COMMERCE DEPARTMENT

March 4, 2021

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

RE: **Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G004/M-20-562

Dear Mr. Seuffert:

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

> Petition of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. (Great Plains or the Company) for Approval of Changes in Contract Demand Entitlements.

These *Supplemental Comments* are in response to Great Plains' *Informational Update* filed on October 31, 2020. The petitioner on behalf of Great Plains is:

> Travis R. Jacobson
> Director of Regulatory Affairs
> Great Plains Natural Gas Company
> 705 West Fir Avenue
> PO Box 176
> Fergus Falls, Minnesota 56538-0176

The Department recommends that the Minnesota Public Utilities Commission (Commission) accept the Company's proposed level of demand entitlement and allow Great Plains to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2020. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/ja
Attachments

Before the Minnesota Public Utilities Commission

Supplemental Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G004/M-20-562

I. INTRODUCTION

Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. (Great Plains or the Company), filed a demand entitlement petition on July 1, 2020, with the Minnesota Public Utilities Commission (Commission) to change the levels of demand for natural gas pipeline capacity (*Petition*). On September 30, 2020 the Minnesota Department of Commerce, Division of Energy Resources (Department) filed *Comments* in response to the Company's *Petition*. In its *Comments*, the Department stated that it would provide its final recommendations to the Commission after the Company filed its update on November 1, 2020.

On October 6, 2020, the Company filed its *Reply Comments* agreeing with the Department's assessment of the Company's proposed demand entitlement levels used in planning for the Company's design-day were acceptable.

On October 30, 2020, the Company filed its *Informational Update* which showed the final demand entitlement volumes and costs that would be charged to ratepayers. The Company noted that there were changes to the capacity release levels since the original July 1, 2020 *Petition*.

Great Plains originally planned to release 2,900 Dekatherms (Dth or Dk) per day of firm, winter-only capacity on Viking Gas Transmission (Viking or VGT) and on Northern Natural Gas (Northern or NNG). In its *Comments*, the Department stated the following:[1]

> The Commission's Ordering point 5 of its 19-430 Order requires Great Plains to file in the instant Petition and November 1 Update and Supplemental filing:
>
> - a detailed explanation of excess reserve capacity, any impediments to efforts being made to release the excess capacity, and the impact on the Reserve Margin for the 2020 – 2021 heating season.
> - a detailed description of marketing efforts, when capacity releases were offered, amounts and prices offered but not accepted, and amounts released along with the payments received for those releases.

[1] See the Department's September 30, 2020 *Comments*, pages 11-12.

> In the Company's response to Department IR No. 4, included as Department Attachment 3, the Company stated the following:
>
>> To defray the cost of the excess capacity noted above, Great Plains has proposed capacity releases in each Demand Entitlement Filing following the purchases noted above. In the instant docket, Great Plains proposes to release excess capacity of 2,900 dk/day, of which 2,000 dk/day is on Viking Gas Transmission (VGT) and 900 dk/day is on Northern Natural Gas (NNG), resulting in a proposed reserve margin of 6.7 percent and was addressed under the section titled Capacity Releases. Absent the 2,900 dk/day capacity release, the reserve margin would be 15.4 percent for the 2020 2021 heating season. Great Plains has ongoing preliminary discussions directly with purchasers, but these parties have shown less interest in this capacity for the upcoming heating season.
>>
>> At this time, Great Plains has not encountered impediments to efforts being made to release the excess capacity and will provide a detailed description of marketing efforts, when capacity releases were offered, amounts and prices offered but not accepted, and amounts released along with other payments received for those releases in its Informational Update Filing regarding Great Plains' 2020 Demand Entitlement Filing on or before November 1, 2020 as this information is not currently available.
>
> Thus, the Department expects the Company in its November 1, 2020 Update and Supplemental filing to comply with Ordering Point 5 of the Commission's 19-430 Order.

