MINNESOTA DEPARTMENT OF COMMERCE

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June 2, 2017

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

RE: **Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G011/M-16-651

Dear Dr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) in the following matter:

> A Request by Minnesota Energy Resources Corporation (MERC or the Company) for Approval of a Change in Demand Entitlement for its Customers Served off of the Consolidated System Effective in the Purchased Gas Adjustment (PGA) on November 1, 2016.

MERC submitted an updated filing on November 1, 2016 and a *Letter* on November 16, 2016. The petitioner is:

> Amber S. Lee
> Minnesota Energy Resources Corporation
> 1995 Rahncliff Court, Suite 200
> Eagan, MN 55122

To ensure that the record is complete in this docket, the Department provides the following response to MERC's November 1, 2016 *Update* and November 16, 2016 *Letter.* The Department recommends that the Minnesota Public Utilities Commission (Commission) **accept** the Company's proposed level of demand entitlement and allow MERC to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2016.

The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ MICHAEL RYAN	/s/ SACHIN SHAH
Rates Analyst	Rates Analyst

MR/SS/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

SUPPLEMENTAL COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. G011/M-16-651

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Minnesota Energy Resources Corporation (MERC or the Company) filed a change in demand entitlement petition (Petition) on August 1, 2016 for its customers served off the Consolidated Purchased Gas Adjustment (PGA) system (MERC-Consolidated).[1] MERC-Consolidated serves customers located along three pipelines: Great Lakes Gas Transmission (Great Lakes or GLGT), Viking Gas Transmission Co. (Viking or VGT), and Centra Minnesota Pipelines (Centra).

MERC's filing included decreases in capacity entitlement on both Great Lakes and Viking, which resulted in a negative reserve margin. In other words, the Company did not have enough natural gas pipeline capacity to cover a design day. To address the negative reserve margin, MERC stated that the plan was to contract for additional capacity to ensure a positive reserve margin between the dates of the Petition, August 1st, and the updated filing on November 1, 2016. The Company anticipated that it would contract for approximately 5,000 Dth of pipeline capacity on Centra, Viking, and Great Lakes.[2]

On October 28, 2016, the Department of Commerce, Division of Energy Resources (Department) filed comments recommending that the Minnesota Public Utilities Commission (Commission) accept MERC's peak-day analysis. However, since MERC did not anticipate all its purchases at the time of the filing, the Department indicated that it would provide its final recommendations after reviewing the Company's November 1, 2016 updated filing.

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[1] In its December 21, 2012 Order in Docket No. G007,011/GR-10-977, the Minnesota Public Utilities Commission approved consolidation of MERC's four PGA systems effective July 1, 2013. MERC named the PGA for the Northern Natural Gas customers "MERC-NNG." At the time, MERC's only other PGA system was named "MERC-Consolidated." Effective May 1, 2015, MERC acquired Interstate Power & Light Company's Minnesota natural gas operations and customers. The Commission required MERC to maintain the transitioned customers on a separate PGA until MERC's next rate case. MERC named the PGA for the transitioned customers "MERC NNG-Albert Lea." On August 1, 2016, MERC filed a demand entitlement request for MERC-NNG in Docket No. G011/M-16-650 and MERC NNG-Albert Lea in Docket No. G011/M-16-652.

[2] Petition, page 14.

Because the natural gas heating season spans the five-month period from November through March, the Company has the ability to secure capacity up until November 1st each year. The Company provided an updated filing on November 1, 2016. In the filing, MERC indicated that they were unable to secure 1,000 Dth/day of pipeline capacity on Viking that was planned. MERC indicated that it planned to purchase 1,000 Dth/day of city-gate delivered gas to increase its reserve margin. In addition, MERC indicated that the Centra contract volume increased from 9,100 dth/day to 9,500 dth/day.

On November 16, 2016, MERC filed a Letter confirming that the Company was able to purchase the city-gate delivered natural gas supply for the term of December 2016 through February 2017. As MERC noted, this purchase does not affect the Company's contracted demand entitlements.

