COMMERCE DEPARTMENT

April 26, 2022

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

RE: **Review of 2019-2020 Annual Automatic Adjustment Reports**
Docket No. G999/AA-20-172 and Natural Gas Utilities' 2019-2020 Purchased Gas Adjustment (PGA) True Up Filings (see attached list)

Dear Mr. Seuffert:

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 Commerce Department, Division of Energy Resources' (Department) *Review of the 2019-2020 Annual Automatic Adjustment Reports* (FYE20 AAA Report) for regulated natural gas utilities in Minnesota.

The Department is available should the Minnesota Public Utilities Commission have any questions about the FYE20 AAA Report provided herein.

Sincerely,

/s/ GEMMA MILTICH
Financial Analyst, CPA
Division of Energy Resources

GM/ja
Attachments

Docket Numbers for 2019-2020 Gas Utility PGA True Up Filings

Docket No. G004/AA-20-699	Greater Minnesota Gas, Inc.
Docket No. G022/AA-20-684	Great Plains Natural Gas Company
Docket No. G008/AA-20-698	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas
Docket No. G011/AA-20-656	Minnesota Energy Resource Corporation (MERC) Consolidated PGA system
Docket No. G011/AA-20-655	Minnesota Energy Resource Corporation (MERC) Northern Natural Gas PGA system
Docket No. G002/AA-20-705	Northern States Power Company d/b/a Xcel Energy

Review of the 2019-2020 Annual Automatic Adjustment Reports

Submitted to the
Minnesota Public Utilities Commission

Docket No. G999/AA-20-172

April 26, 2022

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EXECUTIVE SUMMARY – NATURAL GAS UTILITIES

Minnesota Rules 7825.2800 through 7825.2830 require that public utilities using automatic adjustments to recover energy costs file annual reports regarding the operation of these automatic adjustments. The reports provide an opportunity for the Minnesota Public Utilities Commission (Commission) to verify whether utilities have calculated their rate adjustments properly and implemented these rates in a timely manner. The Minnesota Department of Commerce, Division of Energy Resources' (Department's) review of the current year, 2019-2020 (FYE20), filings, built on our experience gained from prior year AAA reports and was informed by our ongoing assessment of the utilities' automatic adjustment filings throughout the reporting period. The Department's FYE20 Annual Automatic Adjustment natural gas report (FYE20 AAA Report) includes analyses of:

- FYE20 automatic adjustment charge calculations, filed pursuant to Minnesota Rule 7825.2810

- Filings reconciling or "truing up" the difference between the revenues collected and actual gas costs incurred by the utilities, as required by Minnesota Rules 7825.2910 and 7825.2700

- Annual reporting requirements pursuant to Minnesota Rules 7825.2810 - 7825.2910 and as ordered by the Commission

- Supplemental data submitted by the utilities in response to Department information requests (IRs)

In the final section of the instant FYE20 AAA Report, the Department provides conclusions and makes specific recommendations to the Commission on the current period's AAA filings, as submitted by the following utilities:

- Greater Minnesota Gas, Inc. (Greater Minnesota or GMG)
- Great Plains Natural Gas Company (Great Plains)
- Minnesota Energy Resources Corp. (MERC) [1]
- CenterPoint Energy Minnesota Gas (CenterPoint or CPE)
- Northern States Power Company d/b/a Xcel Energy - Gas Utility (Xcel Gas or Xcel)

Recovery of energy costs represents an important component in the rates natural gas customers pay. Included in gas utility rates is a true up reflecting the difference between the actual energy costs the utilities incur and the actual energy revenues they recover; these true ups are based the last year's

[1] 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 *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. As of July 1, 2017, per Docket No. G011/GR-15-736, MERC combined its MERC-Albert Lea PGA system with its existing NNG PGA system, leaving two PGA systems: MERC-NNG and MERC-Consolidated.

revenues and costs. For example, an over-recovery of energy 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) applied to that customer class in the following year. Because customers leave and join the utility's system over time, the specific mix of customers on the utility's system likely to changes somewhat from year to year. Therefore, it is probable that some mismatch exists between the specific mix of customers receiving gas service in a given fiscal year and the mix of customers to which the refund or charge associated with the prior year's true up is assigned in subsequent years. While it is not feasible to eliminate such mismatches completely, it is essential that utilities attempt to minimize both over- and under-recoveries to avoid creating substantial inequities among ratepayer generations.

In FYE20, market natural gas prices were lower on average than prices during FYE19. The average FYE20 price was slightly above $2 per Mcf and prices remained under $3 per Mcf for entire reporting period. The Henry Hub price[2] in FYE20 ranged between $1.38 and $2.87, beginning the reporting period at approximately $2.33 per Mcf in July 2019 and ending the reporting period around $1.69 per Mcf in June 2020.

Several factors could explain why market natural gas prices in FYE20 were relatively low. First, weather in Minnesota was overall warmer than normal in FYE20, putting downward pressure on gas prices during the heating season. Second, storage levels in November 2019, the beginning of the FYE20 heating season, were at 3.575 Bcf, the highest level since 2017, and, with FYE20 net withdrawals from storage being below the five-year withdrawal average, the end-of-heating-season storage levels of 2.008 Bcf were 19 percent higher than the corresponding five-year average; [3] this combination of relatively high storage levels and a warmer-than-normal heating season in FYE20 may have contributed to the lower market prices seen throughout FYE20. Third, natural gas production continued to increase in FYE20, and these increases in production outpaced the ongoing growth in natural gas consumption. Although commercial and residential natural gas use fell during the warmer-than-normal FYE20 heating season, increases in LNG exports and demand created by natural-gas-powered electric generators more than offset these heating season declines. These FYE20 production and consumption factors also likely contributed to the relatively low natural gas prices during the reporting period.[4]

Gas prices reached historic lows at the end of FYE20, with the average Henry Hub price falling to $1.38 MMBtu on June 16, 2020, the lowest daily Henry Hub price (in nominal dollars) since December 1998. Henry Hub prices started out low at the beginning of 2020 and remained low into the 2020 summer months as LNG exports and commercial natural gas demand declined somewhat, due at least in part to the impacts of the COVID-19 pandemic on commercial operations. Low natural gas prices and declines in natural gas demand tend to prompt reductions in natural gas production; in June 2020, dry natural gas production totaled about 90 Bcf/d, down nearly 3.7 Bcf/d from March 2020. Because the reductions in natural gas demand toward the end of FYE20 outpaced the declines in production, the already low Henry Hub prices experienced additional downward pressure at that time. [5]

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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 23, 2020: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2020/04_16/
[4] *Id*.
[5] EIA Natural Gas Weekly Update, June 25, 2020: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2020/06_25/

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, there is still a concentration of 51 percent of processing plant capacity along the Gulf coast, making hurricanes an ongoing concern of market interruption.[6] During FYE20, there were no major interruptions in natural gas production due to storms.

[6] https://www.eia.gov/special/gulf_of_mexico/

I. BACKGROUND

Minnesota Rule 7825.2810, Subparts 1 and 2 contain the following requirements for gas utility AAA filings:

Subpart 1

- Paragraph A - Commission-approved base cost of gas
- Paragraph B - Billing amounts in Mcf, Ccf, or Btu for each type of energy cost
- Paragraph C - Billing adjustment amounts
- Paragraph D - Total cost of gas
- Paragraph E - Revenues collected
- Paragraph F - Supplier refunds received
- Paragraph G - Refunds credited to customers

Subpart 2

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

A. NATURAL GAS PRICES

In FYE20, natural gas prices were lower on average than prices during FYE19. The average FYE20 price was slightly above $2 per Mcf and prices remained under $3 per Mcf for entire reporting period. The Henry Hub price in FYE20 ranged between $1.38 and $2.87, beginning the reporting period at around $2.33 per Mcf in July 2019 and ending the reporting period approximately $1.69 per Mcf in June 2020.

The price of residential propane in Minnesota in FYE20 ranged from $1.26-$1.67 per gallon ($14.28-$18.93 per Mcf), a wider price range with a substantially lower minimum than FYE19, during which propane was between $1.54-$1.64 per gallon ($17.45-$18.59 per Mcf).[7] Propane prices continued in FYE20 to be high compared to the cost of natural gas.

B. WEATHER

Compared to 30-year normal weather,[8] the weather in the Minnesota area for FYE20 was generally warmer than normal, with a few weather stations reporting slightly colder-than-normal weather. The annual weather data the Department reviewed ranged from

[7] http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPLLPA_PRS_SMN_DPG&f=W. One gallon of propane equals approximately 0.915 therms and one Mcf equals 10.37 therms. To find the price of propane per Mcf, multiply the price per gallon by (10.37 / 0.915).
[8] Based on weather data from 1981 through 2010.

approximately 6.14 percent warmer at the Duluth weather station to 1.96 percent colder in Rochester. The heating season (November 2019 through March 2020) was, except for the Rochester weather station data, also warmer than normal compared to 30-year normal weather. The FYE20 heating season weather ranged from 8.49 percent warmer at the Fargo, ND weather station to 0.34 percent colder in Rochester.

According to Northern Natural Gas Company's (NNG) June 2020 *Northern Notes*, the FYE20 heating season was warmer than normal for three out of the five winter months, with the heating season being overall normal in the context of the previous five heating seasons, which were a mix of warmer- and colder-than-average. NNG had its highest market area[9] peak delivery day for the season on January 30, 2020, with a delivery of 5.621 Bcf/day. NNG's FYE20 peak delivery day met the previous peak delivery record that occurred on January 30, 2019, when NNG's market area delivery also measured 5.621 Bcf. NNG delivered 4.0 Bcf per day or more to its market area on 39 days of the FYE20 heating season, compared to 50, 35, and 20 days during the FYE19, FYE18, and FYE17 heating seasons, respectively.

Although two major hurricanes, Hurricane Dorian and Hurricane Barry, occurred during FYE20, these storms did not result in substantial or long-lasting natural gas production interruptions.

C. GAS UTILITIES SUMMARY

In our review of the gas utilities' AAA filings, the Department worked to identify/assess (1) systematic patterns of over- or under-recoveries over time, (2) incorrect calculations of annual true up adjustment factors, (3) the utilities' compliance with AAA filing requirements, and (4) additional issues that may warrant Commission attention.

Because customers leave and join the utility's system over time, the specific mix of customers on the utility's system likely changes somewhat from year to year. Therefore, it is probable that some mismatch exists between the specific mix of customers receiving gas service in a given fiscal year and the mix of customers to which the refund or charge associated with the prior year's true up is assigned in subsequent years. Gas costs generally comprise the largest component of the rates natural gas customers pay, so, while it is not feasible to eliminate such mismatches completely, it is essential that utilities attempt to minimize both over- and under-recoveries to avoid creating substantial inequities among ratepayer generations.[10] An over-recovery for a given customer class in one year results in an offsetting decrease in the rates assigned to that customer class in the following year, and an under-recovery in one year increases rates in the subsequent year. The following table summarizes the fuel cost recovery during FYE20 for the gas utilities.

[9] NNG's market area refers to NNG's service territory north of Demarcation, KS.
[10] As discussed further in Section II, CenterPoint and Xcel apply a monthly demand adjustment to their demand cost recovery rates in order to match costs better within the true up year.

Table G1:[11] Summary of Gas Utilities' Annual Demand & Commodity Cost Recovery for FYE20[12]

Utility/System	*Gas Cost Recovered*	*Gas Cost Incurred*	*Over/(Under) Recovery*	*Over/(Under) Recovery*
GMG	$5,697,046	$5,824,041	($126,995)	(2.18%)
Great Plains	$13,880,150	$13,730,115	$150,035	1.09%
MERC-CON	$18,581,679	$17,345,334	$1,236,345	7.13%
MERC-NNG[13]	$129,389,759	$105,622,235	$23,767,524	22.50%
CenterPoint	$453,457,709	$446,843,069	$6,614,640	1.48%
Xcel Gas	$237,250,463	$227,687,372	$9,563,091	4.20%
MN Total	$858,256,806	$817,052,166	$41,204,640	5.04%[14]

As shown in Table G1, except for GMG, the PGA systems[15] each experienced an over-recovery of gas costs (demand and commodity combined), ranging from an over-recovery of 22.5 percent for MERC-NNG to an under-recovery of 2.18 percent for GMG. The $817,052,166 of total gas cost incurred for FYE20 represents a decrease of approximately 25 percent from the $1,089,446,130 of total gas costs incurred in FYE19.

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[11] The information for Table G1 can be found in each of the utilities' True Up Reports, which are shown in Department Attachments G5 through G11.
[12] The recovery in Table G1 includes credits or revenues related to gas costs.
[13] MERC purchased Interstate Power & Light's gas utility serving Minnesota on April 30, 2015, creating the Albert Lea PGA system. In Docket No. G011/GR-15-736, MERC merged the Albert Lea PGA system with its NNG system effective July 1, 2017.
[14] The Minnesota weighted-average amount is calculated by dividing the total over-recovery amount by the total gas costs incurred.
[15] The Department notes that "gas utility" and "PGA system" are, at times, interchangeable in the instant AAA Report.

The following table compares the total FYE20 gas costs incurred to the nominal total gas costs in past reporting periods.

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

Reporting Period	*Annual Gas Cost Incurred*	*Percentage of Increase/ (Decrease) Between Prior Year and FYE20*
FYE20	$817,052,166	
FYE19	$1,089,446,130	(25%)
FYE18	$1,022,826,772	(20%)
FYE17	$862,350,817	(5%)
FYE16	$730,948,119	12%
FYE15	$1,140,929,250	(28%)
FYE14	$1,659,257,488	(51%)
FYE13	$1,063,629,628	(23%)
FYE12	$899,685,483	(9%)
FYE11	$1,228,496,903	(33%)

The total cost of gas for FYE20, $817,052,166, was notably less than the ten-year (2011 – 2020) annual gas cost average of $1,051,462,276.

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

Table G2: Percentage of Over/(Under) Recovery FYE11-FYE20[16]

	GMG	*Great Plains*			*MERC*			*CenterPoint*	*Xcel Gas*
		North	*South*	*Con[17]*	*CON*	*NNG*	*AL[18]*		
FYE11	(3.92)	0.45	(1.95)		2.00	2.58		(0.66)	(0.50)
FYE12	0.58	(7.83)	(4.73)		(2.15)	(6.19)		(4.68)	(3.15)
FYE13	1.46	(3.66)	(1.86)		2.82	0.08		(0.84)	(0.36)
FYE14	(0.27)	(12.09)	(13.57)		(9.25)	(6.45)		(6.88)	(10.47)
FYE15	0.98	1.57	(3.00)		(3.91)	1.90	(27.03)	1.44	(2.24)
FYE16	1.32	(1.66)	(2.48)		0.72	(2.60)	(3.47)	(2.53)	(2.34)
FYE17	(0.91)	(1.00)	(4.48)		1.41	(2.97)	(4.45)	(3.71)	(1.72)
FYE18	(2.67)			(10.07)	(5.86)	(5.23)		(7.97)	(1.56)
FYE19	0.88			3.49	5.05	6.66		(1.11)	(1.34)
FYE20	(2.18)			1.09	7.13	22.50		1.48	4.20
Average	(0.47)	(3.46)	(4.58)	(1.83)	(0.20)	1.03	(11.65)	(2.55)	(1.95)
Cumulative[19]	(1.91)			2.15	6.49	22.81		1.62	4.14

As shown in Table G2, the majority of the PGA systems experienced cumulative over-recoveries during FYE20. The utilities' 2021 true up factors are calculated based on the cumulative amount of under/over-recovery at the end of FYE20. The ten-year averages (FYE11 through FYE20) show an under-recovery for each gas utility, except MERC-NNG. The Department includes an analysis of the over/under-recovery for each utility later in the instant FYE20 AAA Report.

The following Table G3 provides a summary of the current period's over/under-recoveries and illustrates over/under-recoveries for firm and interruptible classes as a whole and by pipeline system for equivalent PGA systems during the FYE20 true up period.

[16] See Department Attachment G2 graph comparing historical true up adjustments.
[17] In Docket No. G004/GR-15-879, Great Plains consolidated its North and South PGA systems into one Consolidated PGA system, effective July 1, 2017.
[18] Effective July 1, 2017, MERC merged its Albert Lea PGA system with its NNG PGA system per Docket No. G011/GR-15-736. MERC purchased Interstate Power & Light's gas utility serving Minnesota on April 30, 2015. In Table G2 for 2014-2015, MERC-AL includes two months of data.
[19] The figures for this row are included in Department Attachment G5 through G11 in each of the utility's True Up Reports. The cumulative over/under-recovery is a calculation based on prior years' true ups and the present year's true up.

Table G3: FYE20 Percentage of Over/(Under)-Recovery by Firm and Interruptible Classes

Utility/System	*Firm*	*Interruptible*[20]	*Total*
GMG	(2.26%)	(1.73%)	(2.18%)
Great Plains	1.07%	1.16%	1.09%
MERC-CON	7.59%	2.30%	7.13%
MERC-NNG	23.19%	14.91%	22.50%
CenterPoint	1.44%	2.00%	1.48%
Xcel Gas	4.61%	0.89%	4.20%
MN Weighted Average	5.22%	3.13%	5.04%

Table G3 shows that only MERC had total over/under-recoveries of more than five percent.

D. IMPACTS ON 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/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
- The "three-cent rule" from Minnesota Rule 7825.2700, Subpart 3

The Department provides the following discussion on each of these factors:

Weather Variance – Weather is typically the largest factor impacting firm natural gas sales volumes. Therefore, changes in weather can significantly affect the recovery of both demand and commodity gas costs.[21] The Department uses data from seven area weather stations to review weather relevant to Minnesota's utilities.[22] The FYE20 data from these weather stations are summarized in Table G4 and in more detail in Attachment G1. Compared to 30-year normal

[20] MERC's interruptible figures include the Joint customers' firm requirements since the Joint customers are not considered firm on the peak day.
[21] 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.
[22] 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).

weather from 1981 to 2010,[23] the annual weather in Minnesota for FYE20 was warmer than normal across most of the state. The FYE20 weather was reported as follows:

Table G4: FYE20 Weather in Minnesota

Weather Station	*Deviation from Normal**
Duluth	(6.14%)
International Falls	(3.00%)
Fargo, ND	1.40%
St. Cloud	(2.31%)
Minneapolis/St. Paul	(4.46%)
Rochester	1.96%
Sioux Falls, SD	0.38%

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

The weather in Minnesota for the heating season from November to March was also overall warmer than normal compared to 30-year normal weather. The heating season weather was as follows:

Table G5: FYE20 Winter Weather in Minnesota

Weather Station	*Deviation from Normal*
Duluth	(3.71%)
International Falls	(3.41%)
Fargo, ND	(8.49%)
St. Cloud	(2.66%)
Minneapolis/St. Paul	(5.30%)
Rochester	0.34%
Sioux Falls, SD	(1.10%)

Recovery of demand costs is affected by weather because utilities calculate the demand portion of their rates based on test year or historical weather-normalized firm sales, but they recover demand costs on each unit of firm gas actually sold. Therefore, when weather is warmer than normal, causing customers to use less gas, utilities may under-recover demand costs. Conversely, utilities may over-recover demand costs when customers use more gas during colder-than-normal periods.

[23] 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.

Due to the warmer-than-normal weather experienced during the winter, all else being equal, utilities would have under-recovered demand costs in FYE20 (interruptible customers are not charged for demand costs). In reality, factors beyond the weather impact demand cost recovery, and the PGA systems had a mix of over/under-recovered demand costs for FYE20. Table G6 summarizes the FYE20 demand cost over/under-recovery:

Table G6: FYE20 Over/(Under)-Recovery of Demand Costs as Filed[24]

GMG	10.54%
Great Plains	(1.38%)
MERC-CON	36.56%
MERC-NNG	35.87%
CenterPoint	(3.13%)
Xcel Gas	less than 0.01%

Recovery of commodity costs is affected by weather and market price fluctuations. The commodity portion of natural gas rates is generally based on price estimates made during the week prior to the beginning of each month. Therefore, an unexpected cold period during the middle of a month, following normal weather in the last week in the preceding month, typically leads 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 typically leads to an over-recovery of commodity costs if actual commodity gas costs correspondingly decline. 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.