In the *Informational Update*, the Company reported that it had released 2,000 Dth per day of Viking capacity as it had originally proposed. In its *Informational Update*, the Company stated the following:[2]

> Pursuant to the April 27, 2020 in Docket No. G004/M-19-430, the Company has provided information regarding its efforts to release capacity. Great Plains utilized the electronic bulletin boards in its marketing efforts for the respective suppliers to post the proposed capacity releases for bids during October 2020. The 2,000 dk capacity release on VGT has been contracted to a purchaser at a rate of $3.9200 per dk for the period November 2020 through March 2021. The 900 dk capacity release on NNG received no bids. Great Plains will continue to post this release to NNG's electronic bulletin board throughout the heating season in the hopes of a

[2] See Great Plains October 30, 2020 *Informational Update*, page 1.

> purchaser placing a bid. The NNG capacity release would impact Great Plains' reserve margin from its currently proposed 9.5% to 6.8%, a decrease of approximately 28%.

As discussed in the *Petition*, Great Plains proposed changes in its demand entitlement that, in total, would have resulted in total demand costs from all source systems of approximately $4,644,325.[3] In the Company's *Informational Update*, Great Plains stated that as a result of the changes in Viking capacity (as described above), and the annual Northern Natural Gas's (NNG) reallocation of TF-12B and TF-12V services, total demand costs are approximately $4,639,972.[4]

The Department responds to the *Informational Update* below.

II. DEPARTMENT ANALYSIS

The Department offers the following analysis of the Company's *Informational Update*, addressing:

- the revised capacity release,
- the associated Purchased Gas Adjustment (PGA) cost;
- the reserve margin; and
- February 2021 cold weather event.

A. REVISED CAPACITY RELEASE

As noted above, Great Plains originally planned to release 2,900 Dth per day of firm, winter-only capacity on Viking and NNG. The Company stated that it was able to secure the contract for the release of 2,000 Dth via a bidder on VGT's electronic bulletin board (EBB) for the period of November 2020 through March 2021.[5] However, the Company was not able to secure any bids for its proposed capacity release of 900 Dth on NNG for the winter heating season as noted above. The Company noted that the only impediments it had encountered in releasing the excess capacity were the lack of corresponding buyer bids on NNG's EBB. The changes are provided in detail in the Company's *Informational Update* Exhibits B through D.

The Department concludes that the capacity release is reasonable and that it complies with Ordering Point 5 of the Commission's 19-430 Order.

B. GREAT PLAINS PGA COST RECOVERY PROPOSAL UPDATE

In its *Comments*, the Department stated the following:[6]

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[3] See Table 1, page 4 in the *Petition*.
[4] See Table 2, page 3 in the Company's *Informational Update*.
[5] Id.
[6] See Department September 30, 2020 *Comments*, pages 12-13.

> The Department recommends that Great Plains in its November 1, 2020 Supplemental Filing and/or Update provide a comparison to the October PGA rather than the July PGA and to update the calculations to reflect the Company's pending rate case with the Commission in Docket No. G004/GR- 19-511.

In its *Informational Update*, the Company stated the following:[7]

> Despite the Company's inability to obtain a bidder for its NNG capacity release, the total cost of demand is $26,137 less than that presented in the July 1 filing. The demand costs to be effective November 1, 2020 are reflected in Table 2, below:

The Department notes that there is an error in the Company's statement. As noted above, in the *Petition*, Great Plains proposed changes in its demand entitlement, in total, would have resulted in total demand costs from all source systems of approximately $4,644,325.[8] In the Company's *Informational Update*, Great Plains stated that as a result of the changes in Viking capacity (as described above), and the annual NNG reallocation of TF-12B and TF-12V services, total demand costs are approximately $4,639,972.[9] Thus, the total cost of demand is approximately $4,353 less than the initial estimate provided in the *Petition*.

Great Plains proposed to reflect the costs associated with its proposed demand entitlements in the PGA effective November 1, 2020. The demand entitlements in Great Plains' *Informational Update* Exhibit B and Table 2 represent the demand entitlements for which the Company's firm customers will pay. Table 3 of the *Informational Update* compares the October 2020 PGA costs to the November 2020 PGA costs for two customer classes. The resulting cost changes, related strictly to changes in demand costs, have the following annual rate effects:

- an annual bill increase of $0.33 or approximately 0.3%, for the average residential customer consuming 77.9 dth annually; and

- an annual bill increase of $1.83 or approximately 0.3%, for the average firm general service customer consuming 434.4 dth annually.

