COMMERCE
DEPARTMENT

February 28, 2018

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

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G011/M-17-587

Dear Mr. Wolf:

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

> In the Matter of Minnesota Energy Resources Corporation's (MERC) Demand Entitlement Filing (Petition) for its Customers Served off of the Consolidated System.

The Petition was filed on August 1, 2017 by:

> Amber S. Lee
> Regulatory and Legislative Affairs Manager
> Minnesota Energy Resources Corporation
> Suite 200
> 1995 Rahncliff Court
> Eagan, Minnesota 55122

On November 1, 2017, MERC submitted its *November Update* (Update) and on January 8, 2018, MERC submitted its *Letter- Regarding Replacement Storage* (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, 2017. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/ja
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce Division of Energy Resources

Docket No. G011/M-17-587

I. SUMMARY OF THE UTILITY'S PROPOSAL

Pursuant to Minnesota Rules part 7825.2910, subpart 2, Minnesota Energy Resources Corporation (MERC or the Company), filed a petition on August 1, 2017 with the Minnesota Public Utilities Commission (Commission or PUC) to change the levels of demand for natural gas pipeline capacity (Petition) for is customers served off the Consolidated Purchased Gas Adjustment (PGA) system (MERC-Consolidated).[1] MERC requested that the Commission approve changes in the Company's recovery of overall level of contracted capacity.[2] 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).

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. On November 1, 2017, MERC filed its *November 1 Update* (Update). On January 8, 2018, MERC submitted its *Letter- Regarding Replacement Storage* (Letter).

MERC proposed to increase Great Lakes' 5-month capacity by 1,550 Dth.[3] The Company also increased Viking's 3-month capacity by 1,500 Dth. The net change to the design-day capacity is an increase of 3,050 Dth. As discussed further below, MERC's projected 2017-2018 design-day

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[1] In its December 21, 2012 Order in Docket No. G007,011/GR-10-977, the Commission approved consolidation of MERC's 4 Purchased Gas Adjustment (PGA) systems effective July 1, 2013. MERC named the PGA for the NNG 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." Pursuant to the Commission's Order in Docket No. G011/GR-15-736, the MERC-NNG and MERC NNG–Albert Lea PGAs were consolidated effective July 1, 2017. On August 1, 2017, MERC filed a demand entitlement request for MERC-NNG in Docket No. G011/M-17-588 (Docket 17-588).

[2] MERC noted in its August cover letter that any updated information would be provided with the Company's November 1, 2017 filing.

[3] Dekatherms.

requirements (overall needs of its firm customers on a design day) increased by 738 Dth (or approximately 1.33 percent) from the previous year.[4]

Using a similar design-day calculation methodology as has been used in the past, MERC proposed to increase its total design day by 1.33%.

The Company projected a 2.99% reserve margin for the upcoming heating season.

MERC estimated that its proposal would cause a decrease in rates for residential customers of $0.0651 per Dth or approximately $5.60 per year for customers assuming an annual usage of 86 Dth.

On January 8, 2018, MERC filed a *Letter* to provide notice that its contract demand would change effective April 1, 2018 due to the acquisition of a storage contract with ANR Pipeline Company (ANR Storage) for a four-year contract term. Because the change occurs April 1, 2018, it does not impact the design-day analysis in this docket. The Company has confirmed that it will provide updated analysis in the 2018-2019 Demand Entitlement filing. In addition, the costs of storage contracts are allocated to the commodity costs.

The Minnesota Department of Commerce, Division of Energy Resources (Department) discusses below the various effects of MERC's proposal on the Company's rates for different customer classes.

MERC requested that the Commission allow recovery of the associated demand costs in the Company's monthly PGA for each district effective November 1, 2017.

In Section II below, the Department's analysis of the Company's request includes the following areas:

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

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[4] See Tables below.

