13.37%**
Fargo, ND	**-24.13%**
St. Cloud	**-15.84%**
Minneapolis/St. Paul	**-16.16%**
Rochester	**-11.55%**
Sioux Falls, SD	**-13.61%**

Recovery of demand costs is affected by weather because the demand portion of utilities' rates is calculated based on test-year or historical weather-normalized firm sales, but is recovered on each unit of firm gas actually sold. Thus, when weather is warmer than normal, utilities may not recover all incurred demand costs due to lower customer use of natural gas. Conversely, utilities may recover more demand costs than they incurred when customers use more gas during the colder-than-normal periods.

Due to the warmer-than-normal weather experienced during the winter, all things being equal, demand costs should have been under recovered (interruptible customers are not charged for demand costs). During FYE16, all of the PGA systems under-recovered demand costs except MERC-Consolidated, ranging from an under-recovery of 1.21 percent for Greater Minnesota to 12.17 percent for MERC-NNG. Each PGA system over/ (under) recovered its demand costs by the percentages shown below.

Table G6 FYE16 Over-/Under-Recovery of Demand Costs as Filed[21]	
Greater Minnesota	(1.21)%
Great Plains North	(10.59)%
Great Plains South	(6.77)%
MERC-Consolidated	1.98%
MERC-NNG	(12.17)%
MERC-AL	(8.30)%
CenterPoint Energy	(3.23)%
Xcel Gas	(5.43)%

In the individual utility true-up evaluations contained in Section II, the effect of weather and other reasons for over- and under-recoveries of demand-costs are discussed in more detail.

Recovery of commodity costs is also affected by weather, as well as price fluctuations. The gas-commodity portion of rates is generally based on price estimates made during the week prior to the beginning of each month. Thus, an unexpected cold period during the middle of a month, following normal weather in the last week in the preceding month, generally will lead to an under-recovery of higher-than-expected gas commodity costs. Conversely, a cold period during the last week of the month followed by normal weather generally leads to an over-recovery of commodity costs if actual commodity gas costs correspondingly decline. Similarly, a prolonged period of either warmer-than-normal or colder-than-normal weather at the beginning of the winter heating season can impact natural gas prices during the remainder of the heating season.

Due to the warmer-than-normal weather experienced during the winter, all things being equal, commodity costs should have been over-recovered. Also, as discussed above in Section I.C, prices during the heating season were lower. During FYE16, four of the PGA systems over-recovered and four under-recovered commodity costs, ranging from negative 2.69 percent for CenterPoint Energy to 3.10 percent for Great Plains North. Each PGA system over/ (under) recovered its commodity costs by the percentages shown below.

[21] The percentages include revenue such as capacity release and curtailment penalty revenue. Capacity release and curtailment penalty revenue decrease the under-recovery percentages, and increase the over-recovery percentages.

Table G7
FYE16 Over-/Under-Recovery of Commodity Costs as Filed[22]

Greater Minnesota	2.02%
Great Plains North	3.10%
Great Plains South	(0.47)%
MERC-Consolidated	0.45%
MERC-NNG	0.01%
MERC-AL	(1.92)%
CenterPoint Energy	(2.69)%
Xcel Gas	(1.44)%

2. **Calculation of the monthly volumetric demand-cost recovery rate**

Changes in demand costs – In general, demand costs are the costs of reserving pipeline capacity to transport firm gas supplies.[23] Pursuant to Minnesota Rules 7825.2910, subpart 2, gas utilities file a petition 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. The petition must include a description of the factors contributing to the need for changing demand and the utility's design-day demand by customer class and the change in design-day demand.

Test-Year Sales Volumes – Since the current non-gas base rate for most utilities' customers generally does not include a separate demand charge, demand costs are recovered through a volumetric rate on all firm sales through the PGA. This volumetric demand-cost recovery rate is computed by dividing contracted annual demand costs by either the test-year demand volume from a utility's most recent general rate case (which, pursuant to Minnesota Rule 7825.2700, subpart 5, must be used for three years following a utility's rate case) or annual demand volume. Minnesota Rules define the annual demand volume as the actual volume of gas sold during the most recent 12 months (historical), adjusted by an average percentage change in sales computed over the preceding three-year period and normalized for weather.

The demand-cost recovery rate is calculated in the monthly PGA by applying FERC-approved natural gas pipeline rates[24] to the Commission's approved demand entitlement level of the utility. Demand entitlements are normally contracted for with

[22] Except for CenterPoint Energy, the percentages include revenue such as balancing penalty revenue. Additionally, commodity costs include storage and balancing costs.
[23] Department Attachment G3 provides a glossary of pipeline demand services and other relevant terminology. Department Attachment G4 provides a chart, by utility, detailing whether pipeline services and other fees are recovered in the demand or commodity portion of the PGA.
[24] If the natural gas pipeline is intrastate then the Commission-approved rates apply.

the natural gas pipeline on an annual basis with the new levels of demand effective November 1. When demand costs change, application of the monthly PGA demand rate may not result in recovery of one-twelfth of the annual demand costs.[25]

Further, sales are generally much greater during winter than during summer months. If the recovery of annual demand costs during the winter months is lower due to warmer-than-normal weather during the heating season, there generally will be an under-recovery of demand costs that year, all else being equal.[26] This under-recovery occurs because the winter months are when the greatest percentage of cost recovery generally occurs.

3. **Capacity Release Credits** – A utility may sell its contracted pipeline capacity ("capacity-release transaction") if the utility determines that a portion of reserved capacity will not be needed to serve its customers. The Commission requires utilities to return to firm ratepayers all revenue from these capacity-release transactions. The monthly PGA and/or the annual true-up amount are credited, thereby reducing the recovery of demand costs. For those utilities that credit the annual true up amount rather than the monthly PGA, this credit will result in an over-recovery of demand costs on a monthly basis, all else being equal.

4. **Deviations between forecasted and actual sales volumes and prices** – For commodity costs, a common cause of over- or under-recovery is the deviation between monthly forecasts and actual sales volumes and commodity prices. For regulatory purposes, natural gas commodity costs are usually a pass-through cost for utilities via PGAs, although market conditions will affect the price of natural gas.

5. **Prorating of customer bills** – When a utility reads a customer's meter in the middle of the month, the registered usage represents consumption from two different PGA (calendar month) periods. Thus, the utility must bill the customer based on an estimate of the consumption that took place during each PGA period. Because this prorated bill will not exactly match the true consumption that took place each month, except by coincidence, over- or under-recoveries typically will result.

[25] Examples of changes that affect the utility's demand costs include changes in the:

- entitlement level;
- assignment of demand to commodity cost;
- allocation of costs between jurisdictions; and
- natural gas pipeline rates approved by FERC.

[26] Likewise, if there is higher demand during the winter months due to colder-than-normal weather, there generally will be an over-recovery of demand costs that year, all else being equal.

6. **The three-cent rule** – Minnesota Rule 7825.2700, subpart 3, specifies that utilities do not need to file monthly PGAs if the change during the month is less than $0.03 per 1,000,000 BTUs (approximately 1 Mcf). This allowance, if exercised by a utility, would cause an over- or under-recovery of gas costs for that month.

To some extent, all of the above-listed factors may affect gas costs and recovery of gas costs for all of Minnesota's gas utilities. The following individual gas utility true-up section highlights the items from this list and any particular causes not included in the list that caused notable over- and under-recoveries for each individual gas utility.

II. REVIEW OF OVER-/UNDER-RECOVERIES AND TRUE-UPS

As discussed above, based on the winter weather being overall warmer than normal and all else being equal, the Department would expect the PGA systems to under-recover demand and commodity costs. All of the PGA systems except for MERC-Consolidated under-recovered demand costs from firm customers. However, only 4 of the 8 PGA systems under-recovered commodity costs. Due to other factors discussed below, four PGA systems over-recovered commodity costs from firm and interruptible customers.

The Department discusses the recovery of gas costs and true-up calculations of each utility's AAA report and true-up filings, along with any general concerns.

A. GREATER MINNESOTA GAS, INC.

1. Recovery of Gas Costs and True-up Calculations

On August 31, 2016, Greater Minnesota submitted its 2016 *Annual Automatic Adjustment Report* in Docket No. G999/AA-16-524 and its *Annual True-up Report* in G022/AA-16-715. GMG included in its reports the information required by Minnesota Rule 7825.2810. The Department concludes that GMG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE16 reporting period, GMG reported that it over-recovered its total gas costs by $51,953, or approximately 1.32 percent, for a cumulative over-recovery of 1.55 percent.[27] By customer class, Greater Minnesota reported over/under-recoveries for the current reporting period as follows:

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[27] The figure of 1.55 percent represents the cumulative over-recovery of $60,620, which is the basis for GMG's FYE16 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Greater Minnesota's true-up filing, Docket No. G022/AA-16-715.

Table G8 – Greater Minnesota Gas
FYE16 Percent Over-Recovery/ (Under-Recovery) by Customer Class[28]
(as filed on August 31, 2016 by Greater Minnesota)

Firm	1.58
Agricultural - Interruptible	(4.16)
General – Interruptible	0.17
Total System	1.32

Using the sales volumes forecasted by Greater Minnesota for the FYE17[29] period results in the true-up factors by customer class as shown below.

Table G8a – Greater Minnesota Gas
True-Up Factors per Mcf by Customer Class
(as filed on August 31, 2016 by Greater Minnesota)

Firm	$(0.0575)
Agricultural - Interruptible	$0.0653
General - Interruptible	$0.0028

The Department's analysis of Greater Minnesota's gas costs shows that Greater Minnesota's over/under-recovery was primarily due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Greater Minnesota under-recovered its current demand costs by $10,252, or approximately 1.21 percent. The demand-cost under-recovery includes capacity-release revenue of $80,919. Without this revenue, there was an under-recovery of demand costs of $91,173 or approximately 10.80 percent. In its *2016 Annual Automatic Adjustment Report*, GMG stated that the over-recovery was due to warmer-than-normal weather.[30]

Weather across the state of Minnesota was between twelve to eighteen percent warmer than normal; specifically, twelve percent warmer in the Rochester area. Based on this information, the Department concludes that Greater Minnesota's over-recovery of demand costs appears to be reasonable.

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[28] A supporting spreadsheet with detailed calculations is contained in Department Attachment G5.
[29] GMG's True-up filing, Attachment A.
[30] GMG's *Annual Automatic Adjustment Report,* page 4.

2. Commodity Costs – Greater Minnesota over-recovered its current commodity costs by $62,205, or approximately 2.02 percent. GMG stated that the commodity recovery rate component is based on estimated purchases prior to the beginning of the month. To the extent estimated volumes and prices vary from actual purchases, a monthly over- or under-recovery will occur.[31]

The Department concludes that GMG's over-recovery of commodity costs appears to be reasonable.

Based on its review, the Department recommends that the Commission accept GMG's FYE16 true-up.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G022/M-11-804. In this Docket, the Commission's December 22, 2011 *Order Authorizing New Retail Service* required GMG to provide, each year in its annual AAA report, for each relevant GMG rate class and for each upstream rate schedule used for purchase for resale service (i.e. for each group of purchase for resale customer) the:

- number of upstream local distribution company (LDC) meters,
- number of retail GMG customers, and
- volume of gas sold to each group of purchase for resale customer.

GMG's New Retail Service is intended to allow more customers to have access to natural gas service. The service is available to customers who do not qualify for new service under another gas utility's main extension tariff, but are willing to pay for GMG's costs of providing natural gas service to them.

The Commission required GMG to provide the information as recommended by Commission Staff in its briefing papers:

> Staff also believes a relatively simple additional annual reporting requirement would allow for some basic monitoring of this service and would be helpful. In addition to requiring GMG to provide a reference in its monthly purchased gas adjustment reports to each of the upstream LDC rate schedules that GMG charges purchase for resale customers, staff recommends that in GMG's annual September 1 automatic adjustment of charges reports, the Company provide for each relevant GMG rate class and for each

[31] GMG's *Annual Automatic Adjustment Report,* page 4.

> upstream rate schedule used for the purchase for resale service: (1) the number of upstream LDC meters, (2) the number of retail GMG customers, and (3) the volume of gas sold to each group of customers.

GMG provided the required information in its filing.[32] The Department concludes that GMG is in compliance with the filing requirements in Docket No. G022/M-11-804.

Docket No. G999/AA-14-580. The Commission's August 24, 2015 *Order* required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. On page 5 of its AAA Report, GMG stated that it "did not have any non-compliant interruptible customers that engaged in unauthorized use during a curtailment period; hence GMG has nothing to report." The Department concludes that GMG complied with the reporting requirements in Docket 14-580.

3. Summary and Recommendations

The Department concludes that GMG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept GMG's FYE16 true-up, Docket No. G001/AA-16-715; and
- allow GMG to implement its true-up, as shown in DOC Attachment G5 of the FYE16 AAA Report.

B. GREAT PLAINS NATURAL GAS COMPANY

1. Recovery of Gas Costs and True-Up Calculations

On August 31, 2016, Great Plains submitted its 2016 *Annual Report of Automatic Adjustment of Gas Charges* in Docket No. G999/AA-16-524 and its *Annual True-Up Report* in Docket No. G004/AA-16-719 in compliance with Minnesota Rule 7825.2810. The Department concludes that Great Plains' report is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE16 reporting period, Great Plains North under-recovered its total gas costs by $85,577, or approximately 1.66 percent, for a cumulative over-recovery of total gas costs of

[32] GMG's *Annual Automatic Adjustment Report,* pages 4-5.

approximately 0.45 percent.[33]

The PGA system for Great Plains South under-recovered total gas cost by $142,507, or approximately 2.48 percent in FYE16, for a cumulative under-recovery of 4.40 percent.[34] Great Plains' over/under-recoveries by district and customer class for the current reporting period is shown below.[35]

Table G9 – Great Plains
FYE16 Percent Over-Recovery/ (Under-Recovery)[36]
(as filed August 31, 2016 by Great Plains)

Class[37]	North District	South District
Firm	(3.41)	(2.36)
Small Volume Interruptible	-	(6.47)
Large Volume Interruptible	-	22.26
Interruptible	4.85	-
Total System	(1.66)	(2.48)

Using the sales volumes forecasted by Great Plains for the FYE17 period results in the following true-up factors by district and by customer class:

[33] The figure of 0.45 percent represents the cumulative over-recovery of $23,342, which is the basis for the August 31, 2016 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Great Plains' true-up filing, Docket No. G004/AA-16-719.
[34] The figure of 4.40 percent represents the cumulative under-recovery of $253,378, which is the basis for the August 31, 2016 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Great Plains' true-up filing, Docket No. G004/AA-16-719.
[35] The term "North District" refers to the five Minnesota communities served by Great Plains via Viking Gas Transmission Company's (Viking) pipeline. These communities are: Fergus Falls, Pelican Rapids, Breckenridge, Crookston, and Vergas. The term "South District" refers to the thirteen Minnesota communities served by Great Plains via Northern's pipeline. These communities are: Belview, Boyd, Clarkfield, Danube, Dawson, Echo, Granite Falls, Marshall, Montevideo, Redwood Falls, Renville, Sacred Heart and Wood Lake.
[36] Supporting spreadsheets with detailed calculations are contained in DOC Attachments G6a and G6b.
[37] Regarding interruptible classes, Great Plains has Small Volume Interruptible (SVI) and Large Volume Interruptible (LVI) classes in the South District, and has a single Interruptible class in the North District.

Table G9a – Great Plains
True-Up Factors per Mcf
(as filed on August 31, 2016 by Great Plains)

Class	North District	South District
Firm	$0.0762	$0.0777
Small Volume Interruptible	-	$(0.0011)
Large Volume Interruptible	-	$3.4102
Interruptible	$(0.1815)	-

a. North District

The Department's analysis shows that during the reporting period, Great Plains under-recovered its gas costs for the North District by $85,577, or approximately 1.66 percent. This over-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Great Plains under-recovered its demand costs for the North District by $189,987, or approximately 10.59 percent, during the reporting period. The demand-cost under-recovery includes capacity release revenue of $38,409. Without this revenue, there was an under-recovery of demand costs of $228,396 or approximately 12.74 percent. Great Plains stated that the under-recovery of demand costs for the North District was due to the following reasons: [38]

    - Weather was 15.93 percent warmer than normal for the twelve months ending June 30, 2016; and
    - Great Plains recovers demand costs on a volumetric basis, while costs are assessed on a fixed monthly basis. Generally, demand costs are under recovered during the summer months, when firm sales volumes are low and over recovered during the winter months when sales volumes are high.

As shown in Section I.E. above, the nearest weather station, Fargo, was 18.50 percent warmer overall and 24 percent warmer during the winter. Based on this information, the Department concludes that Great Plains' current under-recovery of demand costs in the North District appears to be reasonable.

[38] Great Plains' *Annual Automatic Adjustment Report,* page 4.

2. Commodity Costs – Great Plains' North District over-recovered its commodity costs (including penalty revenue of $17,271[39]) by $104,410, or approximately 3.10 percent. Excluding this revenue, the over-recovery of commodity was $87,139, or approximately 2.59 percent. Great Plains stated that the over-recovery was a result of timing differences between the cost of gas recovered in the rates and the actual gas costs.

Despite the warmer-than-normal winter for Great Plains' North District PGA area (which may otherwise result in under-recovery), prices were lower than anticipated throughout the heating season. The Department concludes that Great Plains' over-recovery of commodity costs for the North District appears to be reasonable.

b. South District

The Department's analysis shows that during the reporting period, Great Plains under-recovered its total gas costs for the South District by $142,507, or approximately 2.48 percent. This under-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Great Plains under-recovered demand costs for the South District by $124,190, or approximately 6.77 percent, during the reporting period. Great Plains stated that its under-recovery of demand costs for the South District was due to the following reasons:[40]

   - The weather was 18.39 percent warmer than normal for the twelve months ending June 30, 2016 as shown on Exhibit B, page 5.

   - Great Plains recovers demand costs on a volumetric basis, while costs are assessed on a fixed monthly basis. Generally, demand costs are under-recovered during the summer months, when firm sales volumes are low and over recovered during the winter months when sales volumes are high.

As shown in Section I.E. above, the nearest weather station, Sioux Falls, was 17 percent warmer overall and 13.50 percent warmer during the winter. Based on this information, the Department concludes that Great Plains' under-recovery of demand costs in the South District appears to be reasonable.

2. Commodity Costs – Great Plains' South District under-recovered its commodity costs by $18,317, or approximately 0.47 percent. The commodity-cost under-

[39] Great Plains' response to DOC Information Request No. 9.
[40] Great Plains' AAA Report, page 5.

recovery includes balancing penalty revenue of $32,319.[41] Without this revenue, there was an under-recovery of commodity costs of $50,636 or approximately 1.29 percent.

Based on warmer-than-normal winter for Great Plains' South District, the Department concludes that Great Plains' under-recovery of commodity costs for the South District appears to be reasonable.

In its Annual True-Up Report, Great Plains requested a variance to Minnesota Rules 7825.2700, subparts 4 and 7. Both subparts require that the true-up amount, and its resulting adjustment, be calculated and applied within each customer class. Great Plains stated,

> While reconciling each customer class would result in just and reasonable rates in the normal course, Great Plains respectfully requests a one-time waiver or variance of this aspect of Rule based on the unique circumstances described below where applying the Rule would result in a financial burden on a single customer.
>
> Pursuant to Minn. R. 7829.3200, a waiver or variance of a Rule is appropriate where (1) enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule; (2) granting the variance would not adversely affect the public interest; and (3) granting the variance would not conflict with standards imposed by law. Each criterion is met in the present case.
>
> In particular, in the South District, two of the three large interruptible customers left this rate class in 2015. As a result, the projected annual dk sales over which Great Plains had planned to recover the under recovered GCR balance existing at June 30, 2015 and included in the GCR filing submitted in Docket No. G004/AA-15-794 did not materialize. As a result, $158,318 of the under recovered balance remains to be recovered from the single large interruptible customer remaining in the customer class. Such a result would impose an excessive burden on this single customer within the meaning of Minn. R. 7829.3200.

[41] Great Plains' response to DOC Information Request No. 9.

> As it is unequitable to require the only remaining customer in the large interruptible rate class to bear the burden of the under recovery, Great Plains proposes to spread this under recovered commodity cost over all customer classes based on the pro-rata share of current projected annual dk sales. This approach allows Great Plains to recover its commodity-delivered gas cost, while not unduly burdening the only customer left in the South District large interruptible rate class. This results in a modest increase to the firm and small interruptible classes of $.085 per dk. In this respect, due to the small increase, granting the variance would not adversely affect the public interest.
>
> Finally, granting the variance would not conflict with standards imposed by law as the Commission has the authority to vary its rules for good cause. Moreover, a variance or waiver of the Rule would ensure that rates are just and reasonable for all customers as required under Minn. Stat. § 216B.03.

The Department issued Information Request No. 1 in Great Plains' True-Up Docket No. G004/AA-16-719 (16-719 DOC IR 1) to verify that the two customers that left the system did so in accordance with Great Plains' tariff. In its response, Great Plains stated that both customers complied with its tariff and "provided written notice at least 60 days prior to the end of the contract."

The Department agrees with Great Plains that recovering approximately $158,000 from one interruptible customer would be burdensome to that customer. It appears that no one party has any fault to remedy, so Great Plains should be allowed to recover its under-recovered gas costs. Additionally, all customers could potentially be harmed should Great Plains lose the remaining large interruptible customer. The Department notes that the proposed increase to the true-up factor for Residential customers would be equal approximately $6.55 for the year, or an average of $0.55 per month.[42] Based on the information provided in its initial filing, and in its response to 16-719 DOC IR 1, the Department concludes that Great Plains' request for a variance is reasonable.

2. Compliance and/or Supplemental Reporting Requirements

<u>Docket No. G999/AA-14-580.</u> As noted above, the Commission's August 24, 2015 *Order* also required all Minnesota regulated natural gas utilities to provide information for the next three

[42] Based on data collected from Table G4 in previous years' reports, the average use for Great Plains South Residential customers over the most recent ten years is 77 Mcf.

AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. On page 6 of its AAA Report, Great Plains stated “see Exhibit F for Great Plains’ curtailment activities.” On its Exhibit F, Great Plains explained that it had two curtailment periods during the 2015-2016 heating season and all five customers that were requested to curtail gas usage complied with the request. The Department concludes that Great Plains complied with the reporting requirements in Docket No. 14-580.

Based on its review, the Department recommends that the Commission accept Great Plains’ FYE16 true-up.

3. Summary and Recommendations

The Department concludes that Great Plains’ FYE16 annual automatic adjustment report is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- grant Great Plains’ requested one-time variance to Minnesota Rules 7825.2700, subparts 4 and 7 to allow it to spread its cumulative under-recovered commodity cost from its large interruptible customer class to all customer classes based on the pro-rata share of current projected annual dekatherm sales;
- accept Great Plains’ FYE16 true-ups, Docket No. G004/AA-16-524; and
- allow Great Plains to implement its true-ups, as shown in DOC Attachments G6a and G6b of the FYE16 AAA Repor*t*.

C. MINNESOTA ENERGY RESOURCES CORPORATION (MERC)

In its December 8, 2014 *Order Approving Sale Subject to Conditions*, the Commission approved MERC’s acquisition of Interstate Gas in Docket No. G001,G011/PA-14-107. Ordering Paragraph 4 required MERC to continue to maintain the Interstate Gas PGA for transitioned Interstate Gas ratepayers until MERC’s next general rate case and, at that time, reconcile the two fuel supply systems into one. The sale closed on April 30, 2015.

On September 30, 2015, MERC filed a general rate case in Docket No. G011/GR-15-736. In its Initial Filing, MERC proposed to combine its MERC-NNG and MERC-Albert Lea PGA systems beginning July 1, 2017, following the implementation of final rates. In her Order, the Administrative Law Judge (ALJ) in that case found MERC’s proposed timeline to be reasonable, rather than waiting an additional year before combining the PGA systems.[43] In its October 31,

[43] *Findings of Fact, Conclusions of Law, and Recommendation*, issued August 19, 2016, Findings 752-758, pages 143-144.

2016 *Findings of Fact, Conclusions, and Order,* the Commission approved the ALJ's findings.[44] Therefore, FYE16 contains a full year of data for all three PGA systems; FYE17 will have a full year of data for the combined MERC-NNG and MERC-Consolidated PGA systems.

1. Request for Variances for 2016 AAA and True-Up Reports

On September 1, 2016, MERC filed a letter requesting variances to the filing deadline for its three AAA and True-Up Reports. In its letter, MERC stated,

> MERC requests an extension to file its AAA and True-Up reports. MERC requires additional time for its auditor, Deloitte & Touche, LLP, to complete its audit and Independent Auditors' Report for these filings. MERC requested the auditors to conduct additional review of the AAA reports and as a result the review has taken longer than anticipated and we are still working to complete the review and finalize the schedules for the AAA filings. Therefore, MERC requires additional time to submit its AAA and True-Up filings to the Commission and requests and extension of the September 1 deadline to submit its AAA and True-Up filings imposed by the Commission's rules. MERC will submit these filings as soon as the auditors' review is finalized and the completed Auditors' Reports are available.
>
> Additionally, MERC notes that because of the ongoing review of the AAA and True-Up filings, the annual cost adjustment ("ACA") rates in MERC's September PGA filings were changed to zero. We will maintain these factors through the month of September. Beginning October 1, 2016, MERC will adjust the ACA factors according to the 2016 AAA and True-Up calculations to recover/credit the under/over recovery over the eleven-month period from October 2016 through August 2017.
>
> …
>
> The rules for granting variances are found in Minn. R. 7829.3200, which provides that the Commission may grant a variance to its rules when it determines the following requirements are met:

[44] *Findings of Fact, Conclusions, and Order*, issued October 31, 2016, Ordering Paragraph 2, page 54.

> A. Enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
> B. Granting the variance would not adversely affect the public interest; and
> C. Granting the variance would not conflict with standards imposed by law.
>
> All of the relevant standards support extending the deadline for submitting the AAA and True-Up filings.
>
> First, MERC believes that the requirement to submit the AAA and True-Up filings by the September 1 deadline would impose an excessive burden on the Company because the auditor review is ongoing and the final schedules and annual auditors' report will not be completed in time for a September 1 filing.
>
> Second, the public interest would not be adversely affected by granting the requested variance. To the contrary, allowing an [sic] additional time will support the public interest. MERC's AAA and True-Up filings are only beneficial if the information contained therein is accurate. Allowing the Company additional time to allow the independent auditor to finalize its review will ensure that review is robust and that MERC's filings are complete and accurate.
>
> Third, the Company is unaware of any conflict with any standards imposed by law. Rather, the Commission's rules permitting variances contemplate variances under circumstances such as those presented here.
>
> For the reasons stated herein, MERC respectfully requests that the Commission vary Minn. R. 7825.2700, 7825.2910, and 7825.2820, and any other rules the Commission deems necessary and appropriate to allow the auditor to complete its review so that MERC may submit complete and accurate AAA and True-Up filings. The Company believes the criteria for variance established under Minn. R. 7829.3200 are met under the current circumstances.

MERC stated that it zeroed out all three of its true-up factors for the month of September and would recover the under/over-recoveries over the following eleven months, beginning October 1, 2016. The Department later confirmed that MERC proposed to calculate its true-up factors by recovering the entire previous year's cumulative under-/over-recovery balances over eleven months, rather than twelve months. The resulting true-up factors were slightly higher surcharge rates for MERC-NNG, MERC-AL, and the SVI Demand class in MERC-Consolidated and slightly higher refund rates for the General Service and SVI/SJV/LVI Commodity classes in the MERC-Consolidated PGA system during the 2016-2017 gas year.[45]

MERC's proposal would ultimately surcharge or refund the same total amount of true-up gas costs to ratepayers over the course of the gas year as would be surcharged or refunded under the normal 12-month time period method. However, recovering the true-up over 11 months would create higher monthly true-up rates for five of the seven customer classes across the three PGA systems for October 2016 through June 2017.

Typically in this type of situation, the Department would recommend that the Commission deny the variance requests and deny true-up cost recovery for September 2016 to avoid higher monthly rates than otherwise should have been charged. A rough estimate on potential true-up recovery for the month of September 2016 across all three PGA systems is approximately $30,000.[46]

That said, $30,000 is immaterial in the context of the approximately $94,000,000 of gas costs incurred by MERC in 2015-2016 across all PGA systems. Additionally, the delay of MERC's filings did not disrupt the Department's ability to perform its analysis. The Department believes that, going forward, MERC does not have incentive to delay filing its AAA reports and implement its true-up factors in October, rather than September, as occurred in this instance. If MERC continues to have difficulty filing its annual reports on time in the future, the Department will conduct a deeper review and provide recommendations to the Commission as appropriate.

Therefore, the Department concludes that MERC has met the criteria under Minn. R. 7829.3200 and recommends that the Commission grant MERC's requested variances. In the interest of completeness, the Commission may want to consider granting one-time variances to Minn. R. 7825.2800, 7825.2810, 7825.2830, and 7825.2840 (requiring annual reports to be filed each September 1) in addition to the rules requested by MERC (Minn. R. 7825.2700, 7825.2910, and 7825.2820).

The Department appreciates MERC's efforts to file as quickly as possible by submitting its reports on September 2 (pertaining to MERC-NNG and MERC-AL) and September 26 (pertaining to MERC-Consolidated), 2016. MERC is welcome to provide discussion in its Reply Comments to

[45] SVI = Small Volume Interruptible and SVI/SJV/LVI = Small Volume Interruptible, Small Joint Volume, Large Volume Interruptible.

[46] MERC did not provide projected sales volumes for September 2016, since it zeroed out all true-up factors for that month. The Department used projected sales volumes for September 2015 in the 2014-2015 true-up reports as a rough proxy to calculate the estimated true-up recovery in September 2016.

provide assurance to the Department and the Commission that this situation will not occur in the future.

