MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	March 30, 2023	Agenda Item	4*

Company	All Commission Regulated Natural Gas Utilities
Docket No.	**G-999/AA-19-401** **In the Matter of the Review of the 2018-2019 Annual Automatic Adjustment (AAA) Reports and Annual Purchased Gas Adjustment (PGA) True-up Filings** **G-011/AA-19-517** **In the Matter of Minnesota Energy Resources Corporation – NNG's 2019 True-up Filing** **G-011/AA-19-518** **In the Matter of Minnesota Energy Resources Corporation – Consolidated's 2019 True-up Filing** **G-022/AA-19-542** **In the Matter of Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co., Annual True-up Report** **G-002/AA-19-551** **In the Matter of Northern States Power Company's 2019 Annual Purchased Gas Adjustment True-Up Filing** **G-004/AA-19-555** **In the Matter of Greater Minnesota Gas, Inc.'s Annual True-up Report for 2019** **G-008/AA-19-556** **In the Matter of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas Annual True-up Report**

Issues	Should the Commission accept the natural gas utilities' 2018-2019 annual automatic adjustment reports and 2018-2019 annual true-up filings?

Staff Godwin Ubani godwin.ubani@state.mn.us 651-201-2191

✓ **Relevant Documents** **Date**

Docket No. G-999/AA-19-401

Great Plains – Automatic Adjustment of Gas Charges AAA Annual Report	August 29, 2019
Greater Minnesota Gas – 2019 Annual Automatic Adjustment Report (Public and Trade Secret)	August 30, 2019
Xcel Energy – Gas AAA (Public and Trade Secret)	August 30, 2019
Minnesota Energy Resources Corporation – 2019 Annual Automatic Adjustment Report (Trade Secret)	August 30, 2019
Minnesota Energy Resources Corporation – 2019 NNG Annual Automatic Adjustment Report (Public and Trade Secret)	August 30, 2019
Minnesota Energy Resources Corporation – 2019 Consolidated Annual Automatic Adjustment Report	August 30, 2019
Minnesota Energy Resources Corporation – 2018 2019 Hedging Summary (Public and Trade Secret)	August 30, 2019
CenterPoint Energy – Annual Automatic Adjustment Report (Public and Trade Secret)	September 3, 2019
CenterPoint Energy – 2019 Annual Purchased Gas Adjustment True-Up	September 3, 2019
CenterPoint Energy – Compliance Filing	October 24, 2019
Department of Commerce – Review of the 2018-2019 AAA Reports	April 26, 2022
CenterPoint Energy – Reply Comments	April 28, 2022
Minnesota Energy Resources Corporation – Reply Comments	May 6, 2022
Xcel Energy – Reply Comments	May 6, 2022
Department of Commerce – Response Letter	June 6, 2022

Docket No. G-011/AA-19-517

Relevant Documents	Date
Minnesota Energy Resources Corporation – Initial Filing	August 30, 2019
Docket No. G-011/AA-19-518	
Minnesota Energy Resources Corporation – Initial Filing	August 30, 2019
Docket No. G-022/AA-19-542	
Great Plains – Initial Filing	August 29, 2019
Docket No. G-002/AA-19-551	
Xcel Energy – Initial Filing (Public and Trade Secret)	August 30, 2019
Docket No. G-004/AA-19-555	
Greater Minnesota Gas – Initial Filing	September 3, 2019
Docket No. G-008/AA-19-556	
CenterPoint Energy – Initial Filing	September 3, 2019

I. INTRODUCTION

Minnesota rules 7825.2800 – 7825.2830 require that Minnesota regulated public utilities using automatic adjustments to recover energy costs file annual reports regarding the operation of these automatic adjustments. Through these reports the commission verifies whether the utilities have calculated their rate adjustments properly and implemented the rates in a timely manner.

Each year the natural gas utilities file by September 1 annual automatic adjustment (AAA) reports and annual purchased gas adjustment (PGA) true-up filings for the previous July 1 through June 30 fiscal gas year. Every year, the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) performs an extensive review of the utilities' filings.

In the current dockets, the natural gas utilities incurred and recovered total purchased gas costs during the 2018-2019 fiscal gas year of approximately $1,089,446,130 and $1,089,541,629[1], respectively. there are no issues in dispute.

II. BACKGROUND

Automatic rate adjustments are covered under Minnesota Rules part 7825.2390 through 7825.2920. Each year the Commission reviews the automatic adjustment of charges reported in the natural gas and electric utilities' annual automatic adjustment (AAA) reports and the natural gas utilities' annual true-up filings. The Commission's review is closely tied to the Department's review of these filings.

On or before September 1, 2019, the following gas utilities submitted their AAA reports in this docket (Docket No. G-999/AA-19-401) and true-up filings (true-ups) in the dockets below:

Greater Minnesota Gas, Inc. (GMG)	G-004/AA-19-555
Great Plains Natural Gas Company (Great Plains)	G-022/AA-19-542
Minnesota Energy Resource Corporation (MERC-Consolidated PGA)	G-011/AA-19-518
Minnesota Energy Resource Corporation (MERC-NNG PGA)	G-011/AA-19-517
CenterPoint Energy (CenterPoint Energy or CPE)	G-008/AA-19-556
Northern States Power Company d/b/a Xcel Energy (Xcel Gas)	G-002/AA-19-551

1 Department's Review. P. 4.

Every year, the Department prepares a comprehensive review and analysis of the utilities' annual reports and provides comment on other topics that it believes are relevant. Thus, on April 26, 2022, the Department submitted its Review of the 2018-2019 annual automatic adjustment reports (Review). In its Review, the Department recommended the Commission accept the fiscal year annual reports ending on June 30, 2019 (FYE19) as filed by the gas utilities as being complete in compliance with Minnesota Rules, parts 7825.2390 through 7825.2920. The Department also recommended the Commission accept the annual true-up filings of all the natural gas utilities: GMG, Great Plains, MERC, CPE, and Xcel Gas. However, the Department requested that, in Reply Comments, MERC explain (1) whether and why the $33,283 of "positive" Daily Deliver Variance Charges (DDVCs) is the only DDVC/penalty charge amount that should be included the FYE19 over/under cost recovery calculation for the NNG system and (2) whether and why a difference exists between the DDVC/penalty charge amounts shown in MERC-NNG's FYE19 AAA Report and its reply to Department IR 7.

Also, the Department provided comments on the gas utilities' 2018-2019 gas costs, peak-day demand profiles and pipeline transportation sources, capacity releases, annual auditor reports, lost-and -unaccounted for gas, contractor main strikes and meter testing, purchasing and hedging practices, as well as other topics.

On April 28, 2022, CenterPoint Energy submitted reply comments.