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

A. MERC'S PROPOSED CHANGES

1. Capacity

As an initial matter, the Department confirms that, as required by the Commission's Order Point 9[5] 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.[6]

As indicated in Table 1 below and Department Attachments 1 and 2, MERC's capacity purchases for the 2017 through 2018 heating season reflect an increase in its total entitlement level by 3,050 Dth as follows:

Table 1: MERC's Consolidated Total Entitlement Levels

November 1, 2017 Filing	2016-2017 Entitlement (Dth)	2017-2018 Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Year (%)
Centra	9,500	9,500	0	0.00%
Great Lakes	29,808	31,358	1,550	5.20%
Viking	15,591	17,091	1,500	9.62%
Total Consolidated	54,899	54,899	3,050	5.56%

MERC increased capacity this winter as compared to the prior year by 1,550 Dth and 1,500 Dth for Great Lakes and Viking, respectively. The increase in total capacity was driven by the Company's ability to secure Viking capacity that was not available the prior year. The Company stated in their Update the following:[7]

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[5] 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."
[6] See MERC Attachment 3.
[7] Petition at pages 4-5.

> The increase on Great Lakes Gas Transmission is due to a higher peak day forecast than in the previous year. The reserve margin on Viking Gas Transmission was negative in 2016-2017 due to a lack of available forward haul capacity. However, for 2017- 2018, MERC was able to secure back haul capacity from the interconnect with Northern Natural Gas pipeline at Chisago. This is firm capacity and satisfies the peak day requirements on Viking Gas Transmission.

2. *Compliance with December 5, 2017 Order in Docket No. G011/MR-17-564*

On September 29, 2017 in Docket No. G011/MR-17-564 (Docket 17-564) MERC requested that the Commission approve a new base cost of gas (BCOG) to coincide with the proposed January 1, 2018 implementation of interim rates requested in Docket No. G011/GR-17-563 (Docket 17-563). MERC filed its general rate case on October 13, 2017, two weeks later than its BCOG petition.

On October 23, 2017, the Department filed comments in Docket 17-564 recommending that the Commission approve MERC's BCOG petition and require MERC to provide updates to the base cost of gas in that proceeding as well as certain additional information in other dockets.

On December 5, 2017 the Commission issued its *Order Setting New Base Cost of Gas for Interim Rate Period* in Docket No. 17-564.

The Commission in its December 5, 2017 *Order Setting New Base Cost of Gas for Interim Rate Period* in Docket No. 17-564, Ordering point 5 stated the following:

> MERC shall reconcile its demand costs in its November update in Docket Nos. G-011/M-17-587 and G-011/M-17-588 with the October 1 Purchased Gas Adjustment filed in Docket No. G011/AA-17-703. MERC shall explain any changes and provide this information as a supplement to Docket Nos. G-011/M-17-587 and G-011/M-17-588.

The Department concludes that MERC has complied with the December 5, 2017 Order issued in Docket No. 17-564 by providing the reconciliation in its November Update in docket 17-588.

In the Commission's December 5, 2017 Order issued in Docket No. 17-564, Ordering points 6 and 7 stated the following:

> MERC shall provide detailed information on the status of the [Alberta Energy Company] AECO storage contract replacement in the November update in Docket No. G-011/M-17-587 as a supplement to that docket.
>
> MERC shall also provide in the November update in Docket No. G-011/M-17-587 an updated explanation of its plan to use system baseload and spot market quantities to cover the quantities from the AECO storage contract that MERC decided to release for the remaining term of the contract.

In its *Letter*, MERC stated the following:[8]

> Effective April 1, 2018, MERC has contracted for a new ANR storage contract to replace the AECO/Niska Storage contract that expires April 30, 2018. As discussed in this filing, because the change will be effective April 1, 2018, there will be no impact to MERC's design-day demand and no revised design-day demand by customer class is being submitted with this filing. Additionally, the ANR Storage contract will not affect usage during the remainder of the current demand period because MERC will only inject into storage during the summer months and not use it to meet customer load.
>
> Upon release of the Niska contract, the Company explored various sources and alternatives to provide a storage solution for MERC Consolidated customers. This evaluation yielded two viable options; physical storage in Michigan that could be back-hauled on Great Lakes or synthetic storage in Michigan or at Emerson that would act as storage. Synthetic storage in this case was a winter call option that was priced at the previous summer's indices; which provides a product that operationally and financially looks like physical storage. Ultimately, the Company selected a physical storage option with ANR Pipeline Company beginning April 1, 2018.