2. *Recovery of Gas Costs and True-Up Calculations*

On September 2, 2016, MERC-NNG submitted its 2016 *Annual Automatic Adjustment Report* in Docket No. G011/AA-16-732, the timing of which was not in compliance with Minnesota Rule 7825.2810. The Department concludes that MERC-NNG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE16 reporting period, MERC-NNG under-recovered its total gas costs by $2,462,625, or approximately 2.60 percent, for a cumulative under-recovery of total gas costs of approximately 1.70 percent.[47]

On September 26, 2016, MERC-Consolidated or MERC-CON submitted its 2016 *Annual Automatic Adjustment Report* in Docket No. G011/AA-16-734, the timing of which was not in compliance with Minnesota Rule 7825.2810. The Department concludes that MERC-CON's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

The PGA system for MERC-CON over-recovered total gas cost by $136,238, or approximately 0.72 percent, for a cumulative over-recovery of 1.36 percent.[48]

On September 2, 2016, MERC-AL submitted its 2016 *Annual Automatic Adjustment Report* in Docket No. G011/AA-16-733, the timing of which was not in compliance with Minnesota Rule 7825.2810. The Department concludes that MERC-AL's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE16 reporting period, MERC-AL under-recovered its total gas costs by $189,385, or approximately 3.47 percent, for a cumulative under-recovery of total gas costs of approximately 4.20 percent.[49]

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[47] The figure of 1.70 percent represents the cumulative under-recovery of $1,607,362, which is the basis for the FYE17 true-up adjustment. For a detailed breakdown of the true-up calculations, please see MERC-NNG's true-up filing, Docket No. G011/AA-16-732.
[48] The figure of 1.36 percent represents the cumulative over-recovery of $258,376, which is the basis for the FYE17 true-up adjustment. For a detailed breakdown of the true-up calculations, please see MERC-CON's true-up filing, Docket No. G011/AA-16-734.
[49] The figure of 4.20 percent represents the cumulative over-recovery of $229,312, which is the basis for the FYE17 true-up adjustment. For a detailed breakdown of the true-up calculations, please see MERC-AL's true-up filing, Docket No. G011/AA-16-733.

The Department's analysis indicates that, by customer class and system, MERC's over- or under-recoveries during the current reporting period were as follows:

Table G10 - MERC
FYE16 Percent Over-Recovery/(Under-Recovery)
by System and Class[50]
(as filed on September 2 and 26, 2016 by MERC)

Class[51]	NNG	Consolidated	AL
GS	(1.99)	0.84	(3.17)
SVJ/LVJ/SLVJ Demand	(0.01)	0.00	0.00
SVI/SVJ/LVI/LVJ/SLVI Commodity	(8.99)	(0.07)	(5.15)
Total System	(2.60)	(0.72)	(3.47)

Using the sales volumes forecasted by MERC for the eleven months ending August 31, 2017 results in the following true-up factors by system and class:

Table G10a - MERC
True-Up Factors per Mcf
by System and Customer Class
(as filed on September 2 and 26, 2016 by MERC)

Class	NNG	Consolidated	AL
GS	$0.0301	$(0.0355)	$0.1256
SVJ/LVJ/SLVJ Demand	$0.0000	$0.0027	$0.0000
SVI/SVJ/LVI/LVJ/SLVI Commodity	$0.3906	$(0.1300)	$0.3600

a. MERC-NNG

The Department's analysis shows that MERC under-recovered its total gas costs on its NNG System by $2,462,328, or approximately 2.60 percent during the reporting period. This under-recovery was due to the following demand-cost and commodity-cost factors:

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[50] Supporting spreadsheets with detailed calculations are contained in DOC Attachments G8, G8a, and G9.
[51] MERC has the following classes:

- General Service (GS);
- Small Volume Interruptible (SVI);
- Large Volume Interruptible (LVI);
- Super Large Volume Interruptible (SLVI);
- Small Volume Joint (SVJ);
- Large Volume Joint (LVJ); and
- Super Large Volume Joint (SLVJ).

1. Demand Costs – MERC under-recovered its demand costs for the MERC-NNG system by $2,472,528, or approximately 12.17 percent. The demand-cost under-recovery also includes NNG capacity-release revenue of $499,796.[52] Without this revenue, there was an under-recovery of demand costs of $2,972,325 or approximately 14.28 percent. In addition to mentioning capacity release revenue and curtailment penalty revenues,[53] MERC explained that the under-collection of demand costs was predominantly caused by actual sales being less than projected sales. On September 2, 2016, MERC concurrently filed, with the true up, an Excel spreadsheet that provided an analysis of the over and under recoveries.

As discussed in Section I. above, weather across the state during FYE16 was between twelve to eighteen percent warmer than normal. Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-NNG's under-recovery of demand costs appears to be reasonable.

2. Commodity Costs –MERC-NNG over-recovered commodity costs by $10,201, or approximately 0.01 percent. The commodity-cost over-recovery also includes revenue of $2,263,473 (consisting of balancing revenue of $220,131,[54] NBPL capacity release of $2,013,174,[55] and penalty revenue of $30,168[56]). Without these revenues, there was an under-recovery of commodity costs of $2,253,272, or approximately 3.03 percent. MERC stated that "the over collection of commodity costs was predominantly caused by the difference in projected monthly gas costs compared to actual gas costs. On September 2, 2016, MERC concurrently filed with the true up, an Excel spreadsheet that provided an analysis of the over and under recoveries.

Despite warmer-than-normal weather, MERC slightly over-recovered rather than under-recovered its commodity costs. This departure from expectation is largely driven by the increase in Northern Border Pipeline (NBPL) capacity release credits in FYE16 compared to previous years. In a phone conversation, MERC stated that the increase was mainly due to a sharp increase in the value of its excess capacity on NBPL, but also, in part, due to an increased effort to pursue capacity release by its Gas Supply staff.

Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-NNG's over-recovery of commodity costs appears to be reasonable.

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[52] MERC-NNG's AAA Report, Schedule I.
[53] MERC-NNG had no DDVC penalty revenue in FYE16.
[54] MERC-NNG's AAA Report, Schedule B&E, page 2.
[55] MERC-NNG's AAA Report, Schedule I.
[56] MERC-NNG's AAA Report, Schedule J.

b. MERC-Consolidated

The Department's analysis shows that MERC over-recovered its total gas costs for the Consolidated System by $136,238, or approximately 0.72 percent, during the reporting period. This over-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – MERC over-recovered its demand costs for the MERC-CON system by $65,314, or approximately 1.98 percent. The demand-cost over-recovery includes capacity-release revenue of $68,811[57] and curtailment penalty revenues of $0.[58] Without these revenues, there was an under-recovery of demand costs of $3,497, or approximately 0.11 percent. In addition to mentioning capacity release and curtailment penalty revenues, MERC stated that the "over collection of demand cost was caused by the difference in projected monthly demand costs compared to actual costs. A portion of the over-recollection was offset by actual sales being lower than projected sales."[59] On September 2, 2016, MERC concurrently filed with the true-up an Excel spreadsheet that provided an analysis of the over and under recoveries.

As discussed in Section I. above, weather across the state during FYE16 was between twelve to eighteen percent warmer than normal. Typically, this would lead to an under-recovery of demand costs. However, if the monthly demand costs were lower than projected, then an over-recovery could occur. In addition, MERC-CON would have under-recovered had it not been for its capacity release revenue. Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC- CON's over-recovery of demand costs appears to be reasonable.

2. Commodity Costs – MERC-CON over-recovered commodity costs by $70,924, or approximately 0.45 percent. The commodity-cost over-recovery also includes balancing penalty revenue of $5,629.[60] Without this revenue, there was an over-recovery of commodity costs of $65,295, or approximately 0.41 percent. In its filing, MERC-CON stated that the "over collection was predominantly caused by the difference in projected monthly gas costs compared to actual gas costs."[61] On September 2, 2016, MERC concurrently filed with the true up, an Excel spreadsheet that provided an analysis of the over- and under-recoveries.

[57] MERC- CON's AAA Report, Schedule I.
[58] MERC-CON's AAA Report, Schedule C and D.
[59] See MERC-CON's AAA Report, page 3.
[60] MERC- CON's AAA Report, Schedule B and E, page 1.
[61] MERC-CON's AAA Report, page 3.

Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-CON's under-recovery of commodity costs appears to be reasonable.

c. MERC-Albert Lea

The Department's analysis shows that MERC under-recovered its total gas costs for the MERC-AL system by $189,385, or approximately 3.47 percent, during the reporting period. This under-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – MERC under-recovered its demand costs for the MERC- AL system by $110,132, or approximately 8.30 percent. In its filing, MERC stated that the "under collection of demand cost was predominantly caused by the actual sales being less than projected sales."[62] On September 2, 2016, MERC concurrently filed with the true up an Excel spreadsheet that provided an analysis of the over- and under-recoveries.

As discussed in Section I above, weather across the state during FYE16 was between twelve to eighteen percent warmer than normal. Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-AL's under-recovery of demand costs appears to be reasonable.

2. Commodity Costs – MERC-AL under-recovered commodity costs by $79,253, or approximately 1.29 percent. In its filing, MERC-AL stated that the "under collection was predominantly caused by the difference in projected monthly gas costs compared to actual gas costs."[63] On September 2, 2016, MERC concurrently filed with the true up, an Excel spreadsheet that provided an analysis of the over- and under-recoveries.

Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-AL's under-recovery of commodity costs appears to be reasonable.

3. Compliance and/or Supplemental Reporting Requirements

Docket Nos. G007,011/M-06-1358, G007,011/M-09-262, G007,011/M-11-296, G007,011/M-13-207, and G011/M-15-231.[64] In these dockets, the Commission allowed MERC to recover the

[62] See MERC-AL's AAA Report, page 2.
[63] MERC-AL's AAA Report, page 3.
[64] MERC filed a petition requesting *Extension of Rule Variances to Recover the Costs of Financial Instruments Through the Purchased Gas Adjustment* on January 24, 2017 in Docket No. G011/M-17-85. In its Order issued on May 8, 2017, the Commission granted the variance for an additional four years, until June 30, 2021. The

costs associated with using financial instruments in securing natural gas supplies through the PGA. The *Orders* in these dockets require MERC to report and provide in future AAA filings data on the relative benefits of price hedging contracts, including the average cost per dekatherm for natural gas purchased using financial instruments compared to the relevant monthly and daily spot index prices, together with the following information:

- a list of each hedging instrument entered into;
- the total contracted volumes, for each instrument; and
- the net gain or loss, including all transaction costs for each instrument in comparison to the appropriate monthly and daily spot prices.

The Commission included various other restrictions in its *Orders* and specifically, in its August 17, 2011 *Order* in Docket Nos. G007,011/M-11-296 and G007,011/M-13-207, required MERC to provide, in its AAA Reports, the full post-mortem analysis of their hedged volumes for the preceding heating season compared to other hedging strategies and the prevailing market prices strategy.

MERC included information regarding these *Order* requirements in its AAA Reports, pages 5 and 6, Schedules L and O and in an Excel spreadsheet filed concurrently with the AAA Report. The Department discusses MERC's hedging costs in Section III, part O, of this *Report*.

Docket No. G999/AA-08-1011. The Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with the following information about their hedging programs, beginning in fiscal-year 2010:

- a clearly defined and quantified description of the risk (*i.e.,* catastrophic or other type of event) the companies are insuring against by implementing the hedging strategies. The Company also was directed to include a clearly defined and quantified estimate of probability of the events occurring;

- a quantitative analysis of the value of reducing price volatility and managing price risk (the cost and benefit of these programs to all customers and the companies) that includes:
    - a comparison of what actual low, average, and high usage customer bills (on a monthly basis) would have been with and without the use of the hedging strategies as implemented during the relevant time period; and

Commission also continued the requirement for MERC to provide annual analysis on its hedging program and a post-mortem analysis in its AAA Reports.

  - o a comparison of what these customer bills would have been under budget billing, assuming normal gas usage for low, average, and high-usage customers, and assuming catastrophically high prices; and,

- a quantitative definition of "catastrophically high prices" (in absolute and relative terms), and a bill analysis that shows how these prices would impact low, average, and high-usage customer bills.

MERC included information regarding these *Order* requirements in its AAA Reports, pages 1-8, and in Schedule P. The Department discusses MERC's hedging costs in Section III, part O, of this *Report*.

Docket No. G999/AA-14-580. The Commission's August 24, 2015 *Order* required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. On pages 9-10 of MERC-NNG's AAA Report, MERC stated that there were four occurrences of unauthorized gas use by MERC-NNG customers during the time period. MERC reported the required information for that customer and stated that MERC had a discussion with the customer once curtailment penalties were assessed. The Department concludes that MERC complied with the reporting requirements in Docket No. 14-580 on unauthorized gas use.

4. Summary and Recommendations

The Department concludes that MERC's FYE16 annual automatic adjustment reports are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- find that MERC has met the criteria under Minn. R. 7829.3200 and grant MERC's requested variances to Minn. R. 7825.2700, 7825.2910, and 7825.2820. In the interest of completeness, the Commission may want to consider varying Minn. R. 7825.2800, 7825.2810, 7825.2830, and 7825.2840 in addition to the rules requested by MERC;
- accept MERC-NNG's true-up filing in Docket No. G011/AA-16-732;
- allow MERC-NNG to implement its true-up, as shown in Department Attachment G8 of the FYE16 AAA Report;
- accept MERC-CON's true-up filing in Docket No. G011/AA-16-734;
- allow MERC-CON to implement its true-up, as shown in Department Attachment G9 of the FYE16 AAA Report;
- accept MERC-AL's true-up filing in Docket No. G011/AA-16-733; and

- allow MERC-AL to implement its true-up, as shown in Department Attachment G8a of the FYE16 AAA Report.

D. CENTERPOINT ENERGY

1. Recovery of Gas Costs and True-Up Calculations

On September 1, 2016, CenterPoint Energy submitted its 2016 Annual Automatic Adjustment Report in Docket No. G999/AA-16-524 and its Annual True-Up Report in Docket No. G008/AA-16-730 in compliance with Minnesota Rule 7825.2810. The Department concludes that CenterPoint Energy's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

According to CenterPoint Energy's true-up filing, CenterPoint Energy under-recovered gas costs by $(9,719,223), or approximately (2.53) percent, with a cumulative under-recovery of approximately (2.42) percent[65] of its actual gas cost incurred. By customer class, CenterPoint Energy reported over-/ (under)-recoveries for the current reporting period as follows:

Table G11 - CenterPoint
FYE16 Percent Over-Recovery/ (Under-Recovery) [66]
(As filed on September 1, 2016 by CenterPoint Energy)

Class	
Small Volume Firm	(2.47)
Large General Service	(6.22)
Small Volume Dual Fuel	(3.50)
Large Volume Dual Fuel	(1.60)
Total System	(2.53)

Using the rate-case sales volumes by CenterPoint Energy results in the following proposed true-up factors by class.[67]

[65] The figure of 2.42 percent represents the cumulative under-recovery of $9,288,506, which is the basis for the FYE16 true-up factors. For a detailed breakdown of the true-up calculation, please see CenterPoint Energy's true-up filing, Docket No. G008/AA-16-730.
[66] A supporting spreadsheet with detailed calculations is contained in Department Attachment G10.
[67] See CenterPoint Energy's true up, page 10 for the sales volumes.

Table G11a - CenterPoint
True-Up Factors per Dekatherm (Dth) by Customer Class
(As filed on September 1, 2016 by CenterPoint Energy)

Class	Factor
Small Volume Firm	$0.0667
Large General Service	$0.0136
Small Volume Dual Fuel	$0.0901
Large Volume Dual Fuel	$0.2320

The Department's analysis of CenterPoint Energy's true-up calculation indicates that the current year's deviation between gas-cost recoveries and actual gas costs was primarily caused by the following factors:

1. Demand Costs – CenterPoint Energy under-recovered its demand costs including propane costs[68] by $2,474,722, or approximately 3.11 percent. The demand-cost under-recovery includes off-system sales revenue of $94,994 and curtailment revenue of $0. Without these revenues, there was an under-recovery of demand costs of $2,569,716 or approximately 3.23 percent. In its filing,[69] CenterPoint Energy stated that the demand-cost under-recovery resulted from weather that was about fifteen percent warmer than normal and firm sales that were about 3.3 million Dth less than the weather-normalized sales used to calculate the demand recovery factor (actual firm Cycle sales were 104.9 million Dth vs 108.2 million Dth forecasted for the test year firm sales in Docket G008/GR-15-424.) According to CenterPoint Energy, adjustments to demand from the "demand smoothing" factor brought the demand cost recovery much closer to the demand costs incurred.[70]

The Department refers to its analysis in G008/M-16-228, in which the Department concluded that CenterPoint Energy's demand cost recovery has been reasonable, particularly in the last several years, as compared to its peers.

2. Commodity Costs – CenterPoint Energy under-recovered commodity costs by $7,244,501, or approximately 2.38 percent. The commodity-cost under-recovery includes off-system sales revenue of $367,398, damage revenue of $32,064, and balancing revenue of $549,895. Without these revenues, there was an under-recovery of demand costs of $8,193,858 or approximately 2.69 percent. Regarding the under-recovery, CenterPoint Energy stated that "Commodity-cost recovery

[68] Propane costs of $544,588 are included in demand costs.
[69] See CenterPoint Energy's AAA Report, page 18.
[70] On May 17, 2016, the Commission issued its Order in Docket No. G008/M-16-228 approving CenterPoint's request for a 3-year variance to continue using the smoothing tool, with modifications and reporting requirements.

> rates are based on estimated monthly purchases prior to the start of the month, based on the assumption of "normal" weather. To the extent estimated purchases vary from actual purchases, an over or under recovery will occur."[71]

Based on its analysis, the Department concludes that CenterPoint Energy's under-recovery of commodity costs appears to be reasonable.

2. Compliance and/or Supplemental Reporting Requirements

Docket Nos. G008/M-00-980, G008/M-03-782, G008/M-05-1196, G008/M-07-1063, G008/M-10-857, G008/M-13-728, and G008/M-16-228 (Demand Adjustment Program). In Docket No. G008/M-00-980, CenterPoint Energy requested a three-year pilot program to add a monthly Demand Adjustment Program (Program) to its demand cost recovery rate charged to firm customers in order to provide a better matching of costs and recoveries within the true-up year. In its October 27, 2000 *Order*, the Commission approved the pilot program and required CenterPoint Energy to provide, in its Annual Automatic Adjustment Report, a summary of what the total annual demand-cost recovery would have been absent the Demand Adjustment, the total amount of Demand Adjustment collected, and the total amount of demand costs that will be trued up.[72] In the above-listed dockets, the Commission approved extensions of the Program. In its December 11, 2013 *Order*,[73] the Commission approved CenterPoint Energy's request "to remove the one-month lag in sales from its calculation" of the monthly demand adjustment and ordered continuing reporting requirements from the previous dockets.[74] The Program was again approved by the Commission in Docket No. G008/M-16-228, with no changes from the December 11, 2013 *Order*.[75]

In Exhibits 3 and 4 of its AAA Report, CenterPoint Energy included the required information.[76] In Table G12, since the inception of the Program, the demand-cost recovery results have been as follows:[77]

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[71] See CenterPoint Energy's AAA Report, page 18.
[72] CenterPoint Energy's Demand Adjustment was not charged to its Viking area customers until consolidation of the PGAs in 2005.
[73] Docket No. G008/M-13-728.
[74] Prior to FYE14, this approach was reported as a hypothetical removal of the one-month lag filed in CenterPoint Energy's AAA Reports, Exhibit 4.
[75] Docket No. G008/M-13-728.
[76] See CenterPoint Energy's AAA Report, pages 14-15 for a discussion.
[77] The data in this exhibit does not include "No Surprise Bill©" (NSB) customer data starting with November 2001 until termination of the program in December 2007. NSB customer demand costs were recovered on weather-normalized sales and a fixed recovery rate.

Table G12: CenterPoint's Demand Adjustment Program Recovery Results[78]

	With Program[79]		Without Program	
Year	**Over/(Under)**[80]	**Percent**	**Over/(Under)**	**Percent**
FYE01	$(1,859,854)	(1.6)	$6,060,569	5.2
FYE02	$2,140,282	2.1	($9,835,529)	(9.6)
FYE03	$195,409	0.2	$7,784,072	7.9
FYE04	$(1,167,912)	1.0	$(1,197,490)	(1.0)
FYE05	$(934,612)	(0.8)	$(1,530,385)	(1.3)
FYE06	$(406,837)	(0.4)	$(12,087,038)	(10.4)
FYE07	$7,519,994	7.0	$(286,342)	(0.3)
FYE08	$2,511,582	2.9	$1,322,689	1.5
FYE09	$3,098,947	4.7	$4,489,569	6.8
FYE10	$(5,149,579)	(6.6)	$(7,327,401)	(9.4)
FYE11	$1,164,918	1.5	$3,903,613	5.1
FYE12	$(4,482,056)	(6.0)	$(11,272,158)	(15.1)
FYE13	$7,310,268	10.0	$5,025,956	6.9
FYE14[81]	$688,175[82]	0.9	$11,295,219	15.4
FYE15	$1,882,416	2.4	$7,712,926	9.8
FYE16	$(2,720,436)	(3.4)	$(873,556)	(1.1)

As shown above, FYE16 joins FYE07, FYE08, and FYE13 in that the program did not provide a better match of costs and recoveries within the true-up year than would have been the case without this program.[83] In FYE16, actual under-recovery of $2,720,436 performed worse than the hypothetical under-recovery of $873,556. Although demand smoothing does not always outperform the hypothetical recovery without the program, the Program does improve the match between costs and recoveries in most years. The Department notes that the absolute difference in FYE16 is $1,846,880. Again, the Department refers to Docket G008/M-16-228 for

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[78] From CenterPoint Energy's AAA Report Exhibits 3 and 4.
[79] Program recovery did not include the lag adjustment until FYE14.
[80] For comparison purposes, the variances are calculated using non-prorated data (*i.e.,* calendar-month data rather than billing-month data).
[81] Beginning in FYE14, the Commission approved CenterPoint Energy's request to adjust the Program for a one-month lag in sales.
[82] This figure was corrected. As of FYE14, the Program recovery includes the lag adjustment.
[83] Regarding FYE07, the Commission modified the pilot program in its December 24, 2007 *Order* to account for capacity-release credits due to the large over-recovery in FYE07. The over-recovery was larger due to adding capacity-release credits for the first time starting in January 2008. For FYE08, the demand cost adjustment was not in place for three months (October through December of 2007) since CenterPoint Energy's request for a continued variance in Docket No. G008/M-07-1063 was not approved until December 24, 2007. Thus, the results of the FYE08 demand cost adjustment program may not be indicative of what the results would have been over the full eight months of the program.

the analysis supporting the Commission's decision to grant an additional variance to allow the demand smoothing adjustment to continue.

As stated above, the Commission required CenterPoint to continue reporting requirements from previous dockets. Table G12a shows the over/ (under) recovery with and without a 1-month lag adjustment.

Table G12a: CenterPoint's Demand Adjustment Program
One-Month Lag Adjustment Results[84]

Year	With Lag Adjustment Over/ (Under) Recovery	Without Lag Adjustment Over/ (Under) Recovery
FYE08	$939,032	$1,322,689
FYE09	$3,873,820	$3,098,947
FYE10	$(4,394,252)	$(5,149,579)
FYE11	$2,306,874	$1,164,918
FYE12	$(4,568,677)	$(4,482,056)
FYE13	$3,954,396	$5,025,955
FYE14[85]	$688,175	$(149,278)
FYE15	$1,882,416	$(285,002)
FYE16	$(5,589,748)	$(2,720,436)

In FYE16, the hypothetical $5,589,748 under-recovery assuming a one-month lag adjustment methodology reflects a worse result than the actual methodology without the lag adjustment under-recovery of $2,720,436. The Department concludes that CenterPoint Energy complied with the filing requirements in the Commission's *Order* in Docket No. G008/M-13-728.

Docket Nos. G008/M-01-540, G008/M-08-777, G008/M-12-166, and G008/M-15-912 (Financial Call Options). In Docket No. G008/M-01-540 (Docket No. 01-540), the Commission granted a variance to allow CenterPoint Energy to recover costs associated with financial call options related to swing gas in place of reservation fees through the PGA. The Commission granted an extension of the variance through June 30, 2010 in Docket No. G008/M-08-777 (Docket No. 08-777). Further, the Commission granted an additional extension of the variance through June 30, 2016 and required compliance reports in Docket No. G008/M-12-166. In Docket No. G008/M-15-912, CenterPoint Energy was granted an extension to its variance to recover the costs associated with certain financial instruments through the PGA through June 30, 2020.

[84] From CenterPoint Energy's AAA Report Exhibits 3 and 4.
[85] Beginning in FYE14, the Commission approved CenterPoint Energy's request to adjust the Program to remove the one-month lag. The Commission required CenterPoint Energy to continue to report "the Company's monthly demand adjustment compared to a hypothetical demand-cost recovery rate that reflects a one-month lag."

In its November 3, 2004 *Order Granting Open-Ended Variance to Minn. Rules, Parts 7825.2400, 7825.2500, and 7825.2700* (01-540), the Commission required CenterPoint Energy to:

- include information on the call options contracts and swing contracts with reservation fees used during the year and the price paid for natural gas through each of these types of contractual arrangements; and
- compare the cost of the swing gas actually used with the cost for natural gas in the spot market for the day on which the swing gas was actually used.

CenterPoint Energy complied by including a comparison of the cost of swing gas with the costs for natural gas in the spot market in its Exhibit 6A and B of its AAA Report for Docket No. 01-540. CenterPoint Energy's Exhibit 7 lists hedge volumes and Exhibit 8 estimates impacts on customer bills as a result of using hedging products in its supply portfolio during the true-up period.

In its Report, CenterPoint explained that,

> During winter 2015-2016, when gas flows, CenterPoint Energy pays the daily index (Gas Daily) with no commodity premium for swing gas; therefore all CenterPoint Energy swing gas is valued at the "spot market" price. The cost comparison between CenterPoint Energy's swing gas and "spot market" is zero. Give that it is zero and has been zero for multiple years now, the Company believes that Exhibit 6B is no longer necessary. Should the Company change its business practices where the difference is not zero, the Company will provide this schedule.

The Department agrees with CenterPoint that Exhibit 6B is not necessary as long as its swing gas is valued at the spot market price. The Department recommends that the Commission allow CenterPoint to discontinue this portion of the financial call options compliance until such time that it is relevant again.

In its March 6, 2009 *Order* (08-777), the Commission required the following reporting requirements:

- data on the specifics of any price hedging contracts, including a list of each hedging instrument entered into;
- the totals contracted for each instrument; and
- the net gains or losses, including all transaction costs.

CenterPoint Energy complied by including this information in Exhibit 7 of its AAA Report.[86] The Department concludes that CenterPoint Energy complied with the filing requirements in Docket Nos. 01-540 and 08-777. The Department discusses CenterPoint Energy's hedging costs in Section III, part O, of this FYE16 AAA Report.

Docket No. G999/AA-08-1011. As noted above, the Commission directed CenterPoint Energy, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal-year 2010. CenterPoint Energy provided this information in pages 19-21, as well as in Exhibit 8 of its Annual Report. The Department concludes that CenterPoint Energy complied with the filing requirements in Docket No. G999/AA-08-1011. The Department discusses CenterPoint Energy's hedging costs in Section III, part O, of this FYE16 AAA Report.

Docket No. G008/GR-08-1075 (Off-System Sales). In Docket No. G008/GR-08-1075 (08-1075), CenterPoint Energy was ordered to return "off-system sales" revenues to ratepayers through an initial refund of $5,912,279 and then continue to refund any off-system revenues through subsequent PGA filings. In its November 2, 2009 *Findings of Fact, Conclusions of Law, and Recommendation*, the Commission Ordering Paragraph 72 (d) required CenterPoint Energy to "include a separately identified calculation of the over-/under-recovery of the off-system sales credits to ratepayers and of the incentive" in its annual AAA filing. Ordering Paragraph 72 (c) required that the off-system sales be split between commodity and demand gas costs (*i.e.*, storage exchange and swing sales would be a demand cost credit and other point exchanges would be a commodity cost credit).

CenterPoint Energy included the required information on pages 9 and 13 of its annual true-up filing. Upon review of this information, the Department concludes that CenterPoint Energy's incentive on off-system sales[87] and allocations among classes were calculated correctly. Thus, the Department concludes that CenterPoint is in compliance with the filing requirements in Docket No. 08-1075.

Docket No. G999/AA-14-580. The Commission's August 24, 2015 *Order* required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. On pages 15-16 of its AAA Report, CenterPoint Energy stated that "there were no instances of unauthorized gas use for 2015-2016. Historically the Company has provided an exhibit documenting each instance, but the

[86] With further discussion in Section 6.4, pages 19-21.

[87] In Docket No. G008/GR-08-1075, the Commission allowed CenterPoint Energy to earn an incentive equal to the approved overall rate of return on its off-system sales. On page 13 of its True-Up filing, CenterPoint Energy's incentive totaled $68,042 ($889,059 - $821,017). Thus, CenterPoint Energy used the approved overall rate of return of 7.65 percent ($68,042/$889,059).

Company has not included a blank exhibit." Regarding the utility's communication with each customer on the noncompliance with interruptions, CenterPoint Energy stated:

> The Company intends to continue to reiterate the importance of customers being able to curtail their natural gas usage when called upon. The Company ensures that contact with customers is made promptly after any curtailment event.
>
> In addition, in early September, the Company will be sending its annual Curtailment Contact Information form to all interruptible customers, where it asks customers to update their curtailment contact information and also emphasizes the importance of interruptible customers being able to curtail their gas usage when called upon.