On May 6, 2022, MERC and Xcel Energy submitted reply comments.

On June 6, 2022, the Department response filed a response letter (Department Response) and accepted MERC' explanations regarding the DDVC/penalty charges and indicated it has no further issues with MERC's 2019 AAA reports/true ups.

III. DISCUSSION

1. Department Review

The Department stated:

> In FYE19, natural gas prices were slightly higher on average than prices during FYE18. The average FYE19 price was just above $3 per million cubic feet (MCF) and rose to over $4 per MCF in November and December 2018. The price per MCF hovered near $3 for

most of the reporting period. The Henry Hub price[2] in FYE19 ranged between $2.27 and $4.70, beginning the reporting period at about $2.90 per MCF in July 2018 and ending the reporting period around $2.42 per MCF in June 2019.

Several factors could explain why prices in FYE19 increased slightly compared to the prior year. First, weather in Minnesota was colder than normal in FYE19, putting upward pressure on gas prices during the heating season. Second, storage levels in the months leading up to the 2018-19 heating season were at 3.198 billion cubic feet (BCF), the lowest level since 2005, and, despite FYE19 net withdrawals from storage being 5 percent below the five-year withdrawal average, end-of-heating-season storage levels were at their lowest since 2014.[3] The combination of low storage levels and an early, colder-than-normal start to the heating season in FYE19 may have contributed to the higher market prices seen in the first half of the heating season (November and December 2018). Third, natural gas consumption and production reached record levels in 2018. Production grew steadily over the year - due especially to production in the Appalachian Basin, Permian Basin, and the Haynesville shale formation. Consumption met the production growth by increasing across industrial, residential, and commercial sectors.[4] These 2018 record consumption levels were topped when a polar vortex covered much of the lower 48 states in January 2019. The January 2019 polar vortex especially impacted the Midwest, which saw temperatures 25°F or more below normal for three consecutive days. This cold weather caused some delivery-day gas price increases but, due at least in part to gains in natural gas production, the price spikes were less extreme than in other historical cold weather events. Market hubs in the Midwest and Northeast saw an increase in spot market prices the day before the polar vortex (January 28), with prices returning to near normal the day after the event (February 1).[5]

Gas price volatility for most of 2018 was moderate due to the corresponding record natural gas production. However, NYMEX near-month natural gas futures price volatility increased notably in November and December 2018, coinciding with the historically low pre-heating season gas storage, and growing natural gas consumption that outpaced production levels at the time. The relatively high consumption level during this time can

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[2] 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).

[3] EIA Natural Gas Weekly Update, April 10, 2019: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/04_11/.

[4] EIA Natural Gas Weekly Update, January 10, 2019: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/01_10/#itn-tabs-2.

[5] EIA Natural Gas Weekly Update, February 7, 2019: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/02_07/

be attributed to the colder-than-normal conditions, high levels of net natural gas exports, and the growing use of natural gas in the electric sector.

With the prevalence of shale gas, natural gas production has become more diversified and less reliant on any single basin or area of production. However, 51 percent of U.S. natural gas processing capacity is concentrated along the Gulf coast, making hurricanes an ongoing concern of market interruption.[6] During FYE19, there were several interruptions in natural gas production due to storms.

A. FYE19 AAA Reports and True-Up Filings

The Department noted that, since customers leave and join the utility's system over time, specific customers' mix on the utility's system probably change somewhat from one year to another year. Therefore, it is probable that some mismatch exists between the specific customers' mix receiving gas service in a given fiscal year and the customers' mix to which the refund or charge associated with the prior year's true up is assigned in subsequent years. The Department stated that gas costs generally comprise the largest component of gas utilities' customer's bill. The Department found that gas utilities incurred $1,089,446,130 in natural gas commodity, transportation, storage, and related purchased gas costs for FYE19. This amount represents an increase of $66,619,358 or 6.5% from the level ($1,022,826,772) in FYE18. The gas utilities recovered approximately $1,090,541,629 in natural gas costs in base rate and the monthly purchased gas adjustment (PGA). The PGA system over-and-under-recoveries during FYE19 ranged from a 1.34 percent under-recovery for Xcel gas to an over-recovery of 6.66 percent for MERC-NNG.[7]

The following table (G1) copied from page 5 of the Department' Review summarizes the fuel cost recovery during FYE19 for the gas utilities:

[6] EIA Natural Gas Weekly Update, December 20, 2018: https://www.eia.gov/special/gulf_of_mexico/

[7] Department's Review, p. 4.

Table G1: Summary of Gas Utilities' Annual Demand & Commodity Cost Recovery for FYE19

Utility/System	Gas Cost Recovered	Gas Cost Incurred	Over/(Under) Recovery	Over/(Under) Recovery
GMG	$6,079,223	$6,025,911	$53,312	0.88%
Great Plains	$18,701,798	$18,070,263	$631,535	3.49%
MERC-CON	$25,307,737	$24,090,033	$1,217,704	5.05%
MERC-NNG[17]	$144,460,394	$135,435,851	$9,024,543	6.66%
CenterPoint	$579,532,137	$586,074,385	$(6,542,248)	(1.12%)
Xcel Gas	$315,460,340	$319,749,687	$(4,289,347)	(1.34%)
MN Total	**$1,089,541,629**	**$1,089,446,130**	**$95,499**	**0.01%**

[Footnotes omitted]

The Department indicated in footnote 15 of its Review that information for Table G1 can be found in each of the utilities' True Up Reports, as shown in Department's Attachments G5 through G11.

The Department recommended that the Commission accept each of the utilities' July 1, 2018 - June 30, 2019, fiscal year true-up filings in individual true-up dockets. The Department also recommended the Commission allow each of the utilities to implement its FYE19 true-up(s) as shown in the Department' Attachment G5 though G11 of the Department' Review.

However, the Department found differences between the Daily Delivery Variance Charges (DDVCs) and other penalty charge amounts included in MERC-NNG AAA Report and its October 16, 2019, response to the Department Information Request (IR) No. 7. The Department observed that:

> In MERC-NNG's AAA Report, page 5 of Schedule D.3, MERC included $33,283 of DDVCs in its FYE19 over/under cost recovery calculation for the NNG system; this $33,283 DDVC figure is also included in MERC's response to Department IR 7 as a "positive" DDVC amount. However, in addition to the $33,283 of positive DDVCs, MERC's response to IR 7 shows that the NNG system incurred a punitive DDVC amount of $44,112.30 and other penalty charges of ($175,203.85), resulting in a net total of ($97,808.59) for FYE19.

Accordingly, the Department requested MERC-NNG explain in Reply Comments (1) whether and why $33,283 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE19 over/under cost recovery calculation for the NNG system and (2) whether and why a difference exists between the DDVC/penalty charge amounts shown in MERC NNG's FYE19 AAA Report and its reply to Department IR 7.