Multiple factors affected commodity costs in FYE20. Warmer weather during FYE20 put downward pressure on commodity prices. Although natural gas exports and the use of natural gas in electric generation facilities remained relatively high, demand for natural gas declined for other users due to the warm weather and the impacts of the COVID-19 pandemic on certain commercial activity; the combination of these natural gas demand factors contributed to commodity prices remaining relatively low for FYE20. As weather extremes and periods of abnormal weather become increasingly more common, predicting seasonal commodity prices will also become more difficult. Each PGA system over/under-recovered its commodity costs by the percentages shown in the following table.

[24] 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: FYE20 Over/(Under)-Recovery of Commodity Costs as Filed[25]

GMG	(5.83%)
Great Plains	2.37%
MERC-CON	0.36%
MERC-NNG	18.51%
CenterPoint	3.00%
Xcel Gas	5.62%

Calculation of the Monthly Volumetric Demand Cost Recovery Rate – In general, demand costs are the costs of reserving pipeline capacity to transport firm gas supplies.[26] Pursuant to Minnesota Rules 7825.2910, Subpart 2, gas utilities must file a petition to increase or decrease demand, redistribute demand percentages among classes, or exchange one form of demand for another. The petition must include a description of the factors contributing to the need for the demand change, the utility's design-day demand by customer class, and the change in design-day demand.

Since the current non-gas base rate for most gas 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 Federal Energy Regulatory Commission (FERC)-approved natural gas pipeline rates[27] to the Commission's approved demand entitlement level of the utility. Demand entitlements are normally contracted for with 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.[28] Further, sales are

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[25] Except for CenterPoint, the percentages include revenue such as balancing penalty revenue. Additionally, commodity costs include storage and balancing costs.

[26] 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.

[27] If the natural gas pipeline is intrastate, then the Commission-approved rates apply.

[28] 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
- natural gas pipeline rates approved by FERC

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.[29] This under-recovery occurs because the winter months are the period in which the greatest percentage of cost recovery generally occurs.

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 utility credits the monthly PGA and/or the annual true up, thereby reducing the demand costs to be recovered. 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.

Deviations Between Forecasted and Actual Sales Volumes and Prices – For commodity costs, common causes of over/under-recovery are (1) the deviation between monthly forecasts and actual sales volumes and (2) changes in commodity prices. Market conditions affect the price of natural gas. For regulatory purposes, natural gas commodity costs are usually a pass-through cost for utilities via their PGAs.

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. Therefore, 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 result.

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 the listed factors may affect gas costs and recovery of those costs for Minnesota's gas utilities. The following section highlights the individual gas utility true up results for FYE20 and, as applicable, addresses the factors itemized in the preceding list along with other notable factors that contributed to the FYE20 over/under-recoveries.

[29] 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.

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

The gas utilities had a mix of under/over-recoveries in FYE20. In the following sections, the Department discusses these under/over-recoveries and the corresponding AAA true up calculations. In addition, the Department highlights certain AAA compliance reporting as applicable to the different utilities.

A. GREATER MINNESOTA GAS, INC.

1. Recovery of Gas Costs and True Up Calculations

On September 1, 2020, Greater Minnesota submitted its FYE20 Annual True Up Report in G022/AA-20-699 in compliance with Minnesota Rule 7825.2810. The Department concludes that GMG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For FYE20, GMG reported that it under-recovered its total gas costs by $126,995, or approximately 2.18 percent, for a cumulative under-recovery of 1.91 percent.[30] By customer class, Greater Minnesota reported over/under-recoveries for the current reporting period as follows:

Table G8: Greater Minnesota Gas FYE20 Percent Over/(Under)-Recovery by Customer Class[31]
(As filed by Greater Minnesota)

Firm	(2.26)
Agricultural - Interruptible	(4.22)
General – Interruptible	2.66
Total System	(2.18)

Using the sales volumes forecasted by Greater Minnesota for the FYE21[32] period results in the following true up factors by customer class:

Table G8a: Greater Minnesota Gas True Up Factors per Mcf by Customer Class
(As filed by Greater Minnesota)

Firm	$0.0859
Agricultural - Interruptible	$0.1673
General - Interruptible	$(0.0902)

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[30] The figure of 1.91 percent represents the cumulative under-recovery of $111,522, which is the basis for GMG's FYE21 true up adjustment. For a detailed breakdown of the true up calculations, please see Greater Minnesota's True Up Report, Docket No. G022/AA-20-699.
[31] A supporting spreadsheet with detailed calculations is contained in Department Attachment G5.
[32] GMG's True Up Report, Attachment A.

The Department's analysis of Greater Minnesota's true up calculation indicates that the current year's deviation between gas cost recovery and actual gas costs was primarily due to the following demand and commodity cost factors, about which GMG stated in its AAA Report: "[t]o the extent estimated volumes and prices vary from actual purchases, a monthly over- or under-recovery will occur."[33]

- **Demand Costs** – GMG over-recovered its current demand costs by $136,992, or approximately 10.54 percent. The demand cost over-recovery includes capacity release revenue of $67,504. Without this revenue, there was an over-recovery of demand costs of $69,488, or approximately 5.35 percent.

  Weather across the state of Minnesota in FYE20 was warmer than normal, with the St. Cloud and Minneapolis/St. Paul areas experiencing weather that was 2.31 and 4.46 percent warmer than normal, respectively; the FYE20 weather, all else being equal, would typically cause an under-recovery of demand costs. However, considering the relatively small amount of GMG's over-recovery of FYE20 demand costs, after accounting for the capacity release revenue, the Department concludes that GMG's demand cost over-recovery appears reasonable.

- **Commodity Costs** – GMG under-recovered its FYE20 commodity costs by $263,987, or approximately 5.83 percent. The Department concludes that GMG's under-recovery of commodity costs appears to be reasonable.

2. *Compliance and Supplemental Reporting Requirements*

Docket No. G022/M-11-804: The Commission's December 22, 2011 *Order Authorizing New Retail Service* in Docket No. G022/M-11-804 required GMG to provide in its AAA report, for each relevant 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
- 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 in the following quote included in Commission Staff in briefing papers:

[33] GMG's AAA Report, pdf page 10.

> The Department recommended the Commission require GMG to show in the Company's next rate case that the rates charged for the purchase for resale service cover the cost of adding these new customers to GMG's system. GMG agreed and proposed that it track the capital expenditures and customer load additions provided under this tariff for review in the Company's next general rate proceeding. Staff agrees this is good idea and believes the additional service extension request information recommended earlier in the briefing papers would help GMG demonstrate this point.
>
> 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 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.[34]

On pdf page 10 of its AAA Report, GMG provided the information required by the Commission's December 22, 2011 *Order* in Docket No. G022/M-11-804, and the Department concludes that GMG complied with the reporting requirements as ordered.

Docket Nos. G999/AA-14-580 and G999/AA-17-493: The Commission's August 24, 2015 *Order* in Docket No. G999/AA-14-580 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. In its February 27, 2019 *Order* in Docket No. G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20. On pdf page 11 of its AAA Report, GMG explained that it did not have any non-compliant interruptible customers that engaged in unauthorized gas use during a curtailment period. The Department concludes that GMG complied with the reporting requirements in Docket No. G999/AA-17-493.

[34] Pages 4 -5 of the December 7, 2011 Staff Briefing Papers in Docket No. G022/M-11-804.

3. Summary and Recommendations

The Department concludes that GMG's AAA filings are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department recommends that the Commission:

- Accept GMG's FYE20 true up, Docket No. G001/AA-20-699.
- Allow GMG to implement its true up, shown in Department Attachment G5.

B. GREAT PLAINS NATURAL GAS COMPANY

1. Recovery of Gas Costs and True Up Calculations

On August 31, 2020, Great Plains submitted its FYE20 Annual True Up Report in Docket No. G004/AA-20-684 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 FYE20 reporting period, Great Plains over-recovered its total gas costs by $150,035, or approximately 1.09 percent, for a cumulative over-recovery of total gas costs of approximately 2.15 percent.[35] Great Plains' over-recovery by customer class for the current reporting period is shown in the following table.[36]

Table G9: Great Plains FYE20 Percent Over-Recovery/(Under)-Recovery by Customer Class[37]
(As filed by Great Plains)

Firm	1.07
Interruptible	1.16
Total System	1.09

Using the sales volumes forecasted by Great Plains for FYE21 results in the following true up factors by district and by customer class:

[35] The figure of 2.15 percent represents the cumulative over-recovery of $294,871, which is the basis for the FYE21 true up adjustment. For a detailed breakdown of the true up calculations, please see Great Plains' True Up Report, Docket No. G004/AA-20-684.
[36] Beginning July 1, 2017, Great Plains consolidated its North and South PGA systems into one consolidated PGA system. The term "North District" referred 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" referred 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.
[37] A supporting spreadsheet with detailed calculations is contained in Department Attachment G6.

Table G9a: Great Plains True Up Factors per Mcf by Customer Class
(As filed by Great Plains)

Class	Consolidated System
Firm	$(0.0628)
Interruptible	$(0.1178)

The Department's analysis of Great Plains' true up calculation indicates that the current year's deviation between gas costs recovered and incurred was primarily due to the following demand and commodity cost factors:

- **Demand Costs** – Great Plains under-recovered its demand costs by $64,568, or approximately 1.38 percent, during the reporting period. The demand cost under-recovery includes capacity release revenue of $19,519. On pages 3 – 4 of its AAA Report, Great Plains stated that the under-recovery of demand costs was due to the following:

    - Because Great Plains recovers demand costs on a volumetric basis, it typically under-recovers demand costs during summer months, when sales volumes are low, and over-recovers demand costs during winter months, when sales volumes are high.
    - VGT and NNG implemented interim rate increases that resulted in higher demand costs beginning January 1, 2020.

  The nearest weather station to Great Plains' northern service area, Fargo, ND, was 1.40 percent colder for the year, but 8.49 percent warmer during the November-March heating season. The nearest weather station to Great Plains' southern service area, Sioux Falls, SD, was 0.38 percent colder over the year, but 1.10 percent warmer during the heating season. The mix of colder and warmer-than-normal temperatures throughout FYE20 in Great Plains' service territory may have somewhat offset one another where demand cost recovery is concerned. Based on this information, the Department concludes that Great Plains' relatively minor 1.38 percent current under-recovery of demand costs appears reasonable.

- **Commodity Costs** – Great Plains over-recovered its commodity costs (including penalty revenue of $72,109[38]) by $214,603, or approximately 2.37 percent. Great Plains stated that the over-recovery was partly a result of timing differences between the cost of gas recovered in rates and the actual gas costs.[39]

  The Department concludes that Great Plains' over-recovery of commodity costs appears reasonable.

[38] Great Plains' response to Department IR 9 ($22,219 + $49,890). Responses are available upon request.
[39] Great Plains' AAA Report, page 4.

2. *Compliance and Supplemental Reporting Requirements*

Docket No. G999/AA-14-580 and G999/AA-17-493: The Commission's August 24, 2015 *Order* in Docket No. G999/AA-14-580 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. In its February 27, 2019 *Order* in Docket No. G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

In Exhibit E of its AAA Report and in response to Department IR 8, Great Plains reported that it did not have any non-compliant gas usage in FYE20 and that no changes occurred in how it handles curtailment penalty revenue. The Department concludes that Great Plains complied with the reporting requirements in Docket No. G999/AA-17-493.

3. *Summary and Recommendations*

The Department concludes that Great Plains' AAA filings are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department recommends that the Commission:

- Accept Great Plains' FYE20 true up, Docket No. G004/AA-20-684.
- Allow Great Plains to implement its true up, shown in Department Attachment G6.

C. *MINNESOTA ENERGY RESOURCES CORPORATION*

In its December 8, 2014 *Order Approving Sale Subject to Conditions* in Docket No. G001,G011/PA-14-107, the Commission approved MERC's acquisition of Interstate Power & Light's gas utility serving Minnesota. 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 the relevant *Order*, the Administrative Law Judge (ALJ) in that case found MERC's proposed timeline to be reasonable.[40] In its October 31, 2016 *Findings of Fact, Conclusions, and Order,* the Commission approved the

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

ALJ's findings.[41] FYE20 is the third full year of data for the combined MERC-NNG and MERC-Consolidated PGA systems.

1. Recovery of Gas Costs and True Up Calculations

On September 1, 2020, MERC-NNG submitted its FYE20 True Up Report in Docket No. G011/AA-20-655 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 FYE20 reporting period, MERC-NNG over-recovered its total gas costs by $23,767,524 or approximately 22.50 percent, for a cumulative over-recovery of total gas costs of approximately 22.81 percent.[42]

On September 1, 2020 MERC-CON submitted its FYE20 True Up Report in Docket No. G011/AA-20-656 in compliance with Minnesota Rule 7825.2810. In its True Up Report, MERC-CON requested authorization to return to customers, through the annual true up factors effective September 1, 2020, the difference between the final approved Viking Gas Transmission (Viking) rates effective January 1, 2020 and the interim Viking rates in effect for the period January 1 - June 30, 2020. The July 1, 2020 settlement agreement in Viking's recent rate case proceeding with the FERC, initially filed June 28, 2019, caused the difference between the Viking rates in FYE20. Because MERC did not adjust its monthly PGA filings for the change in Viking rates, MERC-CON under-charged its customers for actual Viking gas costs incurred January-February 2020 and over-charged its customers for Viking gas costs March-June 2020. The impact of the Viking rate difference on the FYE20 true up is a net refund to customers of approximately $23,000, a relatively small amount. The Department concludes that MERC's proposal is reasonable and does not conflict with the automatic adjustment true up procedures provided for in Minnesota Rule 7825.2700. The Department recommends that the Commission allow MERC-CON, through its annual true up factors effective September 1, 2020, to adjust for the difference between the final approved Viking Gas Transmission (Viking) rates effective January 1, 2020 and the interim Viking rates in effect for the period January 1 - June 30, 2020.[43]

On September 22, 2020 in Docket No. G011/AA-20-656, MERC submitted a correction to its FYE20 MERC-CON true up after discovering a commodity cost error in the true up calculation. The error arose from an April 2020 trade that, following a change in the applicable transaction terms, MERC overstated the cost of by $41,433[44] in its true up calculation. Due to this error, the

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[41] *Findings of Fact, Conclusions, and Order*, issued October 31, 2016, Ordering Paragraph 2, page 54.
[42] The figure of 22.81 percent represents the cumulative over-recovery of $24,092,219 which is the basis for the FYE21 true up adjustment. For a detailed breakdown of the true up calculations, please see MERC-NNG's True Up Report, Docket No. G011/AA-20-655.
[43] Relatedly, in Docket No. G011/M-20-702, the Commission approved MERC's request to refund to customers via the MERC-CON PGA for a refund MERC received from Viking in August 2020. The refund MERC received from Viking in August 2020 was also related to the Viking rate case discussed in the instant section.
[44] (1,236,344 corrected FYE20 over-recovery – 1,194,911 initially filed FYE20 over-recovery) = $41,433. The over-recovery figures in the preceding calculation are shown in the exhibits labeled "True-up page 1 of 3" in MERC-

MERC-CON true up adjustment factors implemented by MERC on September 1, 2020 under-refunded customers for MERC's over-collection of FYE20 costs. In its September 22, 2020 filing, MERC proposed to correct its true up adjustment factors to account for the error and implement those corrected adjustment factors beginning October 1, 2020. To make this proposed correction, MERC also requested that the Commission grant the utility a variance to Minnesota Rule 7825.2700, which stipulates that "[t]he true-up adjustment must be computed annually for each class by dividing the true-up amount by the forecasted sales volumes and applied to billings during the next 12-month period beginning on September 1 each year…" and Minnesota Rule 7825.2910, Subpart 4, which states "[g]as utilities shall file and implement on September 1 of each year the true-up adjustment…" MERC provided the following discussion on page 3 of its September 22, 2020 filing to address the criteria outlined in Minnesota Rule 7829.3200, which governs rule variances:

- **Enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule**: MERC explained that not correcting the error through revised true up factors would impose an excessive burden on customers, as the initially filed true up factors would under-refund customers.

- **Granting the variance would not adversely affect the public interest:** MERC reasoned that implementing the corrected true up factors would support the public interest by allowing the utility to refund customers the correct amount of over-recovery.

- **Granting the variance would not conflict with standards imposed by law:** MERC stated that it is unaware of any conflict with any standards imposed by law.

The Department concludes that it is reasonable and appropriate for MERC to correct the error in its FYE20 true up calculation and to refund customers using the corrected true up adjustment factors, effective October 1, 2020. The Department agrees with MERC that its request for a variance to Minnesota Rules 7825.2700 and 7825.2910, Subpart 4, meets the three criteria that Minnesota Rule 7829.3200 stipulates must be met for the Commission to grant a rule variance. Therefore, we recommend that the Commission (1) grant MERC a one-time variance to Minnesota Rules 7825.2700 and 7825.2910, Subpart 4 and (2) approve MERC's proposal to correct its true up adjustment factors, effective October 1, 2020, as shown in MERC's September 22, 2020 correction filing in Docket No. G011/AA-20-656.

CON's September 22, 2020 correction filing and September 1, 2020 True Up Report filing, respectively, in Docket No. G011/AA-20-656.

The Department also concludes that MERC-CON's filings are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. The PGA system for MERC-CON, corrected for the discussed error, over-recovered total gas cost by $1,236,346, or approximately 7.13 percent, for a cumulative over-recovery of 6.49 percent.[45]

MERC reported FYE20 over-recoveries, corrected for the discussed error, as follows:

Table G10: MERC FYE20 Percent Over-Recovery/(Under)-Recovery by System and Class[46]
(As filed by MERC)

Class[47]	NNG	CON
GS	23.19	7.59
SVJ/LVJ/SLVJ Demand	0.00	0.00
SVI/SVJ/LVI/LVJ/SLVI Commodity	14.97	2.33
Total System	22.50	7.13

Using the sales volumes forecasted by MERC for FYE21 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 by MERC)

Class	NNG	CON
GS	$(0.8665)	$(0.2048)
SVJ/LVJ/SLVJ Demand	$0.0000	$0.0014
SVI/SVJ/LVI/LVJ/SLVI Commodity	$(0.4936)	$(0.0178)

a. MERC-NNG

On September 1, 2020, concurrent with its AAA Report, MERC-NNG filed an analysis of its over/under-recoveries. MERC-NNG's net over-recovery for the period was due to the following demand and commodity cost factors:

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[45] The figure of 6.49 percent represents the cumulative over-recovery of $1,126,384, which is the basis for the FYE21 true up adjustment. For a detailed breakdown of the true up calculations, please see MERC-CON's corrected True Up Report, Docket No. G011/AA-20-656.

[46] Supporting spreadsheets with detailed calculations are contained in Department Attachments G8 and G9.

[47] 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)
- Super Large Volume Joint (SLVJ)

- **Demand Costs** – MERC over-recovered its demand costs for the MERC-NNG system by $8,720,367, or approximately 35.87 percent. The demand cost over-recovery also includes NNG capacity release revenue of $3,493,102.[48] Without this revenue, there was an over-recovery of demand costs of $5,227,265, or approximately 21.50 percent. On PDF page 22 of its AAA Report, MERC-NNG explained that the over-collection of demand costs was predominantly caused by capacity release revenues and actual sales being higher than projected sales.

  Based on our review of MERC's analysis of its over/under-recoveries, the Department concludes that MERC-NNG's over-recovery of demand costs appears reasonable.

- **Commodity Costs** – MERC-NNG over-recovered commodity costs by $15,047,157, or approximately 18.51 percent. On PDF page 22 of its NNG AAA Report, MERC explained the overcollection was predominantly caused by capacity release revenues attributable to Bison/NBPL, lower than forecasted gas costs, and differences in actual volumes compared to forecast.