The bill impacts described above relate solely to changes in demand cost and are based on the demand data and information provided by the Company. Based on its review, the Department concludes that the Company's proposal appears to be reasonable.

In addition, on March 1, 2021 the Commission issued its Order in Docket No. G004/GR-19-511, Great Plains' recent rate case, and authorized the Company to implement its final rates

[7] See page 2 in the Company's *Informational Update*.
[8] See Table 1, page 4 in the *Petition*.
[9] See Table 2, page 3 in the Company's *Informational Update*.

effective April 1, 2021. Thus, in its next Demand entitlement filing Great Plains will have the calculations in its Exhibit C updated to reflect the Commission's decisions in the rate case.

C. RESERVE MARGIN

As a result of the proposed capacity releases, the Company's reserve margin is now 9.5%. This reflects an increase in the reserve margin compared to the 2019-2020 heating season's reserve margin of 8.45%.[10] Without the capacity release, the Company's entitlement is 39,145 Dth/day, resulting in a reserve margin of 15.4%. As discussed in detail above and based on the discussion in the Department's *Comments*, the 2020-2021 reserve margin is acceptable.

D. FEBRUARY 2021 COLD WEATHER EVENT

As a result of the recent cold weather event, on February 18, 2021, the Commission issued its Notice of Commission Special Planning Meeting (*February 18, 2021 Notice)* to be held on February 23, 2021 in order to provide the Commission with information about the impacts of the February 2021 cold weather event and the increase in natural gas prices. Questions listed in the *February 18, 2021* Notice included:

1. Why did natural gas prices go up in February 2021 and what were the natural gas spot and index prices before and after this cold weather event?

2. How will this affect customer bills now and in the future?

3. Were any firm customers interrupted during this time period due to natural gas system issues, including low pressure, need to reinforce specific areas of the distribution system, inability to get delivery from suppliers, use of storage and peak shaving? And, if so, in what order were customers interrupted and why?

4. Were any interruptible customers curtailed during this time period and in what order were they curtailed?

Also on February 18, 2021, Commission Staff issued a Memorandum (*Memo*) identifying the dockets gas companies' gas costs are reviewed in and expanding on the list of questions in the *February 18, 2021 Notice*.[11] While one of the questions above refers to customers who fail to curtail or interrupt their use of natural gas supplies when requested to do so by a utility, it does not directly impact Great Plains' need to procure entitlements or calculate the design day as those calculations are based on firm requirements and interruptible usage is not included. However, some and/or all the questions raised in the *February 18, 2021 Notice* and *Memo* will be followed up on by the Department in the upcoming AAA report in Docket No.G999/AA-21-

[10] See *Supplemental Comments* Department Attachments 1 and 2.
[11] See *Supplemental Comments* Department Attachment 3.

114 and/or in Docket No. E,G999/CI-21-135 (Docket 21-135) wherein the Commission has opened an investigation to learn about each utility's operational experiences and the natural gas price impacts during the recent February 2021 Cold Weather Event.

III. DEPARTMENT RECOMMENDATIONS

The Department recommends that the Commission:

- Approve Great Plains' proposed level of demand entitlements as amended by its *Supplemental Filing*; and
- Allow Great Plains to recover associated demand costs through the monthly Purchased Gas Adjustment effective November 1, 2020.

