MINNESOTA PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**February 5, 2025**		**Agenda Item 3***
Company	Minnesota Energy Resources Corp.		
Docket No.	G-011/M-25-68		
	In the Matter of Minnesota Energy Resources Corp.'s Petition for Approval of a Change in Demand Entitlement for its NNG System		
Issues	Should the Commission approve Minnesota Energy Resources Corp.'s Petition for a Change in Demand Entitlement for its NNG System?		
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✓**Relevant Documents**	**Date**
Minnesota Energy Resources Corp. – Compliance Filing	August 1, 2025
Department of Commerce – Comments	September 2, 2025
Minnesota Energy Resources Corp. – Reply Comments	September 12, 2025
Minnesota Energy Resources Corp. – Compliance Filing Update	October 31, 2025
Department of Commerce – Letter	December 16, 2025
Minnesota Energy Resources Corp – Response to Letter	December 23, 2025

Table of Contents

I. Background

On August 1, 2025, Minnesota Energy Resources Corp. (MERC or the Company), filed its Petition for approval of a Change in Demand Entitlement for its Northern Natural Gas (NNG) System.

On September 2, 2025, the Department of Commerce, Division of Energy Resources (Department) filed Comments, in which it recommended approval of the Company's Design-Day analysis; but withheld its final recommendations pending MERC's Reply Comments and update about NNG's rate case at the Federal Energy Regulatory Commission (FERC).

On September 12, 2025, MERC filed Reply Comments in agreement with the Department's recommendation on the Design-Day analysis. The Company further agreed with the Department's recommendation to provide an update regarding NNG's, rate case at the FERC.

On October 31, 2025, MERC filed a compliance update per the Department's request in its September 2, 2025 Comments.

On December 16, 2025, the Department filed a letter with recommendation for approval of the Company's petition.

On December 23, 2025, MERC filed a response letter in agreement with the Department's recommendation for approval of its petition.

II. Discussion

A. MERC – Petition

1. Filing Upon Change in Demand

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NNG, a subsidiary of WEC Energy Group, petitioned the Commission for approval of changes in demand entitlements for MERC-NNG customers served off the Northern Natural Gas interstate pipeline system.[1] Additionally, MERC requested the Commission approve the changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2025.

MERC addressed compliance with the Commission's May 8, 2018 Order in Docket No. G-011/M-15-895, which required MERC to provide a discussion of any capacity substitutions in its annual demand entitlement filings, and Ordering Paragraphs 9 and 10 from the Commission's February 17, 2023 Order in Docket Nos. G-999/CI-21-135 and G-011/CI-21-611.[2]

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[1] MERC's Petition, Docket # G-011/M-25-68; at 3 (Introductory Section page #).

[2] Ordering Paragraph 9 requires discussion of how changes to pipeline capacity affects the Company's supply diversity, and if pipeline capacity comes at a cost premium but increases supply diversity, provide a meaningful

2. MERC's NNG Design-Day Requirements

Minnesota Rule 7825.2910, subpart 2(b) requires that a filing upon change in demand includes the utility's Design-Day demand by customer class and the change in Design-Day demand, if any, necessitating the demand revision. MERC noted that the NNG Design-Day requirement has increased by 7,009 dekatherms (Dth), or 2.4%, from the 2024-2025 heating season.[3] For the Demand Entitlement filing effective November 1, 2025, the total Design-Day requirement for MERC-NNG is 297,178 Dth[4]. The difference between the total Design-Day requirement and total Design-Day capacity results in a 7.76% reserve margin.[5] MERC observed that as required by Ordering Paragraph 9 of the Commission's Order in Docket No. G011/M-15-723, Attachment 3 reflects the separate summer and winter demand entitlements for MERC-NNG. These are indicative of MERC's compliance with prior Commission Orders.

3. MERC's Proposed NNG System Demand-Related Changes

The first type of the two demand entitlement changes is Design-Day Deliverability, which quantifies the amount of firm transportation and storage capacity available to MERC's NNG customers during winter peak periods. The second type does not affect Design-Day Deliverability levels but alters the capacity portfolio and the PGA costs recovered from customers.[6]

a. Design-Day Deliverability Changes

MERC noted that its MERC-NNG's net Design-Day deliverability is unchanged from 2024-2025, as shown in Attachment 3. The Commission's February 17, 2023 Order in Docket Nos. G-999/CI-21-135 and G-011/CI-21-611, requires in Ordering Paragraph 9 that MERC discuss how changes to pipeline capacity affects the Company's supply diversity, and if pipeline capacity comes at a cost premium but increases supply diversity, provide a meaningful cost/benefit analyses of the tradeoff, including a comparison with the least-cost capacity option. The Company stated that it does not have any change to net design-day deliverability for 2025-2026, as compared to 2024-2025.[7]

b. Other Demand Entitlement Changes

MERC asserted that MERC-NNG contract 112495 has a base and a variable component as

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cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option. Ordering Paragraph 10 requires MERC to include in its relevant, annual forward-looking gas planning or hedging filings: A) its expected supply mix across different load and weather conditions throughout each month of the upcoming winter season, B) the forecasted minimum, average, and maximum day load requirements, and C) the expected mix of baseload, storage, and spot supply on those days.