[8] Letter at pages 1-4.

> The ANR Storage Contract will have an annual cost of $531,032 compared to the previous Niska Storage Contract annual cost of $489,996. The newly contracted service will directly bring gas to MERC Consolidated customers via Great Lakes and Viking, so offers significant operational benefits over the prior Niska arrangement.
>
> The cost impact of the change to the MERC Consolidated demand entitlements will be an increase of $0.00374/therm beginning April 1, 2018, as compared to MERC's November 1, 2017 Demand Entitlement filing reflecting the released Niska Storage Contract. Updated Attachment 4 (page 1 and 3) and Attachment 8 are included with this filing.

The Department concludes that MERC has complied with the December 5, 2017 Order issued in Docket No. 17-564 by providing the detailed information on the AECO storage contract replacement in its *Letter* in the instant docket.

In addition, in its *Letter*, MERC stated the following:[9]

> As discussed above, MERC released the Niska Storage Contract effective May 1, 2017 and has entered into the ANR Storage Contract effective April 1, 2018. For the 2017-2018 gas year, MERC replaced the AECO/Emerson swap with a combination of baseload supplies and physical calls. **There is no reduction in operational flexibility or reliability as a result of this replacement, as the lack of MERC contracted pipeline capacity connecting Niska Storage to load removed the typical flexibility associated with Company held physical storage.** The baseload and physical call purchases that replace the AECO/Emerson swap were transacted at Emerson and ensure that MERC Consolidated customers receive the same level of reliability as in the past.

Given that MERC purchased the baseload supplies and physical calls for the duration of the current heating season that have the same level of reliability as in the past and the fact that the Company will have ANR storage in the future as a replacement for its AECO storage contract, the Department concludes that MERC complied with the December 5, 2017 Order issued in Docket No. 17-564.

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[9] Id.

Entitlement levels are discussed in further detail in the reserve margin section below.

B. DESIGN-DAY REQUIREMENTS

As provided in Table 2 below and Department Attachment 2, MERC proposed to increase its total design day by 738 Dth as follows:

Table 2: MERC's Consolidated Design-Day Levels

August 1, 2016 Filing	2016-2017 Design Day (Dth)	2017-2018 Design Day (Dth)	Design-Day Changes (Dth)	Change From Previous Year (%)
Centra	9,132	8,928	(204)	-2.23%
Great Lakes	29,808	30,457	649	2.18%
Viking	16,588	16,881	293	1.77%
Total Consolidated	55,528	56,266	738	1.33%

MERC used a similar approach to what it 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 for the customers in the service area.[10]

MERC obtained the daily large volume transportation, interruptible and joint interruptible volumes by pipeline and weather station (Data A). In addition, MERC obtained the daily small volume interruptible volumes by pipeline and weather station (Data B). MERC calculated the daily firm volumes by subtracting both Data A and Data B from the total throughput volumes.

[10] See discussion at pages 4-5 of the Department's October 15, 2015 comments in Docket No. G011/M-15-722.

In addition, MERC made some adjustments to its data for its regression analysis. In its Petition MERC stated the following:[11]

> 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, it was not included in the regressions.

In its Petition, MERC also stated the following:[12]

> The **Data Preparation** Steps consisted of:
>
> - Identify the coldest Adjusted Heating Degree Day (AHDD) for the time period January 1996-December 2016 for each weather station. Note, this is a change in practice from prior analysis that used a rolling 20-year period. The change was included because many weather stations experienced historically cold weather in the January/February 1996 time period and without inclusion of that additional data from January/February 1996, AHDD were materially lower and not reflective of MERC's capacity needs.

To the Department's knowledge, MERC's prior design-day analyses have relied on the coldest days from 1996. In any event, the Department agrees with MERC that it would not be acceptable to use a rolling 20-year weather period in the design-day calculations when planning for the Company's capacity needs in meeting the design-day.