On April 20, 2017, MERC filed a second Letter to provide notice that its contract demand would change effective May 1, 2017 due to the assignment of a storage contract with Niska Gas Storage for the final year of the contract term. Because the change occurred May 1, 2017, it does not impact the design day analysis in this docket. The Company has confirmed that it will provide updated analysis in the 2017-2018 Demand Entitlement filing.

II. THE DEPARTMENT'S ANALYSIS OF THE COMPANY'S PROPOSAL

The Department's analysis of the Company's request includes the changes to:

- capacity;
- design-day requirements;
- reserve margins; and
- PGA cost recovery.

A. MERC'S PROPOSED CHANGES

1. Capacity

As an initial matter, the Department confirms that, as required by the Commission's Order Point 9[3] of its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, MERC provided separate data on its summer and winter demand entitlements.[4]

As indicated in Table 1 below and DOC Attachments 1 and 2, MERC's capacity purchases for the 2016 through 2017 heating season reflect a decrease in its total entitlement level by 550 Dth as follows:

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[3] Order Point 9 states, "Required MERC to separate its summer and winter demand entitlements as reflected in Attachment 4 of its petitions, rather than combining the data as reflected on Attachment 3 of its petitions."
[4] See MERC Attachment 3.

Table 1: MERC's Consolidated Total Entitlement Levels

August 1, 2016 Filing	2015-6 Entitlement (Dth)	2016-7 Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Year (%)
Centra	9,100	9,500	400	4.40%
Great Lakes	29,758	29,808	50	0.17%
Viking	16,591	15,591	(1,000)	(6.03)%
Total Consolidated	55,449	54,899	(550)	(0.99)%

MERC increased capacity this winter as compared to the prior year by 400 Dth and 50 Dth for Centra and Great Lakes, respectively. The decrease in total capacity was driven by the Company's inability to secure Viking capacity at the level of the year prior. The Company stated in their Update that "there is not a physical lack of capacity on the Viking pipeline to deliver gas to MERC, but instead a contractual lack of available capacity for the upcoming winter." MERC was able to purchase an additional 1,000 Dth/day of delivered supply on Viking for the term December 2016 through February 2017. Entitlement levels are discussed in further detail in the reserve margin section below.

2. Design-Day Requirements

In the *Update* filed November 1, 2016, the design-day levels matched the levels included in the initial filing. The Department continues to recommend approval, as is discussed below.

As provided in Table 2 below and DOC Attachment 2, MERC proposed to increase its total design day by 2,453 Dth as follows:

Table 2: MERC's Consolidated Design Day Levels

August 1, 2016 Filing	2015-6 Design Day (Dth)	2016-7 Design Day (Dth)	Design Day Changes (Dth)	Change From Previous Year (%)
Centra	8,674	9,132	458	5.28%
Great Lakes	28,543	29,808	1,265	4.43%
Viking	15,858	16,588	730	4.60%
Total Consolidated	53,075	55,528	2,453	4.62%

MERC used a similar approach to that used in last year's filing for its design-day analysis. As a result of MERC's telemetry program making it possible for all interruptible customers to have daily metered data, the Company no longer has to estimate interruptible customers' peak-day impact. Instead, MERC obtains the daily large volume transportation, interruptible and joint interruptible volumes by pipeline and weather station (Data A). In addition, MERC obtains the daily small volume interruptible volumes by pipeline and weather station (Data B). MERC calculates the daily firm volumes by subtracting both Data A and Data B from the total throughput volumes.

In its Petition, MERC indicated that it made some adjustments to its data (for example, for the GLGT pipeline, certain adjustments were made for the Bemidji and Cloquet regression analyses). MERC listed the steps followed in preparing the data for its design-day analysis, including:[5]

> Review daily total metered throughput, Data A, and Data B and identify missing or bad reads, and to the extent possible, fix missing or bad reads. To the extent that the data could not be fixed, we did not include it in our regressions.

The Department concludes that MERC's approach to its design-day analysis, as outlined on pages 3-12 of its Petition, appears reasonable.

The Commission's *April 28, 2016 Order* in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, at Order point 12, stated the following:

> Required MERC to explain the reasons that its Demand Day requirements increased over its last 2014-2015 demand entitlements petition for its MERC-Consolidated (Centra Pipeline) and MERC-Albert Lea PGA in a compliance filing within 30 days of the order.