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

Through our review, the Department noted differences between the Daily Delivery Variance Charges (DDVCs) and other penalty charge amounts included in MERC-NNG's AAA Report and its September 22, 2020 response the Department IR 7. In MERC-NNG's AAA Report, page 5 of Schedule D.3, MERC included $1,800 of DDVCs in its FYE20 over/under cost recovery calculation for the NNG system; this $1,800 DDVC figure is also included in MERC's response to Department IR 7 as a "positive" DDVC amount. However, in addition to the ($1,800) of positive DDVCs, MERC's response to IR 7 shows that the NNG system incurred a punitive DDVC amount of ($2,378.75) and other penalty charges of ($192,309.30), resulting in a net total of ($196,488.15) for FYE20. The Department request that MERC explain in Reply Comments (1) whether and why the $1,800 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE20 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 FYE20 AAA Report and its reply to Department IR 7.

b. MERC-CON

On September 1, 2020, concurrent with its 2020 AAA Report, MERC-CON filed an analysis of its over/under-recoveries. On September 22, 2020, MERC filed a corrected analysis of its

[48] MERC-NNG's AAA Report, Schedule D3. Note that MERC-NNG reported $13,061 in curtailment penalty revenue (Schedule C&D of MERC-NNG's AAA Report).

over/under-recoveries, based on the correction of the error previously discussed in this section. MERC's net over-recovery was due to the following demand and commodity cost factors:

- **Demand Costs** – MERC over-recovered its demand costs for the MERC-CON system by $1,185,386, or approximately 36.56 percent. The demand cost over-recovery includes capacity-release revenue of $295,158.[49] Without the capacity release revenue, there was an over-recovery of demand costs of $890,228, or approximately 27.46 percent. On PDF page 20 of its AAA Report, MERC explained that its over-collection of demand costs was caused by capacity release revenues and actual sales being higher than projected sales.

  Based on our review of MERC's analysis of the over/under-recoveries, the Department concludes that MERC-CON's over-recovery of demand costs appears reasonable.

- **Commodity Costs** – MERC-CON over-recovered commodity costs by $50,960, or approximately 0.36 percent. On PDF page 20 of its AAA Report, MERC-CON explained that the overcollection was primarily caused by lower gas costs.

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

2. Compliance and 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, G011/M-15-231, and G011/M-17-85:[50] In the preceding list of dockets, the Commission allowed MERC to recover through the PGA the costs associated with using financial instruments to secure natural gas supplies. 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
- Total contracted volumes, for each instrument
- Net gain or loss, including all transaction costs for each instrument in comparison to the

[49] MERC- CON's AAA Report, Schedule I. Note that MERC-CON reported $312 in curtailment penalty revenue (Schedule C&D of MERC-CON's AAA Report).
[50] 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 Commission also continued the requirement for MERC to provide an annual analysis on its hedging program and a post-mortem analysis in its AAA reports.

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 after-the-fact 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 NNG and CON AAA Reports, Schedules L and O, and in an Excel spreadsheet filed concurrently with its AAA Reports. The Department discusses MERC's hedging costs further in Section III of this FYE20 AAA 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/quantified description of the risk (*i.e.,* catastrophic or other type of event) that the companies are insuring against by implementing the hedging strategies and a clearly defined/quantified estimate of probability of these 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
  - 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

- 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 bill

MERC included these reporting requirements in Schedule P of its NNG and CON AAA Reports.

Docket Nos. G999/AA-14-580 and G999/AA-17-493: 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. In its February 27, 2019 *Order* in Docket G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

On PDF pages 27-28 of MERC-NNG's AAA Report, MERC stated that it called nine curtailments over eight days, and unauthorized gas use occurred on one of these eight days. MERC reported 2,612.21 therms of unauthorized gas use for FYE20, down from 38,097.1 in FYE19, for the NNG system. MERC-NNG's AAA Report included the required information for customers with unauthorized gas use.[51] On PDF pages 25-26 of MERC-CON's AAA Report, MERC reported calling two curtailments and having one day on which unauthorized gas use occurred during FYE20, just as in FYE19. MERC reported 62.35 therms of unauthorized gas use in FYE20, down from 485.8 therms reported in FYE19, for the CON system. MERC-CON's AAA Report included the required information for customers with unauthorized gas use.

The Department concludes that MERC complied with the reporting requirements in Docket No. G999/AA-17-493 on unauthorized gas use.

Docket Nos. G011/M-15-895 and G011/M-18-526: The Commission's May 8, 2018 *Order* in Docket No. G011/M-15-895 required MERC to separately track and report Rochester-specific capacity release information (e.g., volumes, revenue received) in future AAA filings in the same manner that it has in previous filings for short-term capacity releases. MERC-NNG provided this reporting requirement in Schedule I of its AAA Report, showing $1,478,778.71 and 184,832 Dth of capacity release associated with the Rochester expansion project in FYE20.

The Department concludes that MERC complied with the reporting requirements in Docket Nos. G011/M-15-895 and G011/M-18-526 regarding the Rochester-specific capacity release.

3. Summary and Recommendations

The Department concludes that MERC's FYE20 AAA filings are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department requests that MERC explain in Reply Comments (1) whether and why the $1,800 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE20 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 FYE20 AAA Report and its reply to Department IR 7.

The Department recommends that the Commission:

- Accept MERC-NNG's FYE20 true up, Docket No. G011/AA-20-655, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.

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[51] In the *Order* from Docket No. G999/AA-14-580, the Commission required MERC in its next rate case to raise the Company's curtailment penalty from $20 to $50 per dekatherm. MERC did so in Docket No. G011/GR-15-736. The Commission's Order in Docket 15-736 was issued on October 31, 2016, therefore the increased penalty of $5 per therm was first reflected in MERC's filing in Docket No. G999/AA-18-374.

- Allow MERC-NNG to implement its true up, shown in Department Attachment G8, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.
- Accept MERC-CON's FYE20 true up, as corrected in its September 22, 2020 filing in Docket No. G011/AA-20-656.
- Allow MERC-CON, through its annual true up factors effective September 1, 2020, to adjust for the difference between the final approved Viking Gas Transmission (Viking) rates effective January 1, 2020 and the interim Viking rates in effect for the period January 1 - June 30, 2020.
- Grant MERC a one-time variance to Minnesota Rules 7825.2700 and 7825.2910, Subpart 4, and approve MERC's proposal to correct its MERC-CON system true up adjustment factors, effective October 1, 2020, as shown in MERC's September 22, 2020 correction filing in Docket No. G011/AA-20-656.
- Allow MERC-CON to implement its true up, as corrected in its September 22, 2020 filing in Docket No. G011/AA-20-656 and shown in Department Attachment G9.

D. CENTERPOINT

1. Recovery of Gas Costs and True Up Calculations

On September 1, 2020, CenterPoint filed its FYE20 True Up Report in Docket No. G008/AA-20-698 in compliance with Minnesota Rule 7825.2810. The Department concludes that CenterPoint's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

CenterPoint over-recovered gas costs by $6,614,639, or approximately 1.48 percent, with a cumulative over-recovery of approximately 1.62 percent[52] of its actual gas cost incurred. By customer class, CenterPoint reported over/under-recoveries for the current reporting period as follows:

[52] The figure of 1.62 percent represents the cumulative over-recovery of $7,263,828, which is the basis for the FYE21 true up factors. For a detailed breakdown of the true up calculation, please see CenterPoint's True Up Report, Docket No. G008/AA-20-698.

Table G11: CenterPoint FYE20 Percent Over-Recovery/(Under)-Recovery by Customer Class[53]
(As filed by CenterPoint)

Class	
Small Volume Firm	1.46
Large General Service	(1.75)
Small Volume Dual Fuel	2.76
Large Volume Dual Fuel	1.15
Total System	1.48

Using the rate case sales volumes forecasted by CenterPoint results in the following proposed true up factors by class.[54]

Table G11a: CenterPoint True Up Factors per Dekatherm (Dth) by Customer Class
(As filed by CenterPoint)

Class	Factor
Small Volume Firm	$(0.0565)
Large General Service	$0.0160
Small Volume Dual Fuel	$(0.0697)
Large Volume Dual Fuel	$(0.0239)

The Department's analysis of CenterPoint's true up calculation indicates that the current year's deviation between gas cost recovered and incurred was primarily caused by the following factors:

- **Demand Costs** – CenterPoint under-recovered its demand costs, including propane costs,[55] by $3,974,495, or approximately 3.13 percent. The demand cost under-recovery includes off-system sales revenue and curtailment revenue of $0.[56] CenterPoint explained that, with the demand rate being an annualized value, changes in demand costs during FYE20 resulted in timing differences between costs incurred and recovered. CenterPoint also noted that its "demand smoothing" factor brought the demand cost recovery closer to the demand costs incurred.

  Weather at the Minneapolis/St. Paul weather station, where the majority of CenterPoint's load is concentrated, was 4.46 percent warmer than normal for the year and 5.30 percent warmer during the heating season. These temperatures would typically predict an under-recovery of demand costs, which aligns with CenterPoint's demand cost recovery experience in FYE20. The Department discusses CenterPoint's

[53] A supporting spreadsheet with detailed calculations is contained in Department Attachment G10.
[54] See CenterPoint's True Up Report, page 10, for the sales volumes.
[55] Propane costs of $162,658 are included in demand costs. See CenterPoint's True Up Report, page 3.
[56] CenterPoint's True Up Report, page 9.

demand smoothing factor in more detail in the *Compliance and Supplemental Reporting Requirements* subsection that follows.

The Department concludes that CenterPoint's under-recovery of demand costs appears reasonable.

- **Commodity Costs** – CenterPoint over-recovered commodity costs by $9,634,398, or approximately 3.00 percent. The commodity cost over-recovery includes off-system sales revenue of $200,952, damage revenue of $19,385, and balancing revenue of $734,398.[57] Without these revenues, there was an over-recovery of commodity costs of $8,697,663 or approximately 2.71 percent. Regarding the over-recovery, CenterPoint stated that "[c]ommodity-cost recovery 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."[58]

  CenterPoint also provided further commodity price discussion on pages 9 - 10 of its AAA Report; on page 9, in reference to the FYE20 winter, CenterPoint stated:

  > The First-of-Month Market price volatility for winter 2019-2020 averaged 25% compared to CenterPoint Energy's gas supply rate at 20%. This demonstrates that CenterPoint Energy's hedging strategy and storage capabilities have a positive effect on stabilizing gas supply costs. CenterPoint Energy's gas supplies subject to stabilized price mechanisms (that is, storage withdrawals and price hedged physical gas) amounted to 49.2 Bcf or 49.2% of all gas delivered to sales customers during the winter. The 2019 Plan met its objectives of providing adequate supplies at reasonable prices.

  Considering the discussion provided by CenterPoint, the historically low natural gas market prices during FYE20, and the relatively minor amount of over-recovery, the Department concludes that CenterPoint's over-recovery of commodity costs appears reasonable.

[57] *Id*.
[58] CenterPoint's AAA Report, page 23.

2. Compliance and 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, G008/M-16-228, and G008/M-19-342 (Demand Adjustment Program): In Docket No. G008/M-00-980, CenterPoint 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 to provide, in its AAA reports, 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.

In the above-listed dockets, the Commission approved extensions of the Program. In its December 11, 2013 *Order* in Docket No. G008/M-13-728, the Commission approved CenterPoint's request "to remove the one-month lag in sales from its calculation" of the monthly demand adjustment and ordered that CenterPoint continue to comply with the reporting requirements from the previous related dockets. The Commission most recently extended the Program approvals in Docket No. G008/M-19-342, with no substantive changes from the December 11, 2013 *Order* in Docket No. G008/M-13-728. In Exhibits 3 and 4 of its AAA Report, CenterPoint included the required information. Since the inception of the Program, the estimated demand-cost recovery results have been as follows:

Table G12: CenterPoint's Demand Adjustment Program Recovery Results[59]

Year	*Over/(Under) Recovery[60] With Program[61]*		*Over/(Under) Recovery Without Program*	
	Dollars	*Percentage*	*Dollars*	*Percentage*
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[62]	$688,175[63]	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)
FYE17	($6,726,160)	(7.8)	($6,610,120)	(7.7)
FYE18	($1,715,132)	(2.0)	$9,655,090	11.3
FYE19	($6,957,804)	(7.3)	$11,757,769	12.4
FYE20	($12,579,209)	(9.9)	$3,797,414	3.0

As highlighted above, except for FYE07, FYE08, FYE13, FYE16, FYE17, and FYE20, the Program appears to provide a better match of costs and recoveries within the true up year than would have been the case without the Program.[64] The Department refers to Docket No. G008/M-19-

[59] Table data retrieved from CenterPoint's AAA Report Exhibits 3 and 4. Note that Exhibits 3 and 4 use forecasted/estimated data to illustrate the differences in over/under-recovery of demand costs, and, therefore, the over/under-recovery figures in these exhibits do not tie to the actual annual amount that CenterPoint over/under-recovers and reports in its True Up Report.

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

[61] Program recovery did not include the lag adjustment until FYE14.

[62] Beginning in FYE14, the Commission approved CenterPoint's request to adjust the Program for a one-month lag in sales.

[63] This figure was corrected. As of FYE14, the Program recovery includes the lag adjustment.

[64] 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) because CenterPoint'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.

342 for the analysis supporting the Commission's decision to grant the most recent variance to allow the demand smoothing adjustment to continue.

Table G12a shows CenterPoint's estimated over/(under) recovery with and without a 1-month lag adjustment.

Table G12a: CenterPoint's Demand Adjustment Program One-Month Lag Adjustment Results[65]

Year	*Over/(Under) Recovery with Lag Adjustment*	*Over/(Under) Recovery without Lag Adjustment*
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[66]	$688,175	($149,278)
FYE15	$1,882,416	($285,002)
FYE16	($5,589,748)	($2,720,436)
FYE17	($10,981,399)	($6,726,160)
FYE18	($4,873,824)	$9,655,090
FYE19	($5,227,433)	($6,957,804)
FYE20	($13,126,481)	$3,797,414

In FYE20, the estimated under-recovery of $13,126,481, assuming a one-month lag adjustment methodology, reflects a more extreme under/over-recovery amount than the actual methodology without the lag adjustment, which shows an estimated over-recovery of $3,797,414. The Department concludes that CenterPoint complied with the filing requirements in Docket No. G008/M-19-342.

Docket Nos. G008/M-01-540, G008/M-08-777, G008/M-12-166, G008/M-15-912, and G008/M-19-699 (Financial Call Options): In Docket No. G008/M-01-540, the Commission granted a variance to allow CenterPoint 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 this variance in Docket Nos. G008/M-08-777, G008/M-12-166, G008/M-15-912, and G008/M-19-699, with the most recent extension running through June 30, 2024. In its November 3, 2004 *Order* in Docket No. G008/M-01-540, the Commission required CenterPoint to:

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

- 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
- 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.[67]

In its March 6, 2009 *Order* in Docket No. G008/M-08-777 (and in the variance extension dockets following Docket No. G008/M-08-777), the Commission stipulated the following reporting requirements:

- Data on the specifics of any price hedging contracts, including a list of each hedging instrument entered into
- Totals contracted for each instrument
- Net gains or losses, including all transaction costs

In Exhibit 6 of its AAA Report, CenterPoint included information on its swing contracts only, as it did not purchase financial call options. CenterPoint's AAA Report 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.

The Department concludes that CenterPoint complied with the filing requirements in Docket Nos. G008/M-01-540, G008/M-08-777, G008/M-15-912, and G008/M-19-699.

Docket No. G999/AA-08-1011: The Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal year 2010. Pages 24-25 as well as in Exhibits 6, 7, and 8 of CenterPoint's AAA Report provide this information. The Department concludes that CenterPoint complied with the filing requirements in Docket No. G999/AA-08-1011.

Docket No. G008/GR-08-1075 (Off-System Sales): In Docket No. G008/GR-08-1075, the Commission ordered CenterPoint 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's Ordering Paragraph 72 (d) required CenterPoint 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) of the same *Order* required that CenterPoint split the off-system sales between commodity and demand gas costs (*i.e.*, storage exchange and swing sales would be a demand cost credit and

[67] In Docket No. G999/AA-16-524, CenterPoint explained that during the winter, its swing gas is valued the same as "spot market" gas, so there is no comparison to provide. CenterPoint requested to discontinue this compliance item until such time that the difference is not zero, and the Commission approved this request.

other point exchanges would be a commodity cost credit). CenterPoint included the required information on pages 9 and 13 of its True Up Report.

The Department concludes that CenterPoint calculated its incentive on off-system sales[68] and allocations among classes correctly, and that CenterPoint complied with the filing requirements in Docket No. G008/GR-08-1075.

Docket Nos. G999/AA-14-580 and G999/AA-17-493: The Commission's August 24, 2015 *Order* in Docket No. G999/AA-14-580 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. In its February 27, 2019 *Order* in G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20. On page 20 of its AAA Report, CenterPoint indicated that it had no unauthorized gas use on its system in FYE20.

The Department concludes that CenterPoint complied with the reporting requirements in Docket No. G999/AA-17-493.

3. *Summary and Recommendations*

The Department concludes that CenterPoint's FYE20 AAA Report is complete with respect to the filing requirements in Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department recommends that the Commission:

- Accept CenterPoint's FYE20 true up, Docket No. G008/AA-20-698.
- Allow CenterPoint to implement its true up, shown in Department Attachment G10.

E. XCEL GAS

1. *Recovery of Gas Costs and True Up Calculations*

On September 1, 2020, Xcel Gas submitted its FYE20 True Up Report in Docket No. G002/AA-20-705 in compliance with Minnesota Rule 7825.2810. Based on our review, the Department concludes that Xcel's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

[68] In Docket No. G008/GR-08-1075, the Commission allowed CenterPoint to earn an incentive equal to the approved overall rate of return on its off-system sales. On page 13 of its True Up Report, CenterPoint's incentive totaled $17,688 ($218,640- $200,952).

Xcel Gas over-recovered gas costs by $9,563,090, or approximately 4.20 percent, during the reporting period, with a cumulative over-recovery of approximately 4.14 percent.[69] By customer class, Xcel Gas reported under/over-recoveries for the current reporting period as follows:

Table G13: Xcel Gas FYE20 Percent Over-Recovery/(Under)-Recovery by Customer Class[70]
(As filed by Xcel Gas)

Class	
Residential	4.86
Commercial/Industrial (C/I)	4.57
Demand Billed	(1.35)
Demand Billed Commodity	2.49
Small Interruptible (SVI)	4.30
Medium & Large Interruptible (M&LVI)	0.06
Total	4.20

Using the sales volumes forecasted by Xcel Gas for FYE21[71] *results in the following true up factors by class, as calculated by Xcel Gas in its filing:*

Table G13a: Xcel Gas True Up Factors per Dekatherm (Dth) by Customer Class
(As filed by Xcel Gas)

Class	
Residential	($0.1509)
C/I	($0.1476)
Demand Billed Demand	$0.0956
Demand Billed Commodity	($0.0495)
SVI	($0.1167)
M&LVI	($0.0114)

The Department's analysis of Xcel Gas' true up calculation shows that the current year's difference between Xcel's recovered and actual gas costs was primarily caused by the following factors:

- **Demand Costs, Including Demand Billed Costs:** Xcel Gas over-recovered Minnesota demand costs by $1,872, or less than 0.01 percent. The demand cost over-recovery also includes interruptible curtailment penalty revenue of $15,731 and capacity release

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69 The figure of 4.14 percent represents the cumulative over-recovery of $9,418,686, which is the basis for the FYE21 true up adjustments. For a detailed breakdown of the true up calculations, see Xcel Gas' True Up Report, Docket No. G002/AA-20-705.

70 Supporting spreadsheets with detailed calculations are contained in Department Attachment G11.

71 Xcel Gas' True Up Report, Schedule B, page 2.

revenue of $137,983.[72] Without these revenues, Xcel would have under-recovered demand costs.

Xcel explained that because PGA factors are calculated on a forecasted weather normalized basis each month, but collected on actual usage, Xcel typically under-recovers demand costs during periods when actual customer usage is less than forecasted and over-recovers demand costs when usage is greater. Xcel's Monthly Demand Cost True Up Mechanism, approved in Docket No. G002/M-03-843, is designed to offset swings in revenue collection caused by deviations from the forecasted normal weather, and, during the FYE20 heating season, it charged an additional $844,561 of demand costs to customers. As a result, Xcel's slight FYE20 demand cost over-recovery was minimized by the Monthly Demand Cost True-up, without which the utility would have *under*-recovered demand costs by approximately 1.46 percent. [73]

At the Minneapolis/St. Paul weather station, where the majority of Xcel's load is concentrated, annual temperatures were 4.46 percent warmer than normal and 5.30 percent warmer during the heating season. Considering the warmer-than-normal weather, the revenue credits from curtailment penalties and capacity release, and Xcel's Monthly Demand Cost True Up Mechanism, the Department concludes that Xcel Gas' demand cost over-recovery appears reasonable.