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 10, stated in part the following:

> Required MERC to verify its regression analysis results in future demand entitlement filings to ensure the results are consistent with the underlying theory the analysis attempts to explain.

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[11] August 1, 2017 Filing and the *November 1, 2017 Update*, Attachment 12 at page 3.
[12] Id.

In its Petition, MERC stated the following:[13]

> Order Point 10 of the Commission's April 28, 2016, Order in Docket No. G011/M-15-723 required that MERC verify its regression analysis results in future demand entitlement filings to ensure the results are consistent with the underlying theory the analysis attempts to explain. MERC has carefully reviewed the results of its regression analysis and verified that the results are consistent with the underlying theory the analysis attempts to explain. Please see MERC's May 31, 2016, compliance filing in Docket Nos. G011/M-15-722, G011/M-15 723, and G011/M-15-724 for further discussion of this issue.

Thus, MERC complied with the Commission's April 28, 2016 Order described above.

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.

Given the fact that MERC must plan for its design day, MERC's approach does not seem unreasonable. As a result, the Department recommends that the Commission approve the Company's peak-day analysis.

C. TELEMETRY

On April 28, 2016, the Commission issued its Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724 for the 2015-2016 heating season (2016 Order). In the 2016 Order, Ordering point 13 states:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data

[13] August 1, 2017 Filing and the *November 1, 2017 Update*, Attachment 12 at page 9.

> from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

On December 6, 2017, the Commission issued its Order in Docket Nos. G011/M-16-650, G011/M-16-651, and G011/M-16-652 for the 2016-2017 heating season (2017 Order). In the 2017 Order, Ordering point 4 states:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions.

Please see pages 7 – 15 of the Department's January 29, 2018 Comments in Docket No. G011/M-17-588 for our response to the Commission's above requests.

D. PROPOSED RESERVE MARGIN

As shown in Table 3 below and Department 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 1, 2017 Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	2017 Reserve Margin %	2016 Reserve Margin %	Percentage Point Change From Previous Year
Centra	9,500	8,928	572	6.41%	4.03%	2.38%
Great Lakes	31,358	30,457	901	2.96%	0.00%	2.96%
Viking	17,091	16,881	210	1.24%	(6.01)%	7.25%
Total Consolidated	57,949	56,266	1,683	2.99%	(1.13)%	4.12%

The Department notes that, as a result of MERC being able to secure the additional capacity on Great Lakes and Viking, the reserve margin has improved from a negative reserve margin to a positive margin representing an increase of 4.12 percentage points. In addition, the future ANR storage will "directly bring gas to MERC consolidated customers via Great lakes and Viking, so offers significant operational benefits over the prior Niska arrangement".[14] Thus, these changes when considered on an overall basis, improve the reliability of the MERC-Consolidated system.

In its 2017 Order, Ordering point 3 states:

> Required MERC to submit 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, as a supplement to its change in demand entitlements filings for the 2017-2018 heating season, within 10 days of the date of this Order; and

In its December 15, 2017 Compliance Filing submitted in the instant docket, MERC stated in part the following:

> … In general, there is limited risk of MERC of [*sic*] being unable to obtain incremental winter capacity as needed, with the exception of situations of physical constraints where interstate pipeline upgrades are required to obtain additional capacity, in which case MERC would most likely know, and be able to plan in advance for such a situation.
>
> There are various alternative supply strategies that can be used when capacity is not available on an unconstrained pipeline. MERC has two main options for meeting its peak day requirements when capacity is not available: (1) purchase city gate delivered supply; and (2) purchase back-haul capacity. MERC has similar options on all pipelines it uses including Northern Natural Gas ("NNG"), Viking Gas Transmission Pipeline, Great Lakes Gas Transmission, and Centra. In cases where a physical inadequacy of capacity prevents MERC from effectively serving a peak load, upgrades to the pipeline must take place as in the case of the Rochester Expansion Project.
>
> In terms of the capacity on the Viking Gas Transmission pipeline, until the 2016/2017 winter, MERC had been purchasing incremental volumes of forward-haul capacity from Emerson to MERC city gates to cover the annual peak day forecast. In 2016,

[14] Letter at page 3.