In its May 31, 2016 Compliance Filing in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, at pages 4-5, the Company, in part, stated the following:

> MERC provides the following explanation for why its Demand Day requirements increased for MERC-Consolidated Centra Pipeline:
>
> In MERC's 2014-2015 demand entitlement petition, the small volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station was calculated by dividing the volumes consumed by a particular customer group during the highest historical peak month of usage for that customer group by twenty (20) to determine the Maximum Daily Quantity ("MDQ") for that customer group. In this case, 89,727 Dth in December 2013 divided by 20 for an MDQ of 4,486 Dth/day for Centra. In MERC's 2015-2016 demand entitlement petition, MERC ran two regressions. The first regression did not remove the small volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station. This regression resulted in design peak day estimate of 11,690 Dth/day. The second regression removed the small volume transportation, interruptible, and joint interruptible volumes by

[5] Petition at page 6.

> pipeline and by weather station. This regression resulted in a design peak day estimate of 8,788 Dth/day for Centra. Therefore, the difference between the two regressions could be used as an estimate of the small volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station. In this case, the difference equals an MDQ of 2,902 Dth/day.
>
> The decrease of 1,584 Dth/day from 2014-2015 to 2015-2016 (4,486 – 2,902 = 1,584) is the main reason why there was an increase in the design peak day estimate of 1,546 Dth/day. The remaining difference is due to two other factors: new data being used in our regressions from telemetry and new adjustments being made to our regressions due to an updated sales forecast.

The Department notes that the Company's detailed explanation above of the reasons for the increases in the design-day requirements from its previous petition is reasonable. Thus, the Department concludes that MERC complied with the Commission's *April 28, 2016 Order.*

The Department notes that MERC appropriately corrected its models for autocorrelation, as required by the Commission's February 4, 2015 Order in Docket Nos. G011/M-12-1192, G011/M-12-1193, G011/M-12-1194, and G011/M-12-1195 wherein the Commission required that, in its future demand entitlement filings, MERC check the regression models it ultimately uses for autocorrelation and correct the model if autocorrelation is present.

The Department recommends that the Commission accept MERC-Consolidated's peak-day analysis.

3. Reserve Margins

As shown in Table 3 below and DOC Attachment 2, the reserve margins for each area and the total MERC-Consolidated PGA are as follows:

Table 3: MERC's Consolidated Reserve Margin (November 2016 – March 2017)

November 1, 2016 Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	2016 Reserve Margin %	2015 Reserve Margin %	Percentage Point Change From Previous Year
Centra	9,400	9,132	368	4.03%	4.91%	(0.88)%
Great Lakes	29,808	29,808	0	0.00%	4.26%	(4.26)%
Viking	15,591	16,588	(997)	(6.01)%	4.62%	(10.63)%
Total Consolidated	54,899	55,528	(629)	(1.13)%	4.47%	(5.60)%

Table 3a: MERC's Consolidated Reserve Margin (December 2016 – February 2017) Including Purchase of City-Gate Delivered Supply

November 1, 2016 Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	2016 Reserve Margin %	2015 Reserve Margin %	Percentage Point Change From Previous Year
Centra	9,400	9,132	368	4.03%	4.91%	(0.88)%
Great Lakes	29,808	29,808	0	0.00%	4.26%	(4.26)%
Viking	16,591	16,588	3	0.02%	4.62%	(4.60)%
Total Consolidated	55,899	55,528	371	0.67%	4.47%	(3.80)%

Regarding the Centra area of MERC-Consolidated, as indicated above in Section I, MERC increased capacity on Centra by 400 Dth since the initial filing to insure a positive reserve margin.

Also since its August 1, 2016 initial filing, MERC acquired a new, winter-only contract for 3,350 Dth on the Great Lakes system to insure a reserve margin that met the design-day.