[3] MERC's petition; at 2.

[4] *Id*; at 3 and Attachment 1.

[5] *Id*.

[6] *Id*; at 5.

[7] *Id.*

outlined in the NNG's tariffs approved by FERC. The base and variable components are set each year because of MERC's use of contract 112495 during the May – September period, which is driven by customer load. The variable component of this contract increased by 4,153 Dth/day,[8] with a corresponding decrease in the base component. This change does not result in an increase or decrease in demand entitlement levels.

4. Financial Option Units and Premiums

The Company noted that it has started its purchases of future contracts and call options for the 2025-2026 winter period. Financial hedge volumes and costs are shown in Attachments 5 and 11 (pages 1 and 3). The physical forward start and call option premium costs additionally flow through the spreadsheet in Attachment 4, pages 1 and 2, and in Attachment 8.

<u>The NNG 2025-2026 Winter Portfolio Hedging Plans</u> - Minnesota Energy Resources Corporation gas supply purchases are shown in Attachment 6. MERC's hedging strategy covers 60% of normal winter volumes; 30% through physical storage; and 30% through financial instruments (10% futures and 20% options). The weighted average price of currently purchased futures contracts of natural gas for the 2025-2026 winter is $4.6172/Dth.[9]

MERC projected the NNG storage Weighted Average Cost of Gas (WACOG) to be $2.8223/Dth, an increase from last winter WACOG. While the Company continued with its strategy to purchase call options around a $0.10/Dth premium, the overall gas market volatility has continued to keep the strike price of the purchased call options up to an average of $11.0565/Dth. The Company stated that if the NYMEX contract(s) settle above that price, the options are exercised, and MERC customer gas cost is capped at the average strike price. The remaining winter volumes are purchased at index or market prices. All numbers reflected are natural gas costs only and do not include any transportation, storage, hedge premium, or margin costs.[10]

The Commission's February 17, 2023 Order in Docket Nos. G-999/CI-21-135 and G-011/CI-21-611, required that MERC includes in its relevant, annual forward-looking gas planning or hedging filings:

A) its expected supply mix across different load and weather conditions throughout each month of the upcoming winter season,
B) B) the forecasted minimum, average, and maximum day load requirements, and
C) the expected mix of baseload, storage, and spot supply on those days.

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[8] *MERC's Petition; at 5.*

[9] MERC's Petition; pp 6-7.

[10] *Id* at 7.

Attachment 6, page 3, provides this information for the November 2025 through March 2026 period. The Company pointed out that load estimates are based on the previous three years observed data, except for the December through February months, in which the Design Day (i.e. Peak Day) was used to represent the maximum load.

5. Impacts of Telemetry

The Company noted that throughout the year, a number of customers request to switch from interruptible to firm service. MERC evaluates these requests to determine the impact to its system and upstream entitlement levels. Prior to a customer switch, the system capability is evaluated. Consequently, the firm volumes associated with a customer switch fall within the Design-Day parameters and do not impact demand entitlement levels.

6. Rochester Project Compliance

The Commission's May 8, 2018 Order in Docket No. G-011/M-15-895 required MERC to provide a detailed discussion of each capacity substitution in its annual demand entitlement filings on a going-forward basis.[11] The second tranche of additional capacity resulting from the NNG upgrades related to the Rochester Project approved in Docket No. G-011/M-15-895 became available on November 1, 2019. This additional capacity is included for recovery through the commodity portion of the PGA.

Regarding capacity substitution related to the additional Rochester Project capacity, MERC received Commission approval to expand its service into the communities of Balaton and Esko (Docket Nos. G-011/M-16-654 and G-011/M-16-655, respectively). The capacity created by the Rochester Project has allowed MERC to absorb this additional firm sales load (estimated peak load of approximately 2,500 Dth/day) without paying for additional pipeline investments.[12] Additionally, in Docket No. G-011/M-18-460, MERC received Commission approval, by order dated March 29, 2019, to extend service into Pengilly. The Company completed the Pengilly New Area Extension project in November 2019 and has been able to utilize existing capacity to serve the new customers in the Pengilly project area as well.