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Supplemental Comments Department Attachment 1
Docket No. G004/M-20-562
Great Plains Demand Entitlement Historical and Current Proposal

						Proposed As of 11/1/20			
Contract Type	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	2017-2018 Quantity (Mcf)	2018-2019 Quantity (Mcf)	2019-2020 Quantity (Mcf)	2020-2021 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
VGT									
FT-A (12-month)	13,000	13,000	13,000	18,000	18,000	18,000	-		
FT-A (5-month)	2,700	3,400	2,000	2,000	2,000	2,000	-		
BP (5-month)	-	-	1,600	-	-	-	-		
Seasonal Capacity Release				(2,600)	(2,200)	(2,000)	200		
Total VGT	**15,700**	**16,400**	**16,600**	**17,400**	**17,800**	**18,000**	**200**		
NNG									
TFX (12-month)*	2,000	2,000	700	1,000	2,000	2,000	-		
TFX (5-month)	6,200	6,200	6,200	6,200	6,200	6,200	-		
TF12B	4,604	5,421	4,854	3,819	3,921	4,036	115		
TF12V	2,931	2,114	2,681	3,716	3,614	3,499	(115)		
TF5	3,410	3,410	3,410	3,410	3,410	3,410	-		
TFX (Capacity Release)	(1,300)	(1,300)	-	-	-	-	-		
Total NNG	**17,845**	**17,845**	**17,845**	**18,145**	**19,145**	**19,145**	**-**		
Total Entitlement	**33,545**	**34,245**	**34,445**	**35,545**	**36,945**	**37,145**	**200**	**0.54%**	**-0.42%**
Total Annual Transportation	**22,535**	**22,535**	**21,235**	**26,535**	**27,535**	**27,535**	**-**	**0.00%**	
Total Winter Only Transport	**11,010**	**11,710**	**13,210**	**9,010**	**9,410**	**9,610**	**200**	**2.13%**	
Percent of Winter Only Capacity	32.82%	34.19%	38.35%	25.35%	25.47%	25.87%			

Source: Great Plains Exhibit B

Supplemental Comments Department Attachment 2
Docket No. G004/M-20-562
Great Plains Demand Entitlement Analysis*

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Heating Season	Number of Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dth)	Change from Previous Year	% Change From Previous Year	Total Design-Day Capacity (Dth)	Change from Previous Year	% Change From Previous Year	Reserve (7) - (4)	% Reserve [(7)-(4)]/(4)
2020-2021	24,425	109	0.45%	33,922	(144)	-0.42%	37,145	200	0.54%	3,223	9.50%
2019-2020	24,316	76	0.31%	34,066	392	1.16%	36,945	1,400	3.94%	2,879	8.45%
2018-2019	24,240	243	1.01%	33,674	941	2.87%	35,545	1,100	3.19%	1,871	5.56%
2017-2018	23,997	184	0.77%	32,733	335	1.03%	34,445	200	0.58%	1,712	5.23%
2016-2017	23,813	(69)	-0.29%	32,398	131	0.41%	34,245	700	2.09%	1,847	5.70%
2015-2016	23,882	358	1.52%	32,267	1,143	3.67%	33,545	900	2.76%	1,278	3.96%
2014-2015	23,524	296	1.27%	31,124	1,691	5.75%	32,645	2,000	6.53%	1,521	4.89%
2013-2014	23,228	290	1.26%	29,433	339	1.17%	30,645	0	0.00%	1,212	4.12%
2012-2013	22,938	164	0.72%	29,094	158	0.55%	30,645	159	0.52%	1,551	5.33%
2011-2012	22,774	40	0.18%	28,936	(393)	-1.34%	30,486	(1,380)	-4.33%	1,550	5.36%
2010-2011	22,734	(2)	-0.01%	29,329	(515)	-1.73%	31,866	(1,170)	-3.54%	2,537	8.65%
2009-2010	22,736	85	0.38%	29,844	119	0.40%	33,036	(1,170)	-3.42%	3,192	10.70%
2008-2009	22,651	49	0.22%	29,725	(714)	-2.35%	34,206	0	0.00%	4,481	15.07%
2007-2008	22,602	1	0.00%	30,439	(406)	-1.32%	34,206	0	0.00%	3,767	12.38%
2006-2007	22,601			30,845			34,206			3,361	10.90%
Average			0.56%			0.70%			0.63%		7.72%