The Department concludes that CenterPoint Energy complied with the reporting requirements in Docket No. 14-580.

Based on its review, the Department recommends that the Commission accept CenterPoint Energy's FYE16 true-up.

3. Summary and Recommendations

The Department concludes that CenterPoint Energy's FYE16 annual automatic adjustment report is complete with respect to the filing requirements in Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept CenterPoint Energy's FYE16 true-up, Docket No. G008/AA-16-730;
- allow CenterPoint Energy to implement its true up, as shown in Department Attachment G10 of the FYE16 AAA Report; and
- allow CenterPoint to discontinue providing the compliance information regarding the comparison of the cost of swing gas versus spot market gas, currently provided in CenterPoint's Exhibit 6 – Part B.

E. XCEL GAS

1. Recovery of Gas Costs and True-Up Calculations

On September 1, 2016, Xcel Gas submitted its annual true-up filing, Docket No. G002/AA-16-725 in compliance with Minnesota Rule 7825.2810. Based on its review, the Department concludes that Xcel Gas' filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

According to Xcel Gas' September 1, 2016 true-up filing, it under-recovered gas costs by $4,990,733, or approximately 2.34 percent, during the reporting period, with a cumulative under-recovery of approximately 1.59 percent.[88] By customer class, Xcel Gas reported under-recoveries for the current reporting period as follows:

Table G13 - Xcel Gas
FYE16 Percent Over-Recovery/(Under-Recovery)[89]
(As filed on September 1, 2016 by Xcel Gas)

Class	
Residential	(1.71)
Commercial/Industrial (C/I)	(2.56)
Demand Billed	(3.45)
Small Interruptible (SVI)	(2.31)
Medium & Large Interruptible (M&LVI)	(4.37)
Total	(2.34)

USING THE SALES VOLUMES FORECASTED BY XCEL FOR THE YEAR ENDING AUGUST 31, 2017[90] RESULTS IN THE FOLLOWING TRUE-UP FACTORS BY CLASS, AS CALCULATED BY XCEL GAS IN ITS SEPTEMBER 1, 2016 FILING:

[88] The figure of 1.59 percent represents the cumulative under-recovery of $3,399,975, which is the basis for the true-up adjustments. For a detailed breakdown of the true-up calculations, please see Xcel Gas' true-up filing, Docket No. G002/AA-16-725.
[89] Supporting spreadsheets with detailed calculations are contained in Department Attachment G11.
[90] Xcel Gas' true up, Schedule B, page 2.

Table G13a – Xcel Gas
True-Up Factors per Dekatherm (Dth) by Customer Class
(As filed on September 1, 2016 by Xcel Gas)

Class	
Residential	$0.00338
C/I	$0.00564
Demand Billed Demand	$(0.1101)
Demand Billed Commodity	$0.00927
SVI	$0.00217
M&LVI	$0.00951

The Department's analysis of Xcel Gas' September 1, 2016 true-up calculation shows that the current year's deviation between Xcel Gas' gas-cost recoveries and actual gas costs was primarily caused by the following factors:

1. **Demand Costs including Demand Billed costs:** Xcel Gas under-recovered Minnesota demand costs by $2,604,974, or approximately 5.43 percent. The demand-cost under-recovery also includes interruptible curtailment penalty revenue of $0 and capacity-release revenue of $408,418.[91] Without these revenues, there was an under-recovery of demand costs of $3,013,392 or approximately 6.29 percent. According to Xcel Gas, actual FYE16 sales were approximately 12.19 percent lower than forecasted sales in the monthly PGA, resulting in the under-recovery of demand costs.[92]

As discussed further below, Xcel Gas has a Monthly Demand Cost True-Up Mechanism, approved in Docket No. G002/M-03-843. This mechanism is designed to offset swings in revenue collection caused by deviations from the forecasted normal weather. The mechanism credited an additional $2,891,981 of demand costs from customers during the FYE16 heating season due to weather and the cap on the amount of the adjustment per month. Xcel Gas stated that without the mechanism, its under-recovery of demand costs would have been approximately 11.47 percent.[93]

The Department concludes that Xcel Gas' demand cost under-recovery appears to be reasonable.

2. **Commodity Costs (including peak-shaving costs:** During FYE16 Xcel Gas under-recovered commodity costs by $2,385,760, or about 1.44

[91] Xcel Gas' responses to DOC Information Request Nos. 8 and 6.
[92] Xcel Gas' AAA Report, Attachment B, Schedule 3, page 3.
[93] Xcel Gas' AAA Report, Attachment B, Sch. 3, p. 3 and true up, Schedule I.

> percent. The commodity-cost under-recovery also includes balancing penalty revenue of $109,240.[94] Without this revenue, there was an under-recovery of commodity costs of $2,495,000 or approximately 1.51 percent. Xcel Gas stated that the under-recovery was due to:[95]
>
>> …deviations between monthly forecasted prices and actual wholesale commodity gas prices**.** The price deviations between monthly price estimates and actual unit cost were the result of price volatility in the wholesale natural gas commodity market. On an average unit basis, the under-recovery is approximately 0.4 cents per therm. Because customer consumption varies by class from month to month and price deviation varies from month to month, individual classes had varying results.

Based on its analysis, the Department concludes that Xcel Gas' under-recovery of commodity costs appears to be reasonable. Thus, the Department recommends that the Commission accept Xcel Gas' FYE16 true-up.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G002/M-94-103. The Commission required Xcel Gas to return all past, present, and future capacity release revenue from all sources to firm customers using Federal Energy Regulatory Commission (FERC) Account 805.1. Based on Xcel Gas' true up Schedule H, Xcel Gas complied with the Commission's *Order* by returning capacity-release revenue from all sources to firm customers.

Docket No. G002/M-98-1429. The Commission required Xcel Gas to return to ratepayers, in the same manner as penalties are handled, all "additional charge" money (curtailment penalty revenue) received by Xcel Gas under Section 5, sheet 8, of its tariffs for large firm transportation customers' failure to restrict the use of gas. Xcel Gas indicated, on page 2 of Attachment G in its AAA report, that no firm transportation customers incurred "additional charges" for unauthorized use of gas, and Xcel Gas did not receive any "additional charges" monies during the current true-up period.

Docket Nos. G002/M-01-1336, G002/M-03-1627, G002/M-08-46, G999/AA-06-1208, G002/M-12-519, and G002/M-16-88 (Hedging). Xcel Gas requested to continue its PGA rule variance to

[94] Xcel Gas' True Up Report, Schedule D, page 1 and Xcel Gas' response to DOC Information Request No. 9.
[95] Xcel Gas' AAA Report, Attachment B, Schedule 3, page 4.

recover hedging costs through the PGA in Docket No. G002/M-16-88. As a condition of approving and extending rule variances to allow Xcel Gas to include the costs of financial-hedging instruments in its PGAs, the Commission required Xcel Gas to identify the following, separately, in future AAA reports:

- data on the relative benefits of price-hedging contracts, including the average cost per dekatherm for natural gas purchased under financial instruments compared to the comparable monthly and daily spot index prices;
- a list of each hedging instrument entered into;
- the total volumes contracted for, for each instrument;
- the net gain or loss, including all transaction costs for each instrument in comparison to the appropriate monthly and daily spot index prices; and
- a schedule of hedging costs.

Xcel Gas complied by submitting the required information in its Attachment A, Schedule 5, and Attachment G, Schedule 2 of its AAA report and Schedule H of Xcel's true-up filing. The Department discusses Xcel Gas' hedging costs in Section III, part O, of this FYE16 AAA Report.

<u>Docket Nos. G002/M-03-843, G002/M-06-681, G002/M-08-456, G002/M-11-203, and G002/M-14-171 (Demand Cost Mechanism)</u>. On June 11, 2004, the Commission approved a Monthly Demand-Cost True-Up Mechanism, with requirements, and granted Xcel Gas a variance to Minnesota Rule 7825.2700, subpart 5 until September 30, 2006. The Monthly Demand-Cost True-Up Mechanism was implemented in October 2004. In the above dockets, the Commission approved extensions of the program until September 30, 2017.

The mechanism should result in billing rates that are:

- Lower than rates without the mechanism when there is colder-than-normal weather (when natural gas consumption and customer bills are high); and
- Higher than without the mechanism when there is warmer-than-normal weather (when natural gas consumption and customer bills are low).

The Demand Cost Mechanism is adjusted by capacity release as approved in Docket No. G002/M-11-203. The mechanism in place includes caps on the monthly amount. For October, April, and May the cap is 25 percent of the demand-cost recovery rate. The cap for November through March is 125 percent of the levelized demand rate minus the actual demand-cost recovery rate. With respect to annual filings, the Commission required Xcel Gas to identify (by customer class) the monthly demand true-up revenues and summarize the following for each firm non-demand billed customer class in Xcel Gas' annual true-up filings:

- the annual demand-cost recovery absent the adjustments;

- the total annual adjustment recovery; and
- the remaining current year demand-cost recovery true-up balance.

Xcel Gas' FYE16 true-up filing, Schedule (I), includes the required information on the Demand Cost Mechanism results. Since the inception of this program, the demand-cost recovery results have been as follows:

Table G14 – Xcel Gas
Monthly Demand-Cost True-Up Recovery Mechanism Results

	With Program Recovery		**Without Program**	
Year	**Over/(Under)[96]**	**Percent**	**Over/(Under)**	**Percent**
FYE05	$(652,620)	(1.1)	$(3,719,363)	(6.0)
FYE06	$(3,190,837)	(6.0)	$(6,327,057)	(11.9)
FYE07	$4,350,806	8.3	$703,577	1.3
FYE08	$2,628,294	6.1	$3,496,826	8.1
FYE09	$2,433,476	5.5	$3,595,452	8.1
FYE10	$341,457	(0.74)	$846,099	(1.82)
FYE11	$1,784,013	3.71	$2,538,677	5.27
FYE12	$(4,963,775)	(9.96)	$(7,529,571)	(15.11)
FYE13	$2,376,086	4.74	$2,069,183	4.12
FYE14	$7,394,847	15.11	$10,989,489	22.45
FYE15	$2,525,679	5.52	$4,505,962	9.85
FYE16	$(2,638,930)	(5.43)	$(5,530,911)	(11.47)

As shown above, except for FYE07 and FYE13, the program continues to match costs better within the true-up year than would have been the case without this program. In FYE16 actual under-recovery of $2,638,930 outperformed the hypothetical under-recovery of $5,530,911. The Department concludes that Xcel Gas complied with the filing requirements in the Commission's *Order* in Docket No. G002/M-03-843.

<u>Docket No. G999/AA-08-1011</u>. As noted above, the Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal-year 2010. Xcel Gas provided this required information in Attachment G, Schedules 2 through 5 in its AAA Report filing. The Department discusses Xcel Gas' hedging costs in Section III, part O, of this *Report*.

<u>Docket No. G002/M-09-852 and E,G002/M-15-618</u>. On February 18, 2010 in Docket G002/M-09-852, the Commission approved Xcel Gas' variance for a natural gas Capacity Utilization Program for its gas distribution and electric generation business units as a three-year pilot

[96] For comparison purposes, the variances are calculated using non-prorated data (*i.e.,* calendar month rather than billing month data). Excludes Demand Billed Demand.

program and required Xcel Gas to report in the AAA each individual transaction showing quantities and cost, the specific accounting entries and a brief explanation of the transaction. The variance expired on February 18, 2013. In Docket No. E,G002/M-15-618, the Commission accepted Xcel's agreement to continue to report on the transactions related to the Capacity Utilization Plan annually in its AAA Report; Xcel included both the gas and electric transactions.

During the FYE16, the Capacity Utilization Program resulted in net savings to Xcel Gas of approximately $207,053 and savings to Xcel electric of approximately $164,028 from avoided storage fees.[97]

The Department concludes that Xcel Gas is in compliance with the filing requirements in Docket Nos. G002/M-09-852 and E,G002/M-15-618.

Docket No. G999/AA-14-580. The Commission's August 24, 2015 *Order* required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. Xcel Gas provided information on this requirement in its Attachment G, pages 11-12, and in Attachment G, Schedule 8 of its AAA Report. Xcel Gas stated on page 12 that "there were no gas interruptions in the 2015-2016 heating season. Attachment G, Schedule 8 is intentionally left blank."

The Department concludes that Xcel Gas complied with the Commission's Order in Docket No. 14-580 on unauthorized gas use.

3. Summary and Recommendations

The Department concludes that Xcel Gas' filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept Xcel Gas' FYE16 true-up, Docket No. G002/AA-16-725; and
- allow Xcel Gas to implement its true-up, as shown in Department Attachment G11 of the FYE16 AAA Report.

[97] Xcel Gas' AAA Report Attachment G, pages 9-10.

III. ADDITIONAL INFORMATION

A. AVERAGE ANNUAL RESIDENTIAL CUSTOMER BILLS

Using data supplied by the utilities in their responses to Department Information Request No. 1, the Department compared the average annual bills of residential customers for each regulated gas utility in Minnesota. This information is summarized in Graph 1 below and in Department Attachment G13. As in previous reports, and for comparison purposes, the Department developed a typical residential customer's annual bill for each utility, by system, based on the following:

- customer charge;
- per-unit energy consumption rate; and
- average customer consumption of 140 Mcf per year.[98]

In general, a residential customer pays a fixed monthly customer charge and a per-unit energy consumption rate. The per-unit energy consumption rate can be broken down into gas costs and non-gas costs. The level of non-gas costs (referred to as the margin, or gross margin) is approved by the Commission in the utilities' most recent general rate case.[99]

The gas cost for a firm customer includes both demand costs and commodity costs. The demand cost is the amount a utility pays for the right to reserve pipeline capacity or transportation. Demand levels change only with Commission approval of changes proposed in a miscellaneous demand-entitlement filing.[100] However, as interstate pipelines change the rates that they charge or the cost of gas rates change, Minnesota gas utilities automatically pass on these rate changes to their customers through the PGAs.

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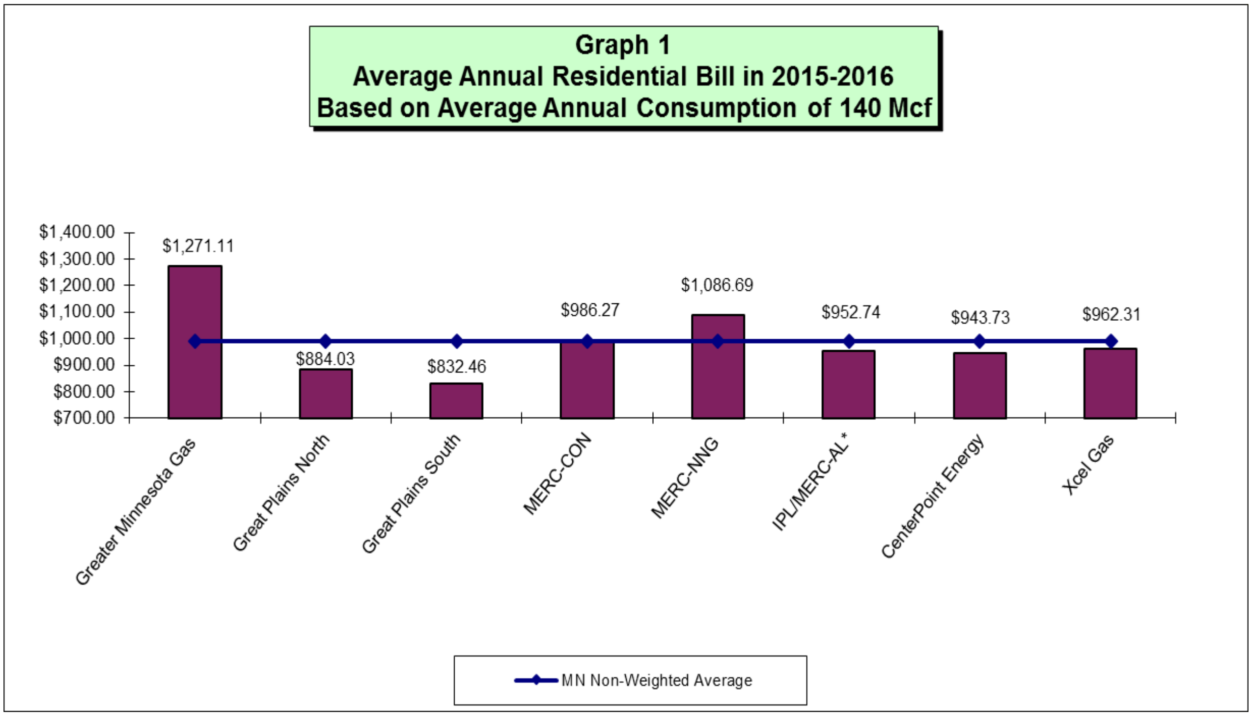
[98] The Department notes that the residential non-weighted average consumption of gas has been lower than 140 Mcf due to decreases in overall natural gas consumption in recent years. The Department continues to use the level of 140 Mcf to allow for comparisons of information among the various years of the Department's AAA reports.

[99] See Section III, part C, for a discussion of margins. Please note that the margins used to calculate total average annual bill are the average rate for the reporting period.

[100] Minnesota LDCs generally file demand entitlement petitions on, or about, July or August 1 of each calendar year. However, demand entitlement filings during other parts of the year also occur.



Graph 1 shows that, based on a consumption level of 140 Mcf, average annual residential bills[101] range from a high of $1,271.11 for customers served by GMG to a low of $832.46 for customers served by Great Plains South.

Table G15 below shows the actual average residential bills and average use for each system during the present reporting period using the data supplied in response to Department Information Request No. 1.

[101] Amounts shown in Graph 1 are not actual averages for customers on any system, since actual averages for each utility depend on actual average consumption levels. Graph 1 is intended to provide a baseline usage comparison that does not vary between years since consumption is held constant at 140 Mcf.

Table G15: Average Annual Residential Bill and Average Use per Utility for the FYE16 Reporting Period

Utility	System	Average Usage Rankings[102]	Average Use[103] (Mcf)	Annual Bill Rankings	Total Annual Bill ($)	Average Cost per Mcf[104] ($)	Annual Customer Charges ($)
Greater Minnesota		**3**	72.5	**8**	$707.43	$9.76	$102.00
Great Plains	North	**2**	68.9	**2**	$474.68	$6.89	$78.00
	South	**1**	63.2	**1**	$418.59	$6.62	$78.00
MERC	CON	**4**	74.5	**5**	$580.84	$7.80	$119.70
	NNG	**5**	76.1	**7**	$645.33	$8.48	$119.70
	AL	**7**	76.4	**3**	$548.54	$7.18	$63.00
CenterPoint Energy		**8**	78.9	**6**	$583.73	$7.40	$118.86
Xcel Gas		**6**	76.2	**4**	$572.99	$7.52	$108.00

As shown in Table G15, based on actual consumption, CenterPoint Energy experienced the highest average consumption (78.9 Mcf), and GMG had the highest average annual residential bill ($707.43) during FYE16.[105]

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[102] The rankings throughout this report are listed in the format from lowest to highest (*e.g.,* average use, cost, and rate).

[103] The average annual usage amount reported in response to Department Information Request No. 1 is not weather normalized but reflects the different heating degree days based on location.

[104] The average cost per Mcf may be different from the annual bill shown in column (6) divided by the average use shown in column (4) due to rounding of the average usage.

[105] From FYE98 through FYE04, MERC-NMU (then Aquila-NMU) experienced both the highest average consumption and corresponding highest average residential bill. MERC-NMU's average consumption and corresponding average bill were as follows:

FYE98..............................138 Mcf $834.26
FYE99..............................114 Mcf $649.02
FYE00..............................116 Mcf $720.24
FYE01..............................153 Mcf $1,338.20
FYE02..............................141 Mcf $841.33
FYE03..............................157 Mcf $1,127.90
FYE04..............................147 Mcf $1,220.25

Since FYE04, the following utilities had the highest consumption and average residential bills, respectively:

Regarding the information provided in Graph 1, Table G15, and Department Attachment G13, the Department notes that costs that utilities incur often are determined by a number of factors, such as: load factor, number of customers, mix of firm and interruptible customers, number of available pipeline systems, weather, past contracts with pipelines and suppliers that are still in effect, access to storage, and provisions of pipeline service as approved by the FERC (*e.g.*, imbalance penalties).

Second, the non-gas portion of the rate (base rate) is developed independently in a general rate case, and utilities file their rate cases at times chosen by the utility. Base rates reflect the cost, based on the test year, of delivering natural-gas service. These non-gas costs are affected by the service territory, customer mix and density, timing of the rate case, and other factors. The Department highlights some of these differences between utilities in the following sections.

B. ANNUAL AVERAGE GAS COSTS

Table G16 below compares the total system annual averages of both the PGA recovered and the actual incurred commodity costs. The figures in Table G16 represent the per-Mcf[106] commodity costs incurred by the utilities and passed on to ratepayers in the monthly PGAs, as reported in the utilities' true-up filings. Certain tables in this report provide the Minnesota weighted average and the Minnesota non-weighted average amounts. The Department includes the non-weighted average since the weighted average is dominated by Minnesota's largest natural gas provider, CenterPoint Energy.

FYE05 Great Plains Crookston	90 Mcf	$961.40
FYE06 Greater Minnesota RS-2	93 Mcf	$1,167.74
FYE07 Greater Minnesota RS-2	95 Mcf	$1,060.31
FYE08 CenterPoint Northern and Great Plains Crookston	100 Mcf	$1,205.75
FYE09 CenterPoint Energy and Great Plains Crookston	97 Mcf	$1,045.63
FYE10 CenterPoint Energy/Interstate Gas and GMG	88 Mcf	$819.99
FYE11 CenterPoint Energy and GMG	95 Mcf	$977.39
FYE12 MERC-NMU and GMG	77 Mcf	$735.34
FYE13 CenterPoint Energy and GMG	94 Mcf	$916.96
FYE14 CenterPoint Energy and GMG	106 Mcf	$1,154.10
FYE15 CenterPoint Energy and GMG	92 Mcf	$893.32
FYE16 CenterPoint Energy and GMG	79 Mcf	$707.43

[106] The Department uses Mcf (one thousand cubic feet) in certain areas of its tables to represent units even though the units may actually be Dth (heat-adjusted Mcf).

Table G16: FYE16
Total Weighted Average Cost of Commodity
PGA Recovered Versus Actual Incurred[107]

Utility	System	Recovered PGA Commodity Rate $/Mcf	Actual Annual Commodity Rate $/Mcf	Percent Over/ (Under) Recovery
Greater Minnesota		$ 3.7690	$ 3.7518	0.46%
Great Plains	North	$ 2.3623	$ 2.2913	3.10%
	South	$ 2.4626	$ 2.4517	0.45%
MERC	CON	$ 3.0152	$ 3.0016	0.45%
	NNG	$ 3.3717	$ 3.3712	0.01%
	AL	$ 2.7934	$ 2.8480	(1.92)%
CenterPoint Energy		$ 2.8265	$ 2.9048	(2.69)%
Xcel Gas		$ 2.5885	$ 2.6206	(1.22)%
Weighted MN Average		**$ 2.8155**	**$ 2.8657**	**(1.75)%**
Non-Weighted MN Average		**$ 2.8986**	**$ 2.9051**	**(0.22)%**

Table G16 demonstrates that most of the PGA systems slightly over-recovered or under-recovered commodity costs. All but one of the PGA systems that over-collected were within 0.46 percent of the actual annual commodity rate. During the reporting period, CenterPoint had the greatest under-recovery of commodity costs, with an under-recovery of approximately 2.69 percent.

Table G16a below shows the FYE16 increase or decrease in the Minnesota non-weighted average commodity costs over previous years' costs back to FYE99. The figures below are nominal costs and are not adjusted for either inflation or weather conditions. Based on these data, during FYE16, the actual Minnesota non-weighted average commodity cost of gas was $2.9051 per Mcf, which represents an approximately 30 percent decrease in prices from the FYE15 reporting period.

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[107] The numbers used and the detailed calculations are contained in Department Attachment G15.

Table G16a: Non-Weighted Average Commodity Costs

Reporting Period	Rate ($/Mcf)	Percent Increase (Decrease) vs. Prior Years
FYE16	$2.9051	
FYE15	$4.1574	(30%)
FYE14	$5.4831	(47%)
FYE13	$3.4442	(16%)
FYE12	$3.5238	(18%)
FYE11	$4.3001	(32%)
FYE10	$4.7259	(39%)
FYE09	$6.1826	(53%)
FYE08	$7.4936	(61%)
FYE07	$7.6177	(62%)
FYE06	$8.8345	(67%)
FYE05	$6.3167	(54%)
FYE04	$5.3364	(46%)
FYE03	$4.7441	(39%)
FYE02	$2.6524	10%
FYE01	$6.0288	(52%)
FYE00	$2.5356	15%
FYE99	$1.9876	46%

As shown above in Table G16, the analysis of "PGA Recovered versus Actual Incurred" commodity costs provides only a partial picture of a utility's gas-purchasing operations. The Department also used the demand cost information submitted by the utilities in their annual true-up reports to develop a "total system" average cost of gas analysis as shown below in Table G17. The comparison of total costs per Mcf experienced by each utility presents another useful analytical tool to compare recovered versus actual gas costs. Below is a summary of the actual total system gas costs experienced during the reporting period by Minnesota gas utilities.

Table G17: FYE16
Total System Gas Costs (Demand and Commodity)[108]

Utility	PGA Recovered ($/Dth)	Rank	Current-Period Actual incurred Gas Cost ($/Dth)	Rank	Actual Over/(Under) ($/Dth)	Percentage Over/(Under) Recovery
Greater Minnesota	$ 3.8015	**7**	$ 3.7518	**6**	$ 0.0497	1.32%
Great Plains						
North	$ 3.4523	**2**	$ 3.5104	**2**	$ (0.0582)	(1.66%)
South	$ 3.5491	**3**	$ 3.6392	**4**	$ (0.0902)	(2.48%)
MERC						
CON	$ 3.6537	**6**	$ 3.6277	**3**	$ 0.0260	0.72%
NNG	$ 4.1806	**8**	$ 4.2923	**8**	$ (0.1117)	(2.60%)
AL	$ 3.6310	**5**	$ 3.7614	**7**	$ (0.1303)	(3.47%)
CenterPoint Energy	$ 3.5609	**4**	$ 3.6637	**5**	$ (0.1028)	(2.81%)
Xcel Gas	$ 3.3316	**1**	$ 3.4114	**1**	$ (0.0797)	(2.34%)
MN Weighted Avg.	**$ 3.5608**		**$ 3.6530**		**$(0.0922)**	**(2.52%)**
MN Non-Weighted Avg.	**$ 3.6451**		**$ 3.7072**		**$(0.0622)**	**(1.68%)**

Total system PGA-recovered and actual-incurred gas costs, as shown in Table G17, provide a comparison of the utilities' total system gas costs (demand and commodity). The first observation that can be garnered from this table is that six of the eight PGA systems under-recovered total gas costs during the reporting period. Of those utilities that under-recovered gas costs, MERC-AL reported the greatest under-recovery at 3.47 percent. The highest over-recovery was reported by GMG at 1.32 percent. MERC-NNG had the highest actual gas cost and Xcel Gas had the lowest actual gas cost.

Table G17a below shows the FYE16 increase or decrease in Minnesota non-weighted average total system gas costs over each of the previous years' rates. The figures below are nominal costs and are not adjusted for either inflation or weather conditions. Based on these data, during FYE16, the actual Minnesota non-weighted average total system cost of gas was $3.7072 per Mcf, representing an approximately 25 percent decrease from the FYE15 reporting period.

[108] The numbers reported in Table G17 are from the true-up filing submitted by each utility. The numbers and the detailed calculations used are contained in Department Attachments G12, G12a, and G16 through G18.

Table G17a: Non-Weighted Average Total System Gas Costs

Reporting Period	Rate ($/Dth)	Percent Increase (Decrease) vs. Prior Years
FYE16	$3.7072	
FYE15	$4.9621	(25%)
FYE14	$6.2268	(40%)
FYE13	$4.3327	(14%)
FYE12	$4.7892	(23%)
FYE11	$5.3295	(30%)
FYE10	$5.7062	(35%)
FYE09	$6.9548	(47%)
FYE08	$8.3613	(56%)
FYE07	$7.8131	(53%)
FYE06	$9.7936	(62%)
FYE05	$7.2930	(49%)
FYE04	$6.2626	(41%)
FYE03	$5.5635	(33%)
FYE02	$3.4941	6%
FYE01	$6.8382	(46%)
FYE00	$3.4529	7%
FYE99	$2.8627	30%

C. PER-UNIT MARGIN CHARGED TO RESIDENTIAL CUSTOMERS

Using data collected from information requests to each utility, the Department developed a list of the annual FYE16 per-unit margins charged by each utility, by pipeline system, to residential customers. Margins are approved by the Commission only at the time of a general rate case. Table G18 below presents the Department's summary of the per-unit margins as of June 30, 2016.

Table G18: FYE16
Actual Per-Unit Margin Rate by PGA System Charged to Residential Customers

Utility	System	Non-Gas Margin ($/Mcf)
Greater Minnesota[109]		$4.4433
Great Plains[110]	North	$1.7227
	South	$1.3385
MERC[111]	CON	$2.3467
	NNG	$2.3434
	AL	$2.3438
CenterPoint Energy[112]		$2.2666
Xcel Gas[113]		$1.8591
MN Non-Weighted Avg.		**$2.3330**

As shown on Table G18, GMG and MERC have the highest residential non-gas margins. The Department notes that GMG is a relatively small company and, thus, its fixed costs are spread over fewer customers. The two lowest residential non-gas margins are for Great Plains South and North.

