MINNESOTA PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	May 17, 2018		Agenda Item # *1
Company	Minnesota Energy Resources Corporation (MERC)		
Docket Nos.	**G-011/M-17-587 (Consolidated PGA area)** **G-011/M-17-588 (Northern Natural Gas (NNG) PGA area)** **In the Matter of the Petitions of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for the Consolidated (17-587) and Northern Natural Gas (17-588) PGA areas**		
Issues	Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements for the 2017-2018 Heating Season for its Consolidated and NNG PGA areas, effective November 1, 2017?		
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✓ **Relevant Documents** **Date**

Docket No. G-011/M-17-587 (Consolidated PGA area)

MERC – Initial Petition and Schedules	August 1, 2017
MERC – Revised Petition and Updated Schedules	November 1, 2017
MERC – Demand Entitlement Compliance Filing	December 15, 2017
MERC – Letter Regarding Replacement Storage	January 8, 2018
Department of Commerce (Department)	February 28, 2018
MERC – Reply Comments	March 8, 2018

Docket No. G-011/M-17-588 (NNG PGA area)

MERC – Initial Petition and Schedules	August 1, 2017
MERC – Revised Petition and Updated Schedules	November 1, 2017
MERC – Demand Entitlement Compliance Filing	December 15, 2017

✓ **Relevant Documents** | **Date**

Relevant Documents	Date
Department – Comments	January 29, 2018
MERC – Reply Comments and Attachments	February 20, 2018
Department – Response to Reply Comments	March 8, 2018

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

I. Statement of the Issues

Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements for the 2017-2018 Heating Season for its Consolidated and NNG PGA areas, effective November 1, 2017?

II. Background

MERC has entered into interstate pipeline contracts (demand entitlements) that permit it to provide retail natural gas sales services. [1] MERC annually reviews and updates these contracts to ensure continued system reliability of its natural gas supply. MERC's annual 2017/2018 demand entitlement petitions request Commission approval to recover certain cost and capacity changes in the entitlements, and to implement the rate impact of these changes through its Purchased Gas Adjustment (PGA) charges.[2]

MERC's two PGA areas are:

- MERC-NNG PGA area - This area includes all of MERC's customers in the old Peoples Natural Gas (PNG) and Northern Minnesota Utilities (NMU) service areas and the Interstate Power & Light (IPL) customers located in the Albert Lea area, that receive delivered natural gas through the Northern Natural Gas Pipeline Company (NNG), an interstate pipeline.[3]
- MERC-Consolidated PGA area - This area includes all of MERC's customers that receive delivered natural gas either through the Viking Gas Transmission (VGT), or Great Lakes Gas Transmission (GLGT), or Centra interstate pipelines.

PUC staff reviewed MERC's 2017-2018 Demand Entitlement petitions, and the *Comments* filed by the Department and MERC. The Department and MERC have resolved the majority of issues raised by the Department. The Department recommended to the Commission that it approve MERC's 2017-2018 demand entitlement petitions for both the NNG and Consolidated PGA areas.

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[1] D*emand entitlements* can be defined as reservation charges paid by the Local Distribution Company (LDC) to an interstate natural gas pipeline to reserve pipeline capacity used to store and transport the natural gas supply for delivery to its system and contract charges associated with the LDC procuring its gas supply; these costs are recovered through the LDC's PGA.

[2] The Purchased Gas Adjustment is a mechanism used by regulated utilities to recover its cost of energy. Minn. Rules 7825.2390 through 7825.2920 enable regulated gas and electric utilities to adjust rates on a monthly basis to reflect changes in its cost of energy delivered to customers based upon costs authorized by the Commission in the utility's most recent general rate case.

[3] MERC's NNG and NNG-Albert Lea PGA areas were consolidated into one PGA area on July 1, 2017, pursuant to the Commission's October 31, 2016 Order*, Order-Findings of Facts Conclusions, and Order*, in Docket No. 15-736.

PUC staff generally agrees with the Department's recommendations, but provides additional discussion for the Commission to consider.

For these briefing papers, PUC staff combined MERC's two PGA areas into one discussion, but discusses issues related to a particular PGA area separately.

III. Minnesota Rules

Minnesota Rule, part 7825.2910, subpart 2 requires gas utilities to make a filing whenever there is a change to its demand-related entitlement services provided by a supplier or transporter of natural gas. [4]

IV. Parties' Comments

1. MERC

Pursuant to Minnesota Rules part 7825.2910, subpart 2, MERC filed its 2017/2018 demand entitlement petition on August 1, 2017 and updated its petitions on November 1, 2017. MERC further updated the Docket No. 17-588 petition in its February 20, 2018 Reply Comments. MERC requests Commission approval to recover certain demand cost changes through its PGA mechanism, effective November 1, 2017, for both MERC-NNG PGA area (Docket No. 17-588) and MERC-Consolidated PGA area (Docket No. 17-587).

a. Design Day Requirements

MERC's Design Day requirements calculation in these petitions is similar to the process that it used in previous demand entitlement filings. MERC performed its regression analysis by interstate pipeline and weather station. Because of its telemetry program, MERC was able to perform its regression analysis with daily-metered retail firm sales and interruptible customer data, except for the old Albert Lea customers.[5] MERC calculated its 2017-2018 design-day requirements at 324,049 Dth/day (an increase of 6,463 Dth/day from MERC's 2016-2017 demand entitlement petition), see Table 1, Columns 2 and 3.