7. MERC-NNG Capacity Releases

As part of the Rochester Expansion Project, MERC has acted each year to execute seasonal capacity releases (i.e. heating season) for any capacity over its Design Day forecast plus 5% reserve margin, as laid out in the Capacity Release Plan filed on August 31, 2017, and approved by the Commission on May 8, 2018. The Company will post its excess capacity for this coming

[11] The Commission's May 8, 2018 Order in Docket No. G011/M-15-895 also required MERC to provide semi-annual updates in Docket No. G011/M-15-895 explaining what, if any, capacity-release-related activity occurred during the previous six months (e.g., when capacity release was offered, amount accepted, prices). The Company has been released from that semi-annual compliance requirement via the Commission's November 14, 2023 Order Accepting Agreement Setting Rates and Updating Base Cost of Gas in Docket No. G011/GR-22-504.

[12] MERC's Petition; at 9.

heating season (2025-2026), totaling 8,205 Dth/day[13] (as shown in Attachment 3), for release to the market in the September 2025 timeframe.

8. MERC-NNG Impacts of Interstate Pipeline Rate Cases

MERC reported that on July 1, 2025, NNG filed a Section 4 rate case with FERC. According to the Company, NNG stated that the proposed increase in rates is driven primarily by the significant capital being invested in the pipeline system to comply with pipeline safety requirements and maintain the reliability of service to customers. NNG has requested that rates go into effect January 1, 2026. Given that the result of the rate case is unknown, MERC has held rates at current levels for determining its demand rate in this proceeding. MERC will reflect actual rate increases in its monthly PGA filing when those rates go into effect.

9. MERC-NNG Future Capacity Outlook

Per its 2023-2024 and 2024-2025 Demand Entitlement filings, MERC has identified decreased reserve margins within different operating areas of the MERC-NNG system, as well as at a Total System level.[14] While MERC-NNG has a Total System surplus of 8,205 Dth/day for the 2025-2026 heating season, it is not expected to have enough capacity to meet its 5% reserve margin at a Total System level.[15] There are operating areas of MERC-NNG that have excess capacity, like the Rochester area. Other operating areas are however short on capacity, such as the MERC gates in the Farmington area. The Rochester and Farmington areas are not integrated. As such, utilizing the excess Rochester capacity to serve the Farmington area is not an operationally viable solution, nor allowed by NNG. Contracting for adequate capacity will mitigate the potential event of insufficient pressures on the distribution system to meet MERC's customer's needs.

Given that MERC-NNG currently has operating areas with insufficient capacity to meet the Peak (and Reserve) need and the forecasted shortages at MERC Total System level,[16] the Company has evaluated various options to meet its needs. To evaluate option scales and economics, MERC forecasted its Peak (and Reserve) needs for a 10-year period. A historic growth rate for the MERC-NNG system for this period was used to forecast the initial 3-year timeframe. Acknowledging the uncertainty of natural gas demand growth in the future, MERC has scaled down that growth rate by 50 percent for the subsequent 3-year period and further scaled down the remainder of the 10-year timeframe by 50 percent (See Table 1).

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[13] MERC's Petition; at 9.

[14] As shown on Attachment 3, Capacity Surplus/Shortage to Design Day + 5% Reserve (Heating Season).

[15] MERC's Petition; at 10.

[16] *Id*.

Table 1: MERC-NNG Growth Rate Assumptions[17]

Heating Season (Nov-Mar)	*YoY Growth Rate*
2026-2029	1.27%
2029-2032	0.64%
2032-2036	0.32%

The Company has analyzed the potential for Liquefied Natural Gas (LNG), contracting for current NNG available capacity, an NNG expansion project, and alternative pipeline opportunities to meet the Peak (and Reserve) need that is forecasted within the next 10 years. MERC has looked to meet its 10-year forecasted need to manage the costs via economies of scale. However, when projects such as these occur, there will be years in which MERC will have excess capacity, over the peak plus 5% reserve, which the Company plans to release.

10. Liquefied Natural Gas

The Company noted that it has analyzed the potential ability for LNG peaking service to meet the total system needs. Siting an LNG facility near a populated area can be a challenge and there was not a feasible site that made sense to meet the needs of this area, as well as the other operating areas with capacity needs. Given that much of MERC's NNG system is in rural, remote areas, an alternative option was to work with NNG on the placement of a MERC-owned LNG facility outside of the populated area, upstream of where the need for more capacity exists. The Company and NNG worked to arrive at a high-level cost estimate as well as to determine the operational requirements for such a facility to cover most of MERC's Design Day needs. MERC however noted that the total costs for this alternative option was not economically or operationally feasible.

11. Currently Available NNG Capacity

This bid was for currently available capacity or for capacity that other pipeline customers were deciding to no longer contract for. NNG responded that there was no open capacity, and that any new capacity was sold as part of the Open Season.[18] MERC's analysis of other alternatives for meeting its needs contains trade secret information, and therefore not provided in this document.