D. REVIEW OF GAS UTILITIES' PEAK-DAY DEMAND PROFILES

THE DEPARTMENT USED DATA FROM RESPONSES TO DEPARTMENT INFORMATION REQUESTS TO DEVELOP A SUMMARY OF EACH GAS UTILITY'S PEAK-DAY DEMAND PROFILE, LOAD FACTOR, AND RESERVE MARGIN. TABLE G19 BELOW PRESENTS A SUMMARY OF THIS INFORMATION.

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[109] Greater Minnesota's most recent rate case was filed in Docket No. G022/GR-09-962. Greater Minnesota's non-gas margin rates were last changed as of November 1, 2010.
[110] Great Plains' most recent rate case was filed in Docket No. G004/GR-15-879, which was still pending before the Commission as of June 30, 2016. The non-gas margins for Great Plains' two systems have been updated based on changes in the Conservation Improvement Program (CIP) tracker account.
[111] MERC's non-gas margins changed effective January 1, 2016 pursuant to the Commission's approval of interim rates in MERC's most recent rate case, Docket No. G011/GR-15-736.
[112] CenterPoint Energy's non-gas margins changed effective October 1, 2015 pursuant to the Commission's approval of interim rates in CenterPoint Energy's most recent rate case, Docket No. G008/GR-15-424.
[113] Xcel Gas' non-gas margin rates were changed with the implementation of final rates on May 1, 2010 in rate case Docket No. G002/GR-09-1153.

Table G19[114]: FYE16
Firm Peak-Day Demand Profiles

Utility/System	Firm Design Day Demand (Mcf)	Firm Peak-Day Demand Deliverability (Mcf)	Annual Firm Throughput (Mcf)	Annual Firm Load Factor[115] %	Reserve Margin[116] %
Greater Minnesota[117]	11,343	12,509	922,596	26.62%	10.28%
Great Plains[118]					
North	15,409	15,700	1,243,821	29.22%	1.89%
South	16,858	17,845	1,247,862	21.94%	5.85%
MERC					
Consolidated[119]	53,075	55,449	5,033,575	32.31%	4.47%
NNG[120]	245,263	252,127	22,927,456	30.71%	2.80%
Albert Lea[121]	13,813	14,190	1,225,639	30.65%	2.73%
CenterPoint Energy[122]	1,317,000	1,343,566	93,327,590	25.72%	2.02%
Xcel Gas[123]	717,478	738,570	58,684,693	29.93%	2.94%
MN Totals	**2,390,239**	**2,449,956**	**184,613,232**	**27.70%[124]**	**2.50%[125]**

As shown above, Minnesota's gas utilities exhibit a firm load factor between approximately 21.94 percent for Great Plains South and approximately 32.31 percent for MERC-Consolidated. Also, the reserve-margin percentage, which includes each utility's contracted transportation and peak-shaving capacity, was approximately 2.50 percent during the reporting period. This level represents a 46 percent decrease in the statewide reserve margin compared to the 4.65 percent figure reported in the last AAA Report. As shown in the table above, the reserve margins range from approximately 1.89 percent for Great Plains North to approximately 10.28 percent for Greater Minnesota.

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[114] See Department Attachment G20.
[115] The load factor equals the daily average firm throughput (annual firm throughput [from Table G19] divided by 365) divided by actual firm peak-day demand (from Table G20).
[116] The reserve margin equals (using values from Table G19) the firm peak-day demand entitlement minus firm design-day demand divided by firm design-day demand.
[117] Regarding the 2015-2016 period, the reserve margin is further discussed in Docket No. G022/M-15-285.
[118] Regarding the 2015-2016 period, the reserve margins are discussed further in Docket No. G004/M-15-645.
[119] Regarding the 2015-2016 period, the reserve margin is further discussed in Docket No. G011/M-15-722.
[120] Regarding the 2015-2016 period, the reserve margins are discussed further in Docket No. G011/M-15-723.
[121] Regarding the 2015-2016 period, the reserve margin is further discussed in Docket No. G011/M-15-724.
[122] Regarding the 2015-2016 period, the reserve margin is further discussed in Docket No. G008/M-15-644.
[123] Regarding the 2015-2016 period, the reserve margin is further discussed in Docket No. G002/M-15-727.
[124] This percent represents the weighted average of Minnesota gas utilities' load factors.
[125] This percent represents the weighted average of Minnesota gas utilities' reserve margins.

The Department supports the continuation of the Commission's requirement that the reserve margins be included in the annual automatic adjustment report since the information is useful for comparison purposes. However, the Department conducted no analysis of the reserve margins in the current filing, but only reported the information in a standardized way. Each utility's reserve margin is analyzed by the Department, and approved by the Commission, in conjunction with that utility's annual demand-entitlement filing.

The Department also used data from responses to information requests to compare each gas utility's firm peak-day demand deliverability to its actual firm peak-day use. Table G20 below presents a summary of this information.

Table G20: FYE16
Comparison of Firm Peak-Day Demand Usage

Utility/System	Firm Peak Day Demand Deliverability[126] (Mcf)	Actual Firm Peak Day Usage (Mcf)	Actual Firm Requirement (%)	Actual Peak Date
Greater Minnesota	12,509	9,495	76%	1/17/16
Great Plains				
North	15,700	11,664	74%	1/9/16
South	17,845	15,582	87%	1/16/16
MERC				
Consolidated	55,449	42,686	77%	1/17/16
NNG	252,127	204,517	81%	1/17/16
Albert Lea	14,190	10,957	77%	1/17/16
CenterPoint Energy	1,343,566	994,146	74%	1/17/16
Xcel Gas	738,570	537,190	73%	1/18/16
MN Totals	**2,449,956**	**1,826,237**	**75%**	

As Table G20 reflects, all of the regulated gas utilities in Minnesota were able to meet their actual firm peak-day FYE16 usage within their proposed demand entitlement levels. The peak day for Minnesota regulated gas utilities occurred on multiple days during the 2015-2016 heating season as indicated above. The utilities had an aggregate peak-day usage, or sendout, of 1,826,237 Mcf. The companies planned for an aggregate peak of 2,449,956 Mcf, implying that approximately 75 percent of the planned peak-day sendout was actually used during

[126] Demand deliverability includes contracted firm transportation, on-line storage capacity, and the maximum daily injection capacity of peak-shaving facilities.

FYE16. The FYE16 aggregate peak represents a 3 percent increase in the peak-day usage compared to the previous heating season.

E. DAILY DELIVERY VARIANCE CHARGES

As mentioned previously, in choosing a reasonable balance of pipeline services, a utility will determine the amount of entitlements and other related pipeline services required to meet the needs of its firm customers reliably. Each utility is required to "nominate" (tell the pipeline) the daily amount of its expected gas use within a certain degree of accuracy. These nominations, and a utility's overall blend of services, determine the utility's ability to provide reliable service on a daily basis, especially during extreme weather fluctuations. In general, when a utility does not nominate its daily amounts (or cannot schedule the amount of capacity needed because of portfolio limitations) within a given percentage of the firm entitlement level actually used, it faces additional pipeline charges (or penalties).

Interstate pipelines (*e.g.,* Northern Natural Gas Co., Viking Gas Transmission Co.) impose balancing penalties on their shippers, such as Minnesota utilities, when these shippers do not nominate their daily capacity amounts within a given percentage of the actual entitlement level used. On NNG's system, these charges (or penalties) are known as positive, negative, or punitive daily delivery variance charges (DDVCs). The current Northern DDVC cost structure for gas taken in excess of nominated levels is as follows:[127]

[127] See Northern Natural Gas Company's FERC Gas Tariff, Vol. No. 1, Sheet No. 53.

Table G21: NNG's DDVC Structure[128]

Type	Current Charge
Negative DDVC	0.40[129]
Positive DDVC	$1.00[130]
Punitive DDVC	5 x SMS Rate[131]
Positive/Critical DDVC:	
- First 2%	$15.00
- Next 3 %	$22.00
Punitive/Critical DDVC:	
- Level I (5 - 10% above)	$56.50
- Level II (more than 10% above)	$113.00

The Commission previously ordered each regulated gas utility to provide a listing of the pipeline penalties each utility incurred.[132] Table G22 below provides a summary of the pipeline penalties incurred during the FYE16 reporting period.

[128] System Overrun Limitation (SOL) and System Underrun Limitation (SUL) are parameters or boundaries that limit the use of System Management Service (SMS) service on days which Northern's system integrity is threatened and SBA provisions are not adequate in maintaining pipeline operations. See Northern Natural Gas' Tariff Sheet 292.
[129] On non-SOL/SUL/Critical days, the rate is the maximum November-March Market Area TI rate during the November-March period and the maximum April-October TI rate during the April-October period.
[130] *Id.*
[131] *Id.*
[132] See Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1171, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-93-1093, and G012/M-93-1251.

Table G22[133]: FYE16
Daily Delivery Variance Charges (DDVC)[134]
Incurred By Utility

Utility/System	DDVC (Mcf)	DDVC ($)	Total Gas Costs ($)	Percent of Total Costs Represented By Penalties (%)
Greater Minnesota	12,190	$312	$3,923,221	0.0080%
Great Plains	18,402	$3,247	$10,915,921	0.0297%
MERC				
Consolidated	0	$0	$19,030,439	0.0000%
NNG	34,906	$28,557	$94,624,912	0.0302%
Albert Lea	0	$893	$5,465,133	0.0163%
CenterPoint Energy	88,960	$46,227	$383,527,682	0.0121%
Xcel Gas[135]	106,300	$22,022	$213,484,094	0.0103%
MN Totals	**260,758**	**$101,258**	**$730,971,402**	**0.0139%**

As shown above, the penalties incurred by the gas utilities range from $0 for MERC-Consolidated to $46,227 for CenterPoint Energy. On a percentage basis, the penalties range from 0 percent MERC-Consolidated to approximately 0.0212 percent for MERC-NNG.

In their responses to the Department's Information Request No. 7, utilities identified the amount of each type of DDVC imposed. Table G23 below provides a summary of the type of DDVC penalty incurred during the FYE16 reporting period.

[133] Table G22 summarizes the data provided in Department Attachment G14.
[134] Viking's charges are called are overrun charges rather than DDVC's. Further, Viking does not have a punitive charge category.
[135] Xcel's charges include DDVCs, as well as overrun charges on the Viking and Williston Basin Interstate Pipeline (WBI) systems.

Table G23[136]: FYE16
Amount of DDVCs Incurred by Type

Utility/System	Positive & Negative	Punitive	Total	Percent of Total MN DDVCs
Greater Minnesota	$189	$123	$312	0.31%
Great Plains	$3,247	$0	$3,247	3.21%
MERC				
Consolidated	$0	$0	$0	0.00%
NNG	$28,557	$0	$28,557	28.20%
Albert Lea	$893	$0	$893	0.88%
CenterPoint Energy	$46,227	$0	$46,227	45.65%
Xcel Gas	$22,022	$0	$22,022	21.75%
MN Totals	**$101,135**	**$123**	**$101,258**	**100%**

As shown above, all Minnesota regulated gas utilities except MERC-Consolidated incurred some type of DDVC during the FYE16. Total DDVC penalties for all gas utilities decreased by $20,580 (from $121,838 for FYE15 to $101,258 for FYE16), or approximately 17 percent, from the amount reported in FYE15. Only GMG experienced punitive penalties during FYE16. The Department notes that NNG's Penalty Charge Credits received by each utility and included in the true ups for FYE16 are separately shown below in Table G25a.

The Department recognizes that nominations require careful analysis and consistent forecasting methods. Major decisions regarding nominations must be made by 1 p.m. the day before the gas day.[137] An intraday nomination is a nomination electronically submitted after the initial nomination. Intraday nominations may be used to nominate new market or supply and can be used to request increases or decreases in total flow, changes to receipt points, or changes in delivery points of scheduled gas.[138] There are three opportunities to make intraday nominations:

- by 10 a.m. on the gas day (to be effective at 2 p.m. on the gas day);
- by 2:30 p.m. on the gas day (to be effective at 6:00 p.m. on that day); and
- by 7:00 p.m. on the gas day (to be effective at 10:00 p.m. on that day).

[136] Table G23 summarizes the data provided in Department Attachment G14.
[137] See Northern Natural Gas Company's FERC Gas Tariff, Sixth Revised Vol. No. 1, Third Revised Sheet No. 257, issued February 1, 2016.
[138] *Id*. Northern reserves the right to limit acceptance of an intraday nomination on a non-discriminatory basis if system integrity will be placed in jeopardy.

The Department also recognizes that a certain level of positive and negative DDVCs is a natural result of daily weather fluctuation, advance nomination decisions, and limited opportunities to make intraday nominations. Moreover, a utility's ability to make appropriate intraday nominations can be limited by the information the utility has from customers about expected gas use on a particular day. Nevertheless, the Department encourages utilities to continue to use the various available tools to minimize DDVC penalties, such as using pipeline storage facilities and peak-shaving plants or curtailing interruptible customers as discussed further below.

F. REVENUE FROM CURTAILMENT AND BALANCING PENALTIES IMPOSED BY REGULATED MINNESOTA GAS UTILITIES

As discussed above in Section III, part E, utilities must nominate and use interstate pipeline capacity in a responsible manner or face penalties. Thus, utilities established guidelines for responsible system use by transportation and interruptible customers, with penalties for those customers who do not use the gas system in a responsible manner.

All of Minnesota's regulated gas utilities have received Commission approval to implement a number of changes in tariff language that:

- add several special conditions on nominations, balancing, and gas use during curtailments;
- introduce penalties to discourage customers from using gas when service is interrupted; and
- encourage customers to nominate and balance gas supplies responsibly.

Curtailment penalties and balancing penalties are discussed below.

1. Curtailment Penalties

Curtailment penalties are fines imposed by regulated Minnesota gas utilities on interruptible customers who fail to curtail or interrupt their use of natural gas supplies when requested to do so by the utility. It is important that interruptible customers who do not use the gas system in a responsible manner be held financially accountable. When interruptible customers choose to take service under an interruptible tariff, they accept the potential of curtailment in return for lower prices than are charged firm customers. That is, interruptible customers do not pay for demand/capacity costs. If an interruptible customer fails to curtail when notified, the utility (not the individual interruptible customer) may face pipeline penalties too, which, in turn, would raise rates to all customers. Conceptually, failure to curtail also could jeopardize reliable gas service to firm customers. Therefore, the Commission approved utility tariffs under which, if interruptible customers fail to respond to curtailment notices, they are charged curtailment penalties.

Below is a summary of the revenue from curtailment penalties imposed on interruptible customers during FYE16.

Table G24[139]: FYE16
Revenue from Curtailment Penalties

Utility/System	Total Penalties ($)	Percent of Total Penalties (%)	Total Costs Incurred[140] ($)	Penalties as a Percent of Total Costs Incurred (%)
Greater Minnesota	$0	0.00%	$3,923,221	0.0000%
Great Plains	$0	0.00%	$10,915,921	0.0000%
MERC				
Consolidated	$0	0.00%	$19,030,439	0.0000%
NNG	$2,811	100%	$94,624,912	0.0030%
AL	$0	0.00%	$5,465,133	0.0000%
CenterPoint Energy	$0	0.00%	$383,527,682	0.0000%
Xcel Gas	$0	0.00%	$213,484,094	0.0000%
MN Total	**$2,811**	**100.00%**	**$730,971,402**	**0.0004%**

As shown above, one utility imposed curtailment penalties on interruptible (or dual-fuel) customers. Penalties as a percent of total costs ranged from 0 percent (multiple utilities) to 0.0030 percent for MERC-NNG. For the reporting period, the total amount of curtailment penalties was $2,811. This amount is a decrease of $887,255 from the FYE15 figure of $890,066. The Department notes that revenues from curtailment penalties identified above are to be returned to all sales customers as a credit to demand cost in the annual true-ups.

The dramatic decrease in curtailment penalty revenue versus FYE15 is due to the significantly warmer-than-normal weather during the 2015-2016 heating season. The 2014-2015 heating season was moderate with a few curtailment days.

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139 The penalties listed in Table G24 are taken from the utilities' responses to Department Information Request No. 8.

140 The figures listed in the column entitled "Total Costs Incurred" in Table G24 are taken from the gas utilities' true-up filings. Total costs incurred include both demand and commodity costs.

2. *Balancing Penalties*

Balancing penalties are fines imposed by regulated Minnesota utilities on transportation customers who fail to nominate the daily amount of expected gas use within a certain degree of accuracy. For the same reasons cited above for interruptible customers, transportation customers must be held financially accountable if they do not use the gas system in a responsible manner. If a transportation customer fails to nominate correctly, the utility (not the individual transportation customer)[141] may face pipeline penalties, which, all else being equal, in turn raises rates to all customers. Northern considers transportation gas as "the first through the meter" (*i.e.*, the pipeline considers transportation gas to be in balance, and shifts any remaining imbalance to sales customers). To avoid having sales customers subsidize transportation customers, utilities impose balancing penalties on specific transportation customers for their imbalances and credit other customers with the resulting revenues.

Table G25 below contains a summary of the revenues generated from balancing penalties imposed on transportation customers and credited to firm sales customers during FYE16.

Table G25[142]: FYE16
Revenue from Balancing Penalties

Utility/System	Balancing Penalty Rev. ($)	Penalty Rev. as a Percent of Total Penalties (%)	Total Gas Costs Incurred[143] ($)	Penalty Rev. as a Percent of Total Costs Incurred (%)
Greater Minnesota	$477	0.07%	$3,923,221	0.0122%
Great Plains	$49,590	6.81%	$10,915,921	0.4543%
MERC				
Consolidated	$5,629	0.77%	$19,030,439	0.0296%
NNG	$13,062	1.79%	$94,624,912	0.0138%
AL	$0	0.00%	$5,465,133	0.0000%
CenterPoint Energy	$549,895	75.55%	$383,527,682	0.1434%
Xcel Gas	$109,240	15.01%	$213,484,094	0.0512%
MN Total	**$727,893**	**100.00%**	**$730,971,402**	**0.0996%**

[141] This situation is generally the case except for transportation customers who sign "End-User Balancing Agreements" with the interstate pipeline. In such cases, the interstate pipeline directly monitors gas use and directly bills the transportation customer any imbalance charges.
[142] The data provided in Table G25 is taken from the response to Department Information Request No. 9.
[143] The figures listed in the column entitled "Total Costs Incurred" in Table G25 are taken from the gas utilities' Annual True-Up filings. Total costs incurred include demand and commodity costs.

As shown above, the revenue from balancing penalties imposed on transportation customers by gas utilities ranges from $0 reported revenues (MERC-AL) to $549,895 (CenterPoint Energy). The percent of total costs ranges from zero percent (Interstate Gas) to 0.4543 percent (Great Plains). The total amount of balancing penalties was $727,893, which is $99,935 less than last year's amount of $827,828. In addition to the above revenue from balancing penalties, NNG pays an annual Penalty Charge Credit to all shippers on its system. The credits reported as received by each utility for FYE16 were as follows:

Table G25a[144]: FYE16 NNG Penalty Charge Credits by Utility

Greater Minnesota	$716
Great Plains	$0
MERC	
Consolidated	$0
NNG	$58,725
AL	$361
CenterPoint Energy	$503,314
Xcel Gas	$61,153
MN Total	**$624,269**

G. PEAK-DAY PIPELINE TRANSPORTATION SOURCES

In its analysis of gas supply peak-day reliability, the Department considered two factors: (1) the various pipeline companies that deliver gas to Minnesota gas utilities, and (2) the number of suppliers currently serving each gas utility (discussed in the next section). Table G26 below shows the variety and contribution of pipelines supplying peak-day firm transportation capacity to Minnesota utilities. The peak-day capacity for FYE16 was 2,563,151 Mcf, which is a decrease of approximately 0.45 percent (11,482 Mcf) from FYE15.

[144] The data provided in Table G25a is taken from the response to Department Information Request No. 9.

Table G26[145]: FYE16
Summary of Utilities' Gas Supply Transportation Sources
Total Minnesota Peak Quantity

Pipeline	Peak-Day Quantity (Mcf per day)	Peak -Day Quantity Percent of Total
Northern Natural Gas Co.	1,777,090	69.33%
Viking Gas Transmission Co.	202,542	7.90%
Great Lakes Pipeline Co.	29,758	1.16%
Other Pipelines	41,561	1.62%
Peak Shaving & Online Storage	512,200	19.98%
MN TOTAL	**2,563,151**	**100.00%**

The percentage of peak-day capacity provided by each of the above sources remains relatively unchanged from the amounts in FYE15. Northern provides by far the greatest amount of peak-day capacity to Minnesota utilities, with approximately 69.33 percent of the total peak-day capacity. Depending on the specific situation of each utility, the number of different pipelines transporting gas to a particular utility for Minnesota ratepayers ranges from one to five. While some utilities may have greater options than others in their ability to decrease costs by choice of pipeline sources, pipeline differentiation does not appear to impact service reliability.

H. VARIETY OF GAS SUPPLIERS

The number of gas suppliers used during the heating season varies by utility, ranging from 0 to 61 for long-term firm supplies, 1 to 61 for firm spot supplies, and from 0 to 5 for interruptible sources. Table G27 below shows the number of long-term firm, firm spot, and interruptible suppliers used by each utility during the 2015-2016 heating season.

[145] The data provided in Table G26 is taken from the response to Department Information Request No. 4.

Table G27[146]: FYE16
Number of Suppliers

Utility	Firm Long-Term Suppliers	Firm Spot Suppliers	Interruptible Suppliers
Greater Minnesota	0	5	5
Great Plains	4	1	4
MERC[147]	61	61	0
CenterPoint	34	34	0
Xcel Gas	11	23	0

In choosing suppliers, all utilities reported that they carefully review the history and performance of potential gas suppliers. Among the criteria considered are reliability, stability, flexibility, reputation, financial condition, communications quality, price, and non-performance penalties. Most of the utilities then proceed on a trial-and-error basis with a selected supplier, assessing whether the supplier may be relied upon for firm sales requirements. After the utilities are satisfied with the supplier's performance, they sign contracts with particular suppliers based on the lowest bids.

I. CAPACITY RELEASE

Capacity release allows gas utilities with transportation entitlements on a pipeline to relinquish unused and unnecessary capacity for variable periods of time and under various conditions. The Commission typically requires utilities to return to ratepayers all revenues from capacity-release transactions through the annual true-up process.[148] Below is a summary of capacity releases and the associated revenues returned to ratepayers during the true-up period.

[146] Table G27 is based on the utilities' responses to Department Information Request No. 4.
[147] MERC provided the number of suppliers from which they can purchase gas. MERC also stated that no interruptible gas is purchased.
[148] See Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1219, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-95-182, and G012/M-93-1251.

Table G28[149]: FYE16
Capacity Release

Utility/System	Capacity Release (Mcf)	Capacity Release ($)	Revenue Per Mcf ($)	Total Gas Costs Incurred[150] ($)	Revenue as a Percent of Total Gas Costs (%)
Greater Minnesota	153,495	$80,919	$0.5272	$3,923,221	2.0626%
Great Plains	859,574	$81,740	$0.0951	$10,915,921	0.7488%
MERC					
Consolidated	1,804,458	$68,811	$0.0381	$19,030,439	0.3616%
NNG	11,014,165	$2,512,971	$0.2282	$94,624,912	2.6557%
AL	150,000	$3,767	$0.0251	$5,465,133	0.0689%
CenterPoint Energy	6,526,801	$325,893	$0.0499	$383,527,682	0.0850%
Xcel Gas	1,390,308	$408,418	$0.2938	$213,484,094	0.1913%
MN Total	**21,898,801**	**$3,482,519**	**$0.1590**	**$730,971,402**	**0.4764%**

Table G28 shows the large diversity in Minnesota for capacity-release transactions, capacity portfolios, and individual situations of each gas utility. The revenue from capacity release ranges from $3,767 for MERC-AL to $2,512,971 for MERC-NNG. As a percent of total gas costs, the capacity-release revenues ranged from 0.0689 percent for MERC-AL to 2.6557 percent for MERC-NNG. Utilities returned a total of $3,482,519 to ratepayers in the true ups in FYE16 compared to the FYE15 amount of $1,219,268. Although the revenue increased in FYE16, the total volumetric capacity-release figures increased only slightly from 21,421,441 Mcf to 21,898,801 Mcf between the FYE15 and FYE16 reporting periods (i.e. a relatively similar level of capacity was released, but at a higher price).

The relative stability in capacity release volume correlates with Table G20, as the actual firm capacity requirement was 75 percent of total capacity on the peak day. The significant increase in capacity release dollars is driven primarily by MERC-NNG. A conversation with MERC revealed two main drivers: the gas supply group at MERC was more aggressive in pursuing capacity release in the 2015-2016 gas year; and the value of its Northern Border capacity increased significantly during the reporting year.

[149] The data listed in Table G28 is based on the utilities' responses to Department Information Request No. 6.
[150] The data listed in the column entitled "Total Cost Incurred" is taken from the gas utilities' AAA filings. Total costs incurred include demand and commodity costs.

J. ANNUAL AUDITOR REPORTS

All regulated utilities are required by Minnesota Rule 7825.2820 to submit an independent auditor's report by September 1 of each year that evaluates the accounting for automatic adjustments for the prior year. Regarding Commission-ordered audit requirements, beginning with the FYE99 AAA report, the Commission has annually required that the gas utilities meet with their independent auditors prior to the auditors' examinations concerning the companies' AAA reports, to review audit procedures and Minnesota Rule 7825.2820.[151] Additionally, the Commission requires gas utilities to direct their independent auditors to include, as one of their procedures, an examination of any significant variations between purchased volumes (per invoices) and sales volumes per the general ledger sales journal.[152] The Commission also requires all gas utilities to continue to have independent auditors verify in writing in their AAA reports that the actual amounts included in the true-up calculations agree with the utilities' accounting books and records.[153]

All gas utilities submitted auditor's reports in compliance with Minnesota Rule 7825.2820. The Department reviewed each auditor's report filed and notes that there were no exceptions indicated by the auditors.

K. LOST-AND-UNACCOUNTED-FOR GAS

Ordering Paragraph 5 in the Commission's April 7, 2011 *Order* in the FYE10 AAA Report requested that the Department continue to develop and report a summary and comparison of each regulated natural gas utility's lost-and-unaccounted-for (LUF) gas percentages and to include a table or attachment that includes the data used in the calculations of the LUF percentages.

Using the formula from the U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration's Form 7100.1-1 to calculate the LUF percentages,[154] the Department developed a comparison of LUF gas by utility. Table G29 below presents the Department's summary of LUF gas percentages for the period July 1, 2015 to June 30, 2016 for Minnesota jurisdictional volumes.

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[151] See Docket Nos. G,E999/AA-98-1130, G,E999/AA-99-1095, G,E999/AA-00-1027, G,E999/AA-01-838, G,E999/AA-02-950, and G,E999/AA-03-1264.
[152] See Docket No. G,E999/AA-97-1212.
[153] See Docket No. G,E999/AA-96-940.
[154] The formula is as follows: [(purchased gas + produced gas) minus (customer use + utility use + appropriate adjustments)] divided by (purchased gas + produced gas) equals percent LUF.

Table G29[155]: FYE16
Lost-and-Unaccounted-For Gas

Utility/System	**Revenue as a Percent of Total Gas Costs (%)**
Greater Minnesota	(1.31)%
Great Plains	
North	1.44%
South	0.53%
MERC	
Consolidated	0.25%
NNG	(1.46)%
Albert Lea	1.78%
CenterPoint Energy	1.89%
Xcel Gas	2.72%
MN Weighted Avg.	**1.77%**

A negative LUF number means that a utility, in effect, "found" gas. As shown in Table G29 above, MERC-NNG and GMG reported negative LUF during the reporting period. As shown in Table G29, the LUF gas ranged from a negative 1.46 percent for MERC-NNG to a positive 2.72 percent for Xcel Gas. The Minnesota weighted average was 1.77 percent.

Regarding MERC-NNG's reported negative LUF, MERC has had a long, and well-documented, history of negative LUF. Please see LUF discussions in the Department's Reports in Docket Nos. G999/AA-09-896 and G999/AA-14-580.

In its previous AAA Report, GMG reported LUF of 0.80 percent, while this year, it reported negative 1.31 percent. The Department requests that GMG provide a discussion in its Reply Comments explaining how GMG came to have "found" gas on its system during FYE16.

The Department concludes that FYE16 LUF percentages are reasonable, contingent on GMG's response in its Reply Comments.

L. REPORTING OF CONTRACTOR MAIN STRIKES AND METER TESTING

In its October 11, 2012, *Order Accepting Progress Reports and Meter Testing Plans* in Docket No. G999/AA-10-885, the Commission required all gas utility companies to file, as part of their

155 See Attachment G19 for detailed calculations.

annual AAA reports, a schedule reflecting the contractor main strikes during the corresponding annual period billings to at-fault contractors. The Commission specifically required that the schedules reflect the date, party involved, repair cost amount, and gas lost amount for each incident. Additionally, the Commission required the utilities to file any updates regarding meter testing within an annual period in their AAA reports starting in 2012.

1. Contractor Main Strikes Reports

Regarding contractor main strikes reports, all of the gas utilities filed the required information.[156] The Department reviewed the reports. In its FYE14 AAA Report, the Department stated that the reports would be more meaningful if the total gas cost charged for main strikes during the period reconciled to the amount in the true up and also if the reports provide the allocation of the gas costs credited to each class in its true up. All of the utilities totaled the gas cost charged for main strikes and indicated how the contractor main strike revenue was treated in the FYE16 true up, therefore complying with the requirement.

2. Meter Testing Updates

Regarding meter testing updates, all of the gas utilities filed the required information with their AAA Reports.

GMG stated:

> GMG's meter testing program has not changed since its comprehensive meter testing plan was approved by the Commission. GMG continues to sample and test at least 20 meters annually. No material problems have been identified during meter testing that demonstrate any trends in meter accuracy or systemic bias by type or size of meter.