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[4] Filing upon a change in demand, is included in the Automatic Adjustment of Charges rule parts 7825.2390 through 7825.2920 and requires gas utilities to file to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.

[5] Approved by the Commission in Docket No. 08-835, MERC's 2008 general rate case, see the Commission's June 29, 2009 Order.

b. MERC's Demand Entitlement Contract Levels

To transport its design-day requirements, MERC uses a series of interstate pipeline contracts (for both transportation and storage services) for each of its PGA areas, i.e. demand entitlements. The 2017-2018 transportation demand entitlement contract levels were modified from the previous year's levels (2016-2017), which results in 324,266 Dth/day of available interstate pipeline transportation capacity (see Table 2, Column 2), an increase of 3,050 Dth/day, see Table 2, Column 3.[6]

MERC-Consolidated's capacity was modified by 3,050 Dth/day by increasing demand entitlement by 1,500 Dth/day on Viking and 1,550 Dth/day on Great Lakes. MERC-NNG's capacity was not altered from the 2016/2017 transportation demand entitlement levels, with the exception of its TF-12 Base and Variable transportation demand entitlement costs, but not the actual entitlement levels.[7]

In Docket No. 17-588, MERC proposed to increase its NNG's FDD storage cycle volume from a total of 1,200,000 Dth in 2016/2017 to 1,500,000 Dth in 2017/2018. MERC will utilize this incremental storage to ensure supply price and reliability during the winter heating season.

c. MERC's Reserve Margin

The Reserve Margin is the difference between MERC's transportation demand entitlements and design-day requirements. MERC stated that its reserve margin in each PGA area is appropriate given the need to balance the uncertainty of design-day conditions, customer demand during these peak conditions, and the need to protect against firm gas supply loss to maintain system reliability, see Table 3, Column 2 (by PGA area) and Table 4, Column 4 (by interstate pipeline).

2. Department

The Department reviewed MERC's proposed design-day requirements, demand entitlements, calculated reserve margins, and the miscellaneous changes that occurred since MERC's 2016-2017 demand entitlement petitions.

a. Design Day Requirements

The Department summarized MERC's proposed 2017-2018 design-day requirements by PGA area, for a total increase of 6,463 Dth/day, see Table 1:

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[6] This includes both MERC's NNG and Consolidated PGA areas.

[7] NNG's tariff permits it to adjust the TF-12 Base and Variable contract components on an annual basis.

Table 1 – MERC's Design Day requirements (Dth/day):

PGA area	2016-2017 Design Day	2017-2018 Design Day	Difference	% increase/ (decrease)
	(1)	(2)	(3)	(4)
MERC-Consolidated	55,528	56,266	738	1.33%
MERC-NNG[8]	262,058	267,783	5,725	2.18%
Total	317,586	324,049	6,463	2.04%

The Department noted that MERC's design-day calculation was similar to MERC's previously used process. MERC's model included the use of daily metered interruptible data, except the old Albert Lea customers.[9] MERC first used the daily interruptible data in its 2015-2016 demand entitlement petitions (represented the first year that 3-years of data was available).[10] The Department noted MERC modified its design-day calculation from using its 20-year rolling average method for heating degree days. Instead, MERC expanded its 20-year average to include the 1995/1996 winter season which represents MERC's coldest winter. The Department concluded that this change was appropriate to use when forecasting MERC's design-day.

The Department believed MERC's design-day approach was not unreasonable and recommended that the Commission approve MERC's peak-day analysis.

b. Demand Entitlement Levels

The Department summarized MERC's proposed changes to its 2017-2018 demand entitlement requirements and Reserve Margin levels, see Tables 2, 3, and 4.

Table 2 – Demand Entitlements requirements (Dth/day):

PGA area	2016-2017	2017-2018	Difference	% increase/ (decrease)
	(1)	(2)	(3)	(4)
MERC-Consolidated	54,899	57,949	3,050	5.56%
MERC-NNG	266,317	266,317	0	0.00%
Total	321,216	324,266	3,050	0.95%

[8] Includes the MERC-Albert Lea demand entitlements for both 2016/2017 and 2017/2018 demand entitlements petitions.

[9] In the Company's 2008 rate case, in Docket No. 08-835, MERC was ordered to incorporate in its interruptible tariff, language that required all interruptible customers to upgrade their meters that would provide daily interruptible throughput data.

[10] However, MERC's old Albert Lea PGA area does not have three-year's daily metered interruptible data available.