1) MERC-NNG Reply Comments

In its May 6, 2022, Reply Comments, MERC stated that Positive and Negative DDVCs, as well as NNG Punitive Charges and Other Penalty Charges should be, and were, all included in the FYE19 over-recovery calculation for the NNG system. MERC's response to Department Information Request No. 7 provided a detailed breakout of these charges for FYE19.[8] While the same breakout is not included in the Schedules to MERC's AAA Report filing, those amounts do flow through the over/under cost recovery calculation for the NNG system. Differences between MERC's response to Department Information Request No. 7 and the Schedules to MERC's AAA Report reflect only differences in the information presented.

According to MERC, only Negative and Positive DDVCs which total $33,283 was reported in Schedule J of MERC-NNG's 2018-2019 AAA Report, as well as in the gas cost shown on Schedule D.3. Also, Other Penalty Charges total of $175,203.85 were reflected on Schedule F&G of MERC-NNG's 2018-2019 AAA Report.[9] The amounts detailed on Schedule F&G are included within the purchase gas costs reflected on Schedule C&D. For FYE19, the Punitive DDVC amount of $44,112.30 was not included in Schedule F&G, but it was included within the purchase gas costs reflected on Schedule C&D. Thus, MERC held that its 2018-2019 gas costs and over-recovery calculation properly included all DDVC, punitive DDVC, and other penalty charges.

MERC explained that differences in presentation, not miscalculations, caused the apparent discrepancies found by the Department. MERC stated that it correctly accounted for its DDVCs/other penalty charges in its 2019 AAA reports/true ups.

2) Department Response to MERC' Reply Comments

The Department reviewed MERC's Reply Comments and agreed with MERC' assertion that the presentation differences had no impact on the Company's accounting for these charges. Thus, the Department stated that it had no further issues with the Company's 2019 AAA reports/true ups.

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[8] In MERC's response to Department Information Request No. 7, MERC provides only Positive and Negative DDVC amounts in response to part a), and provides Positive and Negative DDVCs, as well as NNG Punitive Charges and Other Penalty Charges in response to part b). See Merc Reply Comments, p. 3.

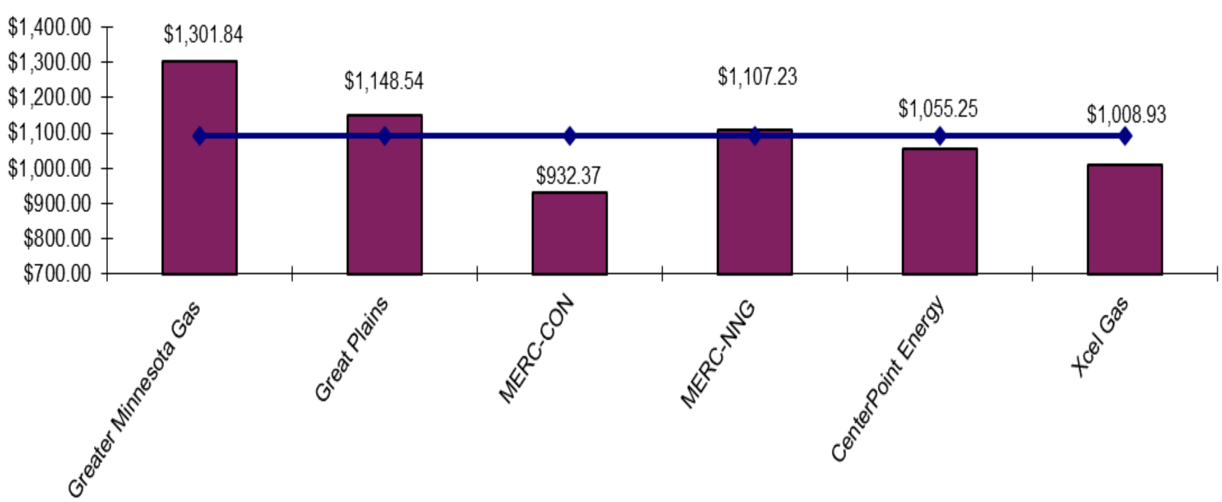
[9] MERC' Reply Comments, p. 3.

B. Comparison between Minnesota Local Distribution Companies (LDCs)

The Department, as shown on pages 38 through 64 of its Review, conducted further review on cost and operating data/information for all of the regulated natural gas local distribution companies.

Based on information furnished by the utilities in response to the Department information request No.1, the Department compared the average annual residential customers bill for each of the regulated utilities based on customer charge, per unit energy consumption and average consumption of 140 MCF per year (summarized in Graph 1 below and in Department's attachment G13). Usually, a residential customer pays a fixed monthly charge and a per-unit energy consumption rate, which consist of gas cost and non-gas cost. 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.[10] Similarly, when interstate pipelines change the rates that they charge or the cost of gas rates change, Minnesota gas utilities, through the PGAs, automatically pass these rate changes to their customers.

Graph 1: Average Annual Residential Bill in 2018-2019 Based on Average Annual Consumption of 140 Mcf[11]



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[10] Minnesota LDCs generally file demand entitlement petitions on, or about, July or August 1 of each calendar year, and are typically updated on November 1. However, demand entitlement filings during other parts of the year can also occur.

[11] See Department Review, at 39.

The Department, for illustrative purposes, used Graph 1 to show that based on consumption level of 140 Mcf, average residential bills range from a high of $1,301.84 for customers served by GMG to a low of $932.37 for customers served by MERC-CON.

The Department indicated that, since actual averages for each utility were the result of actual average consumption levels, the amounts on the Graph 1 are not actual averages for customers on any system. Graph 1 merely intended to provide a baseline usage comparison that remain unchanged between years because consumption remain constant at 140 Mcf.

In its Table G15, the Department provided a comparison that ranks the utilities according to annual usage of an average residential customer and the size of the annual bill for an average residential customer.

Table G15: Average Annual Residential Bill and Average Use per Customer by Utility for the FYE19 Reporting Period Utility for the FYE19 Reporting Period[12]

Utility	*Average Usage Rankings[13]*	*Average Use[14] (Mcf)*	*Annual Bill Rankings*	*Total Annual Bill*	*Average Cost per Mcf[15]*	*Annual Customer Charges*
GMG	2	93.0	6	$899.04	$9.67	$102.00
Great Plains	1	89.0	3	$762.93	$8.57	$90.00
MERC-CON	4	96.2	1	$678.59	$7.06	$121.56
MERC-NNG	3	94.9	5	$789.42	$8.32	$121.56
CenterPoint	6	98.7	4	$779.06	$7.89	$119.00
Xcel Gas	5	98.0	2	$738.65	$7.54	$108.00

12 See Department Review, at 40.

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

14 The average annual usage amount reported in response to Department IR 1 is not weather normalized but reflects the different heating degree days based on location.