Great Plains explained that the 2016 revisions to its Gas Distribution Standards, Section 7, did not affect the meter testing plan. Great Plains provided a red-line copy of its tariff in its Exhibit E. The Department reviewed the revisions and confirms that the revisions did not affect the meter testing plan.

MERC stated that for all of its PGA systems:

[156] See GMG's AAA Report, page 5, Great Plains' AAA Report, Exhibit D, MERC's AAA Reports, Schedule Q, CenterPoint Energy's AAA Report, Exhibit 9 and Xcel Gas' AAA Report, Attachment G, Schedule 7.

> During the time period of January 1, 2015 through December 31, 2015, MERC tested 4,951 meters as part of its meter testing program. Of those meters tested, 4,533 (91.6%) tested between 98% and 102% accurate, 339 meters (6.8%) tested greater than 102% accurate, 73 meters (1.5%) tested less 98% accurate and 6 meters (1%) had no test due to the meter being damaged.[157]

CenterPoint Energy stated:

> CenterPoint Energy continued its meter testing and management program in 2015. Meter samples and tests are conducted over a two year period and the current interval ending 2015 was reviewed. All of the meter lots evaluated are passing the accuracy expectations. As part of the meter management program of previously failed meter lots, the Company exchanged 7,558 'failed' meters during 2015 and year to date through June 2016, 4,426 meters have been exchanged. This work is ahead of the overall replacement plan. The work plan for 2017 has targeted about 3,500 additional meters to be exchanged as previously identified meter groups requiring attention.[158]

Xcel Gas stated that "There were no changes regarding meter testing within the annual reporting period of July 1, 2015 and June 30, 2016."[159]

The Department concludes that the utilities complied with the Commission's Order.

M. MINNESOTA GAS UTILITIES' PURCHASING PRACTICES

In its August 11, 2014 *Order* in Docket No. 13-600, as part of Order Point No. 3, the Commission requested the Department to provide a review of gas purchasing practices to be included in future annual automatic adjustment reports. Specifically, the Commission requested a discussion of the Department's portfolio analysis (gas purchasing practices) and storage rates analysis (discussed in Section N).

The Department analyzes gas procurement in various ways throughout the year, for example:

- review of the utilities' PGAs and filing of subsequent reports;

[157] MERC-NNG's, MERC-CON's and MERC-AL's AAA Reports, pages 8-9.
[158] CenterPoint Energy's AAA Report, page 22.
[159] Xcel Gas' AAA Report, Attachment G, page 11.

- individual meetings with utilities regarding their respective procurement plans for the upcoming year; and
- annual winter pricing recap presentations by the utilities for the Commission.

The Department notes that purchasing practices differ between utilities based on resources available. CenterPoint Energy, MERC, and Xcel Gas use hedging. Great Plains North does not have access to storage, and GMG procures storage only for balancing purposes. Utilities that have peak shaving facilities are CenterPoint Energy and Xcel Gas.[160] GMG uses outside sources to assist in managing its gas resource portfolio.[161] Thus, each gas supply portfolio is unique to the utility.

As discussed in Section I, the weather in FYE16, including the heating season, was warmer than normal. Additionally, natural gas prices were lower in FYE16 than in FYE15 and decreased during the reporting period. At a high level, ranking the annual non-weighted averages of the various types of gas purchase prices by the Minnesota regulated gas utilities creates the following order of prices from lowest to highest for the FYE16: [162]

1) Daily spot-priced gas[163] at $2.3236 per Mcf;
2) Daily index-priced gas[164] at $2.4000 per Mcf;
3) Monthly index-priced gas[165] at $2.5071 per Mcf; and
4) Fixed Price Gas at $2.6503 per Mcf.

To show the various purchasing approaches, the following table compares the percentages of each type of gas purchase (*i.e.*, monthly index-priced gas, daily index-priced gas, monthly spot-priced gas, daily spot-priced gas) to each utility's total portfolio for the FYE16 heating season.

[160] Department Information Request No. 12.
[161] GMG's AAA Report, page 2.
[162] The data is taken from the response to Department Information Request No. 5. Hedging costs are included in the cost of monthly index-priced gas for CenterPoint Energy, MERC, and Xcel Gas.
[163] Daily spot-priced gas purchases refers to gas purchased on the daily spot market, at market prices under a contract that is in effect for only one day or purchase, and delivered to the utility's city gate.
[164] Daily index-priced gas refers to gas purchased under a term contract at a price that is based on and varies with a daily index price at a major trading point (*e.g.*, Demarc, Ventura) and is delivered to the utility's city gate.
[165] Monthly index-priced gas refers to gas purchased under a term contract longer than one day that establishes the price at which the gas will be purchased each month of the contract based upon indexes published on the first day of each month for gas purchased at a major trading point (*e.g.*, Demarc, Ventura) and delivered to the utility's city gate.

**Table G30[166]: FYE16
Portfolio Composition for the Heating Season
(Components as a Percent of Actual Purchases)**

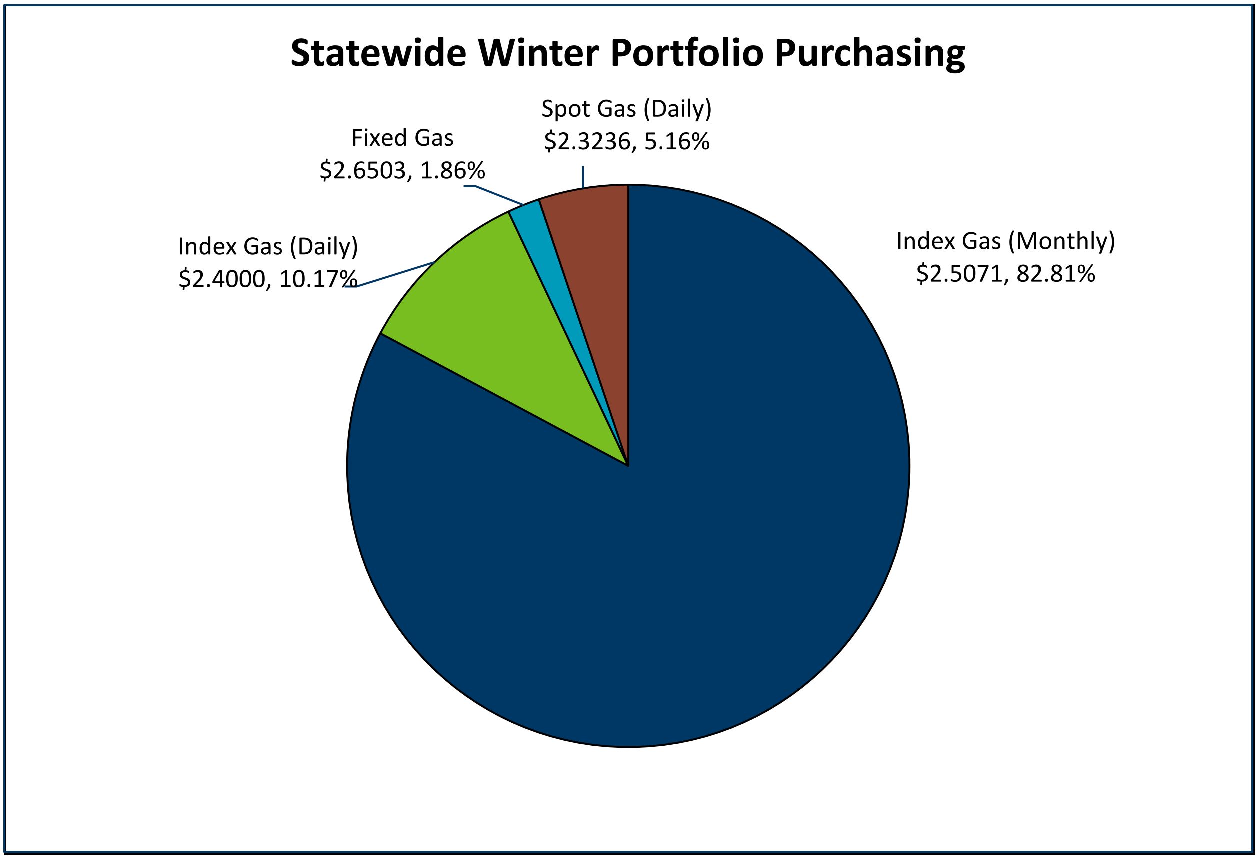
Utility/System	All Gas Purchases	Index Gas (Monthly)	Index Gas (Daily)	Spot Gas (Monthly)	Spot Gas (Daily)	Fixed Gas
Greater Minnesota	100.00%	67.03%	32.97%	0.00%	0.00%	0.00%
Great Plains						
North	100.00%	86.16%	0.00%	0.00%	13.84%	0.00%
South	100.00%	78.79%	0.00%	0.00%	21.21%	0.00%
MERC						
Consolidated	100.00%	94.48%	5.13%	0.00%	0.39%	0.00%
NNG	100.00%	96.79%	2.98%	0.00%	0.23%	0.00%
Albert Lea	100.00%	96.74%	3.02%	0.00%	0.24%	0.00%
CenterPoint Energy	100.00%	82.22%	2.85%	0.00%	0.07%	14.86%
Xcel Gas	100.00%	60.29%	34.44%	0.00%	5.27%	0.00%

Monthly index-priced gas as a percent of the winter portfolio ranged from a low of approximately 60.29 percent (Xcel Gas) to a high of 96.79 percent (MERC-NNG). Of the utilities that purchased daily index-priced gas during the heating season, the percent of the portfolio ranged from a low of 2.85 percent (CenterPoint Energy) to a high of 34.44 percent (Xcel Gas). None of the utilities bought monthly spot gas during the heating season. All of the utilities except Greater Minnesota bought daily spot gas in the winter ranging from a low of 0.07 percent (CenterPoint Energy) to a high of 21.21 percent (Great Plains South). CenterPoint Energy was the only utility that bought fixed price gas at 14.86 percent of its winter portfolio. Comparing Table G30 to Table G16, which shows the actual annual commodity rates, Great Plains purchased the highest percentage of daily spot gas and had the lowest annual average commodity costs per Mcf at $2.2913 and $2.4517 for the North and South Districts, respectively.

Using the annual purchase prices and non-weighted average heating season percentages for FYE16, Graph 2 below illustrates the following statewide regulated natural gas utilities' portfolio make-up:

[166] The information for Table G30 can be found in each of the utility's response to Department Information Request No. 5(c).

Graph 2



In sum, Minnesota gas utilities relied most heavily on monthly index-priced gas, daily spot-priced gas, and daily index-priced gas. Minnesota weather was warmer than normal for the 12 months ending June 30, 2016 and market prices decreased steadily during the FYE16.[167]

N. PER-UNIT STORAGE COST OF GAS AND PERCENTAGE OF STORAGE

Using data from Department Information Request No. 11, the Department compared the non-weighted average FYE16 per-unit storage cost of gas for the individual utilities.[168] Additionally, using data from Department Information Request No. 5(c), the third column shows, by utility,

[167] Storage gas is not shown in Table G30 since storage gas includes all methods, or types, of purchased gas. Thus, storage gas is a subset of total gas purchases and its price is determined by the cost of various types of purchased gas.

[168] Both CenterPoint Energy and Xcel Gas confirmed that, although they consider their storage detail to be trade secret, their total storage rate is public information. Further, Xcel Gas confirmed that its storage percentage is public information.

the percentage of storage used, or withdrawn, during the reporting period compared to the utility's total gas portfolio. The results are shown below in Table G31.

Table G31[169]: FYE16
Actual Per Unit Storage Cost and Percentage of Storage

Utility/System	Storage Costs ($/Mcf)	Percent of Winter Portfolio Comprised of Storage (%)
Greater Minnesota	$2.99	18.03%
Great Plains		
North[170]	$0.00	0.00%
South	$2.72	27.10%
MERC		
Consolidated	$2.21	22.50%
NNG	$2.78	28.52%
AL	$2.69	30.51%
CenterPoint Energy	$2.95	31.03%
Xcel Gas	$2.77	35.51%
MN Weighted Avg.	**$2.85**	
MN Non-Weighted Avg.	**$2.73**	

Table G31 indicates that the actual storage costs, for utilities that used storage for purposes other than balancing, ranged from a low of $2.21 per Mcf for MERC-Consolidated to a high of $2.95 per Mcf for CenterPoint Energy. The Minnesota non-weighted average cost of storage was $2.73 per Mcf. Additionally, the percentage of storage gas withdrawn during the winter as part of the utility's total winter volumes ranged from a low of 18.03 percent for Greater Minnesota to a high of 35.51 percent for Xcel Gas. Thus, 35.51 percent of Xcel Gas's total portfolio for FYE16 was storage gas withdrawn at an average cost of $2.77 per Mcf.

Certain qualifications should be considered when comparing storage costs. For instance, a trade-off between price and reliability applies to storage supplies. Gas supplies in storage fields are often a step removed from gas-producing fields and gathering facilities, thereby providing a greater reliability of supplies during sustained cold periods that may affect wells in the production fields. While gas injected into storage during the non-heating season generally costs less than gas purchased during the heating season (excluding outside factors affecting the

[169] The storage costs listed in this table relate to total storage costs for the entire reporting period, while the portfolio percentages relate solely to those used during the five-month heating season.
[170] Storage is not available for Great Plains North.

natural gas industry that may lead to unusual price fluctuations, which occurred during FYE09), the added cost of using storage facilities and services may result in a higher final per-unit price of the storage gas than gas purchased during the heating season directly from the supplier. However, utilities have more control in using their own storage gas during peak situations. Therefore, the trade-off between price and reliability should be an important consideration in each utility's gas portfolio decisions.

O. MINNESOTA GAS UTILITIES' HEDGING PRACTICES

In its August 11, 2014 *Order Accepting Gas Utilities' Annual Reports and 2012-2013 True-Up Proposals and Setting Further Requirements* in Docket No. 13-600, the Commission requested that the Department provide a review of hedging practices in its review of future annual automatic adjustment reports. Additionally, at its February 4, 2016 Commission Agenda meeting regarding CenterPoint Energy's hedging variance filing in Docket No. G008/M-15-912, the Commission expressed interest in taking a closer look at utility hedging practices given the current state of the natural gas market. On June 28, 2016, the Commission held a Planning Meeting to discuss hedging. A presentation was provided by the utilities that participate in hedging (CenterPoint, MERC, and Xcel).

Background

The goal of hedging is to use appropriate strategies to minimize the risk of cost increases for any given degree of reduced volatility. In a sense, a hedge is an insurance policy that, for a fee, protects utilities (and their ratepayers) against a specific (unfavorable) event occurring during the term of a policy. (An example of such an event is when Hurricane Katrina devastated Southern States, including areas where natural gas facilities were located. Natural gas costs skyrocketed immediately.) Hedging can be used to reduce gas price risk by generating a payment in the event that the market price of natural gas moves in an unfavorable (and unpredicted) direction. There are a number of hedging tools/instruments available in the derivative market such as futures contracts, commodity swaps, "costless" collars, and options.[171]

Three Minnesota LDCs have received Commission approval to recover the costs of financial hedging through their PGAs: CenterPoint Energy, MERC, and Xcel Gas. The Commission also orders financial hedging restrictions based on utility-specific circumstances and information. A more thorough analysis is performed for CPE, MERC, and Xcel Gas in the utilities' respective variance filings, which allow these companies to recover hedging costs through their PGA filings.

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[171] Definitions and examples of each tool are provided in the glossary that is included as Attachment G3.

Weather and various supply issues play a significant role in the commodity price of natural gas, especially during the heating season of November through March. As previously discussed in Section 1.C. *Natural Gas Prices and Weather*, the 2015-2016 heating season was warmer than normal. Further, the natural gas prices decreased during the reporting period. In FYE16, the gas storage inventory level that was at or above the five-year *average* from July until November 2015, when the storage level remained at or above the five-year *high* through June 2016.

Based on the 2015-2016 heating season, the Department expected that CPE, MERC, and Xcel Gas would experience losses on the hedge portion of their purchase portfolios. The following discussion reviews the performance of each utility's hedging program against this expectation.

MERC

MERC uses a 40%/30%/30% hedging strategy to mitigate price volatility and provide reasonably priced natural gas; 40 percent of normal winter requirements are purchased at fixed price, 30 percent are purchased using financial derivatives, and 30 percent are purchased at market rates.[172] This strategy is not one to guarantee the lowest priced gas but to mitigate price volatility, provide reasonably priced natural gas and ensure reliability.[173]

In Docket No. G011/M-15-231, MERC was granted an extension to its variance to recover the costs associated with certain financial instruments through the PGA through June 30, 2017. In Docket No. G011/M-17-85, MERC was granted an additional extension to its variance through June 30, 2021. For details on previous variance dockets and compliance requirements, please see Section II.D.2 *Compliance and/or Supplemental Reporting Requirements*.

For the 2014-2015 heating season, MERC fulfilled its 40 percent fixed price strategy through a combination of pipeline storage and financial futures. MERC procured 30 percent using financial derivatives through Call Options backed physically by first-of-month (FOM) index supply, and 30 percent at market rates usingFOM index supply and the spot market.[174]

In its response to the Department's Information Request No. 15(H), MERC stated that there were no changes to the financial hedging program compared to FYE15.

MERC's hedges provided a financial loss in FYE16 mainly due to the lower prices experienced in the winter months than in the preceding injection season. Since there were no external factors that caused a price spike, this outcome is to be expected. The Department concludes that MERC accomplished its intended purpose of providing reasonable price protection on a portion

[172] MERC's *2016 Annual Automatic Adjustment Report*, pages 1-2.
[173] *Id.*, page 2.
[174] *Id.*, page 2.

of its winter gas supplies, based on the information the company had at the time it executed its hedges.

CenterPoint Energy

CenterPoint Energy's policy is to provide price stabilization for a portion of its winter supply through hedge gas purchases and storage gas, to provide protection against volatile gas prices. The level of stabilization to be achieved is re-determined each year based on analysis that incorporates regulatory guidelines (as to volumes and costs), winter price projections, and available portfolio assets.[175]

In Docket No. G008/M-15-912, CenterPoint Energy was granted an extension to its variance to recover the costs associated with certain financial instruments through the PGA through June 30, 2020. For details on previous variance dockets and compliance requirements, please see Section II.E.2 *Compliance and/or Supplemental Reporting Requirements*.

Regarding its hedging strategy for the 2015-2016 winter season, CPE stated,[176]

> Natural gas prices (as represented by First of Month Ventura prices) peaked in August, and each of the winter months were lower than all of the summer months' pricing. Monthly settle prices for Ventura receipts averaged $2.63 for summer 2015 and $2.17 for winter 2015-2016. Contract storage allows for the purchase of gas during summer months when prices are typically lower, and withdrawal for system use during winter months resulting in a natural price hedge. Although the summer-winter differential this past year did not provide savings from FOM market based rates, they continued to provide valuable upside price protection from any daily swings in Ventura swing supplies. Storage also provided daily operational benefits for which it was purchased. Storage volumes (pipeline and on-system combined) represented 25.6% of the winter system supplies. Physical base load gas purchases containing price protections were made over several months during the summer using multiple RFP's. CenterPoint Energy purchased 26.0 Bcf of total hedged supply and, when combined with 19.8 Bcf of storage volumes (including nearly 1.4 Bcf of Underground storage classified as peaking volumes), provide stabilized prices for 59.3% of winter gas supplies. In addition to

[175] CenterPoint Energy's *Annual Automatic Adjustment Report*, page 5.
[176] *Id.*, pages 5-6.

> providing price stability, the price hedges also provide catastrophic price protection against price fly-ups during unforeseen events such as upstream pipeline ruptures and prolonged extremely cold weather.

According to CenterPoint Energy, hedged gas purchases added approximately $15.5 million (or $0.148 per dekatherm) to CenterPoint Energy's customers' costs during the winter period when compared to buying gas at actual First of Month index pricing.[177]

In its response to the Department's Information Request No. 15(H), CenterPoint Energy stated that there was no significant change in its hedging program from the previous year.

CenterPoint Energy's hedges provided a financial loss in FYE16 due to the lower prices experienced in the winter months; again, since there was no external factor causing prices to spike, this outcome is to be expected. The Department concludes that CenterPoint Energy accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

Xcel Gas

The overall goal of Xcel's Price Volatility Mitigation Plan is to reduce the exposure to and the magnitude of gas price spikes at a reasonable cost to its customers. The goal of the plan is not to attempt to outguess the market or to speculate on the future direction of energy prices.[178] The purpose of Xcel's seasonal strategy is to reduce the potential risk of short-term upsets in the wholesale gas markets and the resulting gas price spikes.[179]

In Docket No. G002/M-16-88 (Docket 16-88), Xcel Gas was granted an extension to its variance to recover the costs associated with certain financial instruments through the Purchased Gas Adjustment (PGA) through June 30, 2020. For details on previous variance dockets and compliance requirements, please see Section II.F.2 *Compliance and/or Supplemental Reporting Requirements*.

In its response to the Department's Information Request No. 15(H), Xcel Gas stated that there were no changes to the financial hedging program for the period July 1, 2015 through June 30, 2016.

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[177] *Id.*, page 9.
[178] Xcel Gas' *Annual Automatic Adjustment of Charges Report*, Attachment A, Schedule 5, page 2.
[179] *Id.*, page 4.

Xcel Gas' hedges provided a financial loss of approximately $5.38 million in FYE16 due to the lower prices experienced in the winter months, which is to be expected as noted above. The Department concludes that Xcel Gas accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

Conclusion and Recommendations

As discussed above, each of the utilities experienced losses due to hedging during FYE16. While this is a loss to ratepayers given the lack of an adverse event during this time period, ratepayers had protection in place in case such an event occurred. Moreover, the Department observes that the natural gas purchases covered by hedges were only a portion of the total winter requirements purchased. The ultimate goal of hedging is to reduce price volatility on a percentage of the utilities' purchase portfolios, not to speculate or make money on commodity prices.

The Department concludes that the utilities' hedging programs performed as expected. The Department recommends that each utility that hedges (including physical and financial) continue to provide a post-mortem analysis, in a format similar to what was provided in this docket, in subsequent AAA filings.

P. DISTRIBUTION PLANNING

In its consideration of the FYE15 AAA Report, the Commission requested that the Department address distribution planning in the next AAA report. The Department issued Information Request No. 18 in this instant docket, in order to collect the relevant data. All utilities responded, however due to staffing and workload constraints, the Department has not yet analyzed this data. The Department's goal is to provide its analysis in a future round of response comments. The following items are the contents of the Department's Information Request No. 18:

A. Please provide a detailed discussion of how the utility plans, constructs, and maintains its distribution system. As part of this response, include a discussion about how the utility decides to add capacity or expand into new, or growing, service territory.
B. Please provide daily throughput data, by each individual Town Border Station (TBS) or delivery point, on the utility's system since November 1, 2012. If available, please provide these data divided by firm, interruptible, and transport load. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
C. Please provide the number of interruption days, by TBS or delivery point, by month since November 2012. To the extent possible, please identify the number of

interruption days that are non-weather related (*e.g.,* reliability purposes). Please also provide these data in Microsoft Excel format with all links, and formulae intact.

D. Please provide, on a daily basis since November 1, 2012 by TBS or delivery point, the maximum deliverable throughput by customer type. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
E. Please provide, by TBS or delivery point, on a daily basis since November 1, 2012 the percentage of deliverable capacity subscribed by the utility. If applicable, please identify other parties, and their percentages of subscribed capacity, at the TBS. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
F. Please provide the following forecasted data, in Microsoft Excel format with all links and formulae intact, by TBS, or delivery point, for the next three heating seasons. If the utility expects daily fluctuation, please provide these data on a daily basis:
    a. Total utility throughput, if possible, divided by customer type (*i.e.*, firm, interruptible, transport); and
    b. Expected firm and total throughput available at the TBS or delivery point.
G. Please provide maps, by county, identifying the location (and name) of any, and all, TBSs or delivery points on the utility's system. If possible, please provide these maps in pdf and GIS executable formats.
    a. Please identify, by county, on the maps in Part F, the location of any, and all, transmission assets on the utility's system.

If the utility has an affiliate transmission or intrastate pipeline utility, please also identify these assets on the maps provided in Part F, by county.

IV. SUMMARY OF THE DEPARTMENT'S RECOMMENDATIONS

The Department includes a number of specific recommendations for future annual automatic adjustment reports to ensure full compliance with Commission Orders and Minnesota Rules 7825.2700 and 7825.2910, and to improve accountability. The Department summarizes its recommendations below.

1. The Department recommends that the Commission accept the FYE16 annual reports as filed by the gas utilities as being complete as to Minnesota Rules 7825.2390 through 7825.2920.

2. The Department recommends each utility that hedges (including physical and financial) continue to provide a post-mortem analysis, in a format similar to what was provided in this docket, in subsequent AAA filings.

A. GREATER MINNESOTA

The Department recommends that the Commission:

- accept GMG's FYE16 true-up as filed in Docket No. G022/AA-16-715; and
- allow GMG to implement its true-ups, as shown in DOC Attachment G5 of the FYE16 AAA Report.

Additionally, the Department requests that GMG provide a discussion in its Reply Comments explaining how GMG came to have "found" gas on its system during FYE16.

B. GREAT PLAINS

The Department recommends that the Commission:

- grant Great Plains' requested one-time variance to Minnesota Rules 7825.2700, subparts 4 and 7 to allow it to spread its cumulative under-recovered commodity cost from its large interruptible customer class to all customer classes based on the pro-rata share of current project annual dekatherm sales;
- accept Great Plains' FYE16 true-ups, Docket No. G004/AA-16-719; and
- allow Great Plains to implement its true-ups, as shown in DOC Attachments G6a and G6b of the FYE16 AAA Report.

C. MERC

The Department recommends that the Commission:

- find that MERC has met the criteria under Minn. R. 7829.3200 and grant MERC's requested variances to Minn. R. 7825.2700, 7825.2910, and 7825.2820. In the interest of completeness, the Commission may want to consider varying Minn. R. 7825.2800, 7825.2810, 7825.2830, and 7825.2840 in addition to the rules requested by MERC;
- accept MERC-NNG's FYE16 true-up filing in Docket No. G011/AA-16-732;
- allow MERC-NNG to implement its true-up, as shown in Department Attachment G8 of the FYE16 AAA Report;
- accept MERC-CON's FYE16 true-up filing in Docket No. G011/AA-16-734;
- allow MERC-Consolidated to implement its true-up, as shown in Department Attachment G9 of the FYE16 AAA Report;
- accept MERC-AL's FYE16 true-up filing in Docket No. G011/AA-16-733; and
- allow MERC-AL to implement its true-up, as shown in Department Attachment G8a of the FYE16 AAA Report.

*D.	CENTERPOINT ENERGY*

The Department recommends that the Commission:

- accept CenterPoint Energy's FYE16 true up, Docket No. G008/AA-16-730; and
- allow CenterPoint Energy to implement its true up, as shown in Department Attachment G10 of the FYE16 AAA Report.

Additionally, the Department agrees with CenterPoint that Exhibit 6B is not necessary as long as its swing gas is valued at the spot market price. The Department recommends that the Commission allow CenterPoint to discontinue this portion of the financial call options compliance until such time that it is relevant again.

*E.	XCEL GAS*

The Department recommends that the Commission:

- accept Xcel Gas' FYE16 true-up, Docket No. G002/AA-16-725; and
- allow Xcel Gas to implement its true-up, as shown in Department Attachment G11 of the FYE16 AAA Report.