[PUC staff note: The transportation demand entitlements reflected in Table 2 do not include the 50,000 Mcf/d Bison and NBPL interstate pipeline contracts (these contracts are "upstream" from NNG).]

c. MERC's Reserve Margin

Table 3 – Reserve Margin Comparison by PGA area (Dth/day):

PGA area	2016-2017 Demand Entitlement Filing	2017-2018 Demand Entitlement Filing	Difference
	(1)	(2)	(3)
MERC-Consolidated	(1.13%)	2.99%	4.12%
MERC-NNG	1.63%	(0.55%)	2.18%

Table 4 – 2017/2018 Design-Day requirements, Demand Entitlements, and Reserve Margin by interstate pipeline (Dth/day):

PGA Area	Design-Day Requirements	Demand Entitlements	Difference	Reserve Margin
	(1)	(2)	(3)	(4)
Consolidated				
Viking	16,881	17,091	210	1.24%
GLGT	30,457	31,358	901	2.96%
Centra	8,928	9,500	572	6.41%
Total Consolidated	56,266	57,949	1,683	2.99%
NNG	267,783	266,317	(1,466)	(0.55%)
Total	324,049	324,266	217	0.07%

The Department also prepared a comparison of reserve margins from 2012/2013 demand entitlement petition to the 2017/2018 demand entitlement petition for the NNG PGA area.

Table 5: MERC's Reserve Margins by PGA area:

Demand Entitlement Period	NNG Reserve Margin %	Consolidated Reserve Margin %
2017/2018	(0.55%)	2.99%
2016/2017	1.632%	(1.13%)
2015/2016	2.79%	4.47%
2014/2015	2.44%	5.65%
2013/2017	4.52%	5.82%
2012/2013	3.50%	5.11%

The Department noted that MERC's reserve margin has been consistently below its preferred five percent margin,[11] but stated that MERC's 2017/2018 negative reserve margin is not reasonable. As a result, the Department requested MERC to respond to information requests.

In response to information request no. 1, MERC stated:

> MERC will continue to monitor weather forecasts and in the event of a potential peak day, will call upon all interruptible customers to curtail their usage and will purchase city-gate delivered gas for the period such supplies are needed (i.e., likely over a short term during the peak day event). The Company will be proactive in its approach with the full understanding of the current capacity situation and that it must act in a conservative manner with respect to the timing and volume of such a purchase.
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> The calculated negative reserve margin amounts to approximately 500 Dth. However, as discussed in MERC's response to Department Information Request No. 3, MERC utilized a conservative peak day estimate for the communities of Esko and Balaton for the 2017/2018 heating season; if MERC had utilized more moderate peak day estimates for these two new communities, the resulting reserve margin would have been slightly higher – closer to 0% but would not have affected the Company's contracted demand entitlements as filed.
>
> The alternative to proceeding with a very small negative reserve margin for the 2017-2018 heating season would have been to enter into a five year capacity contract with NNG at maximum tariffed rates. MERC concluded that in light of the calculated reserve margin and anticipated timing of additional Rochester capacity, entering into a five year contract for additional capacity would not be prudent or in the best interest of customers.[12]

The calculated negative reserve margin amounts to approximately 500 Dth. However, as discussed in MERC's response to Department Information Request No. 3, MERC utilized a conservative peak day estimate for the communities of Esko and Balaton for its 2017/2018 NNG PGA area petition (Docket No. 17-588).

The Department further commented that MERC's demand entitlement petitions reflected numerous errors and misstatements.[13] As a result, the Department requested MERC to provide

[11] In previous dockets, the Department has stated that a Reserve Margin range is between 5%-7%.

[12] See the Department's January 29, 2018 Comments, pp. 17-20.

[13] Ibid, pp. 20-22.

in reply comments certain corrections and omitted information. The Department withheld its final recommendation until it reviewed MERC's reply comments.

In its reply comments, MERC corrected the information and schedules that the Department requested.[14]

In its February 28, 2018 and March 8, 2018 comments, the Department concluded that each of MERC's PGA areas' design-day calculations, transportation demand and storage entitlements and reserve margin calculations were not unreasonable. The Department recommended the Commission approve MERC's peak-day analysis and demand entitlement levels and allow MERC to recover associated demand costs through the monthly PGA effective November 1, 2017.

V. Department Recommendations

a. MERC-Consolidated

The Department recommends that the Commission approve MERC's 2017/2018 Demand Entitlement Petition, as modified by MERC in its November 1, 2017 Update, the January 8, 2018 Letter regarding storage contracts, and the Department's February 28, 2018 Comments, Attachment 3, page 2.

b. MERC-NNG

The Department recommended that the Commission accept MERC's proposed demand entitlement level and allow MERC to recover associated demand costs through the monthly PGA effective November 1, 2017.

VI. PUC Staff Analysis

Staff reviewed MERC's 2017-2018 demand entitlement petitions and appreciates the parties' comments. Even though the Department's analysis uncovered numerous omissions and errors within the petitions, staff believes that most of the relevant factors and all issues were resolved.[15]

MERC's numerous errors and omissions of information caused both the Department and staff additional time in the preparation of its comments and staff briefing papers - staff questions whether this is an efficient use of time. For its 2018/2019 demand entitlement petitions, the Commission may wish to direct MERC to exercise caution in the preparation of its petitions to avoid the complications discovered in the 2017/2018 petitions.