12. Pipeline Alternatives

NNG currently serves areas where MERC is short of capacity. These areas are long distances away from the other pipelines, such as Great Lakes Gas Transmission, Viking Gas Transmission, and Northern Border Pipeline that serve Minnesota customers. An expansion project would

[17] MERC's Petition; at 11.
[18] *Id*; at 12 (Trade Secret).

require significant miles of pipe to be put into the ground to get from these other pipelines to the MERC-NNG areas in need, causing the costs of such expansion to be prohibitive. Additionally, Great Lakes Gas Transmission, Viking Gas Transmission, and Northern Border Pipeline are all sold out of their capacity into the MERC service territory.[19] Consequently, pipeline alternatives were not deemed feasible.

13. NNG Pipeline Expansion

When NNG responded that it would not provide any available capacity at tariff rate, it provided MERC a preliminary cost estimate for a negotiated rate for pipeline capacity made available via an expansion project[20]. The cost estimate was considered the most effective and reliable solution to the alternatives. NNG will assess all their customer volumes and respond with a new rate estimate, given that the volumes have been determined for the project. After a final rate has been determined, MERC and NNG will negotiate a Precedent Agreement (PA) which will include the terms of the project, including responsibilities of both NNG and MERC.[21]

14. Conclusion

MERC requested that the Commission approve the requested changes to be recovered in the PGA beginning November 1, 2025.

B. Department of Commerce – Comments

On September 2, 2025, the Department filed its Comments to MERC's Petition. The Department observed that the instant petition is the ninth in which MERC's NNG and the Albert Lea systems were combined, based on the ruling in Docket No. G-011/GR-15-736.[22] The Department provided its analysis of the Company's proposal in the following sections.

1. Summary of Proposed Changes

MERC proposed to increase its total Design-Day requirement by 7,009 Dth to 297,178 Dth/day. The Company has a total Design-Day capacity of 320,042 Dth/day on its MERC-NNG system and proposes no overall change for the 2025-2026 heating season. Additionally, the Company proposed a reserve margin of 7.76 percent, a decrease of 2.60 percent from the 10.36 percent reserve margin for the 2024-2025 heating season.

MERC's proposed entitlement changes result in an estimated increase in demand costs for residential customers of $0.0050 per Dth, 0.39 percent, or approximately $0.43 per year compared to the rates included in the Company's July 2025 PGA.[23] Commodity costs were

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[19] MERC's Petition; at 13.
[20] *Id;* at 13-14 (Trade Secret).
[21] *Id;* at 14.
[22] Department's Comments at 1.
[23] MERC's Petition, Attachment 4.

included in this petition in compliant with Commission's May 5, 2017 Order, which required the Company to include Rochester Project-related capacity costs in the commodity portion of the monthly PGA.[24] MERC's estimated change to the commodity cost for residential customers is a decrease of $0.0420 per Dth, resulting in an annual decrease of $3.60 for an average customer's bill, or approximately 1.84 percent.[25]

2. Changes to Capacity and Non-capacity Items

a. Capacity Contracts

As noted in Table 2, and also indicated in Department Attachment 1, the Company does not propose changes to its overall entitlement level in its Petition. Capacity levels have however changed, per its 2023-2024 Heating Season Capacity Update Petition on April 2024, wherein the Company purchased an additional 4,777 Dth/day capacity under the TFX (Max Rate) with a term of April 2024 to March 2026.[26]

Table 2: MERC's NNG Total Entitlement Levels[27]

Filing	Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Filing (%)
November 1, 2023	313,756	315,465	1,709	0.54 %
March 28, 2024	315,465	320,242	4,777	1.51%
November 1, 2024	320,242	320,242	0	0.00%
Aug 1, 2025	320,242	320,242	0	0.00%

The Department noted the Company's stated rationale for acquiring the capacity and cost impact as follows:

> MERC has been awarded and acquired an additional 4,777 Dth of capacity on the NNG system via two NNG Open Seasons held in March 2024. As explained by MERC in the Company's November 1, 2023 updated Demand Entitlement filing in the above-referenced docket, while MERC-NNG has surplus capacity at a Total System level through 2023-2024, there are operating areas of MERC-NNG that are very short on capacity. The 4,777 Dth in increased capacity is needed to provide adequate capacity, plus a 5 percent reserve margin, in those areas that are forecasted to be short of design day needs over the forecast horizon.

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[24] In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC) for Evaluation and Approval of Rider Recovery for Its Rochester Natural Gas Extension Project, Order, May 8, 2018, Docket No. G-011/M-15-895, (eDockets) 20175-131604-01 at 15, (hereinafter "May 5, 2017 Order").

[25] Department's Comments; at 4.

[26] MERC's 2023-2024 Heating Season Capacity Update Petition at 2.

[27] MERC's Petition; at 5.