> market conditions changed so that Viking capacity from Emerson to the east gained value and was, therefore, fully subscribed. To compensate, MERC purchased city gate delivered baseload supplies to meet its peak day requirement during the 2016/2017 winter. Firm baseload purchases are as reliable as MERC purchasing gas at Emerson and shipping it to the city gate on its own transport and customers were not put at a greater risk of supply disruption during a peak day event.
>
> For the upcoming 2017/2018 winter season MERC obtained firm "back-haul" capacity on Viking to meet its incremental peak day needs for the upcoming heating season. Back-haul capacity allows for the movement of gas counter to the traditional direction of flow on the pipe through displacement. This capacity is not more or less firm that forward-haul capacity and provides the same level of protection against a peak day.
>
> In summary, the current unavailability of firm, forward-haul capacity on the Viking pipeline is no indication of the ability of the pipeline to meet interconnected load, but rather the result of economic conditions, and MERC has secured backhaul capacity on Viking and as a whole MERC has sufficient capacity to cover its peak day load requirements for its Consolidated PGA for the 2017/2018 heating season.

The Department concludes that MERC complied with Commission's 2017 Order as described above. The Department recommends that the Commission accept MERC's demand entitlement and reserve margin proposal.

In general, 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 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 Attachment 5) and intends to follow-up with the utilities to ask for updated information. The Department 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 may be occurring, 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 continue monitoring the growing inter-relationship between the natural gas and electric industries.

E. THE COMPANY'S PGA COST RECOVERY PROPOSAL

MERC failed to update its comparison of costs (as shown in Attachment 4 of the Petition) to the October PGA in its *November Update* and instead kept the comparison to the July 2017 PGA costs.

In Attachment 3 page 2 of these comments, the Department compares MERC's October 2017 PGA to MERC's projected November 2017 PGA rates to highlight the changes in demand costs. According to the Department's calculations, the Company's demand entitlement proposal would result in the following annual demand cost impacts:

- annual bill increase of $0.77 related to demand costs, or less than 0.15%, for the average General Service customer consuming 86 Dth annually;
- annual bill increase of $5.61 related to demand costs, or approximately 0.17%, for the average Large General Service customer consuming 623 Dth annually; and
- no demand cost impacts related to MERC-NNG's interruptible rate classes.

III. THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission approve MERC's Petition, as modified in its *November Update*, the *Letter,* and Department Attachment 3 page 2.

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Department Attachment 1
Docket No. G011/M-17-587
MERC Consolidated Demand Entitlement Historical and Current Proposal

					Estimated 11/1/17			
Great Lakes Gas Transmisssion	**Contract #**	2014-2015 Quantity (Mcf)	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	2017-2018 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	3,728	3,728	3,728	0		
FT Western Zone (5) winter	FT18283 (5)	0	3,300	3,350	4,900	1,550		
Total Great Lakes		**26,368**	**29,758**	**29,808**	**31,358**	**1,550**	**5.20%**	
Viking Gas Transmission								
FT-A Zone 1 - 1 annual	AF0012	12,493	12,493	12,493	15,591	3,098		
FT-A Zone 1 - 1 winter	AF0209	1,098	1,098	1,098	0	(1,098)		
FT-A Zone 1 - 1 annual	AF0102	2,000	2,000	2,000	0	(2,000)		
FA-A Zone 1 - 1 annual	AFXXXX	0	1,000	0	1,500	1,500		
Total Viking		**15,591**	**16,591**	**15,591**	**17,091**	**1,500**	**9.62%**	
Centra Transmission Holding/Centra Mn Pipelines								
Centra FT - 1 annual		9,500	9,100	9,500	9,500	0		
Total Centra		**9,500**	**9,100**	**9,500**	**9,500**	**0**	**0.00%**	
Total Entitlement		**51,459**	**55,449**	**54,899**	**57,949**	**3,050**	**5.56%**	**1.33%**
Total Annual Transportation		**46,723**	**47,323**	**46,723**	**49,321**	**2,598**	**5.56%**	
Total Winter Only Transport		**4,736**	**8,126**	**8,176**	**8,628**	**452**	**5.53%**	
Percent of Winter Only Capacity		9.20%	14.65%	14.89%	14.89%			