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[14] See MERC's February 20, 2018 Reply Comments, pp. 1-12.

[15] See the Department's February 28, 2018 Comments (Consolidated), and the January 29, 2018 Comments and March 8, 2018 Reply Comments (NNG).

Staff is in agreement with the Department that the NNG negative reserve margin is not a business practice in which a natural gas utility should engage, but MERC's situation is a little different. Starting in November 1, 2018, a portion of the additional NNG capacity approved by the Commission in Docket No. 15-895 (the Rochester Project) will go into service (an additional 15,939 Dth/day). In addition, on November 1, 2019, the second portion of NNG capacity will go into service, thus creating more surplus NNG capacity (an additional 37,093 Dth/day for a total of 53,032 Dth/day). Staff agrees with MERC that it would not be prudent to enter into another NNG capacity contract, the additional NNG Rochester capacity should be sufficient to produce a positive reserve margin in the 2018/2019 demand entitlement petition for the NNG PGA area (see the below discussion).

Staff has summarized MERC's design-day requirements and transportation demand entitlements in ***Appendix A*** and its transportation demand entitlement costs in ***Appendices B and C*** for both PGA areas.

Staff notes that in its October 31, 2016 Order in Docket No. 15-736,[16] the Commission approved MERC's request to consolidate its MERC-NNG and MERC-NNG Albert Lea PGA areas (effective July 1, 2017). MERC has consolidated these PGA areas and that consolidation is reflected in Docket No. 17-588.[17] Docket No. 17-587 (MERC's Consolidated PGA area) was not affected by the consolidation.

PUC staff generally agrees with the Department's recommendations, but provides additional discussion for Commission consideration.

A. Has MERC complied with previous Commission Order requirements?

The Commission's August 6, 2014 Order in Docket Nos. 07-1402, 07-1403, 07-1404, and 07-1405, MERC agreed to include daily estimated use in its design-day models – MERC addressed this information in its petition's Attachment 9. Further, MERC agreed to include average customer counts - MERC addressed this information in its petition's Attachment 10. Staff believes MERC has complied.

The Commission's January 30, 2015 Order in Docket Nos. 10-1166, 10-1167, 10-1168, and 10-1169, required MERC to provide a clarification of its statements regarding system balancing and detailed evidence assuring the Commission that the appropriate customer group is paying for any balancing charges or penalties. MERC's 2017/2018 demand entitlement petitions include evidence of MERC's allocation of balancing costs to the commodity portion of the PGA – see Attachment 4, page 2. Staff believes MERC has complied.

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[16] MERC's last general rate case.
[17] Further, MERC noted that the consolidation of these PGA areas is reflected in its monthly July 2017 PGA filing.

In the April 28, 2016 Order in Docket Nos. 15-722, 15-723, and 15-724, the Commission required MERC to address certain concerns in future demand entitlement petitions.

- Order Point 8 - Required MERC to explain changes made in its compliance petitions that are different from its original petitions, and provide a red-line version of both petitions identifying changes. Staff believes MERC has complied.

- Order Point 9 - Required MERC to separate its summer and winter demand entitlements in its petitions – see MERC's petition, Attachment 3. The Department reviewed MERC's petition and confirmed MERC has complied. Staff agrees with the Department.

- Order Point 10 - 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. The Department noted that MERC appropriately corrected its design-day model for autocorrelation. The Department concluded that MERC had complied with the Commission's requirements. Staff agrees with the Department conclusions.

- Order Point 11 – If the Commission approves MERC's general rate case proposal to consolidate its MERC-NNG and MERC-Albert Lea PGA areas into one PGA area (Docket No. 15-736), direct MERC to work with the Department in developing an appropriate Design Day regression analysis methodology for its subsequent demand entitlement petitions until MERC has three years daily interruptible data available for all its interruptible customers for the consolidated NNG PGA area. Staff believes MERC has complied.

As directed by the Commission's April 28, 2016 Order, MERC worked with the Department to develop an appropriate design-day regression methodology for Docket No. 17-588. Prior to MERC's purchase of the Albert Lea area, the Albert Lea interruptible customer meters did not measure quantities on a daily basis. MERC has since converted these customer's meters to similar meters located in MERC's old NNG PGA area. Until MERC has the necessary three years of daily metered interruptible data for all of its NNG PGA area interruptible customers, MERC intends to utilize the same methodology it had utilized prior to having telemetry equipment for its other interruptible customers (MERC estimated that this methodology will be applicable for another two years).

- Order Point 13 - 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 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.

For the Department's discussion of Ordering Point 13, see the Department's January 29, 2018 Comments in Docket No. 17-588, pp. 11-15.

In the December 6, 2017 Order in Docket Nos. 16-650, 16-651, and 16-652, the Commission required MERC to address certain concerns in future demand entitlement petitions.