	Firm Peak-Day Sendout			Per Customer Metrics			
	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Firm Peak-Day Sendout (Dth)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak-Day Send per Customer (12)/(1)
2020-2021	unknown			0.1320	1.3888	1.5208	unknown
2019-2020	28,451	(1,869)	-6.16%	0.1184	1.4010	1.5194	1.1701
2018-2019	30,320	1,679	5.86%	0.0772	1.3892	1.4664	1.2508
2017-2018	28,641	112	0.39%	0.0713	1.3640	1.4354	1.1935
2016-2017	28,529	1,283	4.71%	0.0776	1.3605	1.4381	1.1980
2015-2016	27,246	(1,853)	-6.37%	0.0535	1.3511	1.4046	1.1409
2014-2015	29,099	1,406	5.08%	0.0647	1.3231	1.3877	1.2370
2013-2014	27,693	3,471	14.33%	0.0522	1.2671	1.3193	1.1922
2012-2013	24,222	5,513	29.47%	0.0676	1.2684	1.3360	1.0560
2011-2012	18,709	(4,269)	-18.58%	0.0681	1.2706	1.3386	0.8215
2010-2011	22,978	1,442	6.70%	0.1116	1.2901	1.4017	1.0107
2009-2010	21,536	(1,731)	-7.44%	0.1404	1.3126	1.4530	0.9472
2008-2009	23,267	540	2.38%	0.1978	1.3123	1.5101	1.0272
2007-2008	22,727	852	3.89%	0.1667	1.3467	1.5134	1.0055
2006-2007	21,875			0.1487	1.3648	1.5135	0.9679
Average			2.63%	0.1032	1.3340	1.4372	1.0870

*The Petition is the fourth in which the Company's South District and North District were combined based on the ruling in Docket No. G004/GR-15-879. The Department combined the districts for comparison.
Source: Great Plains Exhibit D

NOTICE OF COMMISSION SPECIAL PLANNING MEETING

Issued: *February 18, 2021*

DATE:	Tuesday, February 23, 2021
TIME:	2:30 – 3:30 p.m.
LOCATION:	On-line via WebEx
AGENDA:	February 2021 Natural Gas Prices

This planning meeting will provide an opportunity for utilities and partner government agencies to provide the Commission with information about the impact of the February 2021 cold weather event and increase in natural gas prices. (A copy of the agenda for this meeting is attached.)

Viewing Instructions and any additional meeting materials, if any, will be posted on the Commission's website.

SCHEDULING CHANGES? Find out if a meeting is canceled. Call (toll-free) 1-855-731-6208 or 651-201-2213 or visit mn.gov/puc

CHANGE YOUR MAILING PREFERENCES: E-mail docketing.puc@state.mn.us or call 651-201-2234

If reasonable accommodations are needed to enable you to fully participate in a Commission meeting such as sign language or large print materials, please call 651-296-0406 or 1-800-657-3782 at least one week in advance of the meeting.

Persons with a hearing or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

MINNESOTA
PUBLIC UTILITIES COMMISSION

Commission Special Planning Meeting

Tuesday, February 23, 2021, 2:30 – 3:30 pm
February 2021 Natural Gas Prices

A. Comments from Minnesota Natural Gas Local Distribution Companies (LDCs)

(no more than 5 to 7 minutes each)

- Xcel Energy
- CenterPoint Energy
- Minnesota Energy Resources
- Great Plains Natural Gas co.
- Greater Minnesota Gas

1. Why did natural gas prices go up in February 2021 and what were the natural gas spot and index prices before and after this cold weather event?
2. How will this affect customer bills now and in the future?
3. Were any firm customers interrupted during this time period due to natural gas system issues, including low pressure, need to reinforce specific areas of the distribution system, inability to get delivery from suppliers, use of storage and peak shaving? And, if so, in what order were customers interrupted and why?
4. Were any interruptible customers curtailed during this time period and in what order were they curtailed?