15 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

Table G15 shows that customers served by CenterPoint had highest average consumption of 98.7 MCF, and Greater Minnesota Gas customers had the highest average annual residential bill of $899.04. MERC-NNG's customers had the second highest average annual bill, while Great Plains' customers had the lowest annual consumption. The Department noted that many factors affect the size of the average annual residential utility bills. The amount of gas used by an average residential customer is one factor, which is affected by weather, housing conditions and other variables. The second factor would be the company's cost of gas and a third would be the non-gas rates the company is allowed to charge. There are host of other contributing factors, such as, load, 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.[16]

As shown in Table G17, the Department also developed a total system average cost of gas analysis using demand cost information provided in the utilities annual true up reports.

Table G17: FYE19 Total System Gas Costs (Demand and Commodity)[17]

Utility	*PGA Recovered ($/MMBtu)*	*Rank*	*Current-Period Actual incurred Gas Cost ($/MMBtu)*	*Rank*	*Actual Over/(Under) ($/MMBtu)*	*Percentage Over/(Under) Recovery*
GMG	$3.8869	**1**	$3.8528	**2**	$0.0341	0.88%
Great Plains	$4.6831	**5**	$4.5249	**6**	$0.1581	3.49%
MERC-CON	$3.9595	**2**	$3.7690	**1**	$0.1905	5.05%
MERC-NNG	$4.8134	**6**	$4.5127	**5**	$0.3007	6.66%
CenterPoint	$4.3070	**4**	$4.3557	**4**	$(0.0486)	(1.12%)
Xcel Gas	$3.9648	**3**	$4.0187	**3**	$(0.0539)	(1.34%)
MN Weighted Avg.	$4.2547		$4.2543		$0.0004	0.01%
MN Non-Weighted Avg.	$4.2691		$4.1723		$0.0968	2.32%

Total system PGA-recovered and actual-incurred gas costs provides a

[16] See Department Review, at 40.

[17] See Department Review, at 43. The numbers reported in Table G17 are from the true up report submitted by each utility. The numbers and the detailed calculations used are contained in Department Attachments G12, G12a, and G16 through G18.

comparison of the utilities' total system gas costs (demand and commodity). The six PGA systems had a mix of over- and under-recovery of total gas costs during the reporting period, with MERC-NNG reporting the greatest percentage of over-recovery at 6.66 percent. Great Plains had the highest actual gas cost and MERC-CON had the lowest actual gas cost.

C. Department Review of Gas Utilities' Peak Demand Profiles

For its review of gas utilities' peak demand profiles, the Department utilized the data from responses to its information request to create a summary for FYE19 of each gas utility' peak day demand profile, load factor and reserve margin.

Table G19: FYE19 Firm Peak-Day Demand Profiles[18]

Utility	*Firm Design Day Demand (Mcf)*	*Firm Peak-Day Demand Deliverability (Mcf)*	*Annual Firm Throughput (Mcf)*	*Annual Firm Load Factor*	*Reserve Margin*
GMG	12,704	14,109	1,302,354	26.78%	11.06%
Great Plains	33,674	35,545	3,310,998	29.92%	5.56%
MERC-CON	57,071	57,949	4,825,697	22.99%	1.54%
MERC-NNG	275,681	311,756	24,507,563	24.97%	13.09%
CenterPoint	1,373,000	1,409,596	125,202,736	27.36%	2.67%
Xcel Gas	735,741	779,864	76,070,426	32.34%	6.00%
MN Totals	2,487,871	2,608,819	235,219,774	28.41%	4.86%

[Footnotes omitted]

The Table G19 shows gas utilities' firm load factor ranged between approximately 23% (MERC-CON) and 32% (Xcel) and a FYE19 total weighted average reserve-margin percentage of 4.86%, which included each utility's contracted transportation and peak-shaving capacity. This represented a 25.8 percent increase in the statewide reserve margin compared to the FYE18 3.86 percent average.

The Department noted that it conducted no analysis of the reserve margins in this current filing and supports the continuation of the Commission requirement that reserve margin be included in the annual automatic adjustment report, as this information is useful for comparison

[18] See Department Review Attachment G20

purposes.[19]

Staff Comments: Staff notes that reserve margin is an issue dealt with in each utility' annual demand entitlement filing. Each reserved margin is analyzed by the Department and approved by the Commission in the utility annual demand entitlement filings. The gas utilities filed annual demand entitlements for fiscal year 2018-2019 and were approved by the Commission accordingly.[20]

D. Revenue From Curtailment and Balancing Penalties Imposed by Regulated Minnesota Gas Utilities

Generally, utilities are expected to nominate and use interstate pipeline capacity in a reasonable manner and failure to do results in penalties. Thus, utilities have established their own guidelines for system use for transportation and interruptible customers and apply penalties to customers who do not follow these guidelines when using the gas system.

As such, all of Minnesota's regulated gas utilities have received Commission approval to implement 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
- encourage customers to nominate and balance gas supplies responsibly

The Department reviewed the Curtailment and Balancing penalties below.

1. Curtailment Penalties

The Department noted the following:

> 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

19 Department Review at 45.

20 The utilities provided additional discussion on their reserve margins for FYE19 in the following demand entitlement filings: GMG, G-022/M-18-232; Great Plains, G-004/M-18-454; MERC-CON, G-011/M-18-527; MERC-NNG, G-011/M-18-526; CenterPoint, G-008/M-18-462; Xcel Gas, G-002/M-18-528.

> accept the potential of curtailment in return for lower prices than are charged firm customers; unlike firm customers, interruptible customers do not pay for demand/capacity costs. If an interruptible customer fails to curtail when notified, the utility (not the interruptible customer) may face pipeline penalties, which, in turn, would raise rates for all customers. Theoretically, failure to curtail also could jeopardize the reliability of gas service to firm customers. Therefore, the Commission approved utility tariffs under which utilities charge curtailment penalties to interruptible customers who fail to respond to curtailment notices.[21]

As shown on Table G24, the Department presented summarized the revenue derived from curtailment penalties imposed on interruptible customers in FYE19.