- Order Point 3 - 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.

For both petitions, MERC submitted its compliance filing explaining its plans to mitigate the risk of being unable to secure incremental winter capacity on pipelines currently serving MERC. Generally, MERC believes that there is limited risk of being unable to obtain incremental winter capacity as needed, with the exception of where physical constraints exists (such as Rochester) and interstate pipeline upgrades would be required to obtain additional capacity.[18]

MERC claims that there are various alternative supply strategies that can be used when capacity is not available on a pipeline. MERC's two primary options: (1) purchase city-gate delivered supply; and (2) purchase back-haul capacity. MERC believes it has these options on all pipelines providing it service.[19]

For Docket No. 17-587, MERC chose to enter into a back-haul arrangement with Viking that provided additional capacity to serve its customers served off this interstate pipeline. In addition, MERC purchased additional Great Lakes capacity to serve its customers served off this interstate pipeline.

For Docket No. 17-588, MERC did not modify its demand entitlement levels from the levels approved by the Commission in MERC's 2016/2017 demand entitlement petitions, except NNG's annual determination of TF-12 Base and Variable classification.

For situations where pipeline capacity is not available and interstate pipeline expansion is necessary to meet peak-day requirements, MERC would negotiate with interstate pipelines to construct new facilities to meet its needs. MERC believes the Rochester project is an example of when interstate pipeline expansion is necessary. MERC concluded that its negative NNG reserve margin is not unreasonable considering the forthcoming Rochester capacity. MERC does not believe entering into a separate five-year contract for capacity to produce a positive NNG reserve margin would be prudent (Docket No. 17-588).

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[18] See MERC's December 15, 2017 Compliance Filing in these dockets, 17-587 and 17-588.

[19] Includes NNG, Viking, Great Lakes, and Centra.

- Order Point 4 - 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.[20]

In Docket No. 17-588, the Department included a summary of how other natural gas utilities use metered daily interruptible data in the design-day development. Included were Great Plains, CenterPoint Energy, Xcel-Gas, and Greater Minnesota Gas, see the Department's January 29, 2018 Comments, pp. 11-15.

B. Has MERC complied with the Commission's Order requirements in Docket Nos. 17-563 and 17-564 (MERC's current general rate case)[21]

In Docket No. 17-564 (filed on September 29, 2017), 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. 17-563 (filed on October 13, 2017). The Commission's December 5, 2017 Order required that MERC provided certain information in its 2017/2018 demand entitlement petitions (Docket No. 17-587 and 17-588). The Commission required:

- Ordering Point 5 - 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. G-011/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.
- Ordering Point 6 - MERC shall provide detailed information on the status of the AECO storage contract replacement in the November update in Docket No. G-011/M-17-587 as a supplement to that docket.
- Ordering Point 7 - 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.

For Ordering Point 5, the Department concluded that MERC complied with the December 5, 2017 Order by providing the reconciliation in its November 1, 2017 Update, Attachment 3. Staff agrees with the Department's conclusion.

For Ordering Point 6 and 7, MERC notified the Commission that its AECO Storage (Niska Gas Storage) contract had been released for the remainder of the contract term (contract

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[20] Ibid.

[21] See the Commission's December 5, 2017 Order, *Order-Setting New Base Cost of Gas for Interim Period,* p. 3.

terminated April 30, 2018).[22] MERC stated that system conditions made the storage contract operationally difficult to use during the 2017/2018 winter heating season. MERC was unable to obtain take-away transportation capacity to deliver natural gas to the MERC-Consolidated PGA area. MERC noted that it relied on greater use of baseload and spot gas purchases to replace the storage service in the short-term, but planned to contract for replacement storage.[23]

On January 8, 2018, MERC entered into a four-year storage contract with ANR Storage which replaced the AECO contract, effective April 1, 2018 (the beginning of the injection cycle). MERC asserts that the ANR storage did not impact the 2017/2018 demand entitlement levels or costs, but will be included in MERC's 2018/2019 demand entitlement petition.[24]

The Department concluded that MERC complied with the Commission's Order dated December 5, 2017 in Docket Nos. 17-563 and 17-564 (MERC's general rate case) given that during the 2017/2018 winter heating season, MERC was able to purchase adequate baseload gas supply and physical calls to maintain the same level of reliability as in the past. Staff agrees with the Department's conclusions.

C. Should the Commission Approve MERC's ANR Storage Contract in the 2017/2018 Demand Entitlement Petition (Docket No. 17-587), or require MERC to File a Separate Petition Seeking Approval of the ANR Contract, or in the alternative, require MERC to seek approval in its next 2018/2019 Demand Entitlement Petition?

MERC is requesting Commission approval for the proposed ANR storage entitlements, and to allow cost recovery through the Consolidated PGA starting April 1, 2018.[25] MERC compared several gas supply strategies before selecting the ANR option.[26] The injection cycle associated with the ANR contract began April 1, 2018, but MERC states it will not be using the storage capacity until the withdrawal cycle starting at November 1, 2018. Essentially, MERC is requesting pre-approval of the ANR contract in the 2017/2018 demand entitlement petitions.