> The 4,777 Dth of additional capacity that MERC acquired is priced at NNG's tariffed TFX (Max Rate) rate, and has a term of April 2024 – March 2026, which, in comparison to an expansion project, has a much smaller impact on customer rates while aiding capacity shortages in the near-term time period. The impact to customers in the context of the 2023-2024 Demand Entitlement filing will be an increase to demand costs of $323,556 on an annualized basis, as shown on the attached updated Attachment 4, page 2. This results in an increased demand cost of $0.00125 per therm for the period April 1, 2024 – October 31, 2024 as shown in Attachment 4, pages1 and 2.[28] [citations omitted]

With regards to NNG capacity, NNG's reallocation of TF-12B and TF-12V services are not known until the update, but MERC indicated some changes. The changes are in accordance with NNG's tariff approved by FERC. Usually there is no deliverability difference between TF-12B and TF-12V services. The TF-12B decreased by 4,153 Dth/day with a corresponding increase in the same amount to the TF-12V service.

The changes to contract costs per the Petition, does not result in changes to the overall entitlement levels. The contract changes result in an additional $128,576 of demand costs and a decrease of approximately $1,176,694 in commodity costs compared to the 2024-2025 heating season.[29]

b. Changes to Non-Capacity Items

MERC did not propose any new additions to its non-capacity items in this demand entitlement filing.

3. Design-Day Requirements

Table 3 shows MERC's consolidated design-day levels.[30]

Table 3: MERC's NNG Design-Day Levels

Filing	Previous Design-Day (Dth)	Proposed Design-Day (Dth)	Design-Day Changes (Dth)	Change From Previous Year (%)
Aug 1, 2025	290,169	297,178	7,009	2.42%

The Department noted that MERC used a similar approach to last year's filing for its Design-Day analysis. As a result of MERC's telemetry program, the Company no longer needs to estimate interruptible customers' peak-day impact for the customers in the Company's former MERC-

[28] MERC 2023-2024 Heating Season Capacity Update Petition at 2.

[29] Department's Comments; at 6.

[30] MERC Petition, Attachment C at 2-3.

NNG PGA service area. The Company stated the following:[31]

> Order Point 11 from the Commission's April 28, 2016, Order in Docket Nos.G011/M-15-722, G011/M-15-723, and G011/M-15-724, required:
>
> 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, 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.

MERC's 2024-2025 Design-Day regression analysis utilizes daily telemetry data for all the MERC-NNG customers. MERC obtained the daily large volume transportation, interruptible and joint interruptible customer's volumes by pipeline and weather station (Data A). Additionally, the Company obtained the daily small volume interruptible customer's 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.

MERC made some adjustments to its data, for example, the regression analysis for the NNG pipeline. In its Petition MERC stated the following:[32]

> 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:[33]

> Identify the coldest Adjusted Heating Degree Day (AHDD) since January 1996 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.

MERC's prior design-day analyses have relied on the coldest days from 1996.[34] The Department agreed 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 Company's design-day analysis is based on Ordinary Least Squares (OLS)

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[31] MERC Petition, Attachment 12 page 11.

[32] MERC Petition, Attachment 12 at page 3.

[33] *Id*.

[34] Department's Comments; at 8.

regression and daily heating season (i.e., December, January, February) data over the period from December 2022 to February 2025.

Given the complicated nature of MERC's service area, the Company used six separate regression models for the various parts of the NNG PGA area, including Adjusted Heating Degree Days (AHDD) and various other determinants (e.g., month, day of the week, holiday) to estimate daily heating season consumption for each weather station area. The Department reviewed each of MERC's design-day regression models, and except for Ortonville, concluded that the signs of the determinant coefficients are appropriate and reasonable. The Ortonville regression is discussed below.

During the 2018-2019 heating season, MERC's service area, and the entire state of Minnesota, experienced a cold weather outbreak in late January and early February. The Company included information and a discussion regarding this event in its Petition.[35] On an AHDD basis, the cold weather event during the 2018-2019 heating season was the coldest weather on record for all of MERC's NNG PGA system weather stations as shown in Table 4.

Table 4: Coldest Weather Conditions

Station	Date	Avg. Temp (F)	Avg. Wind Speed (mph)	HDD65	AHDD65	AHDD65-1
Bemidji	1/29/2019	-32	14	97	110	84
Cloquet*	1/29/2019	-24	16	89	103	74
Fargo	1/18/1996	-16	34	81	109	85
International Falls	2/2/1996	-34	8	99	107	107
Minneapolis*	1/29/2019	-20	17	85	100	71
Rochester*	1/29/2019	-20	21	85	104	76
Worthington*	1/29/2019	-20	21	85	103	81
Ortonville*	1/29/2019	-23	14	88	101	77

* NNG PGA weather station.

