MINNESOTA PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**June 12, 2025**	**Agenda Item 3***
Company	Minnesota Energy Resources Corp.	
Docket No.	G-011/M-24-269 In the Matter of Minnesota Energy Resources Corp.'s Petition for Approval of a Change in Demand Entitlement for its Consolidated System G-011/M-24-270 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 MERC's proposed demand entitlement capacity for the 2024-2025 Heating Season for its Consolidated PGA area, effective November 1, 2024?
- Should the Commission approve MERC's proposed demand entitlement capacity for the 2024-2025 Heating Season for its NNG PGA area, effective November 1, 2024?

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✓ **Relevant Documents**	**Date**
Docket 24-269	
Minnesota Energy Resources Corp. – Initial Petition	August 1, 2024
Department of Commerce – Comments	October 3, 2024
Minnesota Energy Resources Corp. – Reply Comments	October 14, 2024
Minnesota Energy Resources Corp. – Compliance Filing	November 1, 2024
Department of Commerce – Supplemental Comments	January 29, 2025

✓**Relevant Documents**	**Date**
Minnesota Energy Resources Corp. – Supplemental Reply Comments	February 7, 2025

Docket 24-270

Minnesota Energy Resources Corp. – Initial Petition	August 1, 2024
Department of Commerce – Comments	October 3, 2024
Minnesota Energy Resources Corp. – Reply Comments	October 14, 2024
Minnesota Energy Resources Corp. – Compliance Filing	November 1, 2024
Department of Commerce – Supplemental Comments	January 29, 2025
Minnesota Energy Resources Corp. – Supplemental Reply Comments	February 7, 2025

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I. STATEMENT OF THE ISSUES

Should the Commission approve MERC's proposed demand entitlement capacity for the 2024-2025 Heating Season for its Consolidated PGA area, effective November 1, 2024?

Should the Commission approve MERC's proposed demand entitlement capacity for the 2024-2025 Heating Season for its NNG PGA area, effective November 1, 2024?

II. BACKGROUND

The Commission's February 4, 2015 Order in Minnesota Energy Resources Corporation's (MERC or the Company) 2012-2013 demand entitlement filing required the Company to, in future demand entitlement filings, check regression models for autocorrelation and, if present, correct the model by removing the autocorrelation.[1]

The Commission's April 28, 2016 Order in MERC's 2015-2016 demand entitlement filing required the Company to, in future demand entitlement filings, verify its regression analysis results to ensure consistency with the underlying theory the analysis attempts to explain.[2]

The Commission's May 5, 2017 Order in MERC's Rochester Natural Gas Extension Project petition required the Company to include the related capacity costs in the commodity portion of the monthly Purchased Gas Adjustment (PGA).[3] The Commission's May 8, 2018 Order in the same docket required MERC to, in future demand entitlement filings, provide semi-annual updates regarding Rochester Project capacity releases and a discussion of capacity substitutions.[4]

Order Points 9 and 10 in the Commission's February 17, 2023 Order in the Winter Storm Uri dockets (Uri Dockets) stated the following:[5]

> 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.

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[1] Docket No's. G-011/M-12-1192; G-011/M-12-1193; G-011/M-12-1194 and G-011/M-12-1195.

[2] Docket No's. G-011/M-15-722, G-011/M-15-723, and G-011/M-15-724.

[3] Docket No. G-011/M-15-895.

[4] *Id.*

[5] Docket No's. G-999/CI-21-135, G-008/M-21-138, G-004/M-21-235, G-002/CI-21-610, and G-011/CI-21-611.

10. Each gas utility in this docket shall include in its relevant annual, forward-looking gas planning or hedging filings:

- Its expected supply mixes across different load and weather conditions throughout each month of the upcoming winter season;
- The forecasted minimum, average, and maximum day load requirements;
- The expected mix of baseload, storage and spot supply on those days.