Source: MERC's Attachments 3 & 7

Department Attachment 2
Docket No. G011/M-17-587
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)
2017-2018	35,965	466	1.31%	56,266	738	1.33%	57,949	3,050	5.56%	1,683	2.99%
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)
2017-2018	unknown			0.0468	1.5645	1.6113	unknown
2016-2017	48,796	6,117	14.33%	-0.0177	1.5642	1.5465	1.3746
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-17-587
MERC Consolidated Rate Impacts

General Service-Residential	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.8521	$2.6791	$2.9088	8.57%	-24.49%	8.57%	$0.2297
Demand Cost	$0.7996	$0.7996	$0.7996	$0.7345	-8.14%	-8.14%	-8.14%	($0.0651)
Commodity Margin	$2.4116	$2.3980	$2.4116	$2.4116	0.00%	0.57%	0.00%	$0.0000
Total Cost of Gas	$5.8903	$7.0497	$5.8903	$6.0549	2.79%	-14.11%	2.79%	$0.1646
Average Annual Use	86	86	86	86				
Average Annual Cost of Gas*	$506.57	$606.27	$506.57	$520.72	2.79%	-14.11%	2.79%	$14.16

Large General Service	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.8521	$2.6791	$2.9088	8.57%	-24.49%	8.57%	$0.2297
Demand Cost	$0.7996	$0.7996	$0.7996	$0.7345	-8.14%	-8.14%	-8.14%	($0.0651)
Commodity Margin	$1.6885	$1.8232	$1.6885	$1.6885	0.00%	-7.39%	0.00%	$0.0000
Total Cost of Gas	$5.1672	$6.4749	$5.1672	$5.3318	3.19%	-17.65%	3.19%	$0.1646
Average Annual Use	623	623	623	623				
Average Annual Cost of Gas*	$3,219.17	$4,033.86	$3,219.17	$3,321.71	3.19%	-17.65%	3.19%	$102.55

SV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.8521	$2.6791	$2.9088	8.57%	-24.49%	8.57%	$0.2297
Commodity Margin	$0.9740	$0.9336	$0.9740	$0.9740	0.00%	4.33%	0.00%	$0.0000
Total Cost of Gas	$3.6531	$4.7857	$3.6531	$3.8828	6.29%	-18.87%	6.29%	$0.2297
Average Annual Use	7,637	7,637	7,637	7,637				
Average Annual Cost of Gas*	$27,898.72	$36,548.39	$27,898.72	$29,652.94	6.29%	-18.87%	6.29%	$1,754.22

LV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.8521	$2.6791	$2.9088	8.57%	-24.49%	8.57%	$0.2297
Commodity Margin	$0.5329	$0.5007	$0.5329	$0.5329	0.00%	6.43%	0.00%	$0.0000
Total Cost of Gas	$3.2120	$4.3528	$3.2120	$3.4417	7.15%	-20.93%	7.15%	$0.2297
Average Annual Use	71,526	71,526	71,526	71,526				
Average Annual Cost of Gas*	$229,741.51	$311,338.37	$229,741.51	$246,171.03	7.15%	-20.93%	7.15%	$16,429.52

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	$0.2297	($0.0651)	$0.1646	2.79%	$14.16
Large General Service	$0.2297	($0.0651)	$0.1646	3.19%	$102.55
SV Interruptible Service	$0.2297	$0.0000	$0.2297	6.29%	$1,754.22
LV Interruptible Service	$0.2297	$0.0000	$0.2297	7.15%	$16,429.52