- **Commodity Costs, Including Peak Shaving Costs:** During FYE20 Xcel Gas over-recovered commodity costs by $9,561,218, or 5.62 percent. Xcel Gas stated that the under-recovery was due to:

> …deviations between monthly forecasted price 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. Because customer consumption varies by class from month to month and price deviation varies from month to month, individual classes had varying results. [74]

Based the discussion provided by Xcel and considering the historically low natural gas market prices in FYE20, Department concludes that Xcel's over-recovery of commodity costs appears to be reasonable.

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[72] Xcel Gas' responses to Department IRs 8 and 6. The capacity release revenue of $336,117 includes internal and external capacity release revenues.
[73] Xcel's AAA Report, Attachment B, Schedule 3, page 3.
[74] Xcel Gas' AAA Report, Attachment B, Schedule 3, pages 3-4.

2. Compliance and Supplemental Reporting Requirements

Docket No. G002/M-94-103: The Commission required Xcel to return all past, present, and future capacity release revenue from all sources to firm customers using FERC Account 805.1. In Schedule H of Xcel's True Up Report and Attachment G, Schedule 1, of its AAA Report, Xcel 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 charge" 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, G002/M-16-88, and G002/M-19-703 (Hedging): Xcel Gas requested to continue its PGA rule variance to recover hedging costs through June 30, 2024 in the PGA in Docket No. G002/M-19-703. As a condition of extending rule variance to allow Xcel Gas to recover its costs of financial hedging instruments in its PGA, 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
- Total volumes contracted for, for each instrument
- Net gain or loss, including all transaction costs for each instrument in comparison to the appropriate monthly and daily spot index prices
- 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.

Docket Nos. G002/M-03-843, G002/M-06-681, G002/M-08-456, G002/M-11-203, G002/M-14-171, G002/M-17-101, and G002/M-20-282 (Demand Cost Mechanism): On June 11, 2004, the Commission approved a Monthly Demand Cost True Up Mechanism and granted a variance to Minnesota Rule 7825.2700, subpart 5 for Xcel Gas. Xcel implemented the Monthly Demand Cost True Up Mechanism in October 2004. In Docket No. G002/M-20-282**,** the Commission approved the most recent extension of the program through September 30, 2023.

The Monthly Demand Cost True Up Mechanism should result in billing rates that are:

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

The Demand Cost True Up Mechanism is adjusted by capacity release as approved in Docket No. G002/M-11-203. This mechanism includes caps on the monthly amount. For April through October, 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's annual true up filings:

- Annual demand cost recovery absent the adjustments
- Total annual adjustment recovery
- Remaining current year demand cost recovery true up balance

Xcel's FYE20 True Up Report, Schedule I, includes the required information on the Demand Cost True Up Mechanism results. Since the implementation of this mechanism, the demand cost recovery results have been as follows:

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

Year	*Over/(Under)[75]Recovery with Mechanism*		*Over/(Under) Recovery without Mechanism*	
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)
FYE17	($996,915)	(2.09)	($2,881,719)	(6.05)
FYE18	$4,167,484	8.76	$7,625,510	16.03
FYE19	$3,098,460	6.38	$6,871,379	14.14
FYE20	$1,872	0.00	$(842,689)	(1.46)

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

Table G14 shows that, 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. The Department concludes that Xcel Gas complied with the filing requirements in the Commission's *Order* in Docket No. G002/M-03-843.

Docket Nos. E,G999/AA-08-1011 and G999/AA-14-580: The Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal year 2010. Xcel provided this required information in Attachment G, pages 7-9, and Attachment G, Schedules 2-5, in its AAA Report.

Docket Nos. G002/M-09-852 and E,G002/M-15-618: On February 18, 2010 in Docket G002/M-09-852, the Commission approved Xcel's Capacity Utilization Program for its gas distribution and electric generation business units as a three-year pilot program and required Xcel Gas to report in the AAA each individual transaction showing quantities, cost, specific accounting entries, and a brief explanation of the transaction. The pilot expired on February 18, 2013. In Docket No. E,G002/M-15-618, the Commission approved the Capacity Utilization Plan as a permanent program and accepted Xcel's agreement to continue to report on the transactions related to the Capacity Utilization Plan annually in its AAA reports. The approved Capacity Utilization Plan includes both natural gas and electric transactions.

During FYE20, the Capacity Utilization Plan resulted in net savings and avoided storage fees of $0 to both Xcel Gas and Xcel Electric.[76]

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

Docket Nos. G999/AA-14-580 and G999/AA-17-493: The Commission's August 24, 2015 *Order* in Docket No. G999/AA-14-580 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. In its February 27, 2019 *Order* in Docket No. G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

Xcel Gas reported 10 therms of unauthorized gas use for FYE20 and detailed its communication procedures to avoid or address unauthorized use.[77] The Department concludes that Xcel Gas complied with the Commission's *Order* in Docket No. G999/AA-17-493.

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[76] Xcel Gas' AAA Report, Attachment G, pages 10-11 and Schedule 6.
[77] Xcel's AAA Report, Attachment G, pages 14-15 and Schedule 8.

Docket Nos. G002/M-15-149, G002/M-16-396, G002/M-17-510, G002/M-18-323 and G002/M-18-631: The Commission's October 21, 2015 *Order* and July 19, 2016 *Order* required that Xcel Gas list the Kansas natural gas storage tax costs and revenues as separate line items in the AAA and PGA true up reports as well as in true up report Schedules C and D (page 1-2 and 4 of 4). Additionally, Xcel Gas is required to submit a report detailing the total amount paid to Kansas and collected from ratepayers during the gas year. In Docket No. G002/M-18-631, Xcel Gas requested and was granted a three-year variance for collection of taxes through 2021.

Xcel Gas included the required information in its AAA Report, Attachment G, pages 12-13, stating the following:

> The Minnesota share of the Kansas natural gas storage-related ad valorem tax costs for the years 2009-2014 is $5,006,347, of which $1,004,045 was amortized for the July 2019 to June 2020 gas year. The total amount of tax recovered from Minnesota gas ratepayers for this lump sum tax assessment during the July 2019 to June 2020 gas year is $1,007,266.
>
> The annual Kansas tax expense is recorded on a current basis. However, because the PGA gas year captures 12-months of tax expense recorded during July – June period, it reflects a portion of the KS taxes assessed in 2019 and estimated for 2020. Using the 2019 tax level as a proxy for 2020, $725,443 was included in the PGA rate for the current natural gas AAA year. $623,037 was allocated to Minnesota. The current reporting period also includes a $52,093 increase in Kansas tax for Minnesota due to a true-up for 2019 actual billed tax.…The total amount of tax collected from Minnesota gas ratepayers during the July 2019 to June 2020 gas year is $625,930.

The Department concludes that Xcel Gas complied with the Commission's *Orders* in Docket Nos. G002/M-15-149, G002/M-16-396, G002/M-17-510, G002/M-18-323 and G002/M-18-631.

Docket No. G999/AA-18-374: At the April 26, 2018 Commission 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 had its internal audit department investigate the issue. The investigation identified, among other things, that Xcel had an allocation issue regarding gas volumes used at its High Bridge plant, one of Xcel's natural-gas-powered electric generation units. The LDC communicates to NNG the volumes used by the High Bridge plant (a natural gas transport customer). NNG uses these volumes to allocate costs between the LDC and electric utility. Due to a measurement error, the High Bridge volumes were understated to NNG over several years (FYE14-FYE17), meaning that the plant used more gas than they brought onto the system (i.e., Xcel Gas was charged for more and Xcel Electric was charged for less gas than they used). Based on the over/undertake cash-out mechanism in its transportation tariffs, Xcel estimated the total system cost impact at approximately $6 million ($4.2 million for the four years of FYE14-FYE17, and $1.8 million for the FYE18 gas year). Xcel included a total system credit of $6 million ($5.2 million for Minnesota) in its FYE18 gas true up filing, with the true up factors applied to customer bills over the following 12 months.[78]

In Point 21 of its November 13, 2019 *Order* in the FYE18 AAA reports, Docket No. G999/AA-18-374, the Commission 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 due September 1, 2020).

On page 16 of Attachment G of its AAA Report, Xcel stated that it "…calculated interest of $589,692 for the 2013-2017 prior period adjustment portion of the High Bridge allocation error, based on the Prime Rate. This interest was included as a credit to customers in the December 2019 Purchased Gas Adjustment filed November 26, 2019 (Docket No. G002/AA-19-747). In the November 26, 2019 PGA filing, the interest calculation was provided as Attachment 1 and the credit was shown on Schedule A, page 3, line 20a, Credit for High Bridge Interest on Refund." The Department reviewed the High Bridge PGA credit described by Xcel in the preceding quote, and we conclude that Xcel complied with the High Bridge adjustment requirements in the Commission's November 13, 2019 *Order* in Docket No. G999/AA-18-374.

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 our review, the Department recommends that the Commission:

- Accept Xcel Gas' FYE20 true up, Docket No. G002/AA-20-705.
- Allow Xcel Gas to implement its true up, shown in Department Attachment G11.

III. ADDITIONAL INFORMATION

A. AVERAGE ANNUAL RESIDENTIAL CUSTOMER BILLS

Using data supplied by the utilities in their responses to Department IR 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 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:

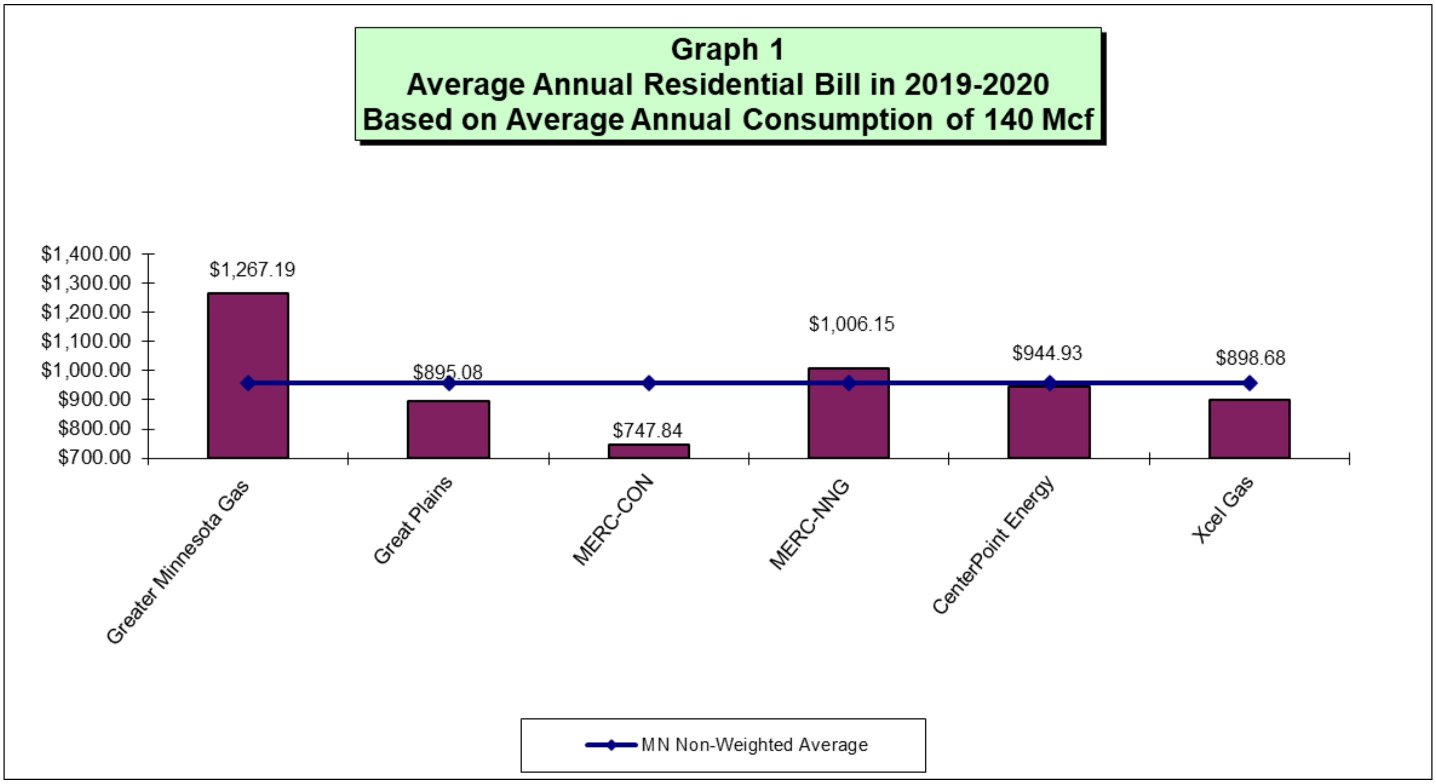
[78] Xcel Gas's FYE18 AAA Report in Docket No. G999/AA-18-374, Attachment G, pages 2-3.

- customer charge
- per-unit energy consumption rate
- average customer consumption of 140 Mcf per year[79]

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.[80]

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.[81] 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.

[79] 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.
[80] Further discussion on margins in provided later in the instant Section III. Please note that the margins used to calculate total average annual bill are the average rate for the reporting period.
[81] 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.



Graph 1 shows that, based on a consumption level of 140 Mcf, average annual residential bills[82] range from a high of $1,267.19 for customers served by GMG to a low of $747.84 for customers served by MERC-CON.

The following Table G15 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 IR 1.[83]

[82] Amounts shown in Graph 1 are not actual averages for customers on any system, as 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.
[83] Responses are available upon request.

Table G15: Average Annual Residential Bill and Average Use per Utility for the FYE20 Reporting Period

Utility	*Average Usage Rankings*[84]	*Average Use*[85] *(Mcf)*	*Annual Bill Rankings*	*Total Annual Bill*	*Average Cost per Mcf*[86]	*Annual Customer Charges*
GMG	**1**	83.2	**6**	$794.46	$9.55	$102.00
Great Plains	**1**	83.2	**2**	$574.70	$6.91	$105.42
MERC-CON	**5**	89.3	**1**	$518.21	$5.80	$114.00
MERC-NNG	**3**	86.3	**5**	$664.07	$7.69	$114.00
CenterPoint	**6**	89.3	**4**	$646.84	$7.24	$121.80
Xcel Gas	**4**	89.0	**3**	$610.64	$6.86	$108.00

As shown in Table G15, based on actual consumption, CenterPoint and MERC-CON customers had the highest average consumption (89.3 Mcf), and GMG had the highest average annual residential bill ($794.46) during FYE20.[87]

In reference to the information provided in Graph 1, Table G15, and Department Attachment G13, the Department notes that utility costs are driven by several factors, including 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 (*e.g.*, imbalance penalties).

The non-gas portion of a utility's base rates are developed independently in a general rate case proceeding. 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

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[84] The rankings throughout this report are listed in the format from lowest to highest (*e.g.,* average use, cost, and rate).
[85] 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.
[86] 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.
[87] Since FYE09, the following utilities had the highest consumption and average residential bills, respectively:

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
FYE17 CenterPoint Energy and GMG	81 Mcf	$704.72
FYE18 CenterPoint Energy and GMG	95 Mcf	$837.70
FYE19 CenterPoint Energy and GMG	99 Mcf	$899.04

GMG continues to have the highest average residential bills, due to its high non-gas margin. See Table G18 for more detail.

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[88] commodity costs incurred by the utilities and passed on to ratepayers in the monthly PGAs, as reported in the utilities' true up reports. Certain tables in the instant FYE20 AAA Report provide the Minnesota weighted average and the Minnesota non-weighted average amounts. The Department includes the non-weighted average, because the weighted average is dominated by CenterPoint, Minnesota's largest natural gas provider.

Table G16: FYE20 Total Weighted Average Cost of Commodity PGA Recovered Versus Actual Incurred[89]

Utility	*Recovered PGA Commodity Rate $/Mcf*	*Actual Annual Commodity Rate $/Mcf*	*Percent Over/ (Under) Recovery*
GMG	$2.7918	$2.9647	(5.83%)
Great Plains	$2.3607	$2.3061	2.37%
MERC-CON	$2.3507	$2.3491	0.07%
MERC-NNG	$3.4036	$2.8721	18.51%
CenterPoint	$2.4584	$2.3868	3.00%
Xcel Gas	$2.4485	$2.3182	5.62%
Weighted MN Average	$ 2.5615	$ 2.4233	5.70%
Non-Weighted MN Average	$ 2.6356	$ 2.5328	4.06%

Table G16 demonstrates that all the PGA systems, except GMG, over-recovered FYE20 commodity costs, with MERC-NNG having greatest percentage of over-recovery at 18.51 percent.

The following Table G16a shows the difference between FYE20 and prior year Minnesota non-weighted average commodity costs; these figures are nominal costs and are not adjusted for either inflation or weather conditions. Based on the data, the actual Minnesota non-weighted average commodity cost of gas during FYE20 was $2.5328 per Mcf, which represents an approximately 28 percent decrease compared to the FYE19 reporting period. Table G16a shows

[88] 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).
[89] The numbers used and the detailed calculations are contained in Department Attachment G15.

that the FYE20 commodity cost level was lower than in all the prior reporting periods over the last 20 years.

Table G16a: Non-Weighted Average Commodity Costs

Reporting Period	*Rate (Mcf)*	*Percentage of Increase/ (Decrease) Between Prior Year and FYE20*
FYE20	$2.5328	
FYE19	$3.5072	(28%)
FYE18	$3.3743	(25%)
FYE17	$3.4053	(26%)
FYE16	$2.9051	(13%)
FYE15	$4.1574	(39%)
FYE14	$5.4831	(54%)
FYE13	$3.4442	(26%)
FYE12	$3.5238	(28%)
FYE11	$4.3001	(41%)
FYE10	$4.7259	(46%)
FYE09	$6.1826	(59%)
FYE08	$7.4936	(66%)
FYE07	$7.6177	(67%)
FYE06	$8.8345	(71%)
FYE05	$6.3167	(60%)
FYE04	$5.3364	(53%)
FYE03	$4.7441	(47%)
FYE02	$2.6524	(5%)
FYE01	$6.0288	(58%)

The analysis in Table G16, comparing the PGA commodity costs recovered versus those actually incurred, 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 in the following Table G17. The comparison of total costs per Mcf incurred 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 for Minnesota gas utilities during FYE20.

Table G17: FYE20 Total System Gas Costs (Demand and Commodity)[90]

Utility	*PGA Recovered ($/MMBtu)*	*Rank*	*Current-Period Actual incurred Gas Cost ($/MMBtu)*	*Rank*	*Actual Over/(Under) ($/MMBtu)*	*Percentage Over/(Under) Recovery*
GMG	$3.7329	**5**	$3.8161	**6**	$(0.0832)	(2.18%)
Great Plains	$3.5331	**4**	$3.4949	**4**	$0.0382	1.09%
MERC-CON	$3.0861	**1**	$2.8807	**1**	$0.2053	7.13%
MERC-NNG	$4.5703	**6**	$3.7308	**5**	$0.8395	22.50%
CenterPoint	$3.3737	**3**	$3.3245	**3**	$0.0492	1.48%
Xcel Gas	$3.2342	**2**	$3.1038	**2**	$0.1304	4.20%
MN Weighted Avg.	$3.4670		$3.3005		$0.1664	5.04%
MN Non-Weighted Avg.	$3.5884		$3.3918		$0.1966	5.80%

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). All six PGA systems, except GMG, had an over-recovery of total gas costs during the reporting period, with MERC-NNG reporting the greatest percentage of over-recovery at 22.50 percent. GMG had the highest and MERC-CON had the lowest actual gas cost per MMBtu.

The following Table G17a shows the difference between FYE20 and prior year Minnesota non-weighted average total system gas costs over each of the previous years' rates; these figures are nominal costs and are not adjusted for either inflation or weather conditions. Based on the data, the actual Minnesota non-weighted average total system cost of gas was $3.3918 per Mcf for FYE20, representing an approximately 19 percent decrease from the FYE19 reporting period.

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[90] 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.