Table G24: Fye19 Revenue from Curtailment Penalties[22]

Utility/System	Total Penalties	Percent of Total Penalties	Total Gas Costs	Percent f Total Gas Cost Represented by Penalties
GMG	$0	0.00%	**$** $6,025,911	0.0000%
Great Plain	$0	0.00%	$18,070,263	0.0000%
MERC-CON	$2,429	0.13%	$24,090,158	0.0101%
MERC-NNG	$190,486	9.82%	$135,435,723	0.1406%
CenterPoint	$972,724	50.15%	$586,074,385	0.1660%
Xcel Gas	$773,969	39.90%	$319,749,687	0.2421%
MN Total	$1,939,608	100.00%	$1,089,446,127	0.1780%

Table G24 shows that three utilities charged curtailment penalties on interruptible customers for FYE19 of total amount of $1,939,608, an increase of $672,194 from the FYE18 curtailment penalties of $1,267,414. The Department noted the increase was mainly due CenterPoint who did not charge curtailment penalties in the preceding reporting period and added that Penalties charged to customers in FYE19 constitute a very small portion of total costs for the period. The utilities return the revenues from these curtailment penalties to firm customers as a credit to demand cost in the annual true ups.

The Department alluded to impact of the severe cold weather event in FYE19 and noted thus:

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[21] Department Review at 50.

[22] The penalties listed in Table G24 are taken from the utilities' responses to Department IR 8. Responses are available upon request.

Docket No. E,G-999/CI-19-160 In the Matter of a Commission Inquiry into the Impact of Severe Weather in January and February 2019 on Utility Operations and Service addressed, among other things, the unauthorized gas use that took place during the severely cold weather associated with the polar vortex of the FYE19 heating season. CenterPoint's and Xcel's relatively high levels of unauthorized gas use were among the topics scrutinized by the investigation. The Commission's November 6, 2019, Order in Docket No. E,G-999/CI-19-160 approved certain changes to the utilities' tariffs for interruptible customers and required compliance filings aimed at mitigating future unauthorized gas usage as well as improving the management of future extreme weather events.

The Department did not address unauthorized gas usage and its related penalties for FYE19, because they were addressed in the Commission investigation in Docket No. E,G-999/CI-19-160.

Although the Department did not review the utilities unauthorized gas usage and its related penalties, it indicated it was aware of the ongoing unauthorized gas usage issue facing Minnesota Natural gas systems and pledged to continue to carefully review this issue in future AAA reports.

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 as cited for interruptible customers, transportation customers must be held financially accountable if they do not use the gas system in a responsible manner. As shown in Table G25, the Department summarized the revenues generated from balancing penalties imposed on transportation customers and credited to firm sales customers in FYE19.

Table G25: FYE19 Revenue from Balancing Penalties[23]

Utility/System	*Balancing Penalty Rev.*	*Penalty Rev. as a Percent of Total Penalties*	*Total Gas Cost*[24]	*Penalty Rev. as a Percent of Total Gas Costs*
GMG	$6,658	0.62%	$6,025,911	0.1105%
Great Plains	$10,408	0.97%	$18,070,263	0.0576%
MERC-CON	$59,218	5.50%	$24,090,158	0.2458%
MERC-CON	$167,344	15.54%	$135,435,723	0.1236%
CenterPoint	$714,055	66.29%	$586,074,385	0.1218%
Xcel Gas	$119,495	11.09%	$319,749,687	0.0374%
MN Total	$1,077,178	100.00%	$1,089,446,127	0.0989%

Table G25 shows the FYE19 revenue from balancing penalty revenue collected from transportation customers by gas utilities ranges from $6,658 (GMG) to $714,055 (CenterPoint). The FYE19 total balancing penalty revenue of $1,077,178 represents a 16 percent decrease from the FYE18 amount of $1,278,071.

The Department also noted that NNG paid annual penalty charge credit to all shippers on its system. The Department presented below in Table G25a the amount of credits received from NNG for FYE19, based on data it received from the utilities in response to the Department's Information Request No. 9.

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[23] Department Review at 52. The data provided in Table G25 is taken from the response to Department IR 9.

[24] The figures listed in the column entitled "Total Costs Incurred" are taken from the gas utilities' true up reports. Total costs incurred include demand and commodity costs.

Table G25a: FYE19 NNG Penalty Charge Credits by Utility

GMG	$2,396,104
Great Plain	$61,867
MERC:	
CON	$0
NNG	($53,696)
CenterPoint	($388,600)
Xcel Gas	$158,853
MN Total	$2,174,527

E. Department Review of LDC Gas Purchasing Practices

- In its August 11, 2014, Order in Docket No. G-999/AA-13-600, the Commission requested the Department, in future AAA filings, include a review of gas purchasing practices including: a review of the utilities' PGAs and filing of subsequent reports;
- 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 noted that the utilities use different purchasing practices from one another based on resources available:[25]

> CenterPoint, MERC, and Xcel Gas use hedging. Great Plains does not have access to storage in its northern service territory, and GMG procures storage only for balancing purposes. CenterPoint and Xcel Gas have peak-shaving facilities. GMG uses outside resources to assist in managing its gas portfolio.[26] In addition, gas utilities have multiple ways to purchase natural gas. For example, the largest share of natural gas purchases, across all utilities, comes from monthly index-priced gas.[27] Other types of purchases include daily spot-priced

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[25] Department Review at 60-71.

[26] GMG's AAA Report, page 2.

[27] 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.

gas,[28] daily index-priced gas,[29] or fixed price gas.

F. Annual Auditor Reports

Minnesota Rule 7825.2820 requires all Minnesota regulated utilities to submit to the Commission an independent auditor's report by September 1 of each year that evaluates the accounting for automatic adjustments for the reporting period. Thus:

> Beginning with the FYE99 AAA report, the Commission has required that the gas utilities meet annually with their independent auditors, prior to the auditors' examination of the utility AAA reports, to review the relevant examination procedures and Minnesota Rule 7825.2820.[30] Additionally, the Commission requires gas utilities to direct their independent auditors to include among their procedures a review of any significant variations between purchased volumes (per invoices) and sales volumes (per the general ledger sales journal).[31] The Commission also requires all gas utilities to continue to have independent auditors verify in writing that the actual amounts included in the AAA true up calculations agree with the utilities' accounting books and records.[32]

The Department noted that all gas utilities complied with Minnesota Rule 7825.2820 by submitting their auditor's report. The auditor's reports contained no exceptions, that is, all the reports contained auditor's Clean Opinion.

G. Lost-and-Unaccounted for Gas (LUF)

In its April 7, 2011, Order in Docket G-999/AA-09-896, the Commission requested the Department continue to develop and report a summary and comparison of each of the natural gas utility' LUF gas. Accordingly, the Department developed a comparison of LUF gas by utility using the formula from U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration's Form 7100.1-1 to calculate the LUF percentages.[33]

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[28] Daily spot-priced gas purchases refer 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.

[29] 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

[30] 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

[31] Docket No. G,E999/AA-97-1212.

[32] Docket No. G,E999/AA-96-940.

[33] 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. See also Department's Review, p. 55.