B. Comments and Questions for the LDCs from State Agencies

- Minnesota Department of Commerce, Division of Energy Resources
- Minnesota Office of the Attorney General, Residential Utilities Division

MINNESOTA
PUBLIC UTILITIES COMMISSION

MEMORANDUM

Date: February 18, 2021

To: Commissioners
Will Seuffert, Executive Secretary

From: Bob Harding, PUC Staff

Re: Commission Special Planning Meeting – February 23, 2021
February 2021 Cold Weather Event and its Impact on Natural Gas Prices

Background Information on Fuel Cost Dockets and Questions and Topics for Further Discussion

On Friday, February 12, 2021, there was a large increase in natural gas prices in the wholesale natural market. Anecdotal reports suggest natural prices increased from approximately $3 per dekatherm to as much as or more than $200 per dekatherm. Most of this increase in price for gas delivered to Minnesota appears to have been weather and demand related. This was evidenced by increases in various index prices for natural gas at locations throughout the United States.

The last time there were significant increases in natural gas prices and disruptions in natural gas service in Minnesota was during the cold weather event of January 28 through February 1, 2019. One of the results of the 2019 investigation was that Xcel Energy and CenterPoint Energy were also required to submit information about system reinforcement projects completed during the year.[1] Another requirement was that the gas utilities update and modify the provisions for failure to curtail penalties in their tariffs and thoroughly review their procedures for handling cold weather events.

The purpose of this memo is to identify the dockets gas companies' gas costs are reviewed in. Also, at the end of this memo is a list of questions that expands on the list of questions that are on the agenda for the special planning meeting on Tuesday, February 23, 2021. If there is interest in collecting additional information, one or more of these questions could be asked at

[1] ORDER APPROVING MODIFICATION OF CURTAILMENT PENALTIES AND TARIFFS AND REQUIRING REPORTS, In the Matter of a Commission Inquiry into the Impact of Severe Weather in January and February 2019 on Utility Operations and Service, Docket No. E,G-999/CI-19-160 (November 6, 2019)

the Commission meeting or the gas companies could be asked to respond to these questions in writing after the meeting.

There is also a brief discussion about the impact this increase in natural gas prices could have on electric prices, however, staff expects this will be discussed at the Commission's MISO Quarterly Review on March 5, 2021.

Gas Cost Dockets

The month-to-month changes in the commodity cost of gas that are applied to customer bills are reported and reviewed by the Department of Commerce. These reports are typically submitted towards the end of the month and include the LDC's forecasted commodity cost of gas for the following month.[2] The wholesale prices the gas companies expect to pay in March would be applied to customer bills for gas consumed in March. These filings are not submitted to or routinely reviewed by the Commission.

The gas utilities are also required to obtain approval for changes (increases and decreases) in the amount of pipeline capacity they have an entitlement to under contract with the pipelines. These are the annual change in demand entitlement filings that are reviewed to ensure the LDCs have enough capacity under contract to provide service under design-day weather conditions. As a result of the planning issues that were discovered in the 2019 investigation, the Department has begun to include a review of whether the LDCs have coordinated its planning for the amount of pipeline capacity it needs with the planning for how much distribution capacity is needed on its own system. The changes in demand entitlement are provisionally approved when filed pursuant to Commission rules.[3]

[2] Minn. Rules, part 7825.2910, subpart 1. Filing By Gas Utilities. Monthly reports. Gas utilities shall submit monthly to the department purchased gas adjustment reports, which must include: A. a summary of adjustments that were implemented in the previous month and the computation of each adjustment; B. an explanation of significant changes between the base gas cost and current cost, quantified as to changes in price and source of gas; C. the estimated previous month's and year-to-date commodity-delivered gas cost by supplier; D. estimated gas volumes purchased from suppliers whose gas rates are not regulated by the Federal Energy Regulatory Commission; and E. estimated costs of gas purchased in item D expressed as a percentage of all commodity-delivered gas costs and demand-delivered gas costs. The department shall summarize the monthly reports every three months and submit the summary to the commission for review.

[3] Minn. Rules, part 7825.2910, subpart 2. Filing By Gas Utilities. Filing upon change in demand. Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another. A filing must contain: A. a description of the factors contributing to the need for changing demand; B. the utility's design-day demand by customer class and the change in design-day demand, if any, necessitating the demand revision; C. a summary of the levels of winter versus summer usage for all customer classes; and D. a description of design-day gas supply from all sources under the new level, allocation, or form of demand.