As stated above and in the Company's *Update*, MERC was unable follow through on its plan to contract for an additional 1,000 Dth/day of Viking capacity for the November 1, 2016 – March 31, 2017 period. MERC explained the solution as follows:

> MERC will purchase 1,000 dth/day of city-gate delivered supply on Viking for the December 2016 - February 2017 term. MERC anticipates completing this purchase in November 2016 and will provide notice in this docket once the purchase has been completed. A city-gate purchase means that the commodity supplier is responsible for delivering gas, on Viking, from its supply point to MERC's city-gate. There is not a physical lack of capacity on the Viking pipeline to deliver gas to MERC, but instead a contractual lack of available capacity for the upcoming winter. Moving forward, MERC will look into the most cost-effective option for meeting this capacity need for a longer term. The proposed commodity purchase will provide certainty that MERC can meet the forecast peak day for the upcoming winter season. With the planned city-gate purchase, the MERC Consolidated reserve margin moves from negative 1.13% to positive 0.67%.[6]

The Company also noted via footnote "that the purchase of city-gate delivered supply will not impact MERC's Demand entitlements or PGA demand costs." The Department notes that ratepayers will not be avoiding the cost of transporting the gas on Viking. Given that the transaction is for city-gate delivery, the transportation costs will be imbedded in the commodity costs.

[6] Petition Update, November 1, 2016, Attachment 1 Pages 13 -14.

The Department appreciates MERC's detailed explanation and work to make certain that ratepayers would not have a negative reserve margin during the December through February term, which is most likely to see the winter peak-usage day. It is concerning though that the Company was unable to secure Viking capacity for the winter potentially putting ratepayers at risk of not having reliable service. The Department recommends that the Commission require the Company to file a compliance filing to explain how, going forward, MERC plans to mitigate the risk of being unable to secure incremental winter capacity.

The Department recommends that the Commission accept MERC's demand entitlement and reserve margin proposal, and require the Company to provide additional information on how MERC will minimize the risk to ratepayers in securing incremental winter capacity going forward.

The Department notes that, in contrast to the electric utility industry, natural gas reserve margins are utility-specific rather than regionally specific, as more fully discussed in DOC Attachment 4. However, given Minnesota's efforts to expand natural gas use in under- and unserved areas, and the increasing use of natural gas for electricity generation, there is a growing need to more closely examine reserve margins and to integrate natural gas supply planning with electric resource planning. In light of this recognition, the Department has issued information requests (see DOC Attachment 5) and will review those responses, in addition to information provided in the annual service quality and annual automatic adjustment reports, to ascertain, among other things, the number and timing of interruptions (curtailments) that have occurred in the past 5 years, and the causes of those curtailments, as a first step in assessing whether the demand entitlements procured, including reserve margins in place at those times were sufficient or justified, and to begin monitoring the growing inter-relationship between the natural gas and electric industries.

B. THE COMPANY'S PGA COST RECOVERY PROPOSAL

In its *Update*, the Company compared its October 2016 PGA to its projected November 2016 PGA rates to highlight the changes in demand costs (see DOC Attachment 3). The Company's entitlement levels reflected in the Update would result in the following annual demand cost impacts:

- Annual bill decrease of $1.25 related to demand costs, or approximately 2.25 percent, for the average General Service-Residential customer consuming 75 Dth annually;
- Annual bill decrease of $9.97 related to demand costs, or approximately 2.25 percent, for the average Large General Service customer consuming 597 Dth annually;
- no demand cost impacts related to MERC-Consolidated's interruptible rate classes.

III. THE DEPARTMENT'S RECOMMENDATIONS

Based on our review, the Department recommends that the Commission approve MERC's *Petition*, as modified in its November 1, 2016 *Update* and November 16, 2016 *Letter*.

The Department also recommends that they Commission require MERC to submit, as a compliance filing within 10 days of the date of the Order in the present docket, an explanation regarding how MERC plans to mitigate the risk of being unable to secure incremental winter capacity on all pipelines through which MERC currently contracts for natural gas capacity.