Table G29[34] summarizes LUF gas percentages for FYE19 for Minnesota jurisdictional volumes.

Table G29: FYE19 Lost-and-Unaccounted-For Gas[35]

Utility/System	Revenue as a Percent of Total Gas Costs
GMG	0.70%
Great Plains	0.78%
MERC-CON	(0.90%)
MERC-NNG	(0.98%)
CenterPoint	1.38%
Xcel Gas	1.90%
MN Weighted Avg.	1.24%

A negative LUF number indicates that a utility, in effect, found gas. LUF gas ranged from a negative 0.98 percent for MERC-NNG to a positive 1.90 for Xcel Gas and this appeared consistent with prior reporting periods. Below is the Department's discussion of MERC and Xcel Gas' LUF.

1) MERC

Both MERC-NNG and MERC-CON systems reported negative lost gas during the reporting period, as was the case in the last five reporting periods specifically for MERC-NNG and also was the case in last two reporting periods for MERC-CON. MERC has had a long and well-documented history of negative LUF and has been unable to point to a cause for its consistently negative LUF.
Though, MERC has previously investigated its negative LUF and found some errors contributing to it in the past, MERC has not found anything that was consistently pointing to billing errors, metering errors, or purchased gas accounting methodologies.

The Commission's February 27, 2019, Order in Docket No. G-999/AA-17-493 (2019 Order)

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[34] Department Review at 56.

[35] See Department Attachment G19 for detailed calculations.

required MERC to submit, within 30 days of the Commission's Order, a compliance filing outlining a plan to investigate its LUF gas. That Order further required that MERC file a report on the results of that investigation in its fiscal Year 2019 AAA Report.

On March 26, 2019, MERC submitted its Compliance Filing, proposing a plan to further investigate negative LUF on the NNG-PGA.

On April 25, 2019, the Department filed comments recommending that MERC conduct the investigation into negative LUF for both the NNG and Consolidated-PGA.

On May 6, 2019, MERC filed reply comments in Docket No. G-999/AA-18-374 agreeing that it would investigate for both the NNG and Consolidated PGAs. MERC investigated Pressure Factor calculation, audited Town Boarder Station (TBS) Purchases to Sales, British Thermal Unit (BTU) Factors, and Meter Reading Practices (involving 1500 farm tap customers). Below are presented the results of that investigating for MERC-NNG PGA.

MERC reviewed pressure factor calculations used by NNG and compared those calculations to those used by MERC, as a pressure factor is used to adjust for gas pressure as they flow through the meter. Then the pressure factor is used along with BTU factor to convert the volume of gas measured by the meter into the heating value of the gas or BTU. The review disclosed:

> …that MERC and NNG use different atmospheric pressures in determining gas volumes. All else equal, this differential would cause MERC to show a consistently negative LUF when comparing NNG's measured throughput to MERC's sales for any given period of time. The differential in atmospheric pressure used in the correction factor accounts for a difference of approximately 1%, which translates to the volume of gas metered. Stated another way, NNG measures 1% less gas than MERC given the same meter reading and flow. This is a significant contributing factor to the negative LUF that has persisted.

MERC also audited purchases at each MERC-CON PGA TBS versus sales made to customers behind each TBS for FYE2019 reporting period and noted:

> Purchases by TBS for a calendar month are relatively straightforward because the pipeline metering data is readily available. Sales data, however, reflects meter data that is collected in cycles throughout the month, so some measure of variances by month are expected. Variances would, therefore, be expected to be positive some months and negative in others. This was borne out in the analysis. The sales data by TBS was determined by grouping customers by mailing address to their closest TBS. Again, some variances were to be expected here. Mailing addresses would not be a perfect match to a TBS, especially since some communities shared mailing addresses yet could be connected to different TBS on different pipelines (e.g., the towns surrounding Grand Rapids can be connected to either Great Lakes pipeline or NNG pipeline).

For MERC-NNG, a similar analysis was begun just like the one that was done for the MERC-CON PGA. However, unlike the Consolidated PGA, MERC's NNG system is significantly larger and more complex, with many more communities overlapping MERC billing areas. Also, MERC noted that the PGA areas for NNG and Albert Lea were separated in three of the last AAA years. Albert Lea had a positive LUF in those three years and NNG had a negative LUF. Thus, MERC stated that without considerably more detailed mapping and study, it was unable to offer a conclusion using this analysis.

MERC also reviewed BTU factors obtained from NNG pipeline to see if there exist any significant differences between stations and noted thus:

> The BTU factor converts measured gas volumes (CCF) into the heating value of the natural gas (therm). Heating values of natural gas vary depending on the source of the gas. Because the BTU factors are directly downloaded from the pipeline to the MERC billing system, it is likely that the only way the BTU factors would be an issue is if customers were incorrectly assigned to a BTU area that was significantly different than the gas they were actually consuming. With regards to BTU factors, it is also useful to note that the daily factors are averaged to determine the monthly BTU factor to be applied to a customer's metered usage. These averages are not weighted, so some LUF variances can occur simply based upon the customer load profiles.

MERC stated that it did not evaluate further the NNG BTU factors due to the inconclusive results obtained from the review of Viking Pipeline' BTU factors in the Consolidated PGA.

Additionally, MERC reviewed Meter Reading Practices of its NNG PGA area that includes over 1,500 farm tap customers. These customers are required to submit meter reads to MERC every month. Those reads are verified by MERC with a physical read once each year. Other MERC customers may experience periodic estimated meter reads but a physical read within the next calendar month would correct for variances due to the estimated reads. Based on this, MERC held that meter reading practices should be not materially affect the annual LUF%.

MERC described its investigation as shown above and concluded that its meter testing program results have tended toward accuracy readings of more than 100% (i.e., fast meters), so a negative LUF% would tend to be more likely than a positive LUF%. Thus, In the light of this observation and the impact of the pressure factor analysis, MERC held that LUF gas of (0.98%) for the current AAA period was reasonable.[36]

For MERC-CON, meter testing program results trend same way as mentioned above for NNG. Prior years' experiences in the Consolidated PGA area do not show a consistent negative LUF%,

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[36] MERC-NNG' AAA Report, p. 4. See also Department' Review, p.56.

instead LUF% have fluctuated between positive and negative. An audit of throughput by TBS and a review of BTU factors did not identify any systemic measurement issues or errors. Thus, MERC held that the negative LUF for the Consolidated PGA of (-0.90%) appears reasonable and no further analysis needed at this time.[37]

The Department concluded that MERC complied with the Commission's 2019 Order and stated that MERC's investigation did provide some plausible reasons as to why the utility has had negative LUF gas, and would likely continue to have, negative LUF gas. The Department held it has no further issues to raise and therefore at this time has no additional concerns around MERC's negative LUF gas.