The Commission generally does not pre-approve cost recovery for interstate pipeline transportation and storage contracts absent a statutory or rule based requirement that requires the Commission to do so.[27] Gas utilities routinely enter into precedent agreements

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[22] Filed in its April 20, 2017 update in Docket 16-651. The release was for May 1, 2017 to April 30, 2018.
[23] MERC contacted several storage providers and had high level discussions regarding the availability and viability of various options. In addition to physical storage, MERC considered the potential benefits of a synthetic storage service.
[24] See MERC's January 8, 2018 Letter, pp. 1-4.
[25] Minn. R. 7825.2910, Subp. 2, requires that 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.
[26] See Department's February 28, 2018 Comments in Docket No. 17-587, pp. 4-6.
[27] The only pipeline contracts the Commission pre-approved (that staff is aware of) are the agreement between Xcel (NSP) and Viking when both companies were under common ownership. Minn. Stat.

without prior approval from the Commission.[28] The Commission's normal review process for demand entitlement contracts occurs at the same time as the review of the demand entitlement filings that gas utilities make pursuant to Minn. Rules, part 7825.2910, subpart 2. These filings are typically made once a year on or about August 1 (later updated on November 1) to coincide with the start of the winter heating season and the interstate pipeline's contract year. When changes occur at other times during the year, the utilities file approval requests at the same time as the changes occur in the contract levels.

Pursuant to Minn. Rules, part 7825.2920, subpart 1, the PGA rates used to recover the cost of these contracts "are provisionally approved and may be placed into effect without Commission action." In exchange for being authorized to immediately recover the cost of these contracts from ratepayers without pre-approval, these arrangements are subject to after-the-fact prudence and reasonableness reviews, as are all other automatically recovered gas costs, in the demand entitlement dockets, the annual true-up filing dockets, and the review of the annual automatic adjustment reports.

Previously, MERC has requested pre-approval of demand entitlement contracts, in Docket No. 08-698 (Bison and Northern Borders Pipeline (NBPL)) and in Docket No. 15-895 (Rochester Expansion Project). In Docket No. 08-698, the Commission chose not to take action because no statute or rule required the contracts to be pre-approved. In Docket No. 15-895, Minn. Stat. § 216B.1638 (2016) – the Recovery of Natural Gas Extension Project (NGEP) Costs required the Commission to approve the contract between MERC and NNG because the project provided natural gas service to unserved or inadequately served areas – in this case, the City of Rochester and surrounding areas where MERC was deficient in capacity.

Staff questions whether MERC is prematurely requesting Commission approval of its ANR storage contract. The 2017/2018 demand entitlement petitions were originally filed on August 1, 2017 and subsequently updated on November 1, 2017 – so these petitions did not include the ANR storage contract. From this docket's record, staff is unsure whether the Department and other parties had the necessary information to render an informed recommendation.

If the Commission decides to approve the ANR storage contract in Docket No. 17-587, which would be a deviation from the normal regulatory framework, the result may reduce MERC's risk associated with entering these types of contracts and increase its customers risk, and could further result in lessening MERC's incentive to negotiate the best cost gas supply arrangements for its customers. By reducing MERC's associated business risk, the Return on Equity in its next general rate case (Docket No. 17-563) may need to be adjusted downward to account for the reduced risk.

216B.48 and Minnesota Rule 7825.2200(B) required the Commission to approve the affiliated agreement between related parties. To staff's knowledge, MERC and ANR are not affiliated.

[28] For example, the Commission did not formally approve the precedent agreements CPE, Xcel, and others entered into with Northern Natural Gas Company ("NNG" or "Northern Natural") as part of NNG's Northern Lights expansion project.

Staff believes that the Commission may wish to exercise caution when deciding whether to approve MERC's ANR storage contract in this docket (Docket No. 17-587). If the Commission chooses to approve the ANR storage contract in Docket No. 17-587, staff suggests the Commission limit its approval to the specific, unique circumstances present in this filing, and indicate that the Commission does not intend to routinely pre-approve these types of agreements.

D. Other Capacity Changes to MERC-Consolidated

In the 2017/2018 demand entitlement petition, MERC contracted for additional Great Lakes capacity of 1,550 Dth/day and for additional Viking capacity of 1,500 Dth/day (MERC-Consolidated PGA area (for a total of 3,050 Dth/day)).[29] The Great Lakes increase is caused by a higher peak-day forecast than in the 2016-2017 demand entitlement petition. Further, in its 2016-2017 demand entitlement petition, MERC's Viking reserve margin was negative, caused by the lack of forward-haul capacity. In this petition, MERC secured NNG back-haul capacity (upstream capacity) delivered to Viking (downstream capacity) at the Chisago interconnection. MERC believes that this back-haul capacity satisfies the Viking peak-day requirements for MERC's-Consolidated PGA area.