In previous demand entitlement filings, the MERC's planning objective was based on the coldest day, defined as the highest AHDD, for each of its regional regression models. Starting with the 2019 demand entitlement filing, the Company considered the day prior to the coldest day (AHDD65-1) when determining whether a specific date represents the planning objective for a weather station. MERC provided the following explanation.[36]

> While the January 2019 cold weather outbreak was significant, it was not considered to be as severe as the weather conditions experienced in 1996. With

[35] MERC Petition; at 8, and Attachment 12 at pages 4-5.

[36] *Id.*

the exception of Worthington, the 1996 weather conditions overall were colder when considering both the current day and the prior day weather conditions.

Consequently, the following planning objective data for the various weather stations were used in the Company's design-day analysis.

Table 5: MERC Planning Objective Data

Station	Date	Avg. Temp (F)	Avg. Wind Speed (mph)	HDD65	AHDD65	AHDD65-1
Bemidji	2/1/1996	-34	8	99	107	94
Cloquet*	2/2/1996	-31	7	96	103	100
Fargo	1/18/1996	-16	34	81	109	85
International Falls	2/2/1996	-34	8	99	107	107
Minneapolis*	2/2/1996	-25	8	90	97	92
Rochester*	2/2/1996	-27	10	92	101	94
Worthington*	1/29/2019	-20	21	85	103	81
Ortonville*	1/14/2009	-21	11	86	95	86

* NNG PGA weather station.

For each of the regression models in Table 5, except Worthington, MERC's planning objective did not occur during the data period (2019 through 2022). As such, the Company adjusted the results to approximate usage at the planning objective. The Company's combined regression analyses resulted in a design-day estimate of 282,406 Dth/day. However, as explained in MERC's filing, the Company modified the analysis such that the ultimate design-day estimate was based on a higher throughput estimate that factors in a volume risk adjustment. This adjustment resulted in a calculated design-day estimate of 297,178 Dth/day, which is 7,009 Dth/day greater than the design-day estimate in last year's demand entitlement filing. The Company stated that volume risk adjustments were incorporated into the forecast to provide a confidence level that the daily metered load under design conditions would not exceed the daily metered regression estimate.[37]

Additionally, MERC tried to estimate firm peak day estimates for each of its gate stations. The Commission's April 28, 2016 Order in Docket Nos. G-011/M-15-722, G-011/M-15-723, and G-011/M-15-724, at Ordering Paragraph 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.

[37] Department's Comments; at 9; and Petition, Attachment 12 at page 6.

MERC stated the following in its Petition:[38]

> 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.

In its analysis for Ortonville, MERC used a regression model with a negative intercept term. The Department concluded that while MERC's use of a negative intercept in its Ortonville regression analysis is not ideal, their concerns remain somewhat mitigated as described in the Department's previous comments,[39] where the Department stated:

> In conclusion, the Department agrees that MERC appropriately excluded the non-winter months from its analysis. Because both the non-weather and weather sensitive needs are implicit in the December, January, and February historical data, and in light of the fact that Ortonville represents a relatively minor portion of MERC's overall capacity needs, the Department's concern regarding the negative intercept is somewhat mitigated. However, in its future demand entitlement filings, the Department recommends that MERC check the results of its regression analysis to ensure the results are consistent with the underlying theory the analysis attempts to explain.

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

The Department noted that MERC appropriately corrected its models for autocorrelation, as required by the Commission's February 4, 2015 Order, 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.

Since MERC must plan for its Design-Day, the Department concluded that its approach is not unreasonable. Consequently, the Department recommended that the Commission approve the Company's peak-day analysis.

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[38] MERC Petition, Attachment 12 at pages 10-11.

[39] In the Matter of a Petition by Minnesota Energy Resources Corporation MERC -Northern Natural Gas (NNG), for Approval of Changes in Contract Demand Entitlement for the 2015-2016 Heating Season Supply Plan effective November 1, 2015, Department of Commerce, Response Comments, February 22, 2016, Docket No. G-011/M-15-723, (eDockets) 20162-118555-01 at 3-4.

4. Proposed Reserve Margin

The proposed reserved margin, as shown in Table 6 and Department Attachment 1, is 23,064 Dth, or 7.76%.[40]

Table 6: MERC-NNG Reserve Margin

Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
Aug 1, 2025	320,242	297,178	23,064	7.76%	(2.60)%

The proposed reserve margin of 7.76% represents a decrease of 2.60 percentage points as compared to last year's reserve margin of 10.36%. The higher reserve margin is driven by the Rochester Project and the nature of large natural gas projects. The Commission was aware of these facts when it approved the Rochester Project and required MERC to explore methods such as capacity release to mitigate higher reserve margins.

Based on its review of MERC's historic design-day data, regression results, and the nature of the Rochester Project and associated capacity expansions, the Department concluded that MERC's reserve margin is acceptable.