2020-2021 Change in Demand Entitlement filings

Company	Docket No.	Status
Xcel Energy	M-20-633	Pending
CenterPoint Energy	M-20-565 & M-21-102	Pending
MERC	M-20-636 & M-20-637	Order - 1/25/2021
Great Plains Natural Gas	M-20-562	Pending
Greater Minnesota Gas	M-20-391	Commission meeting – 3/11/2021

Total annual gas costs are reviewed when the LDCs submit their automatic adjustment of charges reports on September 1st for the previous gas year that includes the twelve-month period of July 1st through June 30th.[4] These reports also include an annual true-up rate adjustment filing for the previous gas year. In the annual true-up, the gas companies are allowed to collect/refund the difference between what they collected from customers and what they paid suppliers.

Annual Automatic Adjustment Reports

Gas Year	Docket No.	Status
Jul. '17 – Jun. '18	AA-18-374	Order – 11/13/2019
Jul. '18 – Jun. '19	AA-19-401	DOC Report - Expected 5/20/2021
Jul. '19 – Jun. '20	AA-20-172	DOC Report – Expected 5/20/2021
Jul. '20 – Jun. '21	AA-21-114	Initial Filings Expected - 9/1/2021

Xcel, CenterPoint and MERC are also authorized to recover the cost of using financial instruments to hedge their cost of gas. Costs are recovered through their monthly purchased gas rate adjustments. These are multi-year rule variances and they have been in effect for a long time and extended several times for each utility.

Gas Hedging – Rule Variances

	Docket No.	Status
Xcel Energy	M-19-703	Order – 2/12/2020
CenterPoint Energy	M-19-699	Order – 1/13/2020
MERC	M-20-833	Pending

One of the conditions of the financial hedging rule variance granted to CenterPoint is that CenterPoint submit its gas supply plan each year in a compliance filing. In addition, CPE typically meets with PUC and Department staff to go over their plan.

Staff does not believe any of the other gas utilities are required to submit annual compliance filings with their gas supply plans. However, it is staff's understanding that Xcel meets with the Department each year to review Xcel's plan.

[4] Minn. Rules, part 7825.2910, subpart 4. Filing By Gas Utilities. True-up filing. Gas utilities shall file and implement on September 1 of each year the true-up adjustment computed under part 7825.2700, subpart 7, for the previous year commencing July 1 and ending June 30.

In addition, in 1994, the Commission declined to adopt a formal gas integrated resource planning process in which a gas supply plan would probably have been required as well as a recognition of the LDC's DSM programs.[5]

Electric Price Issues

The cold weather and increase in natural gas prices appear to have also had an impact on the electric utilities. Mainly through MISO energy prices (LMPs) which impact utilities' energy prices in different ways. (Day-ahead vs Real-time LMP, long or short in energy position.) Most of the Minnesota utilities clear the majority of their load in the day ahead market; hence the day-ahead LMP will have the most impact on ratepayers' rates.

The real-time LMP is very volatile and receives the most attention in the media. However, it can have lesser impact to ratepayers. Also, electric utilities have a natural hedging position with their own generators. As long as the utility is not short with energy, the maximum risk exposure to a utility is capped by its own fuel price for generators. If Minnesota electric utilities were able to sell energy into the MISO market they may have benefitted from this cold weather event or if they were short on generation, they may have incurred additional energy cost based on their generation capability.

Staff does not have specific information about whether Xcel, MP or Otter Tail were net sellers or buyers of energy during this time period, however, if they were short capacity and buying energy, then any excess energy costs above forecast would flow through the FCA. Under the Commission's revised FCA procedures, if actual (total) FCA costs for the year exceed forecasted costs then, when they make their annual compliance filing, the utilities may seek to recover the additional costs.