The Commission's January 17, 2024 Order accepted MERC-Consolidated's 2023-2024 demand entitlement and required the Company to, in its next demand entitlement filing, provide an update on the Viking Gas Transmission rate case.[6]

The Commission's July 16, 2024 Order approved MERC-NNG's (Northern Natural Gas) 4,777 Dth additional capacity purchase and its corresponding demand costs increase to be implemented on April 1, 2024.[7]

On August 1, 2024, MERC filed its MERC-Consolidated and MERC-NNG 2024-2025 demand entitlement Petitions, seeking approval of changes for customers served on the Centra, Viking and Great Lakes Gas Transmission (Consolidated) pipelines, as well as the NNG pipeline. In both filings, MERC proposed recovery of the requested demand entitlement changes through its Purchased Gas Adjustment (PGA) beginning November 1, 2024.

On October 3, 2024, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed comments in both dockets recommending approval of MERC's Design-Day Analysis but withheld final recommendations until after the Company's November 1, 2024 update.

On October 14, 2024, MERC filed reply comments in both dockets agreeing with the Department recommendations on Design Day Analyses for the Consolidated and NNG PGA areas and recommended Commission approval.

On November 1, 2024, in compliance with Commission orders, MERC filed updates in both dockets to its August 1, 2024 Petitions noting redline and highlighting changes in the affected schedules.[8]

On January 29, 2025, the Department filed supplemental comments in both dockets recommending approval of MERC's proposed levels of demand entitlement and to allow cost

[6] Docket No. G-011/M-23-358.

[7] Docket No. G-011/M-24-155.

[8] Docket No's. G-011/M-15-722, G-011/M-15-723, and G-011/M-15-724.

recovery through the monthly PGA beginning November 1, 2024.

On February 7, 2025, MERC filed supplemental reply comments in both dockets agreeing with the Department recommendations and recommending Commission approval.

III. RELEVANT STATUTES

Minn. R. 7825.2910, Subp. 2 indicates the following:

> Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another. A filing must contain:
>
> - A description of the factors contributing to the need for changing demand;
> - The utility's design-day demand by customer class and the change in design-day demand, if any, necessitating the demand revision; and
> - A summary of the levels of winter versus summer usage for all customer classes;
> - A description of design-day gas supply from all sources under the new level, allocation, or form of demand.[9]

IV. PARTIES COMMENTS

A. MERC – Consolidated PGA Area (Docket 24-269)

1. Minnesota Energy Resources Corp. – Initial Petition

MERC-Consolidated serves customers located along the Great Lakes Gas Transmission (Great Lakes or GLGT), Viking Gas Transmission (Viking or VGT) and Centra Minnesota (Centra) Pipelines.

MERC's Petition proposed two demand entitlement changes. The first is Design-Day deliverability, which quantifies the amount of available firm transportation and storage capacity during winter peak periods. The second alters the capacity portfolio and PGA costs to be recovered.

By acquiring additional GLGT capacity and updating Centra contract volumes, MERC proposed to increase its design-day requirement by 588 dekatherms (Dth) to 57,736 Dth/day. MERC-Consolidated's Design-Day levels are shown in Table 1.

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[9] See *FILING BY GAS UTILITIES*. 2024 Minnesota Statutes. https://www.revisor.mn.gov/rules/7825.2910/

Table 1: MERC-Consolidated's Design-Day Levels

Pipeline	2023-2024 Design-Day (Dth)	2024-2025 Proposed Design-Day (Dth)	Design-Day Changes (Dth)	Change From Previous Year (%)
Centra	9,691	9,626	(65)	-0.67%
Great Lakes	29,497	30,245	748	2.54%
Viking	17,960	17,866	(94)	-0.52%
Total Consolidated	57,148	57,736	588	1.03%

MERC proposed to increase its design-day deliverability from 62,019 Dth in 2023-2024 to 64,429 Dth in 2024-2025,[10] which results in an 11.59 percent estimated reserve margin.[11] The increased capacity volumes are driven by the Great Lakes (2,202 Dth) and Centra pipelines (208 Dth).

GLGT's increased capacity did not impact MERC's supply diversity and maintained deliverability at current tariff rates, which were expected to be less costly than future pipeline expansions. During GLBT's Open Season, only the Emerson receipt point was available and Liquefied Natural Gas (LNG) was not considered a viable operational or cost effective option.

Centra's increased capacity reflects an updated peak day estimate for customers served by that pipeline and no alternative supply basins were available for a small capacity increase.