5. The Company's PGA Cost Recovery Proposal

The Company compared its July 2025 PGA to its projected November 2025 PGA rates in Attachment 4, to highlight the changes in demand costs. According to MERC's calculations, the Company's demand entitlement proposal would result in the following annual demand cost impacts:

- annual bill increase of $0.34 related to demand costs, or approximately 0.39%, for the average General Service customer consuming 86 Dth annually;
  annual bill increase of $79.93 related to demand costs, or approximately 0.39%, for the average Large Volume Firm customer consuming 15,986 Dth annually; and
- no demand cost impacts related to MERC-NNG's interruptible rate classes.

The Department noted that MERC appropriately included the Rochester Project related demand costs in the commodity portion of the PGA, as required by the Commission's May 8, 2018 Order. The Department therefore showed the commodity related bill impacts that include the Rochester Project in MERC's calculations in Table 7.

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40 In the Department's Comments, the proposed reserved margin and percentage in the sentence were listed as 30,073 Dth, or 10.36%, from the previous period. The Department consented with the correction.

Table 7: Comparison of July 2025 PGA Commodity Cost to Projected November 2025 PGA Proposal by Customer Class

Customer Class	Annual Difference ($/yr/customer)	Percentage Change
Residential	($3.60)	(1.84)%
Small Commercial	($32.80)	(1.84)%
Large Commercial	($671.42)	(1.84)%
Small Interruptible	($172.61)	(1.84)%
Large Interruptible	($927.83)	(1.84)%

The Department will provide its final recommendations after the Company files its November 2025 Update.

6. MERC-NNG's Future Capacity Outlook

For the areas MERC has shortage on capacity, as discussed under item 9, page 7 of this Briefing Papers, the Department is in the process of evaluating MERC's discussion regarding its future capacity outlook and will provide its comments after the Company's November Update.

7. MERC's Rochester Project Compliance

Based on the Department's review of MERC's response provided on page 6 of these Briefing papers, under item 6, the Department concluded that MERC complied with the Commission's Rochester Project compliance requirement.

8. Commission Orders in Docket Nos. G-999/CI-21-135 AND G-011/CI-21-611

In the Commission's February 17, 2023 Order, Ordering Paragraphs 9 and 10 state as follows:

> 9. In future contract demand entitlement filings, the gas utilities in this docket shall discuss how changes to their pipeline capacity affect their supply diversity and, if pipeline capacity comes at a cost premium but increases supply diversity, provide a meaningful cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option.
>
> 10. Each gas utility in this docket shall include in its relevant annual, forward-looking gas planning or hedging filings:[41]
>
> A) Its expected supply mixes across different load and weather conditions throughout each month of the upcoming winter season;
> B) The forecasted minimum, average, and maximum day load

[41] February 17, 2023 Order at 23.

requirements; and

C) The expected mix of baseload, storage, and spot supply on those days.

MERC provided the required information for Ordering Paragraph 9, as reflected on page 4 above, under Item 3(a). Regarding compliance with Ordering Paragraph 10, MERC noted that it provided the requested information in its Attachment 6, stating as follows:[42]

> Attachment 6, page 3, provides this information for the November 2025 through March 2026 period. Load estimates are based on the previous three years observed data, except for the December through February months, in which the Design Day (i.e. Peak Day) was used to represent the maximum load. While three years of historical data provide a reasonable estimate, conditions can deviate and provide load requirements different from those in the past.

The Department concluded that MERC complied with the February 17, 2023 Order. The Department also concluded that MERC's explanations regarding its compliance with the ordering paragraphs 9 and 10 are acceptable. The Department however stated that the prudency of the natural gas costs and actions taken by MERC to minimize those costs will be evaluated in a future proceeding when MERC files its annual automatic adjustment report and true up filing on September 1, 2026.[43]

9. Northern's Rate Case at Federal Energy Regulatory Commission

On July 1, 2025 NNG filed a rate case at FERC in Docket No. RP25-989 and proposed dramatic increases in their rates. The rates are effective January 1, 2026, subject to refund.

The Department recommended that MERC filed its Reply Comments; provide an update on the NNG rate case at FERC and MERC's efforts in those proceedings, including the projected impacts on demand costs.

10. Recommendations

The Department recommended approval of the Company's Design-Day Analysis, but withheld final recommendations for the remainder of the Company's Petition until MERC files its Reply Comments and files its update in November 2025.

C. MERC. – Reply Comments

On September 12, 2025, MERC filed its Reply Comments to the Department's September 2,

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[42] MERC's Petition, Attachment C at 7.

[43] Department's Comments; at 14.

2025[44] Comments; in agreement with the Department's recommendations on the Design-Day analysis. Additionally, MERC concurred with the Department's recommendation to provide an update regarding NNG's Rate Case at the FERC, including the projected impacts of the NNG rate case; for instance, on demand costs and on its future capacity outlook in the Company's November 2025 update.