Table G17a: Non-Weighted Average Total System Gas Costs

Reporting Period	*Rate (Mcf)*	*Percentage of Increase/ (Decrease) Between Prior Year and FYE20*
FYE20	$3.3918	
FYE19	$4.1723	(19%)
FYE18	$4.0254	(16%)
FYE17	$4.1520	(18%)
FYE16	$3.7072	(9%)
FYE15	$4.9621	(32%)
FYE14	$6.2268	(46%)
FYE13	$4.3327	(22%)
FYE12	$4.7892	(29%)
FYE11	$5.3295	(36%)
FYE10	$5.7062	(41%)
FYE09	$6.9548	(51%)
FYE08	$8.3613	(59%)
FYE07	$7.8131	(57%)
FYE06	$9.7936	(65%)
FYE05	$7.2930	(53%)
FYE04	$6.2626	(46%)
FYE03	$5.5635	(39%)
FYE02	$3.4941	(3%)
FYE01	$6.8382	(50%)

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

The Department used data from utility information request responses to develop a summary of each gas utility's peak-day demand profile, load factor, and reserve margin. The following Table G19 presents a summary of this information.

Table G19: FYE20 Firm Peak-Day Demand Profiles[91]

Utility	*Firm Design Day Demand (Mcf)*	*Firm Peak-Day Demand Deliverability (Mcf)*	*Annual Firm Throughput (Mcf)*	*Annual Firm Load Factor*[92]	*Reserve Margin*[93]
GMG	14,244	15,275	1,222,851	28.66%	7.24%
Great Plains	34,066	36,945	3,086,396	29.72%	8.45%
MERC-CON	57,065	58,649	5,428,877	33.83%	2.78%
MERC-NNG	280,796	314,349	26,290,450	32.69%	11.95%
CenterPoint	1,399,000	1,478,099	115,732,906	30.88%	5.65%
Xcel Gas	743,696	792,833	71,499,792	38.03%	6.61%
MN Totals	2,528,867	2,696,150	223,261,272	33.13%	6.61%[94]

Table G19 shows that Minnesota's gas utilities exhibit a firm load factor between approximately 29 and 38 percent for GMG and Xcel Gas, respectively. The weighted average reserve-margin percentage, which includes each utility's contracted transportation and peak-shaving capacity, was 6.61 percent for FYE20, representing a 36 percent increase in the statewide reserve margin compared to the FYE19 4.86 percent average.

The Department supports the continuation of the Commission's requirement that the reserve margins be included in the AAA reports, because the information is useful for comparison purposes. However, the Department conducted no analysis of the reserve margins in the current filing, as each utility's reserve margin is analyzed by the Department and approved by the Commission the annual demand-entitlement filings.

Using data provided by the utilities in response to information requests, the Department compared each gas utility's firm peak-day demand deliverability to its actual firm peak-day use. The following Table G20 summarizes this information.

[91] See Department Attachment G20.
[92] 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).
[93] 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.
[94] This percent represents the weighted average of Minnesota gas utilities' reserve margins.

Table G20: FYE20 Comparison of Firm Peak-Day Demand Usage

Utility/System	*Firm Peak Day Demand Deliverability*[95] *(Mcf)*	*Actual Firm Peak Day Usage (Mcf)*	*Actual Firm Requirement*	*Actual Peak Date*
GMG	15,275	11,689	77%	02/13/20
Great Plains	36,945	28,451	77%	02/12/20
MERC-CON	58,649	43,960	75%	02/13/20
MERC-NNG	314,349	220,338	70%	02/13/20
CenterPoint	1,478,099	1,026,658	69%	02/13/20
Xcel Gas	792,833	515,125	65%	01/16/20
MN Totals	2,696,150	1,846,221	68%	

Table G20 shows that all regulated gas utilities in Minnesota were able to meet their actual firm peak-day FYE20 usage within their proposed demand entitlement levels. The utilities had an aggregate peak-day usage, or send out, of 1,846,221 Mcf, representing 68 percent of their aggregate planned peak of 2,696,150 Mcf for FYE20. The FYE20 aggregate actual peak day usage is 19 percent lower than the 2,268,062 Mcf reported in FYE19.

D. DAILY DELIVERY VARIANCE CHARGES

In choosing a reasonable balance of pipeline services, a utility determines 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 daily service, especially during extreme weather. In general, when a utility does not nominate its daily amounts (or cannot schedule the amount of capacity needed due to portfolio limitations) within a given percentage of the actual entitlement level used, it faces pipeline penalty charges.

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 penalty charges are known as positive, negative, or punitive daily delivery variance charges (DDVCs). The current Northern DDVC cost structure for gas usage exceeding nominated levels is as follows:[96]

[95] Demand deliverability includes contracted firm transportation, on-line storage capacity, and the maximum daily injection capacity of peak-shaving facilities.
[96] See Northern Natural Gas Company's FERC Gas Tariff, Vol. No. 1, Sheet No. 53.

Table G21: NNG's DDVC Structure[97]

Charge Type	*Current Charge*
Negative DDVC	0.40[98]
Positive DDVC	$1.00[99]
Punitive DDVC	5 x SMS Rate[100]
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 they incurred.[101] Table G22 provides a summary of the pipeline penalties incurred during the FYE20 reporting period.

Table G22:[102] **FYE20 Daily Delivery Variance Charges (DDVC)**[103] **Incurred**

Utility/System	*DDVC (Mcf)*	*DDVC*	*Total Gas Costs*	*Percent of Total Gas Costs Represented by Penalties*
GMG	4,542	($1,396)	$5,824,040	(0.0240%)
Great Plains	20,532	($3,406)	$13,730,115	(0.0248%)
MERC-CON	0	$0	$17,345,334	0.0000%
MERC-NNG	4,683	($196,488)	$105,622,234	(0.1860%)
CenterPoint	246,693	($383,850)	$446,843,069	(0.0859%)
Xcel Gas[104]	15,044	$30,325	$227,687,372	0.0133%
MN Totals	291,494	($554,815)	$817,052,164	(0.0679%)

[97] 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 for which Northern's system integrity is threatened and System Balancing Agreement (SBA) provisions are not adequate in maintaining pipeline operations. See Northern Natural Gas' Tariff Sheet 292.
[98] 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.
[99] *Id.*
[100] *Id.*
[101] 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.
[102] Table G22 summarizes the data provided in Department Attachment G14.
[103] Viking's charges are called overrun charges rather than DDVC's. Further, Viking does not have a punitive charge category.
[104] Xcel's charges include DDVCs, as well as overrun charges on the Viking and Williston Basin Interstate Pipeline (WBI) systems.

Table G22 shows that, on a percentage basis, the penalties comprise a very small portion of the utilities' gas costs. In their responses to the Department's IR 7, utilities identified the amount of each type of DDVC imposed. Table G23 provides a summary of the type of DDVC penalty incurred during the FYE20 reporting period.

Table G23: FYE20 Amount of DDVCs Incurred by Type[105]

Utility/System	*Positive & Negative*	*Punitive*	*Total*	*Percent of Total MN DDVCs*
GMG	($2,023)	$628	($1,396)	0.25%
Great Plains	($3,406)	$0	($3,406)	0.61%
MERC-CON	$0	$0	$0	0.00%
MERC-NNG	($194,109)	($2,379)	($196,488)	35.42%
CenterPoint	($383,850)	$0	($383,850)	69.19%
Xcel Gas	$30,325	$0	$30,325	(5.47%)
MN Totals	($553,064)	($1,751)	($554,815)	100%

Table G23 shows that all Minnesota regulated gas utilities, except MERC-CON incurred some type of DDVC during the FYE20. Total DDVC penalties for all gas utilities was ($554,815) in FYE20, compared to $89,012 in FYE19. Only GMG and MERC-NNG incurred punitive penalties during FYE20. The NNG penalty charge credits received by each utility are shown separately 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.[106] An intraday nomination is one electronically submitted after the initial nomination. Intraday nominations may be used to nominate 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.[107] There are three opportunities to make intraday nominations:

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

The Department also recognizes that a certain level of positive and negative DDVCs is a natural result of daily weather fluctuation, advanced nomination decisions, and limited opportunities to make intraday nominations. Moreover, a utility's ability to make appropriate intraday

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[105] Table G23 summarizes the data provided in Department Attachment G14.

[106] See Northern Natural Gas Company's FERC Gas Tariff, Sixth Revised Vol. No. 1, Third Revised Sheet No. 257, issued February 1, 2016.

[107] *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.

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 available tools to minimize DDVC penalties, such as using pipeline storage facilities and peak-shaving plants or curtailing interruptible customers, as discussed further in a later section.

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

As mentioned, utilities must nominate and use interstate pipeline capacity within certain parameters or face penalties. Therefore, utilities have established 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. All 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 following sections discuss curtailment penalties and balancing penalties.

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 those charged to 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 the utility's 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. Below is a summary of the revenue from curtailment penalties imposed on interruptible customers during FYE20.

Table G24: FYE20 Revenue from Curtailment Penalties[108]

Utility/System	*Total Penalties*	*Percent of Total Penalties*	*Total Gas Costs*	*Percent of Total Gas Costs Represented by Penalties*
GMG	$0	0.00%	$5,824,041	0.0000%
Great Plains	$0	0.00%	$13,730,115	0.0000%
MERC-CON	$312	1.07%	$17,345,334	0.0018%
MERC-NNG	$13,061	44.88%	$105,622,234	0.0124%
CenterPoint	$0	0.00%	$446,843,069	0.0000%
Xcel Gas	$15,731	54.05%	$227,687,372	0.0069%
MN Total	$29,104	100.00%	$817,052,165	0.0036%

Table G24 shows that three utilities charged curtailment penalties on interruptible (or dual-fuel) customers. For FYE20, these utilities charged a total of $29,104 in curtailment penalties, a decrease of $1,910,504 from the FYE19 curtailment penalties of $1,939,608. Penalties charged to customers in FYE20 made up 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.

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 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 transportation customer)[109] may face pipeline penalties, which, all else being equal, in turn raises rates for 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 contains a summary of the revenues generated from balancing penalties imposed on transportation customers and credited to firm sales customers during FYE20.

[108] The penalties listed in Table G24 are taken from the utilities' responses to Department IR 8. Responses are available upon request.
[109] This is generally true, 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.

Table G25: FYE20 Revenue from Balancing Penalties[110]

Utility/System	*Balancing Penalty Rev.*	*Penalty Rev. as a Percent of Total Penalties*	*Total Gas Costs*	*Penalty Rev. as a Percent of Total Gas Costs*
GMG	$1,115	0.11%	$5,824,041	0.0191%
Great Plains	$22,219	2.25%	$13,730,115	0.1618%
MERC-CON	$0	0.00%	$17,345,334	0.0000%
MERC-NNG	$132,915	13.47%	$105,622,234	0.1258%
CenterPoint	$734,399	74.45%	$446,843,069	0.1644%
Xcel Gas	$95,826	9.71%	$227,687,372	0.0421%
MN Total	$986,474	100.00%	$817,052,165	0.1207%

Table G25 shows the revenue from balancing penalty revenue collected from transportation customers by gas utilities ranges from $0 (MERC-CON) to $734,399 (CenterPoint) for FYE20. The FYE20 total balancing penalty revenue of $986,474 represents an 8 percent decrease from the FYE19 amount of $1,077,178. In addition to the above revenue from balancing penalties, NNG pays an annual penalty charge credit to all shippers on its system. The utilities reported receiving the following credits for FYE20:

Table G25a: FYE20 NNG Penalty Charge Credits by Utility[111]

GMG	$2,829,200
Great Plains	$49,890
MERC-CON	$0
MERC-NNG	($196,488)
CenterPoint	($422,853)
Xcel Gas	$186,172
MN Total	$2,445,921

F. PEAK-DAY PIPELINE TRANSPORTATION SOURCES

In its analysis of gas supply peak-day reliability, the Department considered (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). The following Table G26 shows the variety and contribution of pipelines supplying peak-day firm transportation capacity to Minnesota utilities. The peak-day capacity for FYE20 was 2,872,178 Mcf, an increase of about six percent from the 2,701,717 Mcf reported for FYE19.

[110] The data provided in Table G25 is taken from the response to Department IR 9.
[111] The data provided in Table G25a is taken from the response to Department IR 9.

**Table G26: FYE20 Summary of Utilities' Gas Supply Transportation Sources
Total Minnesota Peak Quantity[112]**

Pipeline	*Peak-Day Quantity (Mcf per day)*	*Peak -Day Quantity Percent of Total*
Northern Natural Gas Co.	2,052,284	71.45%
Viking Gas Transmission Co.	218,575	7.61%
Great Lakes Pipeline Co.	31,358	1.09%
Other Pipelines	52,961	1.84%
Peak Shaving & Online Storage	517,000	18.00%
MN Total	2,872,178	100.00%

The percentage of peak-day capacity provided by each of the pipelines listed in Table G26 aligns closely with the FYE19 percentages. NNG provides by far the greatest amount, 71.45 percent, of peak-day capacity to Minnesota utilities. 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 more options than others in choosing pipeline sources, pipeline differentiation does not appear to impact service reliability.

G. VARIETY OF GAS SUPPLIERS

The number of gas suppliers used during the heating season varies by utility, ranging from 2 to 72 for long-term firm supplies, 2 to 72 for firm spot supplies, and 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 FYE20 heating season.

Table G27:[113] FYE20 Number of Suppliers

Utility	*Firm Long-Term Suppliers*	*Firm Spot Suppliers*	*Interruptible Suppliers*
GMG	4	5	5
Great Plains	2	2	4
MERC[114]	72	72	0
CenterPoint	14	7	0
Xcel Gas	18	15	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,

[112] The data provided in Table G26 is taken from the response to Department IR 4.
[113] Table G27 is based on the utilities' responses to Department IR 4.
[114] MERC provided the number of suppliers from which they can potentially purchase gas. MERC also stated that it does not purchased an interruptible gas supply.

flexibility, reputation, financial condition, communications quality, price, and non-performance penalties. Most of the utilities proceed on a trial-and-error basis with a selected supplier, assessing whether the supplier may be relied upon for firm sales requirements. Once utilities are satisfied with the supplier's performance, they execute contracts based on the lowest bids.

H. 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 certain conditions. The Commission typically requires utilities to return to ratepayers all revenues from capacity-release transactions through the annual true up process.[115] Below is a summary of capacity releases and the associated revenues returned to ratepayers during the true up period.

Table G28: FYE20 Capacity Release[116]

Utility/System	*Capacity Release (Mcf)*	*Capacity Release*	*Revenue Per Mcf*	*Total Gas Costs*	*Revenue as a Percent of Total Gas Costs*
GMG	52,188	$67,504	$1.2935	$5,824,041	1.1591%
Great Plains	949,400	$70,708	$0.0745	$13,730,115	0.5150%
MERC-CON	6,207,400	$295,158	$0.0475	$17,345,334	1.7017%
MERC-NNG	32,493,892	$12,508,603	$0.3850	$105,622,234	11.8428%
CenterPoint	3,285,412	$166,099	$0.0506	$446,843,069	0.0372%
Xcel Gas	1,527,979	$137,983	$0.0903	$227,687,372	0.0606%
MN Total	44,516,271	$13,246,054	$0.2976	$817,052,165	1.6212%

Table G28 shows the diversity in Minnesota for capacity-release transactions, capacity portfolios, and individual situations of each gas utility. The revenue from capacity release ranges from $67,504 for GMG to $12,508,603 for MERC-NNG. Utilities returned a total of $13,246,054 to ratepayers in the FYE20 true ups, compared to $4,846,150 in FYE19. The total volumetric capacity-release figures increased from 34,614,312 Mcf in FYE19 to 44,516,271 Mcf in FYE20. The increase in capacity release volume correlates with the data in Table G20, as the actual firm capacity requirement was just 68 percent on the peak day in FYE20, compared to 87 percent in FYE19.

[115] 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.
[116] The data listed in Table G28 is based on the utilities' responses to Department IR 6.

I. 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 reporting period. 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.[117] 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).[118] 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.[119]

All gas utilities submitted auditor's reports in compliance with Minnesota Rule 7825.2820. The auditors' reports filed contained no exceptions.

J. LOST-AND-UNACCOUNTED-FOR GAS

Ordering Paragraph 5 in the Commission's April 7, 2011 *Order* for the FYE10 AAA reports 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 and to include a table or attachment showing the data used in calculating 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,[120] the Department developed a comparison of LUF gas by utility. Table G29 presents the Department's summary of LUF gas percentages for FYE20 for Minnesota jurisdictional volumes.

[117] 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.
[118] Docket No. G,E999/AA-97-1212.
[119] Docket No. G,E999/AA-96-940.
[120] 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: FYE20 Lost-and-Unaccounted-For Gas[121]

Utility/System	*Revenue as a Percent of Total Gas Costs*
GMG	(0.61%)
Great Plains	0.10%
MERC-CON	(2.47%)
MERC-NNG	(1.00%)
CenterPoint	1.90%
Xcel Gas	2.16%
MN Weighted Avg.	1.57%

A negative LUF number means that a utility, in effect, "found" gas. Consistent with prior reporting periods, Table G29 shows that MERC-NNG and MERC-CON reported negative LUF during FYE20. GMG also reported negative LUF for this period. The Department refers to our FYE19 AAA Report in Docket No. G999/AA-19-401 for additional discussion on MERC's investigation into its negative LUF.

K. 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 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

In its FYE14 AAA Report, the Department stated that the reports would be more meaningful if (1) the total gas costs charged for main strikes during the period are reconciled to the amount in the true up and (2) the reports provide the allocation of the gas costs credited to each customer class. Regarding contractor main strikes reporting, all the gas utilities filed the required information.[122]

[121] See Department Attachment G19 for detailed calculations.
[122] See GMG's AAA Report, pdf page 11; 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.

2. Meter Testing Updates

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

Utility	*Meter Testing Update Information*	*AAA Report Page Reference*
GMG	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.	11
Great Plains	The Gas Distribution Standards, Section 7 was updated, specifically the combination of the Random Sampling Section and Large Capacity Meters Section. Great Plains has removed the Large Capacity Meters Section and combined small and large meter random sampling in the Random Sampling Section so that all meters are held to the same standards.	5
MERC	In 2019, MERC made a temporary modification to the meter testing program due to the Automated Meter Infrastructure ("AMI") project, which started in 2019. In 2019, MERC temporarily suspended the statistical meter sample testing program during AMI deployment, and focused meter replacement on the meters with large amounts of deficiencies and older meters that may be difficult to do an index exchange on while out in the field. During 2019, and throughout the remainder of the AMI project, MERC is replacing meters that the AMI deployment vendor finds issues with. This temporary modification provides for efficient meter testing while concurrent resources can be utilized during AMI deployment. From January 1, 2019, to December 31, 2019, MERC tested 3,919 meters as part of its meter testing program. Of those meters tested, 3,625 (92.5%) tested between 98% and 102% accurate. 225 meters (5.7%) tested greater than 102% accurate, 61 meters (1.6%) tested less than 98% accurate, and 8 meters (0.20%) had no test due to the meter being damaged.	25 (CON) & 27 (NNG)
CenterPoint	CenterPoint continued its meter testing and management program in 2019. Meter samples and tests are conducted over a two-year period and the results of current interval 2019-2020 have been reviewed. All meter lots evaluated are presently passing the accuracy expectations. During 2019 CenterPoint exchanged 1,912 'failed' meters, and year-to-date through June 2020, 465 meters have been exchanged. Per the meter management program, the work plan for 2020 is set to target an additional 2,627 meters to be exchanged as previously identified meter groups requiring attention. This work is slightly behind schedule due to COVID-19 restrictions and service protocols.	26
Xcel Gas	There were no changes regarding meter testing within the annual reporting period of July 1, 2019 and June 30, 2020.	Attachment G, page 11

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

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

- review of the utilities' PGAs and filing of subsequent reports
- individual meetings with utilities regarding their respective procurement plans for the upcoming year
- 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, 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.[123] GMG uses outside resources to assist in managing its gas portfolio.[124] 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.[125] Other types of purchases include daily spot-priced gas,[126] daily index-priced gas,[127] or fixed price gas.[128]

M. 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. G999/AA-13-600, the Commission requested that the Department provide a review of hedging practices in its review of future

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[123] Department IR 12. Responses available upon request.
[124] GMG's AAA Report, pdf page 8.
[125] 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.
[126] 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.
[127] 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.
[128] Storage gas is not included in this discussion, 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.

annual automatic adjustment reports. Additionally, at the February 4, 2016 Commission Agenda meeting regarding CenterPoint'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 manage the risks associated with market price 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. Hurricane Katrina is an example of such an event, as it caused severe damage in the southern U.S., including areas with natural gas facilities, and natural gas costs skyrocketed immediately. Hedging can be used to reduce gas price risk by generating a payment when the market price of natural gas moves in an unfavorable (and unpredicted) direction. The objective is not to guarantee the lowest priced gas, but to mitigate price volatility, provide reasonably priced natural gas, and ensure reliability. There are several hedging tools/instruments available in the derivative market such as futures contracts, commodity swaps, "costless" collars, and options.[129]

Three Minnesota LDCs have received Commission approval to recover the costs of financial hedging through their PGAs: CenterPoint, MERC, and Xcel Gas. The Commission also orders financial hedging restrictions based on utility-specific circumstances and information. In separate, periodic variance request filings, the Department performs an analysis for each of the applicable utilities' respective requests to continue recovering hedging costs through their PGAs.