If the electric utilities were net sellers then ratepayers may be due refunds. In an April 15, 2020 compliance letter, Docket No. E-002/AI-19-622, Xcel explained how it handles merchant energy trading activity:

> Xcel Energy's proprietary, or non-asset based, trading activity is one of two main categories of short-term wholesale trading, the other being asset-based trading. Asset-based transactions involve the sales of excess energy or capacity from Company-owned generation assets. Non-asset based (or proprietary) transactions, on the other hand, are undertaken as energy market opportunities to make revenues, and are unrelated to meeting the needs of the "native load" customers (retail customers and requirements wholesale customers taking service at cost based rates).

[5] ORDER DECLINING TO ADOPT TWO FEDERAL STANDARDS, In the Matter of an Investigation into Standards Regarding the Encouragement of Investments in Conservation and Energy Efficiency by Gas Utilities under 15 USC 3203 as amended by Section 115 of the Energy Policy Act of 1992, Docket No. G-999/CI-93-895 (May 4, 1994)

> Xcel Energy's traders conduct both proprietary and asset-based trading. The Company does not, however, intermix its proprietary and asset-based trades. In other words, proprietary transactions are only made to or from the Proprietary Book, and asset-based trades are only made to or from the Generation Book.
>
> Prior to the Company's 2010 Rate Case (Docket No. E002/GR-10-971), we shared non-asset based margins (revenues less costs) with customers. In the settlement of the 2010 Rate Case, however, the Company agreed to change the ratemaking treatment of non-asset based trading margins: non-asset based margins, as well as the fully-allocated costs of those activities, now are removed from the cost of service.

Staff also notes that in 2020, the Commission approved MP's request to shift its accounting for wholesale sales credits to its fuel clause adjustment rather than including them in its calculations for establishing base rates.[6] The majority of MP's sales credits are for a single large wholesale customer, however, asset-based wholesale sales credits may also arise from opportunity-based transactions in the MISO market. The Commission may want to ask MP to explain how it handles this revenue for fuel cost recovery purposes.

Staff is unaware of possible cost impacts to Otter Tail's customers; however, a review of Otter Tail's forecasted February 2021 FCA costs were $10.2 million of which $5.2 million, or 51%, was purchased power. OTP's asset-based margins were only forecasted to be $84,000. Based on this information, Staff suspects that actual February 2021 FCA costs may be higher than forecasted.

Staff expects this could be explored in more detail at the Commission's MISO Quarterly Review on March 5, 2021.

[6] In the Matter of the Emergency Petition of Minnesota Power for Approval to Move Asset-Based Wholesale Sales Credits to the Fuel Clause Adjustment and Resolve Rate Case, Docket No. E-015/M-19-429

Possible Questions and Topics for Further Discussion

1. Why did natural gas prices go up in February 2021, how high are natural gas prices now, and how long are natural gas prices expected to stay at this level?

2. How much higher are these prices than the forecasted cost of gas in the February 2021 monthly Purchased Gas Adjustment (PGA) report?

3. How will this affect gas customers' bills for February 2021, March 2021 and the annual true-up of gas costs for the July 1, 2020 through June 30, 2021 gas year?

4. For the Minnesota LDCs that engage in natural gas price hedging, please describe the effect this had on your company's cost of gas during this time period?

5. How will this affect customers who may already be having trouble paying their gas bills?

6. Has this cold weather event and the high gas prices had a disproportionate impact on Minnesota's BIPOC communities or the gas utilities ability to provide service to Minnesota BIPOC communities?

7. Were there any problems during the February 2021 cold weather with the delivery of natural gas into the facilities and systems operated by Minnesota LDCs?

8. Have any Minnesota LDCs had to provide local reinforcement to their distribution systems to maintain service to firm customers or have any firm customers been interrupted during this time period?

9. Have any Minnesota LDCs curtailed service to interruptible customers and to what extent?

10. Have interruptible customers complied with curtailment requests from their LDCs?

11. Have the cold weather related events in Texas and elsewhere had any clearly identifiable impact on any aspect of Minnesota utilities operations and ability to maintain expected levels of customer service?

12. Have the Minnesota LDCs communicated effectively with their customers about gas prices during this cold weather?

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
Supplemental Comments

Docket No. G004/M-20-562

Dated this 4th day of March 2021

/s/Sharon Ferguson

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_20-562_M-20-562
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