The Company stated that it would be available to address any questions the Department may have after review of MERC's November 2025 update to the demand entitlement petitions. The Company requested the Commission accept the Design-Day analyses for the NNG and Consolidated PGA areas.

D. MERC – November 1 Update to Petition

On October 31, 2025, MERC filed an update to its August 1, 2025 Petition, per Commission's April 28, 2016 Order in Docket Nos. G-011/M-15-722, G-011/M-15-723, and G-011/M-15-724; which required that "MERC explain changes made in its compliance petitions that are different from its original petitions, and provided a redline version of both petitions identifying changes." Accordingly, MERC provided redlined changes and highlighted changes in the affected schedules.

The Company noted that it has completed its purchases of future contracts and call options for the 2025-2026 winter period. The final financial hedge volumes and costs are shown in Attachments 5 and 11 (pages 1 and 3). The call option premium costs flow through the spreadsheet in Attachment 4, pages 1 and 2, and in Attachment 8.[45] Additionally, the rate comparisons in Attachment 4, page 1, have been updated to MERC's October 1, 2025, PGA rates.[46]

E. Department of Commerce – Letter

The Department filed a letter on December 16, 2025, in which it acknowledged that MERC filed its update to the Petition. In the update, MERC provided the following: an updated rate comparison using its October 2025 PGA rates; an update on the NNG rate case; and MERC-NNG's future capacity outlook.[47] The updated PGA commodity rate does not impact the demand entitlement costs. In addition, MERC provided the requested update to the NNG pending rate case at FERC by stating that settlement discussions are still ongoing between NNG and the interveners.[48]

With regards to MERC-NNG's future capacity outlook, the Company provided additional

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44 In MERC's Reply Comments, the date for the Department's Comments was mistakenly stated as October 3, 2024. MERC consented to this footnoted corrective reference.

45 MERC's October 31, 2025 Updated Compliance Filing; at 1.

46 *Id*.

47 Department's December 16, 2025 Letter*; 2.*

48 *Id*.

information on the proposed expansion project that is still in progress. The Department however observed that pursuant to Minn. R. 7829.2910, subp. 2, the prudency of the proposed expansion project, and/or future capacity, can only be reviewed for reasonableness when MERC files the required petition, and when there is a change in the demand levels.

After review of MERC's Reply Comments and its November Update, the Department recommended approval of the Company's proposed level of demand entitlement and to allow MERC to recover the associated demand costs through the monthly PGA effective November 1, 2025.

F. MERC – Response to Department's Letter

On December 23, 2025, MERC filed a response to the Department's December 16, 2025 letter. The Company agreed with the Department's recommendations for approval of its Design-Day analysis, proposed level of Demand Entitlement and to allow MERC to recover the associated demand cost through the respective monthly NNG PGA effective November 1, 2025.

Regarding the Department's comments about MERC-NNG's future capacity outlook, MERC acknowledged the Department's citation to Minn. R. 7825.2910, subp. 2, which establishes a process for Commission review of a change in demand. Although the Company did not request a preapproval of the NNG capacity expansion in this proceeding, it believes that review of the reasonableness of the proposed capacity expansion can occur before the incremental capacity is in service and prior to implementing new rates incorporating the cost of the incremental capacity.[49] Additionally, MERC noted that it provided the necessary details to support the alternatives evaluated, the need for the proposed capacity expansion, and the associated costs in this proceeding to ensure the Department and other interested parties have sufficient time to allow for the review of the prudence and reasonableness of the proposed capacity expansion prior to implementation of new rates, in accordance with Commission direction in prior dockets involving significant pipeline expansion projects.[50]

III. Staff Comments

Staff reviewed MERC's Petition and finds that its Design-Day forecast, reserve margin, and capacity portfolio for the 2025–2026 heating season are reasonable and compliant with Minnesota Rules and prior Commission Orders. Staff notes that in its updated filing, MERC provided all the information requested by the Department, including the detail regarding its MERC-NNG's Future Capacity Outlook and the update on the pending NNG FERC rate case. Staff concurs with the Department's recommendations for approval of MERC's Petition.

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[49] MERC's Response to Department's December 16, 2025 letter; at 2.

[50] *Id*. (See footnote number 2 on page 3).

IV. Decision Options

1. Approve Minnesota Energy Resource Corp.'s Petition for approval of a Change in Demand Entitlement for its NNG System and authorize the Company to recover the associated demand costs through the monthly PGA effective November 1, 2025.

Or

2. Deny Minnesota Energy Resource Corp.'s petition for approval of a Change in Demand Entitlement for its NNG System and do not authorize the Company to recover the associated demand costs through the monthly PGA effective November 1, 2025.