/lt

FYE16
RECORDED UNWEIGHTED HEATING DEGREE DAYS

Annual Data											
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2010-2011	Season 2011-2012	Season 2012-2013	Season 2013-2014	Season 2014-2015	Season 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)	2015-2016 vs. Prior 5-Yr. Avg.
DULUTH	9,709	9,444	9,514	7,635	9,366	10,342	9,276	8,186	-15.69%	-13.32%	-11.28%
INTERNATIONAL FALLS	10,216	10,221	10,303	8,424	10,713	11,511	10,283	8,995	-11.95%	-11.99%	-12.22%
FARGO, ND	9,019	8,802	9,311	6,840	9,403	9,679	8,469	7,172	-20.48%	-18.52%	-17.94%
ST CLOUD	8,744	8,532	8,716	6,744	8,872	9,524	8,143	7,170	-18.00%	-15.96%	-14.64%
MPLS/ST PAUL	7,805	7,580	7,708	5,924	7,708	8,597	7,528	6,283	-19.50%	-17.11%	-16.15%
ROCHESTER	8,150	7,722	7,927	6,066	7,825	8,917	8,068	6,796	-16.61%	-11.99%	-12.43%
SIOUX FALLS, SD	7,683	7,706	8,057	6,058	7,884	8,320	7,568	6,380	-16.96%	-17.21%	-15.80%

Winter Data (November 2015 - March 2016)											
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2010-2011	Season 2011-2012	Season 2012-2013	Season 2013-2014	Season 2014-2015	Season 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)	2015-2016 vs. Prior 5-Yr. Avg.
DULUTH	7,169	6,952	7,097	5,716	6,822	8,028	7,145	6,046	-15.66%	-13.03%	-13.15%
INTERNATIONAL FALLS	7,728	7,589	7,776	6,165	7,747	8,869	7,691	6,574	-14.93%	-13.37%	-14.06%
FARGO, ND	7,145	7,589	7,545	5,534	7,226	7,849	6,873	5,758	-19.41%	-24.13%	-17.81%
ST CLOUD	6,853	6,665	7,005	5,340	6,731	7,724	6,583	5,609	-18.15%	-15.84%	-15.99%
MPLS/ST PAUL	6,295	6,108	6,399	4,864	6,040	7,117	6,257	5,121	-18.65%	-16.16%	-16.53%
ROCHESTER	6,437	6,136	6,484	4,862	6,052	7,297	6,553	5,427	-15.69%	-11.55%	-13.16%
SIOUX FALLS, SD	6,157	6,105	6,538	4,882	6,037	6,813	6,278	5,274	-14.34%	-13.61%	-13.68%

Source: U of M Monthly Heating & Cooling Summary Tables
http://www.climate.umn.edu/cawap/eddsum/eddsum.asp
Old website (above) was replaced with the following in 2014:
http://www.dnr.state.mn.us/climate/historical/energy.html

RECORDED UNWEIGHTED HEATING DEGREE DAYS

Source: U of M Monthly Heating & Cooling Summary Tables http://www.climate.umn.edu/cawap/eddsum/eddsum.asp

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)
	DULUTH	July	67	63	15	-77.61%	-76.19%
		August	100	86	81	-19.00%	-5.81%
		September	328	298	149	-54.57%	-50.00%
		October	662	678	574	-13.29%	-15.34%
		November	1,120	1,088	844	-24.64%	-22.43%
		December	1,599	1,556	1,187	-25.77%	-23.71%
		January	1,775	1,699	1,611	-9.24%	-5.18%
		February	1,435	1,399	1,376	-4.11%	-1.64%
		March	1,240	1,210	1,028	-17.10%	-15.04%
		April	788	762	809	2.66%	6.17%
		May	413	426	370	-10.41%	-13.15%
		June	182	179	142	-21.98%	-20.67%
	TOTALS		9,709	9,444	8,186		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)
	INTERNATIONAL FALLS	July	52	70	47	-9.62%	-32.86%
		August	96	111	129	34.38%	16.22%
		September	354	353	220	-37.85%	-37.68%
		October	712	743	665	-6.60%	-10.50%
		November	1,206	1,184	945	-21.64%	-20.19%
		December	1,751	1,714	1,313	-25.01%	-23.40%
		January	1,942	1,878	1,696	-12.67%	-9.69%
		February	1,540	1,530	1,517	-1.49%	-0.85%
		March	1,289	1,283	1,103	-14.43%	-14.03%
		April	767	772	826	7.69%	6.99%
		May	370	419	367	-0.81%	-12.41%
		June	138	164	167	21.01%	1.83%
	TOTALS		10,217	10,221	8,995		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)
	*FARGO**	July	16	16	12	-25.00%	-25.00%
		August	34	34	32	-5.88%	-5.88%
		September	239	220	97	-59.41%	-55.91%
		October	603	606	444	-26.37%	-26.73%
		November	1,131	1,086	856	-24.31%	-21.18%
		December	1,609	1,578	1,290	-19.83%	-18.25%
		January	1,802	1,728	1,597	-11.38%	-7.58%
		February	1,435	1,410	1,195	-16.72%	-15.25%
		March	1,168	1,152	820	-29.79%	-28.82%
		April	646	626	626	-3.10%	0.00%
		May	265	273	176	-33.58%	-35.53%
		June	71	73	27	-61.97%	-63.01%
	TOTALS		9,019	8,802	7,172		

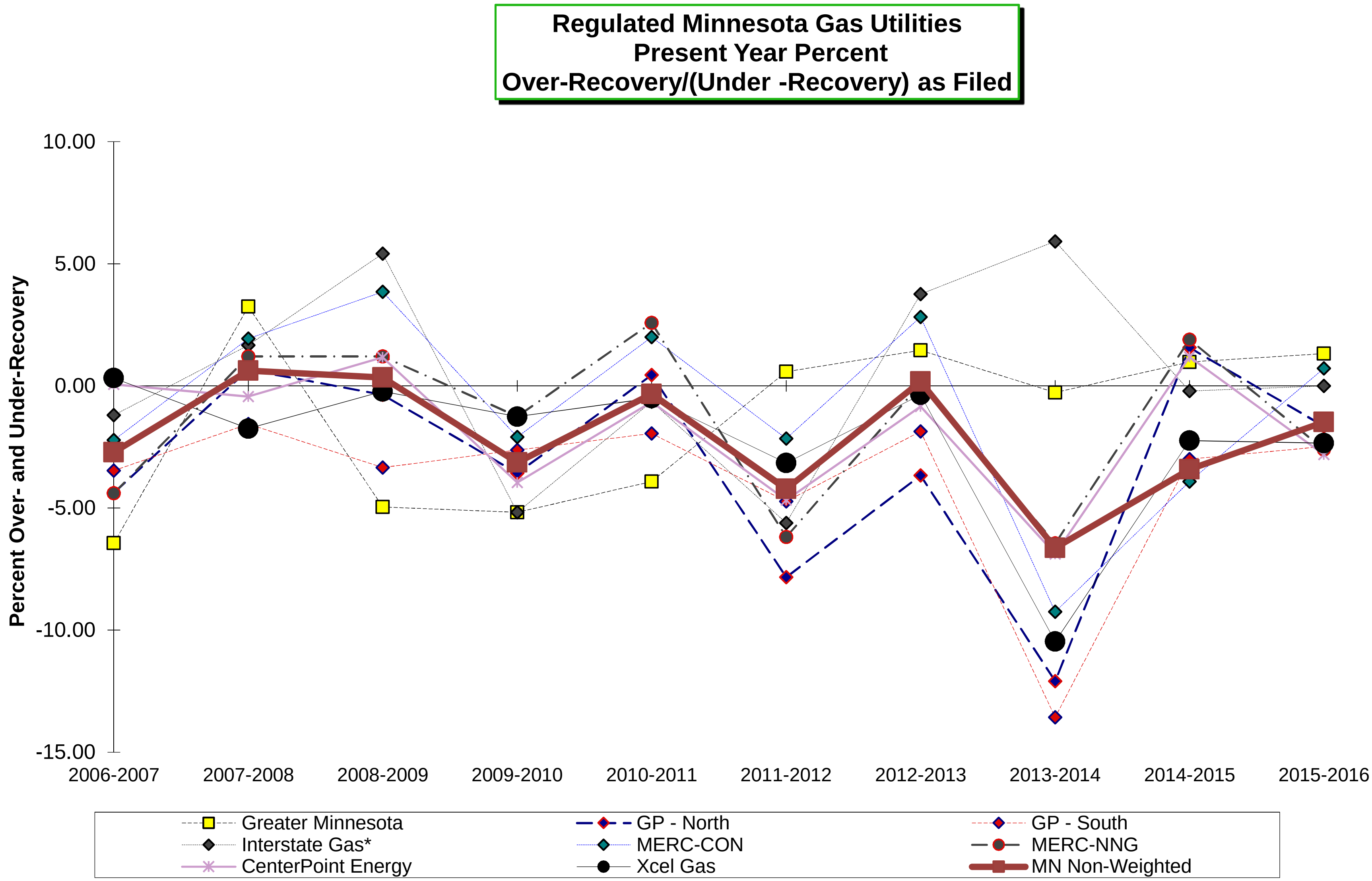
RECORDED UNWEIGHTED HEATING DEGREE DAYS

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)
	ST CLOUD	July	18	17	12	-33.33%	-29.41%
		August	46	41	40	-13.04%	-2.44%
		September	247	228	106	-57.09%	-53.51%
		October	593	599	501	-15.51%	-16.36%
		November	1,071	1,040	800	-25.30%	-23.08%
		December	1,557	1,522	1,183	-24.02%	-22.27%
		January	1,735	1,655	1,580	-8.93%	-4.53%
		February	1,372	1,344	1,229	-10.42%	-8.56%
		March	1,118	1,104	817	-26.92%	-26.00%
		April	630	617	605	-3.97%	-1.94%
		May	278	287	264	-5.04%	-8.01%
		June	79	78	33	-58.23%	-57.69%
	TOTALS		8,744	8,532	7,170		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)
	MPLS/ST PAUL	July	6	5	2	-66.67%	-60.00%
		August	17	14	13	-23.53%	-7.14%
		September	172	154	59	-65.70%	-61.69%
		October	504	507	398	-21.03%	-21.50%
		November	971	939	703	-27.60%	-25.13%
		December	1,433	1,404	1,071	-25.26%	-23.72%
		January	1,608	1,531	1,463	-9.02%	-4.44%
		February	1,266	1,236	1,156	-8.69%	-6.47%
		March	1,017	998	728	-28.42%	-27.05%
		April	552	530	509	-7.79%	-3.96%
		May	215	218	174	-19.07%	-20.18%
		June	43	44	7	-83.72%	-84.09%
	TOTALS		7,804	7,580	6,283		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)
	ROCHESTER	July	14	11	17	21.43%	54.55%
		August	34	27	42	23.53%	55.56%
		September	205	177	82	-60.00%	-53.67%
		October	541	521	447	-17.38%	-14.20%
		November	994	936	762	-23.34%	-18.59%
		December	1,460	1,406	1,081	-25.96%	-23.12%
		January	1,632	1,530	1,546	-5.27%	1.05%
		February	1,301	1,253	1,223	-6.00%	-2.39%
		March	1,050	1,011	815	-22.38%	-19.39%
		April	597	553	531	-11.06%	-3.98%
		May	262	245	229	-12.60%	-6.53%
		June	60	52	21	-65.00%	-59.62%
	TOTALS		8,150	7,722	6,796		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2015-2016	2015-2016 vs. Normal (71-00)	2015-2016 vs. Normal (81-10)
	SIOUX FALLS, SD	July	7	8	5	-28.57%	-37.50%
		August	19	23	27	42.11%	17.39%
		September	170	173	58	-65.88%	-66.47%
		October	509	536	352	-30.84%	-34.33%
		November	985	972	784	-20.41%	-19.34%
		December	1,423	1,421	1,196	-15.95%	-15.83%
		January	1,554	1,499	1,460	-6.05%	-2.60%
		February	1,222	1,218	1,090	-10.80%	-10.51%
		March	973	995	744	-23.54%	-25.23%
		April	551	562	478	-13.25%	-14.95%
		May	224	248	180	-19.64%	-27.42%
		June	45	51	6	-86.67%	-88.24%
	TOTALS		7,682	7,706	6,380		



Prepared by the Minnesota Department of Commerce

GLOSSARY

TERMS AND ACRONYMS	*DEFINITION*
ACA	*Annual Charge Assessment* is a charge paid to the Federal Energy Regulatory Commission (FERC) to defray the agency's administrative costs.
Brokered Reservation Charge	This demand component of the Purchased Gas Adjustment (PGA), which is reservation charges paid to the supplier of natural gas for transportation and other costs incurred to reserve upstream pipeline capacity to get gas.
C/I	*Commercial/Industrial*.
DDVC	*Daily Delivery Variance Charge* - Shippers are required to take actual daily volumes at their delivery point(s) as close to daily scheduled volumes as possible. In the event that actual daily volumes vary from daily scheduled volumes, Shippers are subject to Daily Delivery Variance Charges (DDVC) after a tolerance has been considered.
LGS	*Large General Service.*
LMS	*Load Management Service* is Viking's no-notice service used to provide additional tolerances for shippers, beyond the allowed 5 percent tolerance.
LVDF	*Large Volume Duel Fuel.*
LVI	*Large Volume Interruptible.*
MDQ	*Maximum Daily Quantity.*
PGA (LDCs)	*Local Distribution Company's Purchased Gas Adjustment* is a mechanism used by regulated utilities to recover its cost of energy. Minnesota Rules 7825.2390 through 7825.2920 enable regulated gas (and electric) utilities to adjust rates on a monthly basis to reflect changes in its cost of energy delivered to customers based upon costs authorized by the Minnesota Public Utilities

Commission in the utility's most recent general rate case.

SBA..*System Balancing Agreements* are contracts between Northern Natural Gas (Northern) and shippers on its system who agree to use their facilities and supplies to maintain Northern's system integrity. Costs to Northern for such services are recovered with a surcharge.

SMS..*System Management Service* is Northern's no-notice service which provides additional tolerances for shippers, beyond the allowed 5% tolerance.

SOL..*System Overrun Limitation* is a parameter or boundary that limits the use of SMS service on days which Northern's system integrity is threatened and SBA provisions are not adequate in maintaining pipeline operations.

SVDF..*Small Volume Dual Fuel.*

SVF..*Small Volume Firm.*

SVI...*Small Volume Interruptible.*

Throughput Services.........................*Throughput Services* may be defined as the Total Aggregate MDQ for a shipper in Northern's Market Area. This Total Aggregate MDQ is the total of the individual MDQs of TF12-B, TF12-V, and TF5. A shipper's Total Aggregate MDQ is per contract with Northern; however, the three individual MDQs (used for billing purposes) are subject to limitations. First, TF5 cannot exceed 30 percent of Total Aggregate MDQ. Next, the remainder is split between TF12-B and TF12-V on the contract's anniversary date, with the TF12-B equaling total town border station (TBS) deliveries for the previous May through September. Thus, TF12-V would equal Total Aggregate MDQ less TF5 and TF12-B. These services are available in the Market Area only.

TERMS AND ACRONYMS	*DEFINITION*
TF12-B	*Transportation - Firm for 12 months - Base Level.* See Throughput Services.
TF12-V	*Transportation - Firm for 12 months - Variable Level.* See Throughput Services.
TF5	*Transportation - Firm for 5 months*. See Throughput Services.
TFX...	*Transportation - Firm* (Negotiable terms) is available to any shipper to acquire firm transportation services where the service needed is not conducive to the parameters set out under Throughput Services.
TI..	*Transportation - Interruptible*.

Hedging Terms and Examples

TERMS AND ACRONYMS	*DEFINITION*
Futures Contracts	Firm commitments to make or accept delivery of a specified quantity and quality of a commodity during a specific month in the future at a price agreed upon at the time the commitment is made.
Futures Contract Example	Party A expects to need gas in January and wants to make sure that they do not have to pay more than \$5.60. Party A buys a contract for January gas at \$5.60 to lock in the price. As the strike date approaches, the futures price should – and usually does – converge towards the bidweek prices. If the bidweek price for gas at Henry Hub is \$6.15, the purchaser buys physical gas for \$6.15 and sells the future contract back at the prevailing future market price, around \$6.15 per MMBtu. Party A has a gain of \$0.55 per MMBtu on the future transaction. The gain on the futures contract offsets the fact that Party A was forced to buy gas at \$6.15 per MMBtu. When the cost of the gas is combined with the “gain” on the future contract, the “net” gas cost is \$5.60 per MMBtu, which was the locked in price.

TERMS AND ACRONYMS	*DEFINITION*
	If, however, the bidweek price for gas is $5.25 per MMBtu, the purchaser will buy their gas for $5.25 and take a $0.35 loss on the futures contract. Nevertheless, the "net" cost remains $5.60 per MMBtu because the loss is "offset" by the fact that Party A can buy the gas at a lower price.
Gas Prices	
Citygate Price	The price for gas delivered at the citygates. Citygates are the transfer point or measuring station at which upstream pipelines connect to the LDC's distribution system.
Retail Price	The price charge to the ultimate consumer.
Spot Prices	The price for a one-time, open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.
Wellhead Price	The price of crude oil or natural gas at the mouth of the well.
Hedging	A trade designed to reduce risk. Usually done by covering future commitments at a fixed price in the future, through either options or futures contract.
Marginal Prices	The price of the next increment of supply. Published data generally presents daily averages for weekdays (excluding holidays).
Non-commercial Open Interest	The net non-commercial open interest represents total "long" open interest contracts minus total "short" positions held by non-commercial customers. It represents a reasonable proxy for speculative positions in natural gas futures markets. Natural gas prices tend to increase when net non-commercial open interest is above zero and to decrease when net non-commercial open interest is below zero.

TERMS AND ACRONYMS	*DEFINITION*
Open Interest	The number of open or outstanding contracts for which an individual or entity is obligated to an exchange because that individual or entity has not yet made an offsetting sale or purchase, an actual contract delivery, or in the case of options, exercised the option.
Options	A contract between two parties in which one party has the right, but not the obligation, to buy or sell an underlying asset.
Call Option	An option that gives the holder the right (but not the obligation) to buy a futures contract at a fixed price, on or before a specified date. The grantor of the option is obliged to sell the futures contract at the fixed price if the holder exercises the option.
Call Option Example	Party A buys a call option for the month of May with a strike price of $5.10 for $0.26 to insure against a large price increase. If the May price is $5.50 per MMBtu, the value of the option is $0.40. Party A can sell the option at the strike date for a net gain of $0.14. Party A would then buy the physical gas of the market price of $5.50 per MMBtu for a net gas cost of $5.36. If the May price drops to $4.00 per MMBtu, the value of the option is zero and Party A loses the entire initial cost of the option for a net loss of $0.26. Party A would then buy the physical gas at the market price of $4.00 per MMBtu for a net cost of $4.26 per MMBtu which is well below the strike price of the option.
Put Option	An option that gives the holder the right (but not the obligation) to sell a specified futures contract at a fixed price, on or before a specified date. The grantor of the option has the obligation to take delivery of the futures contract if the option is exercised.
Strike Price	The price at which an option holder has the right to buy or sell and underlying commodity/derivative.

TERMS AND ACRONYMS	*DEFINITION*
Risk-free Rate	The rate of interest that can be earned without assuming any risk.
Out-of-the-Money Option	An option which has no intrinsic value. A put option is out-of-the-money when its strike price is below the value of the underlying futures contract. A call option is out-of-the-money when its strike price is above that of the underlying futures contract.
Price Collar	A contract between a buyer and seller of a commodity whereby the buyer is assured that he will not have to pay more than some maximum price and whereby the seller is assured of receiving some minimum price. Under the terms of a collar, no payment is made when the index price falls within the dead band. A payment is made when the cash price falls outside the “dead band” based upon the difference in the index price and the limit of the dead band. The other party charges an origination fee for the collar.
Price Collar Example	A purchaser, wanting to insure against large price increases, buys a three-month collar at $6.00 per MMBtu with a $0.15 spread around the $6.00 price. If the cash price is between $5.85 and $6.15, no payment is made on the collar. Over the three-month period, the index price for physical gas averages $6.25 per MMBtu. The purchaser buys gas at index, but is paid $0.10 on the collar for a net cost of gas of $6.15. If the index price averages $5.70, the purchaser buys at index but has to pay $0.15 on the collar for a net cost of gas of $5.85 per MMBtu. If the average of index price over the three-month period falls between $5.85 and $6.15, no payment is made for the collar.

TERMS AND ACRONYMS	*DEFINITION*
Price Range	The spread of prices during a specific period. In markets with a uniform product and an open bidding process (e.g., the stock market), the range is often defined as the average spread between the bid price and the ask price during a specific time period. For markets without a uniform product, and where bid and ask prices are not typically available (such as natural gas markets for all locations with the possible exception of the NYMEX Henry Hub contract), the range is typically measured as the difference between the daily high price and the daily low price.
Commodity Swap	A contract between two parties. A swap differs from a futures contract in that it specifies "marker" price that does not vary during the term of the contract. The contract obligates the parties to make payment equal to the difference between the cash price and the "trigger" price. If the cash price is above the "trigger" price, the seller of the swap pays the buyer, if the cash price is below the "trigger," buyer pays the seller. The terms of settlement can be negotiated between the parties, thus there are an almost infinite variety of swaps. For natural gas swaps, it is particularly valuable to commercial interests to be able to enter in swap at specific locations along the gas pipeline system (i.e., interconnects, citygates, and pipeline receipt and delivery points, etc.)
Commodity Swap Example	A purchaser wanting to lock in a $6.00 price for gas at Ventura over the next 3 months signs a swap agreement with another party. Over the three-month period, the index price averages $6.25 per MMBtu. The purchaser buys the physical gas at the index price of $6.25 and is paid $0.25 on the swap for a "net" gas cost of $6.00. If however, the price averages $5.70 per MMBtu, the purchaser buys at the index price but has to pay $0.30 per MMBtu to the other party under the terms of the swap. The net gas cost remains $6.00 per MMBtu.

Throughput Services	CPE	Great Plains No.	Great Plains So.	GMG	Interstate	MERC NNG	MERC-CON	MERC AL	Xcel Gas
NNG TF-12	D		D	D	D	D		D	D
NNG TF-5	D		D	D	D	D		D	D
NNG TFX	D	D	D	D	D	D		D	D
Viking FT-A	D	D	D				D		D
Great Lakes FT							D		D
ANR FTS-1									D
WBI FT									D
Centra FT							D		
Balancing, Storage, Reservation Fees									
Balancing SMS, LMS **2/**	A	A	A	C	A	C	C	C	C
NNG storage FDD	A		A		A	D/C **1/**	D/C **1/**		A
NGPL storage	A								
BP Canada storage									
Niska storage									
ANR storage									A
AECO storage							D/C **1/**		
Other supplier or producer reservation fees	A				A				

D=Demand cost
A=Costs are allocated to firm and interruptible classes costs
C=Commodity cost

1/ The Commission's Aug. 6, 2014 Order in Docket Nos. G007/M-07-1402, G011/M-07-1403, G011/M-07-1404, and G011/M-07-1405 approved moving storage into commodity as of Nov. 1, 2014. Thus, there were four months of costs in demand and eight months of costs in commodity.

2/ The Commission's November 14, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-up Proposals, and Setting Further Requirements* in Docket No. 12-756 required all regulated gas utilities to prospectively recover balancing service costs, and credit the utility's penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that can reasonably be implemented.

Greater Minnesota Gas, Inc.
2015-2016 True Up
Docket No. G022/AA-16-715
As Filed on August 31, 2016

Ten Year Summary of Gas-Cost Recovery

Year Ended 6/30	**Present Year Percent Over (Under) Recovery**	**Cumulative Percent Over (Under) Recovery**
2006-2007	-6.44%	
2007-2008	3.25%	
2008-2009	-4.96%	
2009-2010	-5.18%	
2010-2011	-3.92%	
2011-2012	0.58%	
2012-2013	1.46%	
2013-2014	-0.27%	
2014-2015	0.98%	
2015-2016	**1.32%**	**1.55%**
10 Year Average	-1.32%	

Recovery By Class

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PREVIOUS TRUE-UP OVER/(UNDER) ENDING BALANCE
FIRM	$3,634,611	$3,577,988	$56,623	**1.58%**	$8,968
AGRICULTURAL - INTERRUPTIBLE	$116,390	$121,437	($5,047)	**-4.16%**	$394
GENERAL - INTERRUPTIBLE	$224,173	$223,796	$377	**0.17%**	($695)
TOTAL	**$3,975,174**	**$3,923,221**	**$51,953**	**1.32%**	**$8,667**

	(6) (3)+(5)	(7) (6)/(2)	(8)	(9) (6)/(8)
	CUMULATIVE OVER/(UNDER) BALANCE	CUMULATIVE %	Estimated Sales (Mcf)	True Up (Refund)/Collection
FIRM	$65,591	**1.83%**	1,141,640	**($0.0575)**
AGRICULTURAL - INTERRUPTIBLE	($4,653)	**-3.83%**	71,250	**$0.0653**
GENERAL - INTERRUPTIBLE	($318)	**-0.14%**	113,545	**$0.0028**
TOTAL	**$60,620**	**1.55%**	**1,326,435**	

Greater Minnesota Gas, Inc.
2015-2016 True Up
Docket No. G022/AA-16-715
As Filed on August 31, 2016

RECOVERY BY CLASS	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RESIDENTIAL - FIRM	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND COST	$432,854	$426,512	$6,342	1.49%
COMMODITY COST	$1,477,034	$1,398,291	$78,743	5.63%
TOTAL	$1,909,888	$1,824,803	$85,085	4.66%
COMMERCIAL - FIRM				
DEMAND COST	$17,165	$16,798	$367	2.18%
COMMODITY COST	$58,852	$55,690	$3,162	5.68%
TOTAL	$76,017	$72,488	$3,529	4.87%
INDUSTRIAL - FIRM				
DEMAND COST	$366,901	$381,935	($15,034)	-3.94%
COMMODITY COST	$1,208,628	$1,221,377	($12,749)	-1.04%
TOTAL	$1,575,529	$1,603,312	($27,783)	-1.73%
FLEX RATE - FIRM				
DEMAND COST	$17,054	$18,981	($1,927)	-10.15%
COMMODITY COST	$56,123	$58,404	($2,281)	-3.91%
TOTAL	$73,177	$77,385	($4,208)	-5.44%
AG. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$116,390	$121,437	($5,047)	-4.16%
TOTAL	$116,390	$121,437	($5,047)	-4.16%
IND. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$103,553	$104,878	($1,325)	-1.26%
TOTAL	$103,553	$104,878	($1,325)	-1.26%
FLEX RATE - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$120,620	$118,918	$1,702	1.43%
TOTAL	$120,620	$118,918	$1,702	1.43%

Greater Minnesota Gas, Inc.
2015-2016 True Up
Docket No. G022/AA-16-715
As Filed on August 31, 2016

RECOVERY BY COMPONENT	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER/(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND COST:				
Residential - Firm	$432,854	$426,512	$6,342	1.49%
Commercial - Firm	$17,165	$16,798	$367	2.18%
Industrial - Firm	$366,901	$381,935	($15,034)	-3.94%
Flexible Rate - Firm	$17,054	$18,981	($1,927)	-10.15%
Agricultural - Interruptible	$0	$0	$0	0.00%
Industrial - Interruptible	$0	$0	$0	0.00%
Flexible Rate - Interruptible	$0	$0	$0	0.00%
TOTAL	$833,974	$844,226	($10,252)	-1.21%
COMMODITY COSTS:				
Residential - Firm	$1,477,034	$1,398,291	$78,743	5.63%
Commercial - Firm	$58,852	$55,690	$3,162	5.68%
Industrial - Firm	$1,208,628	$1,221,377	($12,749)	-1.04%
Flexible Rate - Firm	$56,123	$58,404	($2,281)	-3.91%
Agricultural - Interruptible	$116,390	$121,437	($5,047)	-4.16%
Industrial - Interruptible	$103,553	$104,878	($1,325)	-1.26%
Flexible Rate - Interruptible	$120,620	$118,918	$1,702	1.43%
TOTAL	$3,141,200	$3,078,995	$62,205	2.02%
DETAIL OF DEMAND RECOVERY				
Viking Zone 1	$208,109	$241,257	($33,148)	-13.74%
Viking Zone 1-2	$134,318	$119,380		
TFX-5	$418,006	$487,472	($69,466)	-14.25%
TFX- 7	$56,321	$57,942	($1,621)	-2.80%
TFX - 12	$16,605	$19,096	($2,491)	-13.04%
TF Capacity Release	$0	($80,919)	$80,919	-100.00%
SMS Demand	$615	$0	$615	0.00%
TOTAL	$833,974	$844,228	($10,254)	-1.21%

Great Plains Natural Gas North District
2015-2016 True-Up
Docket No. G004/AA-16-719
As Filed on August 31, 2016

Ten Year Summary of Gas Cost Recovery:

	Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
GP-North	2006-2007	-4.37%	
GP-North	2007-2008	0.67%	
GP-North	2008-2009	-0.36%	
GP-North	2009-2010	-3.57%	
GP-North	2010-2011	0.45%	
GP-North	2011-2012	-7.83%	
GP-North	2012-2013	-3.66%	
GP-North	2013-2014	-12.09%	
GP-North	2014-2015	1.57%	
GP-North	2015-2016	**-1.66%**	**0.45%**
	10-Year Average	-3.08%	

Recovery By Class

	(1)	(2)	(3) (1)-(2)	(4) (3)/(2)	(5)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Recovery	Present Year Over/(Under) Recovery	Prior Year True-Up Over/(Under) Beginning Balance
FIRM	$3,929,499	$4,068,162	($138,663)	**-3.41%**	$28,861
INTERRUPTIBLE	$1,148,113	$1,095,027	$53,086	**4.85%**	$33,986
Total	**$5,077,612**	**$5,163,189**	**($85,577)**	**-1.66%**	**$62,847**

	(6)	(7) (3)+(5)+(6)	(8) (7)/(2)	(9)	(10)
	Prior Year Recovery	Cumulative True-Up Over/(Under) Ending Balance	Cumulative %	Projected Sales (Mcf)	True Up Per Mcf (Refund)/Collection
FIRM	$23,556	($86,246)	**-2.12%**	1,131,600	**$0.0762**
INTERRUPTIBLE	$22,516	$109,588	**10.01%**	603,800	**($0.1815)**
Total	**$46,072**	**$23,342**	**0.45%**		

Great Plains Natural Gas North District
2015-2016 True-Up
Docket No. G004/AA-16-719
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	(1)	(2)	(3) (1)-(2)	(4) (3)/(2)
Detail of Current Costs by Class			PRESENT YEAR	PRESENT YEAR
			OVER/(UNDER)	OVER/(UNDER)
FIRM	COST RECOVERY	COST INCURRED	RECOVERY ($)	COLLECTION (%)
Viking				
FT-A	$293,691	$332,564	($38,873)	-11.69%
FT-A (Zone 1-1; Zone 1-2)	$83,130	$95,599	($12,469)	-13.04%
Seasonal FT-A	$10,332	$13,384	($3,052)	-22.80%
Seasonal FT-A Reservation Charge	$33,252	$38,240	($4,988)	-13.04%
TFX Seasonal	$106,030	$121,971	($15,941)	-13.07%
TFX Winter	$689,502	$792,807	($103,305)	-13.03%
TFX Summer	$361,990	$407,551	($45,561)	-11.18%
BP Seasonal Gas Contract	$25,272	$29,479	($4,207)	-14.27%
TFX Capacity Release		($38,409)	$38,409	-100.00%
Total Demand	$1,603,199	$1,793,186	($189,987)	-10.59%
Commodity Cost	$2,326,300	$2,274,976	$51,324	2.26%
TOTAL	$3,929,499	$4,068,162	($138,663)	-3.41%
INTERRUPTIBLE				
Commodity Cost	$1,148,113	$1,095,027	$53,086	4.85%
TOTAL	$1,148,113	$1,095,027	$53,086	4.85%

Great Plains Natural Gas North District
2015-2016 True-Up
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Recovery by Class		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
FIRM					
	Demand	$1,603,199	$1,793,186	($189,987)	-10.59%
	Commodity	$2,326,300	$2,274,976	$51,324	2.26%
	Total	$3,929,499	$4,068,162	($138,663)	-3.41%
INTERRUPTIBLE					
	LMS Demand	$0	$0	$0	0.00%
	Commodity	$1,148,113	$1,095,027	$53,086	4.85%
	Total	$1,148,113	$1,095,027	$53,086	4.85%

Recovery by Component		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
Demand					
	Firm	$1,603,199	$1,793,186	($189,987)	-10.59%
	Total	$1,603,199	$1,793,186	($189,987)	-10.59%
Commodity					
	Firm	$2,326,300	$2,274,976	$51,324	2.26%
	LMS Demand	$0	$0	$0	0.00%
	Interruptible	$1,148,113	$1,095,027	$53,086	4.85%
	Total	$3,474,413	$3,370,003	$104,410	3.10%

Great Plains Natural Gas South District
2015-2016 True-Up
Docket No. G004/AA-16-719
As Filed by Great Plains on August 31, 2016

Ten Year Summary of Gas Cost Recovery:

	Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
GP-South	2006-2007	-3.47%	
GP-South	2007-2008	-1.56%	
GP-South	2008-2009	-3.34%	
GP-South	2009-2010	-2.62%	
GP-South	2010-2011	-1.95%	
GP-South	2011-2012	-4.73%	
GP-South	2012-2013	-1.86%	
GP-South	2013-2014	-13.57%	
GP-South	2014-2015	-3.00%	
GP-South	2015-2016	**-2.48%**	**-4.40%**
	10-Year Average	-3.86%	

RECOVERY BY CLASS

	(1)	(2)	(3) (1)-(2)	(4) (3)/(2)	(5)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Recovery	Present Year Over/(Under) Recovery	Prior Year True-Up Over/(Under) Beginning Balance
FIRM	$4,770,923	$4,886,278	($115,355)	**-2.36%**	($257,377)
Small Vol. Interrupt.	$716,145	$765,723	($49,578)	**-6.47%**	($19,840)
Large Vol. Interrupt.	$123,157	$100,731	$22,426	**22.26%**	($174,056)
Total	**$5,610,225**	**$5,752,732**	**($142,507)**	**-2.48%**	**($451,273)**

	(6)	(7) (3)+(5)+(6)	(7a)	(8) (7)/(2)	(9)	(10)
	Prior Year Recovery	Cumulative True-Up Over/(Under) Ending Balance	One-Time Reallocation Lg. Interruptible	Cumulative %	Projected Sales (Mcf)	True Up Per Mcf (Refund)/Collection
FIRM	$255,407	($117,325)	($128,305)	**-2.47%**	1,509,900	**$0.1627**
Small Vol. Interrupt.	$69,773	$355	($26,614)	**0.05%**	313,200	**$0.0838**
Large Vol. Interrupt.	$15,222	($136,408)	$154,919	**-53.36%**	40,000	**($0.4628)**
Total	**$340,402**	**($253,378)**	**$0**	**-4.40%**		

Note: $154,919 of Large Vol. Interruptible One-Time Reallocation in column (7a) is the sum of ($158,318) under-recovery plus ($3,399) under-recovery allocated balance. Please see Great Plains's True-Up, Docket No. G004/AA-16-719, page 2 and Exhibit B, page 1.