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 FYE20 heating season was overall warmer than normal and, although natural gas prices fluctuated with some volatility between approximately $1.68 and $2.87 Mcf throughout the heating season, prices remained relatively low. Storage levels at the beginning of the FYE20 heating season were at their highest since 2017, and, with FYE20 net withdrawals below the five-year withdrawal average, the end-of-heating-season storage levels were 19 percent higher than the corresponding five-year average. [130] The following discussion reviews the performance of each utility's hedging program.

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

[129] Definitions and examples of each tool are provided in the glossary that is included as Attachment G3.
[130] EIA Natural Gas Weekly Update, April 23, 2020:
https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2020/04_16/

are covered by financial hedges (10 percent futures and 20 percent call options).[131] In Docket No. G011/M-17-85, the Commission granted an extension through June 30, 2021 to the rule variance that allows MERC to recover the costs associated with certain financial instruments through the PGA. Regarding FYE20, MERC stated, in its response to the Department's IR No. 15(H), that there were no changes to the financial hedging program compared to the previous reporting period.

In FYE20, MERC's hedging portfolio provided gas at a higher cost than if it did not hedge.[132] The Department concludes 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.

CenterPoint: CenterPoint's policy is to provide price stabilization for a portion of its winter supply through hedge 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.[133] In Docket No. G008/M-15-912, the Commission granted an extension through June 30, 2020 to a rule variance that allows CenterPoint to recover the costs associated with certain financial instruments through the PGA.

In its response to the Department's IR No. 15(H), CenterPoint stated that there was no significant change in its hedging program from the previous year. Regarding its hedging strategy for the FYE20 winter season, CPE 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 27.2% 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 23.1 Bcf of total hedged supply and, when combined with 26.1 Bcf of storage volumes, provide stabilized prices for 51.3% of winter gas supplies. This is slightly higher than plan due to reduction in sales.
>
> 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.

[131] MERC's AAA Report, PDF page 13, section titled "2019-2020 Gas Procurement Policies".
[132] *Id*., Trade Secret Schedule L.
[133] CenterPoint's AAA Report, page 8.

> …market prices for winter gas (futures winter strip) during 2019 started around $3.00 until June when it hovered between $2.50 and $2.75 until the beginning of the winter season. [134]

According to CenterPoint, its hedging program in FYE20 resulted in commodity costs passed through the PGA that were, on average, $0.0242 per dekatherm higher than they would have been without hedging. [135] CenterPoint's response to Department IR 15 indicates that the utility's hedging program resulted in costs that were overall higher than if it had purchased all gas at market priced gas in FYE20. The Department concludes 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.

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. 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.[136] In Docket No. G002/M-16-88, the Commission granted an extension through June 30, 2020 to a rule variance that allows Xcel Gas to recover the costs associated with certain financial instruments through the PGA.

In its response to the Department's IR 15(H), Xcel Gas stated that there were no changes to the financial hedging program for FYE20.

Xcel Gas' hedges provided a net loss of approximately $3,175,905 in FYE20.[137] The Department concludes 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.

Conclusion and Recommendations: The purpose of the discussed gas utility hedging activity is to reduce price volatility on a portion of the utilities' purchase portfolios; the objective is not to speculate on commodity prices or profit from the results of hedging. The Department concludes that the utilities' hedging program performance appears reasonable. The Department recommends that each utility using hedging, physical or financial, continue to provide in subsequent AAA filings, in a format similar to that in the current docket, an analysis of their hedging activity performance.

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[134] *Id.*, page 12.
[135] *Id.,* page 25.
[136] Xcel Gas' AAA Report, Attachment A, Schedule 5, pages 2-3.
[137] *Id.*, Attachment G, Trade Secret Schedule 2.

IV. SUMMARY OF THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission take the following action:

1. Accept the FYE20 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.

3. For Greater Minnesota Gas:

   - Accept GMG's FYE20 true up, Docket No. G001/AA-20-699.
   - Allow GMG to implement its true up, shown in Department Attachment G5.

4. For Great Plains:

   - Accept Great Plains' FYE20 true up, Docket No. G004/AA-20-684.
   - Allow Great Plains to implement its true up, shown in Department Attachment G6.

5. For MERC:

   - The Department requests that MERC explain in Reply Comments (1) whether and why the $1,800 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE20 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 FYE20 AAA Report and its reply to Department IR 7.

   - Accept MERC-NNG's FYE20 true up, Docket No. G011/AA-20-655, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.

   - Allow MERC-NNG to implement its true up, shown in Department Attachment G8, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.

   - Accept MERC-CON's FYE20 true up, as corrected in its September 22, 2020 filing in Docket No. G011/AA-20-656.

- Allow MERC-CON, through its annual true up factors effective September 1, 2020, to adjust for the difference between the final approved Viking Gas Transmission (Viking) rates effective January 1, 2020 and the interim Viking rates in effect for the period January 1 - June 30, 2020.

- Grant MERC a one-time variance to Minnesota Rules 7825.2700 and 7825.2910, Subpart 4, and approve MERC's proposal to correct its MERC-CON system true up adjustment factors, effective October 1, 2020, as shown in MERC's September 22, 2020 correction filing in Docket No. G011/AA-20-656.

- Allow MERC-CON to implement its true up, as corrected in its September 22, 2020 filing in Docket No. G011/AA-20-656 and shown in Department Attachment G9.

6. For CenterPoint:
   - Accept CenterPoint's FYE20 true up, Docket No. G008/AA-20-698.
   - Allow CenterPoint to implement its true up, shown in Department Attachment G10.

7. For Xcel Gas:

   - Accept Xcel Gas' FYE20 true up, Docket No. G002/AA-20-705.
   - Allow Xcel Gas to implement its true up, shown in Department Attachment G11.

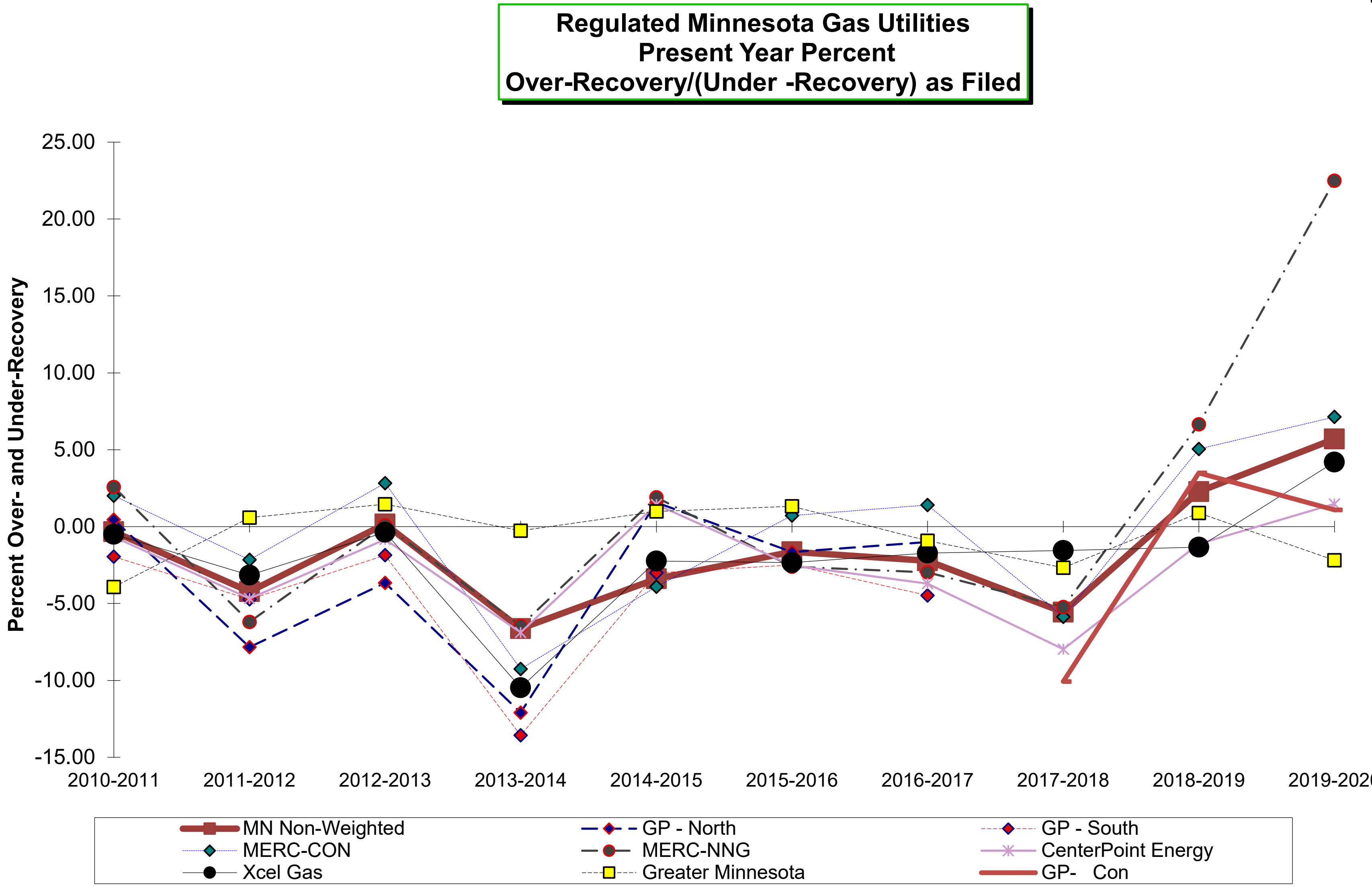
FYE20
RECORDED UNWEIGHTED HEATING DEGREE DAYS

Annual Data												
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2013-2014	Season 2014-2015	Season 2015-2016	Season 2016-2017	Season 2017-2018	Season 2018-2019	Season 2019-2020	2019-2020 vs. Normal (71-00)	2019-2020 vs. Normal (81-10)	2019-2020 vs. Prior 5-Yr. Avg.
DULUTH	9,709	9,444	10,342	9,276	8,186	8,138	9,560	9,448	8,864	-8.70%	-6.14%	-0.65%
INTERNATIONAL FALLS	10,216	10,221	11,511	10,283	8,995	9,088	10,454	10,740	9,914	-2.96%	-3.00%	0.02%
FARGO, ND	9,019	8,802	9,679	8,469	7,172	7,452	8,912	9,810	8,925	-1.04%	1.40%	6.72%
ST CLOUD	8,744	8,532	9,524	8,143	7,170	7,327	8,687	9,256	8,335	-4.68%	-2.31%	2.69%
MPLS/ST PAUL	7,805	7,580	8,597	7,528	6,283	6,310	7,579	8,024	7,242	-7.21%	-4.46%	1.36%
ROCHESTER	8,150	7,722	8,917	8,068	6,796	6,900	8,065	8,555	7,873	-3.40%	1.96%	2.56%
SIOUX FALLS, SD	7,683	7,706	8,320	7,568	6,380	6,463	7,569	7,927	7,735	0.68%	0.38%	7.71%

Winter Data (November 2019 - March 2020)												
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2013-2014	Season 2014-2015	Season 2015-2016	Season 2016-2017	Season 2017-2018	Season 2018-2019	Season 2019-2020	2019-2020 vs. Normal (71-00)	2019-2020 vs. Normal (81-10)	2019-2020 vs. Prior 5-Yr. Avg.
DULUTH	7,169	6,952	8,028	7,145	6,046	6,136	7,242	7,109	6,694	-6.63%	-3.71%	-0.62%
INTERNATIONAL FALLS	7,728	7,589	8,869	7,691	6,574	6,750	7,922	7,937	7,330	-5.15%	-3.41%	-0.61%
FARGO, ND	7,145	7,589	7,849	6,873	5,758	5,974	7,139	7,680	6,945	-2.80%	-8.49%	3.89%
ST CLOUD	6,853	6,665	7,724	6,583	5,609	5,784	6,865	7,184	6,488	-5.33%	-2.66%	1.30%
MPLS/ST PAUL	6,295	6,108	7,117	6,257	5,121	5,234	6,204	6,446	5,784	-8.12%	-5.30%	-1.17%
ROCHESTER	6,437	6,136	7,297	6,553	5,427	5,606	6,408	6,773	6,157	-4.35%	0.34%	0.06%
SIOUX FALLS, SD	6,157	6,105	6,813	6,278	5,274	5,255	6,075	6,336	6,038	-1.93%	-1.10%	3.33%

Source: MN Dept of Natural Resources, Heating/Cooling Degree Day Table
http://www.dnr.state.mn.us/climate/historical/energy.html

Prepared by the Minnesota Commerce Department, Division of Energy Resources


Regulated Minnesota Gas Utilities
Present Year Percent
Over-Recovery/(Under -Recovery) as Filed
Percent Over- and Under-Recovery
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
-10.00
-15.00
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
MN Non-Weighted
GP - North
GP - South
MERC-CON
MERC-NNG
CenterPoint Energy
Xcel Gas
Greater Minnesota
GP- Con

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.

TERMS AND ACRONYMS | *DEFINITION*

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*.

<u>Hedging Terms and Examples</u>

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

TERMS AND ACRONYMS	*DEFINITION*
	"net" gas cost is $5.60 per MMBtu, which was the locked in price. 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	GMG	MERC NNG	MERC-CON	Xcel Gas
NNG TF-12	D	D	D	D		D
NNG TF-5	D	D	D	D		D
NNG TFX	D	D	D	D		D
Viking FT-A	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	C	C	C	C
NNG storage FDD	A	A		C **1/**	C **1/**	A
NGPL storage	A					
BP Canada storage						
Niska storage						
ANR storage						A
AECO storage					C **1/**	
Other supplier or producer reservation fees	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.
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

Greater Minnesota Gas, Inc.
2019-2020 True Up
Docket No. G022/AA-20-699

Ten Year Summary of Gas-Cost Recovery

Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
2010-2011	-3.92%	
2011-2012	0.58%	
2012-2013	1.46%	
2013-2014	-0.27%	
2014-2015	0.98%	
2015-2016	1.32%	
2016-2017	-0.91%	
2017-2018	-2.67%	
2018-2019	0.88%	
2019-2020	**-2.18%**	**-1.91%**
10 Year Average	-0.47%	

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	$4,798,717	$4,909,875	($111,158)	**-2.26%**	$2,166
AGRICULTURAL - INTERRUPTIBLE	$558,902	$583,539	($24,637)	**-4.22%**	$7,905
GENERAL - INTERRUPTIBLE	$339,427	$330,627	$8,800	**2.66%**	$5,402
TOTAL	**$5,697,046**	**$5,824,041**	**($126,995)**	-2.18%	**$15,473**

	(6) (3)+(5)	(7) (6)/(2)	(8)	(9) (6)/(8)
	CUMULATIVE OVER/(UNDER) BALANCE	CUMULATIVE %	Estimated Sales (Mcf)	True Up (Refund)/Collection
FIRM	($108,992)	**-2.22%**	1,268,650	**$0.0859**
AGRICULTURAL - INTERRUPTIBLE	($16,732)	**-2.87%**	100,040	**$0.1673**
GENERAL - INTERRUPTIBLE	$14,202	**4.30%**	157,470	**($0.0902)**
TOTAL	**($111,522)**	-1.91%	**1,526,160**	

Greater Minnesota Gas, Inc.
2019-2020 True Up
Docket No. G022/AA-20-699

RECOVERY BY CLASS	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
RESIDENTIAL - FIRM				
DEMAND COST	$933,446	$837,525	$95,921	11.45%
COMMODITY COST	$2,166,323	$2,346,566	($180,243)	-7.68%
TOTAL	$3,099,769	$3,184,091	($84,322)	-2.65%
COMMERCIAL - FIRM				
DEMAND COST	$53,156	$48,383	$4,773	9.87%
COMMODITY COST	$125,794	$137,672	($11,878)	-8.63%
TOTAL	$178,950	$186,055	($7,105)	-3.82%
INDUSTRIAL - FIRM				
DEMAND COST	$449,777	$413,479	$36,298	8.78%
COMMODITY COST	$1,070,221	$1,126,250	($56,029)	-4.97%
TOTAL	$1,519,998	$1,539,729	($19,731)	-1.28%
FLEX RATE - FIRM				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$0	$0	$0	0.00%
TOTAL	$0	$0	$0	0.00%
AG. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$558,902	$583,539	($24,637)	-4.22%
TOTAL	$558,902	$583,539	($24,637)	-4.22%
IND. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$339,427	$330,627	$8,800	2.66%
TOTAL	$339,427	$330,627	$8,800	2.66%
FLEX RATE - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$0	$0	$0	0.00%
TOTAL	$0	$0	$0	0.00%

Greater Minnesota Gas, Inc.
2019-2020 True Up
Docket No. G022/AA-20-699

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	$933,446	$837,525	$95,921	11.45%
Commercial - Firm	$53,156	$48,383	$4,773	9.87%
Industrial - Firm	$449,777	$413,479	$36,298	8.78%
Flexible Rate - Firm	$0	$0	$0	0.00%
Agricultural - Interruptible	$0	$0	$0	0.00%
Industrial - Interruptible	$0	$0	$0	0.00%
Flexible Rate - Interruptible	$0	$0	$0	0.00%
TOTAL	$1,436,379	$1,299,387	$136,992	10.54%
COMMODITY COSTS:				
Residential - Firm	$2,166,323	$2,346,566	($180,243)	-7.68%
Commercial - Firm	$125,794	$137,672	($11,878)	-8.63%
Industrial - Firm	$1,070,221	$1,126,250	($56,029)	-4.97%
Flexible Rate - Firm	$0	$0	$0	0.00%
Agricultural - Interruptible	$558,902	$583,539	($24,637)	-4.22%
Industrial - Interruptible	$339,427	$330,627	$8,800	2.66%
Flexible Rate - Interruptible	$0	$0	$0	0.00%
TOTAL	$4,260,667	$4,524,654	($263,987)	-5.83%
DETAIL OF DEMAND RECOVERY				
Viking Zone 1	$302,941	$294,111	$8,830	3.00%
Viking Zone 1-2				
TFX-5	$771,675	$702,738	$68,937	9.81%
TFX- 7	$87,303	$84,131	$3,172	3.77%
TF - 12	$274,460	$285,911	($11,451)	-4.01%
TF Capacity Release	$0	($67,504)	$67,504	-100.00%
SMS Demand	$0	$0	$0	0.00%
TOTAL	$1,436,379	$1,299,387	$136,992	10.54%

Great Plains Natural Gas North District
2019-2020 True-Up
Docket No. G004/AA-20-684

Ten Year Summary of Gas Cost Recovery:

	Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
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%	
GP-North	2016-2017	-1.00%	
GP-Con	2017-2018	-10.07%	
GP-Con	2018-2019	3.49%	
GP-Con	2019-2020	**1.09%**	**2.15%**
	10-Year Average	-2.97%	

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	$11,045,470	$10,928,026	$117,444	**1.07%**	$640,239
INTERRUPTIBLE	$2,834,680	$2,802,089	$32,591	**1.16%**	$106,374
Total	**$13,880,150**	**$13,730,115**	**$150,035**	**1.09%**	**$746,613**

	(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	($565,999)	$191,684	**1.75%**	3,052,800	**($0.0628)**
INTERRUPTIBLE	($35,778)	$103,187	**3.68%**	875,800	**($0.1178)**
Total	**($601,777)**	**$294,871**	**2.15%**		

Per Docket No. G004/GR-15-879, the North and South Districts' gas costs were consolidated into a single system, effective July 1, 2017. Great Plains presented its annual reporting as one PGA system beginning in this instant docket.