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Department Attachment 1
Docket No. G011/M-16-651
MERC Consolidated Demand Entitlement Historical and Current Proposal

		Historical Demand Entitlements			Actual 11/1/16			
Great Lakes Gas Transmisssion	Contract #	2013-2014 Quantity (Mcf)	2014-2015 Quantity (Mcf)	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
FT Western Zone annual	FT0016	10,130	10,130	10,130	10,130	0		
FT Western Zone annual	FT15782	9,000	9,000	9,000	9,000	0		
FT Western Zone (12) annual	FT17891 (12)	3,600	3,600	3,600	3,600	0		
FT Western Zone (5) winter	FT17891 (5)	3,638	3,638	3,728	3,728	0		
FT Western Zone (5) winter	FT18283 (5)	0	0	3,300	3,350	50		
Total Great Lakes		**26,368**	**26,368**	**29,758**	**29,808**	**50**	**0.17%**	**4.43%**
Viking Gas Transmission								
FT-A Zone 1 - 1 annual	AF0012	12,493	12,493	12,493	12,493	0		
FT-A Zone 1 - 1 winter	AF0209	1,098	1,098	1,098	1,098	0		
FT-A Zone 1 - 1 annual	AF0102	2,000	2,000	2,000	2,000	0		
FA-A Zone 1 - 1 annual	AFXXXX*	1,500	0	1,000	0	(1,000)		
Total Viking		**17,091**	**15,591**	**16,591**	**15,591**	**(1,000)**	**-6.03%**	**4.60%**
Centra Transmission Holding/Centra Mn Pipelines								
Centra FT - 1 annual		9,500	9,500	9,100	9,500	400		
Total Centra		**9,500**	**9,500**	**9,100**	**9,500**	**400**	**4.40%**	**5.28%**
Total Entitlement		**52,959**	**51,459**	**55,449**	**54,899**	**(550)**	**-0.99%**	**4.62%**
Total Annual Transportation		**48,223**	**46,723**	**47,323**	**46,723**	**(600)**	**-1.27%**	
Total Winter Only Transport		**4,736**	**4,736**	**8,126**	**8,176**	**50**	**0.62%**	
Percent of Winter Only Capacity		8.94%	9.20%	14.65%	14.89%			

Source: MERC's Attachments 3 & 7

Department Attachment 2
Docket No. G011/M-16-651
MERC Consolidated 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)
2016-2017*	35,499	700	2.01%	55,528	2,453	4.62%	54,899	(550)	-0.99%	(629)	-1.13%
2015-2016	34,799	402	1.17%	53,075	4,369	8.97%	55,449	3,990	7.75%	2,374	4.47%
2014-2015	34,397	390	1.15%	48,706	(1,342)	-2.68%	51,459	(1,500)	-2.83%	2,753	5.65%
2013-2014	34,007	377	1.12%	50,048	(2,241)	-4.29%	52,959	(2,000)	-3.64%	2,911	5.82%
2012-2013	33,630			52,289			54,959				
Average			1.36%			1.66%			0.07%		3.70%

	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)
2016-2017*	unknown			-0.0177	1.5642	1.5465	unknown
2015-2016	42,679	(3,072)	-6.71%	0.0682	1.5252	1.5934	1.2264
2014-2015	45,751	6,845	17.59%	0.0800	1.4160	1.4960	1.3301
2013-2014	38,906			0.0856	1.4717	1.5573	1.1441
Average			17.59%	0.0780	1.4710	1.5489	1.2371

Source: MERC's Attachment 1

Department Attachment 3
Docket No. G011/M-16-651
MERC Consolidated Rate Impacts

General Service-Residential	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.8521	$3.1294	$3.2126	$3.0133	-21.78%	-3.71%	-6.20%	($0.1993)
Demand Cost	$0.7996	$0.8006	$0.7422	$0.7255	-9.27%	-9.38%	-2.25%	($0.0167)
Commodity Margin	$2.3980	$2.1806	$2.3980	$2.3980	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$7.0497	$6.1106	$6.3528	$6.1368	-12.95%	0.43%	-3.40%	($0.2160)
Average Annual Use	75	75	75	75				
Average Annual Cost of Gas*	$528.73	$458.30	$476.46	$460.26	-12.95%	0.43%	-3.40%	($16.20)