Great Plains Natural Gas South District
2015-2016 True-Up
Docket No. G004/AA-16-719
As Filed by Great Plains on August 31, 2016

	(1)	(2)	(3) (1)-(2)	(4) (3)/(2)
Detail of Current Costs by Class			PRESENT YEAR	PRESENT YEAR
			OVER/(UNDER)	OVER/(UNDER)
FIRM	COST RECOVERY	COST INCURRED	RECOVERY ($)	RECOVERY (%)
Northern				
TF12 Base	$389,247	$420,239	($30,992)	-7.37%
TF12 Variable	$288,533	$302,051	($13,518)	-4.48%
TF5 (November - March)	$237,402	$258,359	($20,957)	-8.11%
TFX	$551,503	$574,541	($23,038)	-4.01%
TFX Negotiated Contract	$123,542	$134,459	($10,917)	-8.12%
FT-A Viking	$152,845	$157,309	($4,464)	-2.84%
FDD-1 Reservation	$87,659	$92,434	($4,775)	-5.17%
FDD-1 Demand Charges	$10,501	$42,386	($31,885)	-75.23%
Propane Peaking Facilities Credit	($94,614)	($102,945)	$8,331	-8.09%
TFX - Capacity Release	($35,447)	($43,472)	$8,025	-18.46%
Commodity Costs	$3,059,752	$3,050,917	$8,835	0.29%
TOTAL	$4,770,923	$4,886,278	($115,355)	-2.36%
SVI				
Commodity Costs	$710,778	$733,390	($22,612)	-3.08%
FDD-1 Demand Charge	$5,367	$32,333	($26,966)	-83.40%
Adjustments			$0	0.00%
TOTAL	$716,145	$765,723	($49,578)	-6.47%
LVI				
Commodity Costs	$122,271	$91,220	$31,051	34.04%
FDD-1 Demand Charge	$886	$9,511	($8,625)	-90.68%
TOTAL	$123,157	$100,731	$22,426	22.26%

Great Plains Natural Gas South District
2015-2016 True-Up
Docket No. G004/AA-16-719
As Filed by Great Plains on August 31, 2016

Recovery by Class			(1)	(2)	(3) (1)-(2)	(4) (3)/(2)
			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY ($)	PRESENT YEAR OVER/(UNDER) RECOVERY (%)
FIRM						
	Demand		$1,711,171	$1,835,361	($124,190)	-6.77%
	Commodity		$3,059,752	$3,050,917	$8,835	0.29%
		Total	$4,770,923	$4,886,278	($115,355)	-2.36%
INTERRUPTIBLE						
	Commodity		$839,302	$866,454	($27,152)	-3.13%
		Total	$839,302	$866,454	($27,152)	-3.13%

Recovery by Component			(1)	(2)	(3) (1)-(2)	(4) (3)/(2)
			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY ($)	PRESENT YEAR OVER/(UNDER) RECOVERY (%)
Demand						
	Firm		$1,711,171	$1,835,361	($124,190)	-6.77%
		Total	$1,711,171	$1,835,361	($124,190)	-6.77%
Commodity						
	Firm		$3,059,752	$3,050,917	$8,835	0.29%
	Interruptible		$839,302	$866,454	($27,152)	-3.13%
		Total	$3,899,054	$3,917,371	($18,317)	**-0.47%**

Prepared by the Minnesota Department of Commernce, Division of Energy Resources

MERC - NNG
2015-2016 True-up
Docket No. G011/AA-16-732
(As filed on September 2, 2016)

SUMMARY OF GAS COST RECOVERY:

	Year Ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
MERC-PNG	2007	-4.39%	
MERC-PNG	2008	1.21%	
MERC-PNG	2009	1.21%	
MERC-PNG	2010	-1.25%	
MERC-PNG	2011	2.58%	
MERC-PNG	2012	-6.19%	
MERC-PNG	2013	0.08%	
MERC-Northern System	2014	-6.45%	
MERC-Northern System	2015	1.90%	
MERC-Northern System	**2016**	**-2.60%**	**-1.70%**
	10-YEAR AVERAGE	-1.39%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (3) / (2)	(5)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER/(UNDER) BEGINNING BALANCE
GS	$84,627,735	$86,346,748	($1,719,013)	**-1.99%**	$1,071,948
SVJ/LVJ/SLV Demand	$11,593	$11,594	($1)	**-0.01%**	$1
SVI/SVJ/LVI/LVJ/SLVI Commodity	$7,523,258	$8,266,572	($743,314)	**-8.99%**	($216,983)
	$92,162,586	**$94,624,914**	**($2,462,328)**	**-2.60%**	**$854,966**

	(6) (3) + (5)	(7) (6) / (2)	(8)	(9) (6) / (8)
	CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	CUMULATIVE %	ESTIMATED SALES (DTH)	TRUE-UP FACTORS (REFUND)/COLLECT
GS	($647,065)	-0.75%	21,529,714	**$0.0301**
SVJ/LVJ/SLV Demand	$0	0.00%	1,139	**$0.0000**
SVI/SVJ/LVI/LVJ/SLVI Commodity	($960,297)	-11.62%	2,458,732	**$0.3906**
	($1,607,362)	-1.70%	**23,989,584**	

MERC - NNG
2015-2016 True-up
Docket No. G011/AA-16-732
(As filed on September 2, 2016)

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY CLASS						
General Service (GS)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$17,831,135	$20,303,663	($2,472,528)	-12.18%
	COMMODITY		$66,796,600	$66,043,085	$753,515	1.14%
		TOTAL	$84,627,735	$86,346,748	($1,719,013)	-1.99%
Small & Large Volume Interruptible (SVI/LVI)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$0	$0	$0	0.00%
	COMMODITY		$7,474,142	$8,216,071	($741,929)	-9.03%
		TOTAL	$7,474,142	$8,216,071	($741,929)	-9.03%
Small & Large Volume Joint, Super Large Volume (SVJ/LVJ/SLV)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$11,593	$11,594	($1)	-0.01%
	COMMODITY		$49,116	$50,501	($1,385)	-2.74%
		TOTAL	$60,709	$62,095	($1,386)	-2.23%

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY COMPONENT						
			RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY	PRESENT YEAR OVER/(UNDER) RECOVERY
DEMAND	GS		$17,831,135	$20,303,663	($2,472,528)	-12.18%
DEMAND	SVI/LVI		$0	$0	$0	0.00%
DEMAND	SVJ/LVJ/SLV		$11,593	$11,594	($1)	-0.01%
		TOTAL	$17,842,728	$20,315,257	($2,472,529)	-12.17%
COMMODITY	GS		$66,796,600	$66,043,085	$753,515	1.14%
COMMODITY	SVI/LVI		$7,474,142	$8,216,071	($741,929)	-9.03%
COMMODITY	SVJ/LVJ/SLV		$49,116	$50,501	($1,385)	-2.74%
		TOTAL	$74,319,858	$74,309,657	$10,201	0.01%

MERC - Albert Lea
2015-2016 True-up
Docket No. G011/AA-16-733
(As filed on September 2, 2016)

SUMMARY OF GAS COST RECOVERY:

	Year Ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
:-Albert Lea (MERC purchased IPL 4/30/15)	2015	-27.03%	-29.68%
	2016	**-3.47%**	**-4.20%**
	AVERAGE	-15.25%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (3) / (2)	(5)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER/(UNDER) BALANCE
GS	$4,494,245	$4,641,184	($146,939)	**-3.17%**	$1,106
SVJ/LVJ/SLVJ Demand	$0	$0	$0	**0.00%**	$0
SVI/SVJ/LVI/LVJ/SLVI Commodity	$781,503	$823,949	($42,446)	**-5.15%**	($41,033)
	$5,275,748	**$5,465,133**	**($189,385)**	**-3.47%**	**($39,927)**

	(6) (3) + (5)	(7) (6) / (2)	(8)	(9) (6) / (8)
	CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	CUMULATIVE %	ESTIMATED SALES (DTH)	TRUE-UP FACTORS (REFUND)/COLLECT
GS	($145,833)	-3.14%	1,161,505	**$0.1256**
SVJ/LVJ/SLV Demand	$0	0.00%	0	**$0.0000**
SVI/SVJ/LVI/LVJ/SLVI Commodity	($83,479)	-10.13%	231,878	**$0.3600**
	($229,312)	-4.20%	**1,393,383**	

MERC - Albert Lea
2015-2016 True-up
Docket No. G011/AA-16-733
(As filed on September 2, 2016)

			(1)	(2)	(3)	(4)
RECOVERY BY CLASS					(1) - (2)	(3) / (2)
General Service (GS)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$1,217,031	$1,327,163	($110,132)	-8.30%
	COMMODITY		$3,277,214	$3,314,021	($36,807)	-1.11%
		TOTAL	$4,494,245	$4,641,184	($146,939)	-3.17%
Small & Large Volume Interruptible (SVI/LVI)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$0	$0	$0	0.00%
	COMMODITY		$781,503	$823,949	($42,446)	-5.15%
		TOTAL	$781,503	$823,949	($42,446)	-5.15%
Small & Large Volume Joint, Super Large Volume (SVJ/LVJ/SLV)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$0	$0	$0	0.00%
	COMMODITY		$0	$0	$0	0.00%
		TOTAL	$0	$0	$0	0.00%

			(1)	(2)	(3)	(4)
RECOVERY BY COMPONENT					(1) - (2)	(3) / (2)
			RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY	PRESENT YEAR OVER/(UNDER) RECOVERY
DEMAND	GS		$1,217,031	$1,327,163	($110,132)	-8.30%
DEMAND	SVI/LVI		$0	$0	$0	0.00%
DEMAND	SVJ/LVJ/SLV		$0	$0	$0	0.00%
		TOTAL	$1,217,031	$1,327,163	($110,132)	-8.30%
COMMODITY	GS		$3,277,214	$3,314,021	($36,807)	-1.11%
COMMODITY	SVI/LVI		$781,503	$823,949	($42,446)	-5.15%
COMMODITY	SVJ/LVJ/SLV		$0	$0	$0	0.00%
		TOTAL	$4,058,717	$4,137,970	($79,253)	-1.92%

MERC - Consolidated
2015-2016 True-up
Docket No. G011/AA-16-734
(As filed on September 26, 2016)

TEN YEAR SUMMARY OF GAS-COST RECOVERY:

	Year ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
MERC-NMU	2006-2007	-2.22%	
MERC-NMU	2007-2008	1.94%	
MERC-NMU	2008-2009	3.85%	
MERC-NMU	2009-2010	-2.09%	
MERC-NMU	2010-2011	2.00%	
MERC-NMU	2011-2012	-2.15%	
MERC-NMU	2012-2013	2.82%	
MERC-Consolidated	2013-2014	-9.25%	
MERC-Consolidated	2014-2015	-3.91%	
MERC-Consolidated	2015-2016	**0.72%**	**1.36%**
	10-YEAR AVERAGE	-0.83%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (3) / (2)	(5)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER/(UNDER) BEGINNING BALANCE
GS	$16,580,834	$16,442,758	$138,076	**0.84%**	$33,054
SVJ Demand	$11,688	$11,688	$0	**0.00%**	($5)
SVI/SJV/LVI Commodity	$2,574,154	$2,575,992	($1,838)	**-0.07%**	$89,089
	$19,166,676	**$19,030,438**	**$136,238**	**0.72%**	**$122,138**

	(6) (3) + (5)	(7) (6) / (2)	(8)	(9) (6) / (8)
	CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	**CUMULATIVE %**	Estimated Sales (Dth)	True-Up Factors (Refund)/Collection
GS	$171,130	**1.04%**	4,821,391	**($0.0355)**
SVJ Demand	($5)	**-0.04%**	1,875	**$0.0027**
SVI/SJV/LVI Commodity	$87,251	**3.39%**	671,333	**($0.1300)**
	$258,376	**1.36%**	**5,494,600**	

MERC - Consolidated
2015-2016 True-up
Docket No. G011/AA-16-734
(As filed on September 26, 2016)

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY CLASS						
General Service (GS)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$3,347,344	$3,282,030	$65,314	1.99%
	COMMODITY		$13,233,490	$13,160,728	$72,762	0.55%
		TOTAL	$16,580,834	$16,442,758	$138,076	0.84%
SVI/SJV/LVI						
	DEMAND		$11,688	$11,688	$0	0.00%
	COMMODITY		$2,574,154	$2,575,992	($1,838)	-0.07%
		TOTAL	$2,585,842	$2,587,680	($1,838)	-0.07%

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY COMPONENT			RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	PERCENT OVER/(UNDER) RECOVERY
DEMAND	General Service (GS)		$3,347,344	$3,282,030	$65,314	1.99%
DEMAND	SVI/SVJ/LVJ		$11,688	$11,688	$0	0.00%
		TOTAL	$3,359,032	$3,293,718	$65,314	1.98%
COMMODITY	General Service (GS)		$13,233,490	$13,160,728	$72,762	0.55%
COMMODITY	SVI/SVJ/LVJ		$2,574,154	$2,575,992	($1,838)	-0.07%
		TOTAL	$15,807,644	$15,736,720	$70,924	0.45%

CenterPoint Energy
2015 - 2016 True-Up
Docket No. G008/AA-16-730
As Filed on September 1, 2016

TEN YEAR SUMMARY OF GAS-COST RECOVERY:

Year Ended 6/30	PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
2006-2007	0.06%	
2007-2008	-0.44%	
2008-2009	1.17%	
2009-2010	-3.96%	
2010-2011	-0.66%	
2011-2012	-4.68%	
2012-2013	-0.84%	
2013-2014	-6.88%	
2014-2015	1.44%	
2015-2016	**-2.53%**	**-2.42%**
10-YEAR AVERAGE	-1.73%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (5) / (2)	(5)	(6)	(7) (5) / (2)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	NetPresent Year Over/(Under) Collection (%)	Credits Against Present Gas Costs	Net Present Year Over/(Under) Collection ($)	NetPresent Year Over/(Under) Collection (%)
SVF	$339,918,953	$349,498,972	($9,580,019)	**-2.74%**	$940,337	($8,639,682)	**-2.47%**
LGS	$158,909	$169,939	($11,030)	**-6.49%**	$466	($10,564)	**-6.22%**
SVDF	$26,672,859	$27,727,471	($1,054,612)	**-3.80%**	$83,687	($970,925)	**-3.50%**
LVDF	$6,013,386	$6,131,299	($117,913)	**-1.92%**	$19,861	($98,052)	**-1.60%**
	$372,764,107	**$383,527,681**	**($10,763,574)**	**-2.81%**	**$1,044,351**	($9,719,223)	**-2.53%**

	(8)	(9) (5) + (7)	(10) (8) / (2)	(11)	(12) - (8) / (10)
	Prior Year True Up Over/(Under) Balance	Cumulative Over/(Under) Collection ($)	**CUMULATIVE %**	Estimated Sales (DT)	**True-Up Factors (Refund)/Collection**
SVF	$1,420,713	($7,218,969)	**-2.07%**	108,162,930	**$0.0667**
LGS	$10,026	($538)	**-0.32%**	39,545	**$0.0136**
SVDF	($98,633)	($1,069,558)	**-3.86%**	11,866,503	**$0.0901**
LVDF	($901,389)	($999,441)	**-16.30%**	4,308,230	**$0.2320**
	$430,717	**($9,288,506)**	**-2.42%**	**124,377,208**	

CenterPoint Energy
2015 - 2016 True-Up
Docket No. G008/AA-16-730
As Filed on September 1, 2016

RECOVERY BY CLASS		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
SMALL VOLUME FIRM		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND		$76,854,678	$78,868,487	($2,013,809)	-2.55%
PROPANE		$0	$544,487	($544,487)	-100.00%
COMMODITY		$263,064,275	$270,085,998	($7,021,723)	-2.60%
	TOTAL	$339,918,953	$349,498,972	($9,580,019)	-2.74%
LARGE GENERAL SERVICE					
DEMAND		$28,517	$39,836	($11,319)	-28.41%
PROPANE		$0	$101	($101)	-100.00%
COMMODITY		$130,392	$130,002	$390	0.30%
	TOTAL	$158,909	$169,939	($11,030)	-6.49%
SMALL VOLUME DUAL FUEL					
COMMODITY		$26,672,859	$27,727,471	($1,054,612)	-3.80%
	TOTAL	$26,672,859	$27,727,471	($1,054,612)	-3.80%
LARGE VOLUME DUAL FUEL					
COMMODITY		$6,013,386	$6,131,299	($117,913)	-1.92%
	TOTAL	$6,013,386	$6,131,299	($117,913)	-1.92%

RECOVERY BY COMPONENT			(1) RECOVERY	(2) COST INCURRED	(3) (1) - (2) OVER/(UNDER) RECOVERY	(4) (3) / (2) OVER/(UNDER) RECOVERY
DEMAND	SVF		$76,854,678	$78,868,487	($2,013,809)	-2.55%
DEMAND	LGS		$28,517	$39,836	($11,319)	-28.41%
PROPANE	SVF		$0	$544,588	($544,588)	-100.00%
		TOTAL	$76,883,195	$79,452,911	($2,569,716)	-3.23%
COMMODITY	SVF		$263,064,275	$270,085,998	($7,021,723)	-2.60%
COMMODITY	LGS		$130,392	$130,002	$390	0.30%
COMMODITY	SVDF		$26,672,859	$27,727,471	($1,054,612)	-3.80%
COMMODITY	LVDF		$6,013,386	$6,131,299	($117,913)	-1.92%
		TOTAL	$295,880,912	$304,074,770	($8,193,858)	-2.69%
TOTAL DEMAND AND COMMODITY			$372,764,107	$383,527,681	($10,763,574)	-2.81%

Xcel Gas
2015-2016 True Up
Docket No. G002/AA-16-725
As Filed September 1, 2016

Ten Year Summary of Gas-Cost Recovery:
Excludes Over/Under-Recoveries associated with fixed price programs terminated in 2006-2007 (Docket No. G002/CI-07-541).

Year ended 6/30	Present Year Percent Over/(Under) Recovery	Cumulative Percent Over/(Under) Recovery
2006-2007	0.32%	
2007-2008	-1.75%	
2008-2009	-0.23%	
2009-2010	-1.26%	
2010-2011	-0.50%	
2011-2012	-3.15%	
2012-2013	-0.36%	
2013-2014	10.47%	
2014-2015	-2.24%	
2015-2016	**-2.34%**	**-1.59%**
10-YEAR AVG	-0.10%	

Recovery by Class

	(1)	(2)	(3)	(4)	(5)
			(1) - (2)	(3) / (2)	
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)	Present Year True-Up Over/(Under) Beginning Balance
Residential	$110,325,799	$112,250,660	($1,924,861)	**-1.71%**	$711,963
Commercial/Industrial Firm	$61,942,469	$63,569,234	($1,626,765)	**-2.56%**	$468,047
Demand Billed Demand	$1,567,565	$1,533,609	$33,956	**2.21%**	($2,629)
Demand Billed Commodity	$7,070,909	$7,413,440	($342,531)	**-4.62%**	$85,885
Small Interruptible	$5,886,143	$6,025,408	($139,265)	**-2.31%**	$89,518
Medium & Large Interruptible	$21,700,476	$22,691,744	($991,268)	**-4.37%**	$237,975
TOTAL	**$208,493,361**	**$213,484,095**	**($4,990,734)**	**-2.34%**	**$1,590,759**

	(6)	(7)	(8)	(9)	(10)
			(7)/(2)		
	Prior Period Adj. Over/(Under)	Total Over/(Under) Collection	Cumulative %	Estimated Sales Therms	**True-Up Factors (Therms) (Refund)/Collection**
Residential	$0	($1,212,898)	**-1.08%**	358,946,694	**$0.00338**
Commercial/Industrial Firm	$0	($1,158,718)	**-1.82%**	205,424,450	**$0.00564**
Demand Billed Demand	$0	$31,327	**2.04%**	2,844,240	**($0.01101)**
Demand Billed Commodity	$0	($256,646)	**-3.46%**	27,679,068	**$0.00927**
Small Interruptible	$0	($49,747)	**-0.83%**	22,937,112	**$0.00217**
Medium & Large Interruptible	$0	($753,293)	**-3.32%**	79,178,311	**$0.00951**
TOTAL	**$0**	**($3,399,975)**	**-1.59%**	**694,165,635**	

Xcel Gas
2015-2016 True Up
Docket No. G002/AA-16-725
As Filed September 1, 2016

Recovery by Class		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
Residential		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$28,198,338	$29,677,390	($1,479,052)	-4.98%
TU Sch. D, page 4	Commododity & Peak Shaving	$82,127,461	$82,573,270	($445,809)	-0.54%
	TOTAL	$110,325,799	$112,250,660	($1,924,861)	-1.71%
Commercial/Industrial Firm		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$15,565,823	$16,725,701	($1,159,878)	-6.93%
TU Sch. D, page 4	Commododity & Peak Shaving	$46,376,646	$46,843,533	($466,887)	-1.00%
	TOTAL	$61,942,469	$63,569,234	($1,626,765)	-2.56%
Demand Billed		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$1,567,565	$1,533,609	$33,956	2.21%
TU Sch. D, page 4	Commododity & Peak Shaving	$7,070,909	$7,413,440	($342,531)	-4.62%
	TOTAL	$8,638,474	$8,947,049	($308,575)	-3.45%
Small Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$5,886,143	$6,025,408	($139,265)	-2.31%
	TOTAL	$5,886,143	$6,025,408	($139,265)	-2.31%
Medium & Large Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$21,700,476	$22,691,744	($991,268)	-4.37%
	TOTAL	$21,700,476	$22,691,744	($991,268)	-4.37%

Recovery by Component		RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) (%)
Demand	Residential	$28,198,338	$29,677,390	($1,479,052)	-4.98%
Demand	Commercial/Industrial Firm	$15,565,823	$16,725,701	($1,159,878)	-6.93%
Demand	Demand Billed	$1,567,565	$1,533,609	$33,956	2.21%
	TOTAL DEMAND	$45,331,726	$47,936,700	($2,604,974)	-5.43%
Commodity	Residential	$82,127,461	$82,573,270	($445,809)	-0.54%
Commodity	Commercial/Industrial Firm	$46,376,646	$46,843,533	($466,887)	-1.00%
Commodity	Demand Billed	$7,070,909	$7,413,440	($342,531)	-4.62%
Commodity	Small Interruptible	$5,886,143	$6,025,408	($139,265)	-2.31%
Commodity	Medium & Large Interruptible	$21,700,476	$22,691,744	($991,268)	-4.37%
	TOTAL COMMODITY	$163,161,635	$165,547,395	($2,385,760)	-1.44%

Attachment G12
COMMODITY COSTS
Total Weighted Average Cost of Commodity
PGA Recovered Versus Actual Incurred [2]

PGA System	Recovered PGA Commodity Rate	Rankings	Difference Btwn Recovered PGA Commodity Rate ($/Mcf) And Mn Weighted Avg		Difference Btwn Recovered PGA Commodity Rate ($/Mcf) And Mn Non-Weighted Avg		Actual Annual Commodity Rate	Rankings	Difference Btwn Actual Annual Commodity Rate ($/Mcf) And Mn Weighted Avg		Difference Btwn Actual Annual Commodity Rate ($/Mcf) And Mn Non-Weighted Avg		Percent Over/(Under) Recovery	Rankings
	$/Mcf		$/Mcf	%	$/Mcf	%	$/Mcf		$/Mcf	%	$/Mcf	%		
Greater Minnesota	$ 3.7690	**8**	$ 0.9535	33.87%	$ 0.8703	30.03%	$ 3.7518	**8**	$ 0.8861	30.92%	$ 0.8467	29.14%	0.46%	**4**
Great Plains North***	$ 2.3623	**1**	$ (0.4532)	-16.10%	$ (0.5364)	-18.50%	$ 2.2913	**1**	$ (0.5745)	-20.05%	$ (0.6138)	-21.13%	3.10%	**8**
Great Plains South	$ 2.4626	**2**	$ (0.3528)	-12.53%	$ (0.4360)	-15.04%	$ 2.4517	**2**	$ (0.4140)	-14.45%	$ (0.4534)	-15.61%	0.45%	**2**
MERC-Consolidated	$ 3.0152	**6**	$ 0.1997	7.09%	$ 0.1165	4.02%	$ 3.0016	**6**	$ 0.1359	4.74%	$ 0.0965	3.32%	0.45%	**3**
MERC-NNG	$ 3.3717	**7**	$ 0.5562	19.76%	$ 0.4730	16.32%	$ 3.3712	**7**	$ 0.5055	17.64%	$ 0.4661	16.04%	0.01%	**1**
MERC-AL	$ 2.7934	**4**	$ (0.0220)	-0.78%	$ (0.1052)	-3.63%	$ 2.8480	**4**	$ (0.0178)	-0.62%	$ (0.0572)	-1.97%	-1.92%	**6**
CenterPoint Energy****	$ 2.8265	**5**	$ 0.0110	0.39%	$ (0.0722)	-2.49%	$ 2.9048	**5**	$ 0.0390	1.36%	$ (0.0004)	-0.01%	-2.69%	**7**
Xcel Gas	$ 2.5885	**3**	$ (0.2269)	-8.06%	$ (0.3101)	-10.70%	$ 2.6206	**3**	$ (0.2451)	-8.55%	$ (0.2845)	-9.79%	-1.22%	**5**
Weighted MN Average	**$ 2.8155**						**$ 2.8657**						**-1.75%**	
Non-Weighted MN Average	**$ 2.8986**						**$ 2.9051**						**-0.22%**	
Standard Deviation	**$ 0.4759**						**$ 0.4796**							

***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
2 The numbers reported in this table are from the Annual Automatic Adjustment filing submitted by each utility.
The numbers used and the detailed calculations are contained in Attachment G15.