Great Plains Natural Gas North District
2019-2020 True-Up
Docket No. G004/AA-20-684

	(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 (Zone 1-1; Cat. 3)	$373,569	$366,218	$7,351	2.01%
FT-A (Zone 1-1; Cat. 3)	$233,523	$227,063	$6,460	2.85%
FT-A (Zone 1-1; Cat. 3)	$233,523	$227,063	$6,460	2.85%
FT-A Seasonal	$38,961	$39,355	($394)	-1.00%
BP Contract (Firm Demand)	$0	$0	$0	0.00%
FT-A - Capacity Release	($43,639)	($34,855)	($8,784)	25.20%
FT-A - Capacity Release	($3,871)	($32,174)	$28,303	-87.97%
Northern Natural Gas				
TFX - Winter/Seasonal	$1,454,284	$1,503,402	($49,118)	-3.27%
TFX - Summer	$661,689	$519,846	$141,843	27.29%
TF12 Base - Summer	$199,010	$154,261	$44,749	29.01%
TF12 Base - Winter	$256,008	$265,338	($9,330)	-3.52%
TF12 Variable - Summer	$184,397	$147,050	$37,347	25.40%
TF12 Variable - Winter	$321,416	$331,507	($10,091)	-3.04%
TF5	$330,565	$341,847	($11,282)	-3.30%
TFX - Summer	$101,702	$80,299	$21,403	26.65%
TFX - Winter	$697,990	$721,788	($23,798)	-3.30%
TFX Negotiated Contract - Winter	$119,695	$121,313	($1,618)	-1.33%
FDD-1 Reservation	$138,164	$120,703	$17,461	14.47%
Interruptible Demand Credit	($691,223)	($429,693)	($261,530)	60.86%
Total Demand	$4,605,763	$4,670,331	($64,568)	-1.38%
Commodity Cost	$6,439,707	$6,257,695	$182,012	2.91%
TOTAL	$11,045,470	$10,928,026	$117,444	1.07%
INTERRUPTIBLE				
Commodity Cost	$2,404,987	$2,372,396	$32,591	1.37%
Interruptible Demand Charge	$429,693	$429,693	$0	0.00%
TOTAL	$2,834,680	$2,802,089	$32,591	1.16%

Great Plains Natural Gas North District
2019-2020 True-Up
Docket No. G004/AA-20-684

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		$4,605,763	$4,670,331	($64,568)	-1.38%
	Commodity		$6,439,707	$6,257,695	$182,012	2.91%
		Total	$11,045,470	$10,928,026	$117,444	1.07%
INTERRUPTIBLE						
	LMS Demand		$429,693	$429,693	$0	0.00%
	Commodity		$2,404,987	$2,372,396	$32,591	1.37%
		Total	$2,834,680	$2,802,089	$32,591	1.16%

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		$4,605,763	$4,670,331	($64,568)	-1.38%
		Total	$4,605,763	$4,670,331	($64,568)	-1.38%
Commodity						
	Firm		$6,439,707	$6,257,695	$182,012	2.91%
	Interruptible		$2,834,680	$2,802,089	$32,591	1.16%
		Total	$9,274,387	$9,059,784	$214,603	2.37%

MERC - NNG
2019-2020 True-up
Docket No. G011/AA-20-655

SUMMARY OF GAS COST RECOVERY:

	Year Ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
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%	
MERC-Northern System	2017	-2.97%	
MERC-Northern System	2018	-5.23%	
MERC-Northern System	**2019**	**22.50%**	**22.81%**
	10-YEAR AVERAGE	0.24%	

RECOVERY BY CLASS

	(1) COST RECOVERY	(2) COST INCURRED	(3) PRESENT YEAR OVER/(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)	(5) PRESENT YEAR TRUE-UP OVER/(UNDER) BEGINNING BALANCE
GS	$119,334,181	$96,871,026	$22,463,155	**23.19%**	$289,570
SVJ/LVJ/SLV Demand	$40,683	$40,683	$0	**0.00%**	$0
SVI/SVJ/LVI/LVJ/SLVI Commodity	$10,014,895	$8,710,526	$1,304,369	**14.97%**	$35,125
	$129,389,759	**$105,622,235**	**$23,767,524**	**22.50%**	**$324,695**

	(6) (3) + (5) CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	(7) (6) / (2) CUMULATIVE %	(8) ESTIMATED SALES (DTH)	(9) (6) / (8) TRUE-UP FACTORS (REFUND)/COLLECT^
GS	$22,752,725	23.49%	26,259,146	($0.8665)
SVJ/LVJ/SLV Demand	$0	0.00%	1,140	$0.0000
SVI/SVJ/LVI/LVJ/SLVI Commodity	$1,339,494	15.38%	2,713,616	($0.4936)
	$24,092,219	22.81%	**28,973,901**	

Per Docket No. G011/GR-15-736, the MERC-AL and MERC-NNG gas systems were approved for consolidation per the Commission's October 31, 2016 Findings of Fact, Conclusions, and Order.

MERC - NNG
2019-2020 True-up
Docket No. G011/AA-20-655

RECOVERY BY CLASS

General Service (GS)

		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND		$32,989,268	$24,268,901	$8,720,367	35.93%
COMMODITY		$86,344,913	$72,602,125	$13,742,788	18.93%
	TOTAL	$119,334,181	$96,871,026	$22,463,155	23.19%

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		$9,976,885	$8,680,895	$1,295,990	14.93%
	TOTAL	$9,976,885	$8,680,895	$1,295,990	14.93%

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		$40,683	$40,683	$0	0.00%
COMMODITY		$38,010	$29,631	$8,379	28.28%
	TOTAL	$78,693	$70,314	$8,379	11.92%

RECOVERY BY COMPONENT

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
			RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY	PRESENT YEAR OVER/(UNDER) RECOVERY
DEMAND	GS		$32,989,268	$24,268,901	$8,720,367	35.93%
DEMAND	SVI/LVI		$0	$0	$0	0.00%
DEMAND	SVJ/LVJ/SLV		$40,683	$40,683	$0	0.00%
		TOTAL	$33,029,951	$24,309,584	$8,720,367	35.87%
COMMODITY	GS		$86,344,913	$72,602,125	$13,742,788	18.93%
COMMODITY	SVI/LVI		$9,976,885	$8,680,895	$1,295,990	14.93%
COMMODITY	SVJ/LVJ/SLV		$38,010	$29,631	$8,379	28.28%
		TOTAL	$96,359,808	$81,312,651	$15,047,157	18.51%

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	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%	
MERC-Consolidated	2016-2017	1.41%	
MERC-Consolidated	2017-2018	-5.86%	
MERC-Consolidated	2018-2019	5.05%	
MERC-Consolidated	2019-2020	**7.13%**	**6.49%**
	10-YEAR AVERAGE	-0.20%	

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	$17,024,799	$15,823,446	$1,201,353	**7.59%**	($92,278)
SVJ Demand	$17,182	$17,183	($1)	**-0.01%**	$0
SVI/SJV/LVI Commodity	$1,539,699	$1,504,705	$34,994	**2.33%**	($17,684)
	$18,581,680	**$17,345,334**	**$1,236,346**	7.13%	**($109,962)**

	(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	$1,109,075	**7.01%**	5,415,343	**($0.2048)**
SVJ Demand	($1)	**-0.01%**	696	**$0.0014**
SVI/SVJ/LVI Commodity	$17,310	**1.15%**	971,405	**($0.0178)**
	$1,126,384	**6.49%**	**6,387,444**	

RECOVERY BY CLASS

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
General Service (GS)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$4,410,698	$3,225,311	$1,185,387	36.75%
	COMMODITY		$12,614,101	$12,598,135	$15,966	0.13%
		TOTAL	$17,024,799	$15,823,446	$1,201,353	7.59%
SVI/SJV/LVI						
	DEMAND		$17,182	$17,183	($1)	-0.01%
	COMMODITY		$1,539,699	$1,504,705	$34,994	2.33%
		TOTAL	$1,556,881	$1,521,888	$34,993	2.30%

RECOVERY BY COMPONENT

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
			RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	PERCENT OVER/(UNDER) RECOVERY
DEMAND	General Service (GS)		$4,410,698	$3,225,311	$1,185,387	36.75%
DEMAND	SVI/SVJ/LVJ		$17,182	$17,183	($1)	-0.01%
		TOTAL	$4,427,880	$3,242,494	$1,185,386	36.56%
COMMODITY	General Service (GS)		$12,614,101	$12,598,135	$15,966	0.13%
COMMODITY	SVI/SVJ/LVJ		$1,539,699	$1,504,705	$34,994	2.33%
		TOTAL	$14,153,800	$14,102,840	$50,960	0.36%

CenterPoint Energy
2019-2020 True-Up
Docket No. G008/AA-20-698

TEN YEAR SUMMARY OF GAS-COST RECOVERY:

Year Ended 6/30	PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
2010-2011	-0.66%	
2011-2012	-4.68%	
2012-2013	-0.84%	
2013-2014	-6.88%	
2014-2015	1.44%	
2015-2016	-2.53%	
2016-2017	-3.71%	
2017-2018	-7.97%	
2018-2019	-1.11%	
2019-2020	**1.48%**	**1.62%**
10-YEAR AVERAGE	-2.55%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
				(5) / (2)			(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	$418,498,750	$413,304,850	$5,193,900	**1.26%**	$850,659	$6,044,559	**1.46%**
LGS	$3,107,502	$3,170,658	($63,156)	**-1.99%**	$7,731	($55,425)	**-1.75%**
SVDF	$16,858,843	$16,454,668	$404,175	**2.46%**	$49,629	$453,804	**2.76%**
LVDF	$14,992,613	$14,867,629	$124,984	**0.84%**	$46,717	$171,701	**1.15%**
	$453,457,708	**$447,797,805**	**$5,659,903**	**1.26%**	**$954,736**	$6,614,639	**1.48%**

	(8)	(9)	(10)	(11)	(12)
		(5) + (7)	(8) / (2)		- (8) / (10)
	Prior Year True Up Over/(Under) Balance	Cumulative Over/(Under) Collection ($)	**CUMULATIVE %**	Estimated Sales (DT)	**True-Up Factors (Refund)/Collection**
SVF	$617,031	$6,661,590	**1.61%**	117,894,897	**($0.0565)**
LGS	$12,867	($42,558)	**-1.34%**	2,664,165	**$0.0160**
SVDF	$23,801	$477,605	**2.90%**	6,853,112	**($0.0697)**
LVDF	($4,500)	$167,201	**1.12%**	6,995,812	**($0.0239)**
	$649,199	**$7,263,838**	**1.62%**	**134,407,986**	

CenterPoint Energy
2019-2020 True-Up
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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		$122,421,210	$126,146,615	($3,725,405)	-2.95%
PROPANE		$0	$161,773	($161,773)	-100.00%
COMMODITY		$296,077,540	$286,996,462	$9,081,078	3.16%
	TOTAL	$418,498,750	$413,304,850	$5,193,900	1.26%
LARGE GENERAL SERVICE					
DEMAND		$603,640	$690,072	($86,432)	-12.53%
PROPANE		$0	$885	($885)	-100.00%
COMMODITY		$2,503,862	$2,479,701	$24,161	0.97%
	TOTAL	$3,107,502	$3,170,658	($63,156)	-1.99%
SMALL VOLUME DUAL FUEL					
COMMODITY		$16,858,843	$16,454,668	$404,175	2.46%
	TOTAL	$16,858,843	$16,454,668	$404,175	2.46%
LARGE VOLUME DUAL FUEL					
COMMODITY		$14,992,613	$14,867,629	$124,984	0.84%
	TOTAL	$14,992,613	$14,867,629	$124,984	0.84%

CenterPoint Energy
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			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY COMPONENT			RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) RECOVERY
DEMAND	SVF		$122,421,210	$126,146,615	($3,725,405)	-2.95%
DEMAND	LGS		$603,640	$690,072	($86,432)	-12.53%
PROPANE	SVF		$0	$162,658	($162,658)	-100.00%
		TOTAL	$123,024,850	$126,999,345	($3,974,495)	-3.13%
COMMODITY	SVF		$296,077,540	$286,996,462	$9,081,078	3.16%
COMMODITY	LGS		$2,503,862	$2,479,701	$24,161	0.97%
COMMODITY	SVDF		$16,858,843	$16,454,668	$404,175	2.46%
COMMODITY	LVDF		$14,992,613	$14,867,629	$124,984	0.84%
		TOTAL	$330,432,858	$320,798,460	$9,634,398	3.00%
TOTAL DEMAND AND COMMODITY			$453,457,708	$447,797,805	$5,659,903	1.26%

Ten Year Summary of Gas-Cost Recovery:

Year ended 6/30	Present Year Percent Over/(Under) Recovery	Cumulative Percent Over/(Under) Recovery
2010-2011	-0.50%	
2011-2012	-3.15%	
2012-2013	-0.36%	
2013-2014	-10.47%	
2014-2015	-2.24%	
2015-2016	-2.34%	
2016-2017	-1.72%	
2017-2018	-1.56%	
2018-2019	-1.34%	
2019-2020	**4.20%**	**4.14%**
10-YEAR AVG	-1.95%	

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	$127,872,175	$121,947,084	$5,925,091	**4.86%**	($113,981)
Commercial/Industrial Firm	$74,832,792	$71,562,740	$3,270,052	**4.57%**	($89,660)
Demand Billed Demand	$2,013,827	$2,041,346	($27,519)	**-1.35%**	($4,147)
Demand Billed Commodity	$7,064,287	$6,892,676	$171,611	**2.49%**	($35,123)
Small Interruptible	$5,156,116	$4,943,615	$212,501	**4.30%**	$16,384
Medium & Large Interruptible	$20,311,265	$20,299,911	$11,354	**0.06%**	$82,123
TOTAL	**$237,250,462**	**$227,687,372**	**$9,563,090**	**4.20%**	**($144,404)**

	(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		$5,811,110	**4.77%**	385,204,807	**($0.01509)**
Commercial/Industrial Firm		$3,180,392	**4.44%**	215,530,010	**($0.01476)**
Demand Billed Demand		($31,666)	**-1.55%**	3,313,140	**$0.00956**
Demand Billed Commodity		$136,488	**1.98%**	27,573,744	**($0.00495)**
Small Interruptible		$228,885	**4.63%**	19,613,388	**($0.01167)**
Medium & Large Interruptible		$93,477	**0.46%**	82,331,456	**($0.00114)**
TOTAL	**$0**	**$9,418,686**	**4.14%**	**730,253,405**	

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	$35,083,488	$35,063,608	$19,880	0.06%
TU Sch. D, page 4	Commododity & Peak Shaving	$92,788,687	$86,883,476	$5,905,211	6.80%
	TOTAL	$127,872,175	$121,947,084	$5,925,091	4.86%
Commercial/Industrial Firm		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$20,537,436	$20,527,925	$9,511	0.05%
TU Sch. D, page 4	Commododity & Peak Shaving	$54,295,356	$51,034,815	$3,260,541	6.39%
	TOTAL	$74,832,792	$71,562,740	$3,270,052	4.57%
Demand Billed		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$2,013,827	$2,041,346	($27,519)	-1.35%
TU Sch. D, page 4	Commododity & Peak Shaving	$7,064,287	$6,892,676	$171,611	2.49%
	TOTAL	$9,078,114	$8,934,022	$144,092	1.61%
Small Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$5,156,116	$4,943,615	$212,501	4.30%
	TOTAL	$5,156,116	$4,943,615	$212,501	4.30%
Medium & Large Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$20,311,265	$20,299,911	$11,354	0.06%
	TOTAL	$20,311,265	$20,299,911	$11,354	0.06%

Recovery by Component

		RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) (%)
Demand	Residential	$35,083,488	$35,063,608	$19,880	0.06%
Demand	Commercial/Industrial Firm	$20,537,436	$20,527,925	$9,511	0.05%
Demand	Demand Billed	$2,013,827	$2,041,346	($27,519)	-1.35%
	TOTAL DEMAND	$57,634,751	$57,632,879	$1,872	0.00%
Commodity	Residential	$92,788,687	$86,883,476	$5,905,211	6.80%
Commodity	Commercial/Industrial Firm	$54,295,356	$51,034,815	$3,260,541	6.39%
Commodity	Demand Billed	$7,064,287	$6,892,676	$171,611	2.49%
Commodity	Small Interruptible	$5,156,116	$4,943,615	$212,501	4.30%
Commodity	Medium & Large Interruptible	$20,311,265	$20,299,911	$11,354	0.06%
	TOTAL COMMODITY	$179,615,711	$170,054,493	$9,561,218	5.62%

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	$ 2.7918	**5**	$ 0.2303	8.99%	$ 0.1561	5.92%	$ 2.9647	**6**	$ 0.5414	22.34%	$ 0.4319	17.05%	-5.83%	**5**
Great Plains***	$ 2.3607	**2**	$ (0.2007)	-7.84%	$ (0.2749)	-10.43%	$ 2.3061	**1**	$ (0.1172)	-4.84%	$ (0.2267)	-8.95%	2.37%	**2**
MERC-Consolidated	$ 2.3507	**1**	$ (0.2108)	-8.23%	$ (0.2850)	-10.81%	$ 2.3491	**3**	$ (0.0742)	-3.06%	$ (0.1837)	-7.25%	0.07%	**1**
MERC-NNG	$ 3.4036	**6**	$ 0.8422	32.88%	$ 0.7680	29.14%	$ 2.8721	**5**	$ 0.4488	18.52%	$ 0.3393	13.40%	18.51%	**6**
CenterPoint Energy****	$ 2.4584	**4**	$ (0.1030)	-4.02%	$ (0.1772)	-6.72%	$ 2.3868	**4**	$ (0.0366)	-1.51%	$ (0.1461)	-5.77%	3.00%	**3**
Xcel Gas	$ 2.4485	**3**	$ (0.1130)	-4.41%	$ (0.1871)	-7.10%	$ 2.3182	**2**	$ (0.1051)	-4.34%	$ (0.2146)	-8.47%	5.62%	**4**
Weighted MN Average	**$ 2.5615**						**$ 2.4233**						**5.70%**	
Non-Weighted MN Average	**$ 2.6356**						**$ 2.5328**						**4.06%**	
Standard Deviation	**$ 0.4092**						**$ 0.3014**							

***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****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 Costs[2]

PGA System	PGA Recovered	Actual Total Gas Sales (MMBtu)	PGA Recovered ($/MMBtu)	Rankings	Difference Btwn PGA Recovered And Mn Weighted Avg		Difference Btwn PGA Recovered And Mn Non-Weighted Avg		Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)	Current-Period Actual Incurred Gas Cost ($/MMBtu)	Rankings	Difference Btwn Current-Period Actual Incurred Gas Cost And Mn Weighted Avg		Difference Btwn Current-Period Actual Incurred Gas Cost And Mn Non-Weighted Avg		Actual Over/(Under) ($/MMBtu)	Percent Over/(Under) Recovery
					$/MMBtu	%	$/MMBtu	%					$/MMBtu	%	$/MMBtu	%		
	(1)	(2)	(3) = (1)/(2)						(4)	(5)	(6) = (4)/(5)						(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota Gas	$ 5,697,046	1,526,160	$ 3.7329	**5**	$ 0.2659	7.67%	$ 0.1445	4.03%	$ 5,824,041	1,526,160	$ 3.8161	**6**	$ 0.5156	15.62%	$ 0.4243	12.51%	$ (0.0832)	-2.18%
Great Plains***	$ 13,880,150	3,928,600	$ 3.5331	**4**	$ 0.0661	1.91%	$ (0.0553)	-1.54%	$ 13,730,115	3,928,600	$ 3.4949	**4**	$ 0.1944	5.89%	$ 0.1031	3.04%	$ 0.0382	1.09%
MERC-Consolidated	$ 18,581,679	6,021,183	$ 3.0861	**1**	$ (0.3809)	-10.99%	$ (0.5023)	-14.00%	$ 17,345,334	6,021,183	$ 2.8807	**1**	$ (0.4198)	-12.72%	$ (0.5111)	-15.07%	$ 0.2053	7.13%
MERC-NNG**	$ 129,389,759	28,310,797	$ 4.5703	**6**	$ 1.1033	31.82%	$ 0.9819	27.36%	$ 105,622,235	28,310,797	$ 3.7308	**5**	$ 0.4303	13.04%	$ 0.3390	9.99%	$ 0.8395	22.50%
CenterPoint Energy****	$ 453,457,709	134,407,986	$ 3.3737	**3**	$ (0.0932)	-2.69%	$ (0.2147)	-5.98%	$ 446,843,069	134,407,986	$ 3.3245	**3**	$ 0.0240	0.73%	$ (0.0673)	-1.98%	$ 0.0492	1.48%
Xcel Gas	$ 237,250,463	73,356,655	$ 3.2342	**2**	$ (0.2328)	-6.71%	$ (0.3542)	-9.87%	$ 227,687,372	73,356,655	$ 3.1038	**2**	$ (0.1967)	-5.96%	$ (0.2880)	-8.49%	$ 0.1304	4.20%
Mn Weighted Average	**$ 858,256,806**	**247,551,381**	**$ 3.4670**						**$ 817,052,166**	**247,551,381**	**$ 3.3005**						**$ 0.1664**	**5.04%**
Mn Non-Weighted Average			**$ 3.5884**								**$ 3.3918**						**$ 0.1966**	**5.80%**
Standard Deviation			**$ 0.5314**								**$ 0.3617**							

**NOTE: As of July 1, 2017, MERC-AL was merged with the MERC-NNG PGA system.
***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****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.