Staff reviewed MERC's proposed MERC-Consolidated capacity modifications and believes the additional capacity is justified and reasonable.

[29] There were two changes to the Viking capacity from the 2016/2017 demand entitlement petition, MERC increased Contract FT-A AF0012 by 2,000 Dth/day, while decreasing Contract FT-A AF0102 by 500 Dth/day (1,500 Dth/day net change).

VII. Decision Options

MERC-Consolidated

1. Approve MERC's peak-day analysis for the Consolidated PGA area.

2. Approve MERC's 2017/2018 Demand Entitlement Petition's costs and entitlement levels, as modified by MERC in its November 1, 2017 Update, the January 8, 2018 Letter regarding storage contracts, and the Department's Comments, Attachment 3, page 2.

3. Allow MERC to recover the associated demand costs through its monthly PGA effective November 1, 2017.

MERC-NNG

4. Approve MERC's peak-day analysis for the NNG PGA area.

5. Approve MERC's 2017/2018 Demand Entitlement Petition's costs and entitlement levels, as modified by MERC in its February 20, 2018 Reply Comments.

6. Allow MERC to recover associated demand costs through the monthly PGA effective November 1, 2017.

MERC's ANR Storage Contract

7. Grant MERC's request for advance approval of its ANR storage contract, effective April 1, 2018, in Docket No. 17-587.

8. Deny MERC's request.

9. Dismiss MERC's request without prejudice.

10. Take no action.

Additional Decision Options

11. Direct MERC to exercise caution in the preparation of its 2018/2019 demand entitlement petitions to avoid the complications in the review of the 2017/2018 petitions.

Transportation Demand Entitlements Changes

MERC-Consolidated	16-651	17-587	Difference
	(1)	(2)	(3)
	Mcf	Mcf	Mcf
			(2) - (1)
GLGT FT FT0016	10,130	10,130	0
GLGT FT (12) FT0155	0	0	0
GLGT FT (5) FT0155	0	0	0
GLGT FT FT15782	9,000	9,000	0
GLGT FT (12) FT17891	3,600	3,600	0
GLGT FT (5) FT17891	3,728	3,728	0
GLGT FT (5) FT18462	3,350	4,900	1,550
VGT FT-A AF0012	12,493	14,493	2,000
VGT FT-A AF0209	1,098	1,098	0
VGT FT-A AF0102	2,000	1,500	(500)
VGT FT-A AF0229	0	0	0
VGT FA-A	0	0	0
Wadena Delivered Option	0	0	0
Centra FT-1	9,500	9,500	0
Total Demand Entitlements	54,899	57,949	3,050
Total DD Requirements	55,528	56,266	738
Surplus/Deficient	(629)	1,683	2,312
Reserve Margin	**-1.13%**	**2.99%**	

Transportation Demand Entitlements Changes

MERC-NNG	16-650		17-588	Difference
	(1)		(2)	(3)
	Mcf		Mcf	Mcf
				(2) - (1)
TF-12 Base and Variable	84,709	1/	84,709	0
TF5	36,275	1/	36,275	0
TFX-12	32,297		32,297	0
TFX-5	109,501	1/	109,501	0
Bison	50,000		50,000	0
NBPL	50,000		50,000	0
Northwest Gas (Windom)	2,500		2,500	0
NW Energy (Ortonville)	1,035		1,035	0
NNG Zone Delivery Call Opt	0		0	0
Total Demand Entitlement	266,317		266,317	0
Total DD Requirements	262,058		267,783	5,725
Surplus/Deficient	4,259		(1,466)	(5,725)
Reserve Margin	**1.63%**		**-0.55%**	

1/ Includes Albert Lea's 2016/2017 Demand Entitlements.

[PUC staff note: The Bison and NBPL are used to deliver Rockies supply into NNG - does not add incremental capacity deliveries for MERC's design-day demand entitlements.]

Transportation Demand Entitlements PGA Costs, as adjusted

MERC-Consolidated	16-651	17-587	Difference
	(1)	(2)	(3)
	$	$	$
			(2) - (1)
VGT FT-A AF0012	655,223	760,117	104,894
VGT FT-A AF0209	14,397	14,397	0
VGT FT-A AF0102	109,457	19,668	(89,789)
VGT FT-A AF0229	0	0	0
VGT FA-A	0	0	0
Wadena Delivery Option	0	0	0
GLGT FT FT0016	467,886	467,886	0
GLGT FT (12) FT0155	0	0	0
GLGT FT (5) FT0155	0	0	0
GLGT FT FT15782	415,693	415,693	0
GLGT FT (12) FT17891	166,277	166,277	0
GLGT FT (5) FT17891	71,746	71,746	0
GLGT FT (5) FT18462	64,471	94,301	29,830
Balancing Service	0	0	0
Centra FT-1	1,269,253	1,269,253	0
Centra MN Pipelines	376,086	376,086	0
Total Demand Entitlement	**3,610,489**	**3,655,424**	**44,935**