Compared to July 2024 PGA rates, MERC's proposed entitlement changes would increase annual residential demand costs by approximately $0.0481 per Dth or $4.15 per customer. Effective November 1, 2024, MERC requested recovery of the associated demand costs in the Company's monthly PGA. MERC's Petition also includes the balancing costs allocation to the commodity portion of the PGA.[12]

MERC extended its existing ANR Pipeline Storage contracts through March 31, 2028, while proposing to reduce storage volumes by 2,750 Dth or 2.73 percent. As a result of annual fuel rate changes, changes to storage volumes and rates will occur yearly.[13]

MERC also noted that, on July 28, 2023, Viking Gas Transmission filed a rate case with the Federal Energy Regulatory Commission (FERC). A settlement was reached prior to implementation of interim rates, thus MERC's Petition reflects the settlement demand rates.

[10] Petition, Attachment 3, which reflects separate summer and winter demand entitlements.

[11] Petition, at 3.

[12] Petition, Attachment 4, at 2.

[13] Petition, *Id*., Attachments 7, and 8.

MERC included average customer counts[14] and daily throughput estimates utilizing the Design-Day model to calculate the theoretical peak day and compare to actual consumption.[15] However, MERC does not utilize the Design-Day model to forecast daily/monthly consumption.

The Company's 2024-2025 hedging strategy covers up to 60 percent of normal winter volumes; up to 30 percent through physical storage; and 30 percent through financial instruments (10 percent futures, 20 percent options) and includes future contracts and call options for the winter period.[16] The weighted average price of purchased futures contracts is $3.6461 per Dth.[17]

The Commission's February 17, 2023 Order in the Uri Dockets required MERC provide the following in its relevant, annual forward-looking gas planning or hedging filings:[18]

- Expected supply mix across different load and weather conditions throughout each month of the upcoming winter season
- Forecasted minimum, average, and maximum day load requirements
- Expected mix of baseload, storage, and spot supply on those days

MERC's Petition supplied this information for November 2024 through March 2025.[19] Except for the December through February months, load estimates were based on the previous three years in which the Design Day represented the maximum load.

2. Department of Commerce – Comments

The Department's initial comments focused on MERC's design-day requirements and compliance with the January 17, 2024 Commission Order,[20] while withholding a final recommendation until after MERC provided its November 1, 2024 update.

The Department noted that, similar to previous demand entitlement filings, MERC used the Ordinary Least Squares (OLS) regression and December 2021 through February 2024 heating season data for its design-day analysis.

To estimate daily heating season consumption for each weather station, MERC conducted four

[14] Petition, Attachment 10.

[15] Petition, Attachment 9.

[16] Petition, Attachments 5 and 11 detail the volumes and costs.

[17] Petition, Attachment 11, at 1.

[18] Docket No's. G-999/CI-21-135 and G-011/CI-21-611.

[19] Petition, Attachment 6, at 3.

[20] Docket No. G-011/M-23-358.

separate regression models such as Adjusted Heating Degree Days (AHDD)[21] and various other determinants (e.g., month, day of the week, holiday). The Department noted the Viking regression contained no negative intercept and concluded that MERC's regression models and determinant coefficients were appropriate and reasonable.

While MERC's combined regression analyses resulted in a 54,797 Dth/day[22] design-day estimate, the Company determined a 57,736 Dth/day[23] throughput was more appropriate because it factored in a volume risk adjustment and a higher confidence level.[24]

Prior to MERC's 2019 demand entitlement filing, the Company's planning objective was based on the coldest day (highest AHDD) for its regional regression models. The Department noted that, in January to February 2019, the state of Minnesota experienced a cold outbreak unlike any experienced since the 1995-1996 heating season. As a result, MERC now considers the day prior to the coldest day (AHDD65-1) when determining whether a specific date represents the planning objective for a weather station. MERC's Petition provided the following explanation:[25]

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

Table 2 indicates MERC's planning objective data for its design-day analysis. Except for the Worthington station, MERC's planning objective did not occur during the 2021 – 2024 data period.

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[21] AHDD incorporates the impacts of wind into the weather determinant used to estimate peak day consumption. MERC has historically used AHDD in its design-day analysis.