Attachment G12a
Total System Gas Costs²

PGA System	PGA Recovered	Actual Total Gas Sales (MMBtu)	PGA Recovered ($/MMBtu)	**Rankings**	Difference Btwn PGA Recovered And Mn Weighted Avg $/MMBtu	%	Difference Btwn PGA Recovered And Mn Non-Weighted Avg $/MMBtu	%	Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)	Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**	Difference Btwn Current-Period Actual Incurred Gas Cost And Mn Weighted Avg $/MMBtu	%	Difference Btwn Current-Period Actual Incurred Gas Cost And Mn Non-Weighted Avg $/MMBtu	%	Actual Over/(Under) ($/MMBtu)	Percent Over/(Under) Recovery
	(1)	(2)	(3) = (1)/(2)						(4)	(5)	(6) = (4)/(5)						(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota Gas	$ 3,975,174	1,045,693	$ 3.8015	**7**	$ 0.2407	6.76%	$ 0.1564	4.29%	$ 3,923,221	1,045,693	$ 3.7518	**6**	$ 0.0988	2.71%	$ 0.0445	1.20%	$ 0.0497	1.32%
Great Plains North***	$ 5,077,612	1,470,806	$ 3.4523	**2**	$ (0.1085)	-3.05%	$ (0.1928)	-5.29%	$ 5,163,189	1,470,806	$ 3.5104	**2**	$ (0.1425)	-3.90%	$ (0.1968)	-5.31%	$ (0.0582)	-1.66%
Great Plains South	$ 5,610,225	1,580,748	$ 3.5491	**3**	$ (0.0117)	-0.33%	$ (0.0960)	-2.63%	$ 5,752,732	1,580,748	$ 3.6392	**4**	$ (0.0137)	-0.38%	$ (0.0680)	-1.83%	$ (0.0902)	-2.48%
MERC-Consolidated	$ 19,154,988	5,242,690	$ 3.6537	**6**	$ 0.0929	2.61%	$ 0.0086	0.24%	$ 19,018,750	5,242,690	$ 3.6277	**3**	$ (0.0253)	-0.69%	$ (0.0796)	-2.15%	$ 0.0260	0.72%
MERC-NNG	$ 92,150,994	22,042,556	$ 4.1806	**8**	$ 0.6198	17.41%	$ 0.5355	14.69%	$ 94,613,319	22,042,556	$ 4.2923	**8**	$ 0.6393	17.50%	$ 0.5851	15.78%	$ (0.1117)	-2.60%
MERC-AL	$ 5,275,747	1,452,962	$ 3.6310	**5**	$ 0.0703	1.97%	$ (0.0141)	-0.39%	$ 5,465,133	1,452,962	$ 3.7614	**7**	$ 0.1084	2.97%	$ 0.0541	1.46%	$ (0.1303)	-3.47%
CenterPoint Energy****	$ 372,764,107	104,681,888	$ 3.5609	**4**	$ 0.0001	0.00%	$ (0.0842)	-2.31%	$ 383,527,681	104,681,888	$ 3.6637	**5**	$ 0.0108	0.30%	$ (0.0435)	-1.17%	$ (0.1028)	-2.81%
Xcel Gas	$ 208,493,362	62,580,101	$ 3.3316	**1**	$ (0.2292)	-6.44%	$ (0.3135)	-8.60%	$ 213,484,094	62,580,101	$ 3.4114	**1**	$ (0.2416)	-6.61%	$ (0.2959)	-7.98%	$ (0.0797)	-2.34%
Mn Weighted Average	**$ 712,502,209**	**200,097,444**	**$ 3.5608**						**$ 730,948,119**	**200,097,444**	**$ 3.6530**						**$ (0.0922)**	**-2.52%**
Mn Non-Weighted Average			**$ 3.6451**								**$ 3.7072**						**$ (0.0622)**	**-1.68%**
Standard Deviation			**$ 0.2572**								**$ 0.2636**							

***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
2 The numbers reported in this table are from the Annual Automatic Adjustment filing submitted by each utility.
The numbers used and the detailed calculations tie to Attachment G15 and G16.

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G15 AND TABLE G18)
July 1, 2015 - June 30, 2016

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		2014-2015	**2015-2016**			**2014-2015**	**2015-2016**			**2014-2015**	**2015-2016**			**2014-2015**	**2015-2016**		
Company	**Tariff Rate Designation**	**Annual Customer Charge ($)**	**Annual Customer Charge ($)**	**$ Diff (2) - (1)**	**% Diff (3)/(1)**	**Average Combined Commodity and Demand Charges ($/Mcf)**	**Average Combined Commodity and Demand Charges ($/Mcf)**	**$ Diff (6) - (5)**	**% Diff (7)/(5)**	**Average Non-Gas Commodity Margin ($/Mcf)**	**Average Non-Gas Commodity Margin ($/Mcf)**	**$ Diff (10) - (9)**	**% Diff (11)/(9)**	**Average True-Up ($/Mcf)**	**Average True-Up ($/Mcf)**	**$ Diff (14) - (13)**	**% Diff (15)/(13)**
Greater Minnesota Gas	RS-1	$102.00	$102.00	$0.00	0.00%	$4.6295	$3.9412	($0.6883)	-14.87%	$4.4433	$4.4433	$0.0000	0.00%	$0.0228	-$0.0337	($0.0565)	-247.81%
Great Plains North	N60	$78.00	$78.00	$0.00	0.00%	$5.2513	$3.8741	($1.3772)	-26.23%	$1.7867	$1.7227	($0.0640)	-3.58%	$0.9805	$0.1606	($0.8199)	-83.63%
Great Plains South	S60	$78.00	$78.00	$0.00	0.00%	$4.9237	$3.7515	($1.1723)	-23.81%	$1.4027	$1.3385	($0.0642)	-4.58%	$0.8032	$0.2990	($0.5042)	-62.77%
MERC-CON	MERC000002	$114.82	$119.70	$4.88	4.25%	$4.9814	$3.5753	($1.4061)	-28.23%	$2.2169	$2.3467	$0.1298	5.85%	$0.6757	$0.2678	($0.4080)	-60.37%
MERC-NNG	MERC000001	$114.82	$119.70	$4.88	4.25%	$5.7637	$4.6270	($1.1367)	-19.72%	$2.2169	$2.3434	$0.1265	5.71%	$0.3922	($0.0634)	($0.4555)	-116.15%
IPL/MERC-AL*	MERC000101	$60.00	$63.00	$3.00	5.00%	$4.9678	$4.0160	($0.9518)	-19.16%	$2.0109	$2.3438	$0.3330	16.56%	($0.3517)	($0.0045)	$0.3472	-98.72%
CenterPoint Energy	Residential	$108.45	$118.86	$10.41	9.60%	$4.7189	$3.6303	($1.0886)	-23.07%	$1.9849	$2.2666	$0.2817	14.19%	$0.3398	($0.0050)	($0.3448)	-101.47%
Xcel Gas	101	$108.00	$108.00	$0.00	0.00%	$4.8396	$4.0739	($0.7657)	-15.82%	$1.8591	$1.8591	$0.0000	0.00%	$0.5636	$0.1693	($0.3944)	-69.97%
MN NON-WEIGHTED AVERAGE		$95.51	$98.41	$2.90	3.03%	$5.01	$3.94	($1.0733)	-21.43%	$2.24	$2.33	$0.0928	4.14%	$0.4283	$0.0988	($0.3295)	-76.94%

*IPL and MERC-AL's partial year historical numbers are used for 2014-2015.
Previous reports used simple averages; current report uses weighted averages as provided by the utilities in response to Information Request 1.
The difference between using simple and weighted averages is not significant, however it more accurately reflects average costs throughout the year.

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G15 AND TABLE G18)
July 1, 2015 - June 30, 2016

		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)
		2014-2015	2015-2016			2014-2015	2015-2016			2014-2015	2015-2016			2014-2015	2015-2016		
Company	Tariff Rate Designation	Average Total Cost of Gas ($/Mcf) (6)+(10)+(14)	Average Total Cost of Gas ($/Mcf) (6)+(10)+(14)	$ Diff (18) - (17)	% Diff (19)/(17)	Average Use (Mcf)	Average Use (Mcf)	Mcf Diff (22) - (21)	% Diff (23)/(21)	Total Average Customer Use (Mcf)	Total Average Customer Use (Mcf)	Mcf Diff (26) - (25)	% Diff (27)/(25)	Average Number of Customers	Average Number of Customers	Customer Diff (30) - (29)	% Diff (31)/(29)
Greater Minnesota Gas	RS-1	$9.0956	$8.3508	($0.7448)	-8.19%	7.25	6.04	(1.21)	-16.67%	87.00	72.50	(14.50)	-16.67%	5,137	5,766	629.17	12.25%
Great Plains North	N60	$8.0185	$5.7573	($2.2611)	-28.20%	6.69	5.74	(0.95)	-14.20%	80.30	68.90	(11.40)	-14.20%	8,181	8,244	62.75	0.77%
Great Plains South	S60	$7.1296	$5.3890	($1.7406)	-24.41%	6.03	5.27	(0.77)	-12.71%	72.40	63.20	(9.20)	-12.71%	9,997	10,030	33.33	0.33%
MERC-CON	MERC000002	$7.8741	$6.1898	($1.6843)	-21.39%	7.29	6.21	(1.08)	-14.80%	87.44	74.50	(12.94)	-14.80%	29,323	30,068	744.75	2.54%
MERC-NNG	MERC000001	$8.3728	$6.9071	($1.4657)	-17.51%	7.45	6.34	(1.10)	-14.84%	89.36	76.10	(13.26)	-14.84%	164,399	168,150	3,751.00	2.28%
IPL/MERC-AL*	MERC000101	$6.6269	$6.3553	($0.2716)	-4.10%	7.61	6.37	(1.25)	-16.38%	91.37	76.40	(14.97)	-16.38%	9,176	9,515	339.42	3.70%
CenterPoint Energy	Residential	$7.0437	$5.8919	($1.1518)	-16.35%	7.70	6.58	(1.12)	-14.60%	92.39	78.90	(13.49)	-14.60%	760,426	768,696	8,269.83	1.09%
Xcel Gas	101	$7.2623	$6.1022	($1.1601)	-15.97%	7.42	6.35	(1.07)	-14.39%	89.00	76.20	(12.80)	-14.39%	411,200	414,823	3,622.67	0.88%
MN NON-WEIGHTED AVERAGE		$7.6779	$6.3679	($1.3100)	-17.06%	7.18	6.11	(1.07)	-14.88%	86.16	73.34	(12.82)	-14.88%	174,730	176,912	2,181.61	1.25%

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G15 AND TABLE G18)
July 1, 2015 - June 30, 2016

		(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)
		2014-2015	**2015-2016**			**2014-2015**	**2015-2016**			**2014-2015**	**2015-2016**		
Company	**Tariff Rate Designation**	**Average Total Monthly Bill ($) [(2)/12]+[(18)*(22)]**	**Average Total Monthly Bill ($) [(2)/12]+[(18)*(22)]**	**$ Diff (34) - (33)**	**% Diff (35)/(33)**	**Average Total Annual Bill ($) (2)+[(18)*(26)]**	**Average Total Annual Bill ($) (2)+[(18)*(26)]**	**$ Diff (38) - (37)**	**% Diff (39)/(37)**	**Average Total Annual Bill at 140 Mcf/Year ($) (1)+[(18)*140]**	**Average Total Annual Bill at 140 Mcf/Year ($) (1)+[(18)*140]**	**$ Diff (42) - (41)**	**% Diff (43)/(41)**
Greater Minnesota Gas	RS-1	$74.44	$58.95	-$15.49	-20.81%	$893.32	$707.43	-$185.89	-20.81%	$1,375.39	$1,271.11	-$104.28	-7.58%
Great Plains North	N60	$60.16	$39.56	-$20.60	-34.24%	$721.88	$474.68	-$247.20	-34.24%	$1,200.58	$884.03	-$316.56	-26.37%
Great Plains South	S60	$49.52	$34.88	-$14.63	-29.55%	$594.18	$418.59	-$175.60	-29.55%	$1,076.15	$832.46	-$243.69	-22.64%
MERC-CON	MERC000002	$66.95	$48.40	-$18.54	-27.70%	$803.35	$580.84	-$222.51	-27.70%	$1,217.19	$986.27	-$230.92	-18.97%
MERC-NNG	MERC000001	$71.92	$53.78	-$18.14	-25.22%	$862.99	$645.33	-$217.66	-25.22%	$1,287.02	$1,086.69	-$200.33	-15.57%
IPL/MERC-AL*	MERC000101	$55.46	$45.71	-$9.75	-17.58%	$665.51	$548.54	-$116.96	-17.58%	$987.77	$952.74	-$35.03	-3.55%
CenterPoint Energy	Residential	$63.27	$48.64	-$14.62	-23.11%	$759.21	$583.73	-$175.48	-23.11%	$1,094.56	$943.73	-$150.84	-13.78%
Xcel Gas	101	$62.86	$47.75	-$15.12	-24.04%	$754.37	$572.99	-$181.38	-24.04%	$1,124.72	$962.31	-$162.41	-14.44%
MN NON-WEIGHTED AVERAGE		$63.07	$47.21	-$15.86	-25.15%	$756.85	$566.52	-$190.34	-25.15%	$1,170.42	$989.92	-$180.51	-15.42%

Attachment G14
Daily Delivery Variance Charges (DDVC)
Supporting Tables G22 and G23

Source IR 7

DDVC Volumes (MMbtu)			
Company	Positive & Negative	punitive	total
Greater Minnesota	12,190	-	12,190
Great Plains	18,402	-	18,402
CPE	88,960	-	88,960
MERC-CON	-	-	-
Xcel Gas-MN	106,300	-	106,300
MERC-AL	2,693		
MERC-NNG	34,906	-	34,906
MN Totals	263,451	-	260,758

DDVC ($)					Percent of Total Costs Incurred		
Company	Positive & Negative	punitive	total	Actual Incurred Gas Cost ($)	Positive & Negative	punitive	total
Greater Minnesota	$189	$123	$312	$3,923,221	0.0048%	0.0031%	0.0080%
Great Plains	$3,247	$0	$3,247	$10,915,921	0.0297%	0.0000%	0.0297%
CPE	$46,227	$0	$46,227	$383,527,682	0.0121%	0.0000%	0.0121%
MERC-CON	$0	$0	$0	$19,030,439	0.0000%	0.0000%	0.0000%
Xcel Gas-MN	$22,022	$0	$22,022	$213,484,094	0.0103%	0.0000%	0.0103%
MERC-AL	$893	$0	$893	$5,465,133	0.0163%	0.0000%	0.0163%
MERC-NNG	$28,557	$0	$28,557	$94,624,912	0.0302%	0.0000%	0.0302%
MN Totals	$101,135	$123	$101,258	$730,971,402	0.0138%	0.0000%	0.0139%

Source: IR 7

Note: Xcel's and GP's charges are overrun charges on the Viking pipeline system rather than DDVCs on NNG's pipeline system.

Attachment G15
TOTAL COMMODITY COSTS 1
Rate Class: ALL CLASSES

PGA System	Actual Total Gas Sales (Mcf)	Recovered Annual PGA Commodity Costs ($)	Recovered PGA Commodity Rate ($/Mcf)	Actual Total Gas Sales (Mcf)	Actual Total Annual Commodity Costs ($)	Actual Annual Commodity Rate ($/Mcf)	% Change
	(1)	(2)	(3) = (2)/(1)	(4)	(5)	(6) = (5)/(4)	(7) = (3-6)/(6)
Greater Minnesota	1,045,693	$ 3,941,185	$ 3.7690	1,045,693	$ 3,923,221	$ 3.7518	0.46%
Great Plains North	1,470,806	$ 3,474,413	$ 2.3623	1,470,806	$ 3,370,003	$ 2.2913	3.10%
Great Plains South	1,580,748	$ 3,892,801	$ 2.4626	1,580,748	$ 3,875,527	$ 2.4517	0.45%
MERC-Consolidated***	5,242,690	$ 15,807,644	$ 3.0152	5,242,690	$ 15,736,719	$ 3.0016	0.45%
MERC-NNG***	22,042,556	$ 74,319,858	$ 3.3717	22,042,556	$ 74,309,657	$ 3.3712	0.01%
MERC-AL*****	1,452,962	$ 4,058,717	$ 2.7934	1,452,962	$ 4,137,970	$ 2.8480	-1.92%
CenterPoint Energy****	104,681,888	$ 295,880,912	$ 2.8265	104,681,888	$ 304,074,770	$ 2.9048	-2.69%
Xcel Gas	62,580,101	$ 161,989,541	$ 2.5885	62,580,101	$ 163,996,275	$ 2.6206	-1.22%
MN Weighted Average	200,097,444	$ 563,365,071	$ 2.8155	200,097,444	$ 573,424,142	$ 2.8657	-1.75%
MN Non-Weighted Average			$ 2.8986			$ 2.9051	-0.22%

***NOTE: MERC's four PGA systems (NMU, PNG, GL, VIK) were consolidated into two PGA systems (MERC-CON and MERC-NNG) effective July 1, 2013.
****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
*****NOTE: MERC's purchased Interstate Power's Minnesota operations and created the MERC-AL PGA system, effective May 1, 2015.
1 Recovered and Actual Annual PGA Commodity Costs (columns 2 and 5) are from the Annual True-Up filings submitted by each utility.

Attachment G16
Current-Year Total System Demand and Commodity Costs1
Rate Class: ALL CLASSES

PGA System		PGA Recovered	Actual Total Gas Sales (MMBtu)		PGA Recovered ($/MMBtu)	**Rankings**		Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)		Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**		Actual Over(Under) ($/MMBtu)	Percent Over(Under) Recovery
		(1)	(2)		(3) = (1)/(2)			(4)	(5)		(6) = (4)/(5)			(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota	$	3,975,174	1,045,693	$	3.8015	**7**	$	3,923,221	1,045,693	$	3.7518	**6**	$	0.0497	1.32%
Great Plains North***	$	5,077,612	1,470,806	$	3.4523	**2**	$	5,163,189	1,470,806	$	3.5104	**2**	$	(0.0582)	-1.66%
Great Plains South	$	5,610,225	1,580,748	$	3.5491	**3**	$	5,752,732	1,580,748	$	3.6392	**4**	$	(0.0902)	-2.48%
MERC-Consolidated	$	19,154,988	5,242,690	$	3.6537	**6**	$	19,018,750	5,242,690	$	3.6277	**3**	$	0.0260	0.72%
MERC-NNG	$	92,150,994	22,042,556	$	4.1806	**8**	$	94,613,319	22,042,556	$	4.2923	**8**	$	(0.1117)	-2.60%
MERC-AL	$	5,275,747	1,452,962	$	3.6310	**5**	$	5,465,133	1,452,962	$	3.7614	**7**	$	(0.1303)	-3.47%
CenterPoint Energy	$	372,764,107	104,681,888	$	3.5609	**4**	$	383,527,681	104,681,888	$	3.6637	**5**	$	(0.1028)	-2.81%
Xcel Gas	$	208,493,362	62,580,101	$	3.3316	**1**	$	213,484,094	62,580,101	$	3.4114	**1**	$	(0.0797)	-2.34%
Mn Weighted Average	**$**	**712,502,209**	**200,097,444**	**$**	**3.5608**		**$**	**730,948,119**	**200,097,444**	**$**	**3.6530**		**$**	**(0.0922)**	**-2.52%**
Mn Non-Weighted Average				**$**	**3.6451**					**$**	**3.7072**		**$**	**(0.0622)**	**-1.68%**
Standard Deviation					**0.2572**						**0.2636**				

***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became NNG and Vik. area combined.
1 The numbers reported in this table are from the true ups filing submitted by each utility.
The numbers used and the detailed calculations are contained in Attachment G12a.

Attachment G17
Current-Year Total Demand and Commodity Costs 1
Rate Class: FIRM

PGA System	PGA Recovered	Actual Total Gas Sales (MMBtu)	PGA Recovered ($/MMBtu)	**Rankings**	Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)	Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**	Actual Over(Under) ($/MMBtu)	Percent Over(Under) Recovery
	(1)	(2)	(3) = (1)/(2)		(4)	(5)	(6) = (4)/(5)		(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota	$ 3,634,611	922,596	$ 3.9395	**6**	$ 3,577,988	922,596	$ 3.8782	**4**	$ 0.0614	1.58%
Great Plains North	$ 3,929,499	994,451	$ 3.9514	**7**	$ 4,068,162	994,451	$ 4.0909	**7**	$ (0.1394)	-3.41%
Great Plains South	$ 4,770,923	1,247,862	$ 3.8233	**4**	$ 4,886,278	1,247,862	$ 3.9157	**5**	$ (0.0924)	-2.36%
MERC-Consolidated*** 2	$ 16,580,834	4,383,674	$ 3.7824	**3**	$ 16,442,758	4,383,674	$ 3.7509	**3**	$ 0.0315	0.84%
MERC-NNG*** 2	$ 84,627,736	19,813,216	$ 4.2713	**8**	$ 86,346,747	19,813,216	$ 4.3580	**8**	$ (0.0868)	-1.99%
MERC-AL******	$ 4,494,244	1,172,025	$ 3.8346	**5**	$ 4,641,184	1,172,025	$ 3.9600	**6**	$ (0.1254)	-3.17%
CenterPoint Energy*****	$ 340,077,862	93,264,083	$ 3.6464	**2**	$ 349,668,911	93,264,083	$ 3.7492	**2**	$ (0.1028)	-2.74%
Xcel Gas****	$ 180,906,742	52,163,314	$ 3.4681	**1**	$ 184,766,943	52,163,314	$ 3.5421	**1**	$ (0.0740)	-2.09%
Mn Weighted Average	**$ 639,022,451**	**173,961,221**	**$ 3.6734**		**$ 654,398,971**	**173,961,221**	**$ 3.7618**		**$ (0.0884)**	**-2.35%**
Mn Non-Weighted Average			**$ 3.8396**				**$ 3.9056**		**$ (0.0660)**	**-1.69%**

***NOTE: MERC's four PGA systems (NMU, PNG, GL, VIK) were consolidated into two PGA systems (MERC-CON and MERC-NNG) effective July 1, 2013.
****NOTE: Xcel Gas considers the LGS/Demand Billed customers Firm customers.
*****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005.
******NOTE: MERC's purchased Interstate Power's Minnesota operations and created the MERC-AL PGA system, effective May 1, 2015.
1 The numbers reported in this table are from the true up filings and utility AAA reports.
2 MERC's Interruptible numbers include the Joint customers since Joint customers are not considered firm on the peak day.

This Table was prepared as requested by Commission Staff (See Commission staff briefing papers of November 8, 2001 in Docket No. E,G999/AA-00-1027, page 31). Please keep in mind that the comparisions between the regulated utilities will not be an "apples-to-apples" comparision as each utility has different rate structures and tariffs.

Attachment G18
Current-Year Total Costs1
Rate Class: INTERRUPTIBLE

PGA System		PGA Recovered	Actual Total Gas Sales (MMBtu)		PGA Recovered ($/MMBtu)	**Rankings**		Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)		Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**		Actual Over(Under) ($/MMBtu)	Percent Over(Under) Recovery
		(1)	(2)		(3) = (1)/(2)			(4)	(5)		(6) = (4)/(5)			(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota	$	340,563	123,097	$	2.7666	**4**	$	345,233	123,097	$	2.8046	**4**	$	(0.0379)	-1.35%
Great Plains North***	$	1,148,113	476,355	$	2.4102	**1**	$	1,095,027	476,355	$	2.2988	**1**	$	0.1114	4.85%
Great Plains South	$	839,302	332,886	$	2.5213	**2**	$	866,454	332,886	$	2.6029	**2**	$	(0.0816)	-3.13%
MERC-Consolidated *	$	2,574,154	859,016	$	2.9966	**7**	$	2,575,992	859,016	$	2.9988	**7**	$	(0.0021)	-0.07%
MERC-NNG *	$	7,523,258	2,229,340	$	3.3747	**8**	$	8,266,572	2,229,340	$	3.7081	**8**	$	(0.3334)	-8.99%
MERC-AL *	$	781,503	280,937	$	2.7818	**5**	$	823,949	280,937	$	2.9329	**5**	$	(0.1511)	-5.15%
CenterPoint Energy*****	$	32,686,245	11,417,805	$	2.8627	**6**	$	33,858,770	11,417,805	$	2.9654	**6**	$	(0.1027)	-3.46%
Xcel Gas****	$	27,586,620	10,416,787	$	2.6483	**3**	$	28,717,151	10,416,787	$	2.7568	**3**	$	(0.1085)	-3.94%
Mn Weighted Average	**$**	**73,479,758**	**26,136,223**	**$**	**2.8114**		**$**	**76,549,148**	**26,136,223**	**$**	**2.9289**		**$**	**(0.1174)**	**-4.01%**
Mn Non-Weighted Average				**$**	**2.7953**					**$**	**2.8835**		**$**	**(0.0882)**	**-3.06%**

*NOTE: MERC's Interruptible numbers include the joint customers since Joint customers are not considered firm on the peak day.
***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****NOTE: Xcel Gas considers the LGS/Demand Billed customers Firm customers.
*****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became NNG and Vik. area combined.
1 The numbers reported in this table are from the true up filings and utility AAA reports.

This Table was prepared as requested by Commission Staff (See Commission staff briefing papers of November 8, 2001 in Docket No. E,G999/AA-00-1027, page 31).

Attachment G19
Lost-and-Unaccounted-for Gas
Supporting Table G29

SOURCE: IR 10

Utility Name	Purchased Gas (Mcf)	Purchased Gas Adjustments (Mcf)	Total Gas Purchased (Mcf)	Customer Use Gas (Mcf)	Company Use Gas (Mcf)	Consumed Gas Adjustments (Mcf)	Total Consumed Gas (Mcf)	Lost and Unaccounted Gas (Mcf)	Percent Unaccounted for Gas lost (found)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			(3)=(1)+(2)				(7)=(4)+(5)+(6)	(8)=(3)-(7)	(9)=[(8)/(3)]
Greater Minnesota	1,037,770	0	1,037,770	1,045,694	5,695	0	1,051,389	(13,619)	-1.31%
Great Plains total co. #	3,267,016	(37,223)	3,229,793	3,051,554	0	114,517	3,166,071	63,722	1.97%
Great Plains North								46,582	1.44%
Great Plains South								17,140	0.53%
MERC-AL	1,459,481	19,786	1,479,267	1,452,962	0	0	1,452,962	26,305	1.78%
MERC-Consolidated **	5,255,744	0	5,255,744	5,242,690	0	0	5,242,690	13,054	0.25%
MERC-NNG **	21,817,469	(92,473)	21,724,996	22,042,555	0	0	22,042,555	(317,559)	-1.46%
CenterPoint Energy	107,599,755	(489,112)	107,110,643	104,964,193	121,595	0	105,085,788	2,024,855	1.89%
Xcel Gas Mn jurisdiction *	64,116,163	214,074	64,330,237	62,572,369	7,732	0	62,580,101	1,750,136	2.72%
Statewide Totals	204,553,398	(384,948)	204,168,450	200,372,017	135,022	114,517	200,621,556	3,610,616	1.77%

Great Plains states that its Company use gas volumes are included in the Customer Use Gas column. GP's IR 16 states volumes represent estimated calendar month sales and the true-up volumes represent billed sales volumes.
* Xcel's LNG & propane purchases reported in Purchased Gas Adjustments, column (2).
** MERC's company use gas volumes (15,497 Dth for MERC-CON, 7,629 Dth for MERC-NNG, 35 Dth for MERC-AL) are subtracted from the Purchased Gas, column (1).

Attachment G20
Supporting Schedule to Tables G19 and G20

	Firm Design Day Demand (Mcf) (1)	Firm Design Day Deliverability **w/ Peak-Shaving** (Mcf) (2)	Actual Peak Day Date (Mcf) (3)	Design-Day Customer Numbers (4)	Actual Firm Peak Day Usage (Mcf) (5)	Annual Firm Throughput (Mcf) (6)	Design-Day Use Per Customer (7)	Peak-Day Use Per Design-Day Customer (8)	Annual Firm Load Factor (9)	Reserve Margin (10)	Annual Firm Requirement % (11)
Source:	**IR#2**	**IR#2**	**IR#3**	**IR#2**	**IR#3**	**IR#2**	**(7)=(1)/(4)**	**(8)=(1)/(5)**	**(9)=((6)/365)/(5)**	**(10)=((2)-(1))/(1)**	**(11)=(5)/(2)**
Greater Minnesota	11,343	12,509	01/17/16	7,740	9,495	922,596	1.4655	1.1946	26.62%	10.28%	75.9%
Great Plains North District #	15,409	15,700	01/09/16	11,843	11,664	1,243,821	1.3011	1.3211	29.22%	1.89%	74.3%
Great Plains South District	16,858	17,845	01/16/16	12,039	15,582	1,247,862	1.4003	1.0819	21.94%	5.85%	87.3%
MERC-AL	13,813	14,190	01/17/16	10,690	10,957	1,225,639	1.2921	1.2607	30.65%	2.73%	77.2%
CenterPoint Energy	1,317,000	1,343,566	01/17/16	841,135	994,146	93,327,590	1.5657	1.3248	25.72%	2.02%	74.0%
MERC-CON	53,075	55,449	01/17/16	34,799	42,686	5,033,575	1.5252	1.2434	32.31%	4.47%	77.0%
Xcel Gas (Mn JURISDICTION)	717,478	738,570	01/18/16	450,630	537,190	58,684,693	1.5922	1.3356	29.93%	2.94%	72.7%
MERC-NNG	245,263	252,127	01/17/16	181,460	204,517	22,927,456	1.3516	1.1992	30.71%	2.80%	81.1%
Totals	**2,390,239**	**2,449,956**		**1,550,336**	**1,826,237**	**184,613,232**	**1.5418**	**1.3088**	**27.70%**	**2.50%**	74.5%
TOTAL prior year		2,453,191									
change from prior year		(3,235)									

The North District includes Wahpeton, North Dakota.
NOTE: Xcel's reports Mn Jurisdiction in IR 2 and 3 and MN + ND in IR 4.

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
Review of 2015-2016 Annual Automatic Adjustment Reports

Docket No. G999/AA-16-524; G022/AA-16-715; G004/AA-16-719; G002/AA-16-725; G008/AA-16-730; G011/AA-16-732; G011/AA-16-733; and G011/AA-16-734

Dated this 11th day of August 2017

/s/Sharon Ferguson

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