* 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

Department Attachment 3
Docket No. G011/M-17-587
MERC Consolidated Rate Impacts - Department Calculations

General Service-Residential	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.0133	$2.8664	$2.8664	6.99%	-4.88%	0.00%	$0.0000
Demand Cost	$0.7996	$0.7255	$0.7255	$0.7345	-8.14%	1.24%	1.24%	$0.0090
Commodity Margin	$2.4116	$2.1806	$2.4116	$2.4116	0.00%	10.59%	0.00%	$0.0000
Total Cost of Gas	$5.8903	$5.9194	$6.0035	$6.0125	2.07%	1.57%	0.15%	$0.0090
Average Annual Use	86	86	86	86				
Average Annual Cost of Gas*	$506.57	$509.07	$516.30	$517.08	2.07%	1.57%	0.15%	$0.77

Large General Service	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.0133	$2.8664	$2.8664	6.99%	-4.88%	0.00%	$0.0000
Demand Cost	$0.7996	$0.7255	$0.7255	$0.7345	-8.14%	1.24%	1.24%	$0.0090
Commodity Margin	$1.6885	$1.6579	$1.6885	$1.6885	0.00%	1.85%	0.00%	$0.0000
Total Cost of Gas	$5.1672	$5.3967	$5.2804	$5.2894	2.36%	-1.99%	0.17%	$0.0090
Average Annual Use	623	623	623	623				
Average Annual Cost of Gas*	$3,219.17	$3,362.14	$3,289.69	$3,295.30	2.36%	-1.99%	0.17%	$5.61

SV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.0133	$2.8664	$2.8664	6.99%	-4.88%	0.00%	$0.0000
Commodity Margin	$0.9740	$0.8490	$0.9740	$0.9740	0.00%	14.72%	0.00%	$0.0000
Total Cost of Gas	$3.6531	$3.8623	$3.8404	$3.8404	5.13%	-0.57%	0.00%	$0.0000
Average Annual Use	7,637	7,637	7,637	7,637				
Average Annual Cost of Gas*	$27,898.72	$29,496.39	$29,329.13	$29,329.13	5.13%	-0.57%	0.00%	$0.00

LV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6791	$3.0133	$2.8664	$2.8664	6.99%	-4.88%	0.00%	$0.0000
Commodity Margin	$0.5329	$0.4553	$0.5329	$0.5329	0.00%	17.04%	0.00%	$0.0000
Total Cost of Gas	$3.2120	$3.4686	$3.3993	$3.3993	5.83%	-2.00%	0.00%	$0.0000
Average Annual Use	71,526	71,526	71,526	71,526				
Average Annual Cost of Gas*	$229,741.51	$248,095.08	$243,138.33	$243,138.33	5.83%	-2.00%	0.00%	$0.00

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	$0.0000	$0.0090	$0.0090	0.15%	$0.77
Large General Service	$0.0000	$0.0090	$0.0090	0.17%	$5.61
SV Interruptible Service	$0.0000	$0.0000	$0.0000	0.00%	$0.00
LV Interruptible Service	$0.0000	$0.0000	$0.0000	0.00%	$0.00

* 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.
The BCOG column reflects MERC's 11-30-16 Compliance Filing and the Commision's *February 13, 2017 Order* in Docket No. G011/GR-15-736.
The 'Last Demand Change on 11/1/16' column reflects information from MERC's November 1, 2016 PGA filing in Docket No. G011/AA-16-878.
The 'Most Recent PGA on 10/1/17' column reflects information from MERC's October 1, 2017 PGA filing in Docket No. G011/AA-17-702.

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 Natural Gas Utilities	Date of Request: 11/8/2017
Type of Inquiry:	General	Response Due: 11/20/2017

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

Request Number: **22**
Topic: Distribution Planning
Reference(s): Department Information Request No. 18

Request:

Please provide the above reference, including any and all subparts, updated to the most recent date available.

If this information has already been provided in the application or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s).

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	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
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

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
Comments

Docket No. G011/M-17-587

Dated this 28th day of February 2018

/s/Sharon Ferguson

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