2) Xcel Gas

As was the case in the prior periods, Table G29shows Xcel gas has the highest LUF. In fact, at its April 26, 2018, agenda meeting, the Commission observed that Xcel Gas's LUF gas volumes were higher than the other regulated utilities over the previous several years. Xcel Gas agreed and indicated that it would have its internal audit department investigate the issue. Accordingly, Xcel' internal audit investigated and identified five items to note as part of the unaccounted-for gas volumes[38] as follows:

- Fuel losses incurred in conjunction with storage injections were not separately identified in the Company's response to DOC Information Request 16 (IR 16) and thus would be in the unaccounted-for gas volume total.
- Fuel used in the operations associated with liquefying and vaporizing liquefied natural gas have not been separately identified in IR 16 and would be included in the unaccounted-for total.
- Third-party cash out volumes are not quantified in the Company's reconciliation of purchase and sale volumes in IR 16.
- Metered gas volumes that are not billed because they are associated with vacant premises and/or the owner is unknown are included in the total unaccounted for gas.
- Xcel Gas's investigation also identified an allocation issue regarding gas volumes used at the High Bridge plant. High Bridge is one of Xcel Energy's natural-gas powered electric generation units and is a natural gas transport customer of the LDC. As part of the end-user allocation agreement between High Bridge and LDC, the LDC communicates to Northern Natural Gas (NNG) the volumes used by High Bridge. NNG uses these volumes to allocate costs between the LDC and the

[37] MERC-CON' AAA Report, p. 7. See also Department's Review, p. 57.

[38] Xcel Gas's FYE18 AAA Report in Docket No. G-999/AA-18-374, Attachment G, pages 2-3.

electric utility. The High Bridge volumes were being reported from Supervisory Control and Data Acquisition (SCADA) measurements instead of the MV90 metering (MV90 is billing quality data, SCADA is not). The High Bridge volumes have been understated to NNG over the last several years, and thus the plant has used more gas than they have brought on to the system. The table below shows the volume impact on Lost and Unaccounted for gas of this issue.

Adjustment to Lost and Unaccounted for Total

	MN	*MN Adj*	*Diff*
FYE14	1.30%	1.14%	-0.16%
FYE15	2.46%	2.08%	-0.37%
FYE16	2.72%	2.11%	-0.61%
FYE17	2.52%	2.14%	-0.38%

Xcel made a one-time adjustment to true-up the difference between what the plant burned versus the gas the plant delivered to the system. In order to value this gas, Xcel used its tariff-based cash-out mechanism. The total system cost impact is estimated to be approximately $6 million ($4.2 million for these four years, and $1.8 million for the current 2017-18 gas year), and included a total system credit of $6 million ($5.2 million for Minnesota) in the 2017-18 gas true-up filing. Xcel intends to allocate this adjustment to electric customers through the monthly FCAs.[39]

a. Department Review

The Department stated that Xcel Gas incorrectly reported to NNG the amount of gas used by Xcel Gas' transportation customer, Xcel Electric's High Bridge generating plant, meaning that Xcel Gas was charged for more gas than was actually used while Xcel Electric was charged for less than used.

The Department also noted that in Points 20-22 of the Commission' November 13, 2019, Order in FYE18 AAA reports, Docket No. G-999/AA-18-374, the Commission:

- Approved Xcel's proposed refund to Xcel Gas customers related to the High Bridge Adjustment.

[39] Xcel Gas's FYE18 AAA Report in Docket No. G-999/AA-18-374, Attachment G, pages 2-3.

- Required Xcel to calculate interest at the Prime Rate on the 2013–2017 prior period adjustment portion of the High Bridge allocation error, ($3,669,040), and include it as a credit no later than its next AAA true-up filing (2020 AAA filing due September 1, 2020).
- Required all regulated gas utilities going forward to identify each non-standard prior-period adjustment made in an Annual True-up filing, demonstrate whether each such adjustment is subject to a Minnesota Rule (e.g., Billing Error–Minn. R. 7820.4000, Approval for Automatic Adjustment of Charges, Minn. R. 7825.2920, or some other Rule), and demonstrate the reasonableness of each such adjustment.

Staff notes regarding High Bridge adjustment credit that the Department offered no review of this but indicated to do so in the next Xcel's FYE20 AAA filing. The instant case and Department's Review of the FYE20 AAA and Natural Gas Utilities' PGA True-Up in Docket No. G-999/AA-20-172 are both being heard at the March 30, 2023, agenda meeting.

H. Reporting of Contractor Main Strikes and Meter Testing

In its October 11, 2012, Order in Docket G-999/AA-10-885, the Commission required all gas utilities to file, as part of their annual AAA reports, a schedule reflecting contractor main strikes during the corresponding annual period billing 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 Report

Regarding contractor main strikes reporting, the Department reviewed the reports and stated that all the gas utilities filed the required information.[40] In fact, in its FYE14 AAA Report, the Department opined that the reports would be more meaningful, if the total gas costs charged for main strikes during the period are reconciled to the amount in the true-up and also the reports provide the allocation of the gas costs credited to each customer class.

2. Meter Testing Updates

The Department stated that all the gas utilities filed the required meter testing information with their AAA Reports. The Department reviewed the updates and concluded that the utilities complied with the Commission's Order.

Below the Department provided a short summary of meter testing update information for each

[40] See GMG's AAA Report, page 5; Great Plains' AAA Report, page 4 and Exhibit C; MERC's AAA Reports, Schedule Q; CenterPoint's AAA Report, Exhibit 9; Xcel Gas' AAA Report, Attachment G, Schedule 7.

utility:[41]

a) Greater Minnesota Gas

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.

b) Great Plains (GP)

GP's Gas Distribution Standards were again revised in 2018 and 2019. However, there were no updates regarding meter testing to Section 7 of the Gas Distribution Standards.

c) MERC

In the time period of January 1, 2018, through December 31, 2018, MERC tested 6,872 meters as part of its meter testing program. Of those meters tested, 6,488 (94.4%) tested between 98% and 102% accurate. 328 meters (4.8%) tested greater than 102% accurate, 54 meters (0.80%) tested less than 98% accurate, and 2 meters (0.0%) had no test due to the meter being damaged.

d) CenterPoint Energy (CPE)

CPE continued its meter testing and management program in 2018. Meter samples and tests are conducted over a two-year period. All meter lots evaluated passed the accuracy expectations. During 2018 the Company exchanged 4,265 'failed' meters and, year to date through July 2019, 808 meters had been exchanged. Per the meter management program, the 2019 work plan was set to target an additional 1,170 meters to be exchanged as previously identified meter groups required attention.

e) Xcel Gas

There were no changes regarding meter testing within the July 1, 2018, and June 30, 2019, annual reporting period.