Large General Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.8521	$3.1294	$3.2126	$3.0133	-21.78%	-3.71%	-6.20%	($0.1993)
Demand Cost	$0.7996	$0.8006	$0.7422	$0.7255	-9.27%	-9.38%	-2.25%	($0.0167)
Commodity Margin	$1.8232	$1.6579	$1.8232	$1.8232	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$6.4749	$5.5879	$5.7780	$5.5620	-14.10%	-0.46%	-3.74%	($0.2160)
Average Annual Use	597	597	597	597				
Average Annual Cost of Gas*	$3,865.52	$3,335.98	$3,449.47	$3,320.51	-14.10%	-0.46%	-3.74%	($128.95)

SV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.8521	$3.1294	$3.2126	$3.0133	-21.78%	-3.71%	-6.20%	($0.1993)
Commodity Margin	$0.9336	$0.8490	$0.9336	$0.9336	0.00%	9.96%	0.00%	$0.0000
Total Cost of Gas	$4.7857	$3.9784	$4.1462	$3.9469	-17.53%	-0.79%	-4.81%	($0.1993)
Average Annual Use	5,443	5,443	5,443	5,443				
Average Annual Cost of Gas*	$26,048.57	$21,654.43	$22,567.77	$21,482.98	-17.53%	-0.79%	-4.81%	($1,084.79)

LV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.8521	$3.1294	$3.2126	$3.0133	-21.78%	-3.71%	-6.20%	($0.1993)
Commodity Margin	$0.5007	$0.4553	$0.5007	$0.5007	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$4.3528	$3.5847	$3.7133	$3.5140	-19.27%	-1.97%	-5.37%	($0.1993)
Average Annual Use	66,643	66,643	66,643	66,643				
Average Annual Cost of Gas*	$290,083.65	$238,895.16	$247,465.45	$234,183.50	-19.27%	-1.97%	-5.37%	($13,281.95)

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	($0.1993)	($0.0167)	($0.2160)	-3.40%	($16.20)
Large General Service	($0.1993)	($0.0167)	($0.2160)	-3.74%	($128.95)
SV Interruptible Service	($0.1993)	$0.0000	($0.1993)	-4.81%	($1,084.79)
LV Interruptible Service	($0.1993)	$0.0000	($0.1993)	-5.37%	($13,281.95)

* Average Annual Bill amount does not include customer charges.

Note: MERC updated Average Annual Use in the November 1 *Update* based on Annual Automatic Adjustment Report in Docket No. G999/AA-16-524.

Prepared by the Minnesota Department of Commerce

Attachment 4 – Natural Gas Reserve Margins

Below is a brief summary of the differences between the electric and natural gas industries in terms of setting reserve requirements, and the factors impacting how natural gas reserve margins are developed.

A retail natural gas distribution utility acquires the product demanded by its customers through contracting with a natural gas transmission pipeline company for certain levels of product for specified time periods. A vertically integrated electricity provider supplies most of its own product (through owned generation or purchased power agreements), relying on the non-contractual market [for Minnesota, the Midcontinent Independent System Operator (MISO)] when consumption exceeds the levels planned or outages prevent supply at the planned levels. Thus, the electric industry structure requires interdependency among market participants, necessitating a common reserve margin to ensure balanced reliance on the larger system.

A major factor differentiating electricity and natural gas is a greater availability of storage options for natural gas as opposed to electricity. For example, if natural gas utilities are aware in advance of a cold snap in weather, they may use “line pack” as a way to “store” natural gas temporarily in the pipe for use during the cold snap. Further, when natural gas consumption exceeds the levels planned or pipelines are damaged causing a loss of supply, natural gas utilities may turn to their own storage resources, propane or liquefied natural gas peaking plant capabilities, curtail natural gas supplied to interruptible customers, or seek to procure capacity release opportunities, if any exist at that time and location.

Moreover, there is not an energy market or independent system operator to dispatch resources, as there is in the electric industry, in part because the natural gas systems are less interdependent on each other. Therefore, reserve margins on the natural gas system are utility-specific rather than regionally specific.