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2019 - June 30, 2020

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		2018-2019	**2019-2020**			**2018-2019**	**2019-2020**			**2018-2019**	**2019-2020**			**2018-2019**	**2019-2020**		
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%	$4.0216	$3.9933	($0.0283)	-0.70%	$4.4433	$4.4165	($0.0268)	-0.60%	$0.1054	-$0.0870	($0.1924)	-182.53%
Great Plains	N60	$90.00	$105.42	$15.42	17.13%	$4.9467	$3.9911	($0.9556)	-19.32%	$2.1803	$1.7636	($0.4166)	-19.11%	$0.4341	($0.1144)	($0.5484)	-126.34%
MERC-CON	MERC000002	$121.56	$114.00	($7.56)	-6.22%	$3.0596	$2.2675	($0.7921)	-25.89%	$2.5727	$2.4686	($0.1041)	-4.05%	$0.1592	($0.2087)	($0.3679)	-231.07%
MERC-NNG	MERC000001	$121.56	$114.00	($7.56)	-6.22%	$4.2637	$4.2106	($0.0532)	-1.25%	$2.5727	$2.4686	($0.1041)	-4.05%	$0.2040	($0.3067)	($0.5107)	-250.31%
CenterPoint Energy	Residential	$119.00	$121.80	$2.80	2.35%	$4.2132	$3.6476	($0.5656)	-13.42%	$2.1465	$2.1604	$0.0139	0.65%	$0.3278	$0.0715	($0.2563)	-78.19%
Xcel Gas	101	$108.00	$108.00	$0.00	0.00%	$4.6178	$3.8865	($0.7313)	-15.84%	$1.8571	$1.7600	($0.0971)	-5.23%	($0.0397)	$0.0013	$0.0409	-103.24%
MN NON-WEIGHTED AVERAGE		$110.35	$110.87	$0.52	0.47%	$4.19	$3.67	($0.5210)	-12.44%	$2.63	$2.51	($0.1225)	-4.66%	$0.1985	($0.1073)	($0.3058)	-154.07%

*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 G4 AND TABLE G7)
July 1, 2019 - June 30, 2020

		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)
		2018-2019	2019-2020			2018-2019	2019-2020			2018-2019	2019-2020			2018-2019	2019-2020		
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	$8.5702	$8.3228	($0.2474)	-2.89%	7.75	6.93	(0.82)	-10.54%	93.00	83.20	(9.80)	-10.54%	7,657	8,104	446.58	5.83%
Great Plains	N60	$7.5610	$5.6404	($1.9206)	-25.40%	7.42	6.93	(0.48)	-6.52%	89.00	83.20	(5.80)	-6.52%	8,483	8,550	66.92	0.79%
MERC-CON	MERC000002	$5.7915	$4.5274	($1.2641)	-21.83%	8.02	7.44	(0.57)	-7.17%	96.18	89.28	(6.90)	-7.17%	30,584	30,853	269.17	0.88%
MERC-NNG	MERC000001	$7.0405	$6.3725	($0.6680)	-9.49%	7.91	7.19	(0.71)	-9.00%	94.86	86.32	(8.54)	-9.00%	174,054	182,846	8,792.57	5.05%
CenterPoint Energy	Residential	$6.6875	$5.8795	($0.8080)	-12.08%	8.23	7.44	(0.78)	-9.52%	98.70	89.30	(9.40)	-9.52%	796,294	806,533	10,239.00	1.29%
Xcel Gas	101	$6.4352	$5.6477	($0.7875)	-12.24%	8.17	7.42	(0.75)	-9.18%	98.00	89.00	(9.00)	-9.18%	426,335	430,796	4,461.33	1.05%
MN NON-WEIGHTED AVERAGE		$7.0143	$6.0650	($0.9493)	-13.53%	7.91	7.23	(0.69)	-8.68%	94.96	86.72	(8.24)	-8.68%	240,568	244,614	4,045.93	1.68%

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2019 - June 30, 2020

		(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)
		2018-2019	2019-2020			2018-2019	2019-2020			2018-2019	2019-2020		
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	$74.92	$66.20	-$8.71	-11.63%	$899.03	$794.46	-$104.57	-11.63%	$1,301.83	$1,267.19	-$34.64	-2.66%
Great Plains	N60	$63.58	$47.89	-$15.69	-24.67%	$762.93	$574.70	-$188.23	-24.67%	$1,148.54	$895.08	-$253.46	-22.07%
MERC-CON	MERC000002	$56.55	$43.18	-$13.37	-23.63%	$678.59	$518.21	-$160.38	-23.63%	$932.37	$747.84	-$184.54	-19.79%
MERC-NNG	MERC000001	$65.79	$55.34	-$10.45	-15.88%	$789.42	$664.07	-$125.35	-15.88%	$1,107.23	$1,006.15	-$101.08	-9.13%
CenterPoint Energy	Residential	$64.92	$53.90	-$11.02	-16.97%	$779.06	$646.84	-$132.22	-16.97%	$1,055.25	$944.93	-$110.32	-10.45%
Xcel Gas	101	$61.55	$50.89	-$10.67	-17.33%	$738.65	$610.64	-$128.01	-17.33%	$1,008.93	$898.68	-$110.25	-10.93%
MN NON-WEIGHTED AVERAGE		$64.55	$52.90	-$11.65	-18.05%	$774.61	$634.82	-$139.79	-18.05%	$1,092.36	$959.98	-$132.38	-12.12%

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	4,542	-	4,542
Great Plains	20,532	-	20,532
CPE	246,693	-	246,693
MERC-CON	-	-	-
Xcel Gas-MN	15,044	-	15,044
MERC-NNG	4,683	-	4,683
MN Totals	291,494	-	291,494

	DDVC ($)				Percent of Total Costs Incurred		
Company	Positive & Negative	punitive	total	Actual Incurred Gas Cost ($)	Positive & Negative	punitive	total
Greater Minnesota**	-$2,023	$628	-$1,396	$5,824,040	-0.0347%	0.0108%	-0.0240%
Great Plains	-$3,406	$0	-$3,406	$13,730,115	-0.0248%	0.0000%	-0.0248%
CPE	-$383,850	$0	-$383,850	$446,843,069	-0.0859%	0.0000%	-0.0859%
MERC-CON	$0	$0	$0	$17,345,334	0.0000%	0.0000%	0.0000%
Xcel Gas-MN	$30,325	$0	$30,325	$227,687,372	0.0133%	0.0000%	0.0133%
MERC-NNG*	-$194,109	-$2,379	-$196,488	$105,622,234	-0.1838%	-0.0023%	-0.1860%
MN Totals	-$553,064	-$1,751	-$554,815	$817,052,164	-0.0677%	-0.0002%	-0.0679%

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	1,526,160	$ 4,260,667	$ 2.7918	1,526,160	$ 4,524,654	$ 2.9647	-5.83%
Great Plains North	3,928,600	$ 9,274,387	$ 2.3607	3,928,600	$ 9,059,784	$ 2.3061	2.37%
MERC-Consolidated****	6,021,183	$ 14,153,800	$ 2.3507	6,021,183	$ 14,144,275	$ 2.3491	0.07%
MERC-NNG*****	28,310,797	$ 96,359,808	$ 3.4036	28,310,797	$ 81,312,651	$ 2.8721	18.51%
CenterPoint Energy***	134,407,986	$ 330,432,858	$ 2.4584	134,407,986	$ 320,798,460	$ 2.3868	3.00%
Xcel Gas	73,356,655	$ 179,615,711	$ 2.4485	73,356,655	$ 170,054,493	$ 2.3182	5.62%
MN Weighted Average	247,551,381	$ 634,097,231	$ 2.5615	247,551,381	$ 599,894,317	$ 2.4233	5.70%
MN Non-Weighted Average			$ 2.6356			$ 2.5328	4.06%

***NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
****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: MERC's purchased Interstate Power's Minnesota operations and created the MERC-AL PGA system, effective May 1, 2015.
The MERC-AL PGA system was merged with the MERC-NNG PGA system effective July 1, 2017.
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	$ 5,697,046	1,526,160	$ 3.7329	**5**	$ 5,824,041	1,526,160	$ 3.8161	**6**	$ (0.0832)	-2.18%
Great Plains***	$ 13,880,150	3,928,600	$ 3.5331	**4**	$ 13,730,115	3,928,600	$ 3.4949	**4**	$ 0.0382	1.09%
MERC-Consolidated	$ 18,581,679	6,021,183	$ 3.0861	**1**	$ 17,345,334	6,021,183	$ 2.8807	**1**	$ 0.2053	7.13%
MERC-NNG**	$ 129,389,759	28,310,797	$ 4.5703	**6**	$ 105,622,235	28,310,797	$ 3.7308	**5**	$ 0.8395	22.50%
CenterPoint Energy	$ 453,457,709	134,407,986	$ 3.3737	**3**	$ 446,843,069	134,407,986	$ 3.3245	**3**	$ 0.0492	1.48%
Xcel Gas	$ 237,250,463	73,356,655	$ 3.2342	**2**	$ 227,687,372	73,356,655	$ 3.1038	**2**	$ 0.1304	4.20%
Mn Weighted Average	**$ 858,256,806**	**247,551,381**	**$ 3.4670**		**$ 817,052,166**	**247,551,381**	**$ 3.3005**		**$ 0.1664**	**5.04%**
Mn Non-Weighted Average			**$ 3.5884**				**$ 3.3918**		**$ 0.1966**	**5.80%**
Standard Deviation			**0.5314**				**0.3617**			

**NOTE: MERC merged its Albert Lea PGA system with its NNG PGA system as of July 1, 2017.
***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****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	$ 4,798,717	1,268,650	$ 3.7825	**5**	$ 4,909,875	1,268,650	$ 3.8702	**6**	$ (0.0876)	-2.26%
Great Plains-Consolidated**	$ 11,045,470	3,052,800	$ 3.6181	**4**	$ 10,928,026	3,052,800	$ 3.5797	**4**	$ 0.0385	1.07%
MERC-Consolidated*** 2	$ 17,024,798	5,359,943	$ 3.1763	**1**	$ 15,823,446	5,359,943	$ 2.9522	**1**	$ 0.2241	7.59%
MERC-NNG*** 2	$ 119,334,181	25,483,913	$ 4.6827	**6**	$ 96,871,026	25,483,913	$ 3.8013	**5**	$ 0.8815	23.19%
CenterPoint Energy*****	$ 421,606,253	120,559,062	$ 3.4971	**3**	$ 415,617,118	120,559,062	$ 3.4474	**3**	$ 0.0497	1.44%
Xcel Gas****	$ 211,783,082	63,162,170	$ 3.3530	**2**	$ 202,443,846	63,162,170	$ 3.2051	**2**	$ 0.1479	4.61%
Mn Weighted Average	**$ 785,592,501**	**218,886,538**	**$ 3.5890**		**$ 746,593,337**	**218,886,538**	**$ 3.4109**		**$ 0.1782**	**5.22%**
Mn Non-Weighted Average			**$ 3.6850**				**$ 3.4760**		**$ 0.2090**	**6.01%**

**NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
***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. The MERC-AL PGA system was merged with the MERC-NNG PGA system effective July 1, 2017.
****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

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	$	898,329	257,510	$	3.4885	5	$	914,166	257,510	$	3.5500	6	$	(0.0615)	-1.73%
Great Plains***	$	2,834,680	875,800	$	3.2367	4	$	2,802,089	875,800	$	3.1995	5	$	0.0372	1.16%
MERC-Consolidated *	$	1,556,881	661,240	$	2.3545	2	$	1,521,888	661,240	$	2.3016	2	$	0.0529	2.30%
MERC-NNG *	$	10,055,578	2,826,884	$	3.5571	6	$	8,751,209	2,826,884	$	3.0957	4	$	0.4614	14.91%
CenterPoint Energy*****	$	31,851,456	13,848,924	$	2.2999	1	$	31,225,951	13,848,924	$	2.2548	1	$	0.0452	2.00%
Xcel Gas****	$	25,467,381	10,194,484	$	2.4982	3	$	25,243,526	10,194,484	$	2.4762	3	$	0.0220	0.89%
Mn Weighted Average	**$**	**72,664,305**	**28,664,842**	**$**	**2.5350**		**$**	**70,458,829**	**28,664,842**	**$**	**2.4580**		**$**	**0.0769**	**3.13%**
Mn Non-Weighted Average				**$**	**2.9058**					**$**	**2.8130**		**$**	**0.0929**	**3.30%**

*NOTE: MERC's Interruptible numbers include the joint customers since Joint customers are not considered firm on the peak day.
The MERC-AL PGA system was merged with the MERC-NNG PGA system effective July 1, 2017.
***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****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	1,577,077	0	1,577,077	1,571,781	14,990	0	1,586,771	(9,694)	-0.61%
Great Plains Total Co. #	3,915,106	(48,202)	3,866,904	3,842,549	0	20,565	3,863,114	3,790	0.10%
MERC-Consolidated **	5,875,862	118	5,875,980	6,035,698	(14,515)	0	6,021,183	(145,203)	-2.47%
MERC-NNG **	28,031,282	0	28,031,282	28,331,324	(20,527)	0	28,310,797	(279,515)	-1.00%
CenterPoint Energy	182,750,152	(378,767)	182,371,385	178,819,925	94,914	0	178,914,839	3,456,546	1.90%
Xcel Gas Mn jurisdiction *	75,957,553	185,995	76,143,548	74,492,032	9,098	0	74,501,130	1,642,418	2.16%
Statewide Totals	298,107,032	(240,856)	297,866,176	293,093,309	83,960	20,565	293,197,834	4,668,342	1.57%

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 reports its Purchased Gas in column (1) net of Adjustments in column (2) and Customer Use Gas in column (4) net of Company Use Gas in column (5).

Attachment G20
Supporting Schedule to Tables G19 and G20

	Firm Design Day Demand (Mcf)	Firm Design Day Deliverability **w/ Peak-Shaving** (Mcf)	Actual Peak Day Date (Mcf)	Design-Day Customer Numbers	Actual Firm Peak Day Usage (Mcf)	Annual Firm Throughput (Mcf)	Design-Day Use Per Customer	Peak-Day Use Per Design-Day Customer	Annual Firm Load Factor	Reserve Margin	Annual Firm Requirement %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(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	14,244	15,275	02/13/20	9,090	11,689	1,222,851	1.5670	1.2186	28.66%	7.24%	76.5%
Great Plains #	34,066	36,945	02/12/20	24,119	28,451	3,086,396	1.4124	1.1974	29.72%	8.45%	77.0%
CenterPoint Energy	1,399,000	1,478,099	02/13/20	881,564	1,026,658	115,732,906	1.5870	1.3627	30.88%	5.65%	69.5%
MERC-CON	57,065	58,649	02/13/20	36,580	43,960	5,428,877	1.5600	1.2981	33.83%	2.78%	75.0%
Xcel Gas (Mn JURISDICTION)	743,696	792,833	01/16/20	465,382	515,125	71,499,792	1.5980	1.4437	38.03%	6.61%	65.0%
MERC-NNG	280,796	314,349	02/13/20	204,781	220,338	26,290,450	1.3712	1.2744	32.69%	11.95%	70.1%
Totals	**2,528,867**	**2,696,150**		**1,621,516**	**1,846,221**	**223,261,272**	**1.5596**	**1.3698**	**33.13%**	**6.61%**	68.5%
TOTAL prior year		2,608,819									
Change from prior year		87,331									

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 2019-2020 Annual Automatic Adjustment (AAA) Reports

Docket No. G999/AA-20-172, G004/AA-20-699, G022/AA-20-684, G008/AA-20-698, G011/AA-20-656, G011/AA-20-655, and G002/AA-20-705

Dated this **26th** day of **April 2022**

/s/Sharon Ferguson

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Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-656_AA-20-656
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-656_AA-20-656
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_20-656_AA-20-656
David	Kyto	djkyto@integrysgroup.com	Integrys Business Support	700 North Adams PO Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_20-656_AA-20-656
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Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_20-656_AA-20-656
Michael	Loeffler	mike.loeffler@nngco.com	Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Electronic Service	No	OFF_SL_20-656_AA-20-656
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-656_AA-20-656
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-656_AA-20-656

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_20-656_AA-20-656
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-656_AA-20-656
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_20-656_AA-20-656
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_20-656_AA-20-656
Lisa	Peterson	lisa.r.peterson@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-656_AA-20-656
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources	231 West Michigan St Milwaukee, WI 53203	Electronic Service	Yes	OFF_SL_20-656_AA-20-656
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-656_AA-20-656
Jeff	Sande		Bemidji State University	Box 1 Deputy Hall 1500 Birchmont Drive Bemidji, MN 566012699	Paper Service	No	OFF_SL_20-656_AA-20-656
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th St Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_20-656_AA-20-656

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Tina E	Wuyts	tina.wuyts@wecenergygroup.com	Minnesota Energy Resources Corporation	PO Box 19001 700 N Adams St Green Bay, WI 54307-9001	Electronic Service	Yes	OFF_SL_20-656_AA-20-656
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-684_AA-20-684
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-684_AA-20-684
Travis	Jacobson	travis.jacobson@mdu.com	Great Plains Natural Gas Company	400 N 4th St Bismarck, ND 58501	Electronic Service	Yes	OFF_SL_20-684_AA-20-684
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_20-684_AA-20-684
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-684_AA-20-684
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-684_AA-20-684

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-698_AA-20-698
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Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_20-698_AA-20-698
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Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-698_AA-20-698
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David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_20-698_AA-20-698
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-698_AA-20-698
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Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-698_AA-20-698

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James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-698_AA-20-698
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Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_20-698_AA-20-698
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_20-698_AA-20-698

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Jonathan	Wolfgram	Jonathan.Wolfgram@state.mn.us	Office of Pipeline Safety	445 Minnesota St Ste 147 Woodbury, MN 55125	Electronic Service	No	OFF_SL_20-698_AA-20-698
Donald	Wynia	donald.wynia@centerpointenergy.com	CenterPoint Energy	CenterPoint Energy 505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_20-698_AA-20-698

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Cody	Chilson	cchilson@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	Yes	OFF_SL_20-699_AA-20-699
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-699_AA-20-699
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-699_AA-20-699
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	Yes	OFF_SL_20-699_AA-20-699
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	Yes	OFF_SL_20-699_AA-20-699
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-699_AA-20-699
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-705_AA-20-705
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Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_20-705_AA-20-705
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_20-705_AA-20-705
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-705_AA-20-705
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Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_20-705_AA-20-705
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_20-705_AA-20-705
Lisa	Peterson	lisa.r.peterson@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-705_AA-20-705
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_20-705_AA-20-705
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-705_AA-20-705
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Andrew	Sudbury	Andrew.Sudbury@CenterPointEnergy.com	CenterPoint Energy Minnesota Gas	505 Nicollet Mall PO Box 59038 Minneapolis, MN 55459-0038	Electronic Service	No	OFF_SL_20-705_AA-20-705
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_20-705_AA-20-705
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_20-705_AA-20-705
Donald	Wynia	donald.wynia@centerpointenergy.com	CenterPoint Energy	CenterPoint Energy 505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-705_AA-20-705