I. Minnesota Gas Utilities Hedging Practices

In its August 11, 2014, Order in Docket No. G-999/AA-13-600, the Commission requested the

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[41] Department's Review, p. 60.

Department provide, in future AAA filings, a review of hedging practices in its review of future annual automatic adjustment reports. Also, given the current state of the natural gas market, at its February 4, 2016, agenda meeting regarding CPE's hedging variance filing in Docket No. G-008/M-15-912, the Commission expressed interest in taking a closer look at utility hedging practices.

The Department noted that, based on utility-specific circumstances and information, CenterPoint, MERC, and Xcel Gas have received Commission approval to recover the costs of financial hedging through their PGAs. In separate, periodic variance request filings, the Department performs a thorough analysis in each of the applicable utilities' respective requests to continue recovering hedging costs through their PGAs.

The Department, being cognizant of the effect of weather and other supply issues in the commodity price of natural gas stated:[42]

> 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. The weather during the FYE19 heating season was overall colder than normal, but natural gas prices remained relatively stable during the reporting period, except several weeks of higher prices in November and December 2018. Both at the beginning and end of the FYE19 heating season, natural gas storage levels were below the previous five-year average, and FYE19 net withdrawals from storage were also below the previous five-year average.

The following discussion reviews the performance of each utility's hedging program against expectations that they may experience losses on the hedge portion of their purchase portfolios.

1) 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 a first-of month (FOM) index price, 30 percent are supplied by physical storage, and 30 percent are covered by financial hedges (10 percent futures and 20 percent call options).[43] MERC, in response to the Department's IR No. 15(H), stated that there were no changes to the financial hedging program in FYE19 when compared to the previous reporting period.

The Department noted that, consistent with expectations, in FYE19 MERC's hedging portfolio actually provided a lower cost of gas than if it did not hedge. This invariably led the Department

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42 Departments Review at 62.

43 MERC's AAA Report, PDF page 11, section titled "2018-2019 Gas Procurement Policies".

to conclude that MERC accomplished its intended purpose of providing price protection on a portion of its winter gas supplies using the information available at the time it executed its hedges.

2) CenterPoint Energy

CenterPoint held that its hedging policy is to provide price stabilization for a portion of its winter supply through hedged gas purchases and storage gas. CenterPoint determines the level of price stabilization each year based on an analysis that incorporates regulatory guidelines (as to volumes and costs), winter price projections, and available portfolio assets.[44]

CenterPoint disclosed that there was no significant change in its hedging program from the FYE18. Thus, for FYE19 winter season hedging strategy, CenterPoint stated:

> Contract storage allowed 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. Storage also provided daily operational benefits for which it was purchased. Storage volumes represented 24.5% 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 24.5 Bcf of total hedged supply and, when combined with 25.7 Bcf of storage volumes, provide stabilized prices for 47.8% of winter gas supplies.
>
> In addition to providing price stability, the price hedges also provided catastrophic price protection against price fly-ups during unforeseen events such as upstream pipeline ruptures and prolonged extremely cold weather.
>
> … market prices for winter gas (futures winter strip) during 2018 stayed around $3.00 until October when it increased to over $3.25 for the last month.[45]

CenterPoint noted that its hedging program for FYE19 resulted in commodity costs that passed through the PGA that were on average $0.0554 per dekatherm lower than they would have been without hedging. Thus, the hedging strategy resulted in overall costs of 11% lower than if it had purchased all gas in FYE19 at market price. In view of the above stated facts, the Department opined that CenterPoint accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies using the information available at the time it executed its hedges.

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[44] CenterPoint's AAA Report, page 7.

[45] Id., at p. 11.

3) 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.[46] 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.[47]

The Department's review showed Xcel Gas' hedges in FYE19 yielded a net gain of approximately $1,669,620. Accordingly, the Department concluded that Xcel Gas accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies using the information available at the time it executed its hedges.[48]

Overall, the Department concluded that the utilities' hedging program performance appeared reasonable. Accordingly, the Department recommended that each utility using hedging, whether physical or financial, should continue to provide in subsequent AAA filings, in a format similar to that in the current docket, an analysis of their hedging activity performance

Staff agrees with the Department' view that the purpose of gas utility hedging practice is to mitigate the effect of price volatility on a portion of the utilities' purchased gas portfolios. Infact, the goal of utilities' hedging is not to speculate on commodity prices or even profit from the result of the hedging, but to provide reasonably priced gas and ensure reliability to meet the needs of customers. Staff supports the Departments conclusions and recommendation.

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[46] Xcel Gas' AAA Report, Attachment A, Schedule 5, page 2.

[47] 8 Id., at p. 3.

[48] Id., Attachment G, Trade Secret Schedule 2.

IV. DECISION OPTIONS

All Commission Regulated Natural Gas Utilities

1. Accept the FYE19 annual reports as filed by the gas utilities as being complete as to Minnesota Rules 7825.2390 through 7825.2920. (All Gas Utilities, DOC)

2. Require that each utility using hedging, physical or financial, continue to provide in subsequent AAA filings, in a format similar to that in the instant docket, an analysis of their hedging activity performance. (DOC)

Greater Minnesota Gas (GMG)

3. Accept GMG's FYE19 true up, Docket No. G-001/AA-19-555. (GMG, DOC)

4. Allow GMG to implement its true up, as shown in Department Attachment G5. (GMG, DOC)

Great Plains

5. Accept Great Plains' FYE19 true up in Docket No. G-004/AA-19-542. (Great Plains, DOC)

6. Allow Great Plains to implement its true up, shown in Department Attachment G6. (Great Plains, DOC)

Minnesota Energy Resources Corporation (MERC)

7. Accept MERC-NNG's FYE19 true up in Docket No. G-011/AA-19-517. (MERC, DOC)

8. Allow MERC-NNG to implement its true up, shown in Department Attachment G8 of the Department's Review. (MERC, DOC)

9. Accept MERC-CON's FYE19 true up in Docket No. G-011/AA-19-518. (MERC, DOC)

10. Allow MERC-CON to implement its true up, shown in Department Attachment G9 of the Department's Review. (MERC, DOC)

CenterPoint Energy (CPE)

11. Accept CenterPoint's FYE19 true up in Docket No. G-008/AA-19-556. (CPE, DOC)

12. Allow CenterPoint to implement its true up, shown in Department Attachment G10 of the Department's Review. (CPE, DOC)

Xcel Gas

13. Accept Xcel Gas' FYE19 true up in Docket No. G-002/AA-19-551. (Xcel, DOC)

14. Allow Xcel Gas to implement its true up, shown in Department Attachment G11 of the Department's Review. (Xcel, DOC)