Natural gas reserve margins are not only utility-specific, but there may in effect be different levels of reserve margins in different places on the natural gas utility’s system. That is, it may be misleading to consider one reserve margin as accurately reflecting the ability of the utility to supply natural gas. A utility may have what appears to be a reasonable overall reserve margin, but still experience curtailments at a certain Town Border Station (TBS) due to the inability to physically move available product to that location. Similarly, a utility may have what appears to be an unreasonably low reserve margin but still have large reserve margins at certain locations, with the flexibility (through a loop, for example) to move the excess gas to another location to avoid curtailments.

Appropriate natural gas reserve margins can be set using various methods. For instance, a natural gas reserve margin could be set equal to the output capability of a utility's propane or liquefied natural gas peaking plant because the function of that peaking plant is to provide product at times when demand exceeds pipeline supply. Therefore, it may be reasonable to set the reserve margin at the level of the peaking plant's capacity in order to ensure that peak demand is met should the peaking plant experience an outage. (This approach is called an "N minus one" approach.)

Natural gas utilities procure pipeline supply considering both minimum demand and peak demand. Minimum usage (minimum day load) on a winter day is estimated to ensure that base load gas acquired does not exceed the ability of the company to either use the gas for system load or to inject the gas into storage. The natural gas design-day calculation estimates the maximum firm demand anticipated under the most extreme weather conditions. The extent to which a utility procures entitlements in excess of its estimate of maximum firm demand may vary by utility depending on factors such as how much storage is in place, whether the utility has a peaking plant and the size of the plant, past experience, and expectation for load growth. Further, there may be a need to procure additional entitlements to meet design-day requirements, but the pipeline suppliers may not offer entitlements at the specific level needed. The excess amount procured could be considered, or proposed as, that utility's reserve margin, but the percentage represented by that reserve margin is not the result of a calculation; rather, it was dictated by the need to fulfill design-day needs. In other words, under certain circumstances a reserve margin may exceed the levels traditionally considered reasonable by the Commission, but be legitimately dictated by the availability of supply to meet the obligation to provide firm service.

At this time, the Commission should continue to determine the reasonableness of natural gas resources on a case-by-case basis.

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G999/AA-16-524	☐Nonpublic ☒Public
Requested From:	All regulated gas utilities	Date of Request: 3/10/2017
		Response Due: 3/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

Request Number: **18**
Topic: Distribution Planning

Request:

A. Please provide a detailed discussion of how the utility plans, constructs, and maintains its distribution system. As part of this response, include a discussion about how the utility decides to add capacity or expand in to new, or growing, service territory.
B. Please provide daily throughput data, by each individual Town Border Station (TBS) or delivery point, on the utility's system since November 1, 2012. If available, please provide these data divided by firm, interruptible, and transport load. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
C. Please provide the number of interruption days, by TBS or delivery point, by month since November 2012. To the extent possible, please identify the number of interruption days that are non-weather related (*e.g.,* reliability purposes). Please also provide these data in Microsoft Excel format with all links, and formulae intact.
D. Please provide, on a daily basis since November 1, 2012 by TBS or delivery point, the maximum deliverable throughput by customer type. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
E. Please provide, by TBS or delivery point, on a daily basis since November 1, 2012 the percentage of deliverable capacity subscribed by the utility. If applicable, please identify other parties, and their percentages of subscribed capacity, at the TBS. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
F. Please provide the following forecasted data, in Microsoft Excel format with all links and formulae intact, by TBS, or delivery point, for the next three heating seasons. If the utility expects daily fluctuation, please provide these data on a daily basis:
   a. Total utility throughput, if possible, divided by customer type (*i.e.*, firm, interruptible, transport); and
   b. Expected firm and total throughput available at the TBS or delivery point.
G. Please provide maps, by county, identifying the location (and name) of any, and all, TBSs or delivery points on the utility's system. If possible, please provide these maps in pdf and GIS executable formats.

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: G999/AA-16-524 ☐Nonpublic ☒Public
Requested From: All regulated gas utilities
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Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

a. Please identify, by county, on the maps in Part F, the location of any, and all, transmission assets on the utility's system.
b. If the utility has an affiliate transmission or intrastate pipeline utility, please also identify these assets on the maps provided in Part F, by county.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

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. G011/M-16-651

Dated this 2nd day of June 2017

/s/Sharon Ferguson

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