Transportation Demand Entitlements PGA Costs

MERC-NNG	16-650		17-588	Difference	
	(1)		(2)	(3)	
	$		$	$	
				(2) - (1)	
TF-12 Base and Variable	8,361,576	1/	8,248,205	(113,371)	2/
TF5	2,748,375	1/	2,748,375	0	
TFX-12	2,955,980		2,955,980	0	
TFX-5	8,110,875	1/	8,110,875	0	
Bison	10,493,760		10,493,760	0	
NBPL	4,197,480		4,197,480	0	
TFX 112486	11,366		11,366	0	
TFX 112486	11,366		11,366	0	
TFX7 111866	0		0	0	
Windom	0		0	0	
Ortonville	103,560		103,560	0	
NNG Zone GDD Call Option	0		0	0	
LSP Peaking Service	0		0	0	
Total Demand Entitlement	**36,994,338**		**36,880,967**	**(113,371)**	

Summary of Transportation demand entitlement costs-all PGA areas

PGA Area	16 Total Costs		17 Total Costs	Difference	
	(5)		(6)	(7)	
	$		$	$	
				(6) - (5)	
MERC-Consolidated (NMU)	3,610,489		3,655,424	44,935	
MERC-NNG (PNG)	36,994,338	1/	36,880,967	(113,371)	2/
Total Demand Entitlement	**40,604,827**		**40,536,391**	**(68,436)**	

1/ Includes Albert Lea's 2016/2017 Demand Entitlement PGA Costs.
2/ Represents NNG's Annual November 1 Adjustment for its TF-12 Base and Variable Contracts.

MERC

PUC staff Adjusted 2017/2018 Demand Entitlement Cost

MERC-Consolidated

Contract Type	Contract Number	Monthly Entitlement	Months	Rate	Contract Costs
	(1)	(3)	(4)	(5)	(6)
		Dth		$	$
Viking (VGT)					
FT-A Zone 1 - 1	AF0012	14,493	12	4.3706	$ 760,117
FT-A Zone 1 - 1	AF0012	1,098	3	4.3706	$ 14,397
FT-A Zone 1 - 1	AFXXX	1,500	3	4.3706	$ 19,668
	.				
Total VGT Demand					$ 794,182
Great Lakes (GLGT)					
FT Western Zone	FT0016	10,130	12	$3.8490	$ 467,886
FT Western Zone	FT18528	9,000	12	$3.8490	$ 415,693
FT Western Zone (12)	FT18528 (12)	3,600	12	$3.8490	$ 166,277
FT Western Zone (5)	FT18528 (5)	3,728	5	$3.8490	$ 71,746
FT Western Zone (5)	FTXXXX (5)	4,900	5	$3.8490	$ 94,301
Total GLGT Demand					$ 1,215,903
Centra					
Conversion (103M3 x Rate(C$ 103M3)		9,500	12	$11.1338	$ 1,269,253
CENTRA MINNESOTA PIPELINES		9,500	12	$3.2990	$ 376,086
Total Centra Demand					$ 1,645,339
Total MERC-Consolidated					$ 3,655,424

MERC-NNG

TF12B (Max Rate) Winter	112495	49,219	5	$ 10.2300	$2,517,552
TF12B (Max Rate) Summer	112495	49,219	7	$ 5.6830	$1,957,981
TF12V (Max Rate)	112495	30,290	12	$ 9.0926	$3,304,978
TF5 (Max Rate)	112495	36,275	5	$ 15.1530	$2,748,375
TF12B (Discount-Winter)	112495	5,200	12	$ 7.4951	$467,694
TFX5 (Discount)	112561	0	5	$ -	$0
TFX12 (Max Rate)	112486	10,822	12	$ 9.6288	$1,250,434
TFX Apr (Max Rate)	112486	2,000	1	$ 5.6830	$11,366
TFX Oct (Max Rate)	112486	2,000	1	$ 5.6830	$11,366
TFX5 (Max Rate)	112486	82,688	5	$ 15.1530	$6,264,856
TFX5 (Discount)	112486	1,800	5	$ 10.0320	$90,288
TFX12 (Discount)	111866	1,283	12	$ 4.8640	$74,886
TFX12 (Discount)	111866	8,271	12	$ 5.4720	$543,107
TFX12 (Discount)	111866	11,921	12	$ 7.6025	$1,087,553
TFX5 (Discount)	111866	379	5	$ 4.8640	$9,217
TFX5 (Discount)	111866	2,445	5	$ 5.4720	$66,895
TFX5 (Discount)	111866	22,189	5	$ 15.1392	$1,679,619
Bison	FT0003	50,000	12	$ 17.4896	$10,493,760
NBPL	T8673F	50,000	12	$ 6.9958	$4,197,480
Total NNG					$36,777,407
Northwestern Energy		1,035	12	$ 8.3382	$103,560
Total MERC-NNG					$36,880,967
Total Demand Entitlement Costs					$ 40,536,391

Bison and NBPL are recovered through the commodity PGA charge pursuant to Docket No. 10-1166-68