[22] The Department indicated 54,797 Dth/day. Staff notes this should be 55,042 Dth/day, but considers the discrepancy to be small; therefore, it does not materially impact the underlying analysis. See Regression Total column in Petition, Attachment 1, at 2.

[23] Petition, Attachment 1, at 2.

[24] Petition, Attachment 12, at 6.

[25] Petition, Attachment 12, at 4.

Table 2: 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

* Combined PGA weather station.

The Department also noted that MERC's telemetry program made it possible for interruptible customers to have daily metered data, thus MERC no longer needed to estimate peak-day impact for interruptible customers.

The Department determined that MERC's correcting of its regression models for autocorrelation and its 2023 Viking rate case update complied with the Commission's February 4, 2015[26] and January 17, 2024 Orders.[27] Therefore, the Department recommended MERC's design-day analysis be approved.

3. Minnesota Energy Resources Corp. – Reply Comments

MERC agreed with the Department's recommendations on the Design-Day analyses for the Consolidated area.

4. Minnesota Energy Resources Corp. – Compliance Filing

In accordance with April 28, 2016 Commission Orders,[28] MERC provided redline and highlighted attachments and schedules that explained changes to its Petition.

MERC noted that, for the 2024-2025 winter season, it had completed future contract and call option purchases. The weighted average price of futures contracts changed from $3.6461 to $3.4011 per Dth, while the strike price of purchased call options changed from $7.1686 to $5.7206 per Dth. MERC's final hedge volumes and costs are noted in Attachments 5 and 11, while MERC's updated October 1, 2024 PGA rates and call option premium costs are noted in Attachments 4 and 8.

[26] Docket No's. G-011/M-12-1192, G-011/M-12-1193, G-011/M-12-1194, and G-011/M-12-1195.

[27] Docket No. G-011/M-23-358.

[28] Docket No's. G-011/M-15-722, G-011/M-15-723, and G-011/M-15-724.

5. Department of Commerce – Supplemental Reply Comments

The Department noted that, compared to October 2024 PGA rates, MERC's proposed entitlement changes would increase yearly residential demand costs by approximately $0.0481 per Dth or $4.15 per customer. Regarding bill impacts by customer class, MERC indicated the following:[29]

- Annual bill increase of $4.15 related to demand costs, or approximately 5.72 percent, for the average General Service customer consuming 86 dekatherms annually.
- Annual bill increase of $33.38 related to demand costs, or approximately 5.72 percent, for the average Large Commercial and Industrial customer consuming 694 dekatherms annually.
- No demand cost impacts related to MERC-Consolidated's interruptible rate classes.

The Department recommended that, effective November 1, 2024, MERC's recovery of its proposed demand costs through its monthly PGA be approved.

As shown in in Table 3, the Department summarized MERC's proposed reserve margin by pipeline and noted that MERC's proposed 64,429 Dth of reserve margin is over 7.5 percentage points greater than the 11-year average and likely sufficient to ensure firm reliability on a peak day.

Table 3: MERC-Consolidated Reserve Margin

Pipeline	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year[30]
Centra	10,108	9,626	482	5.01%	2.86%
Great Lakes	33,530	30,245	3,285	10.86%	4.65%
Viking	20,791	17,866	2,925	16.37%	0.61%
Total Consolidated	64,429	57,736	6,693	11.59%	3.07%

The Department determined that MERC's Petition complied with Order Points 9 and 10 of the Commission's February 17, 2023 Order[31] and indicated that the prudency of MERC's actions to minimize natural gas costs will be evaluated when the Company files its annual automatic adjustment (AAA) report and true-up on September 1, 2025.

[29] MERC Update, Attachment 4.

[30] For the 2023-2024 heating season, the reserve margins were as follows: Centra – 2.15%; Great Lakes – 6.21%; Viking – 15.76%; and Total Consolidated – 8.52%.

[31] Docket No's. G-999/CI-21-135 and G-011/CI-21-611.

6. Minnesota Energy Resources Corp. – Supplemental Reply Comments

MERC requested approval of its proposed 64,429 Dth demand entitlement and, effective November 1, 2024, recovery of associated costs through the monthly PGA.

B. MERC – NNG PGA Area (Docket 24-270)

1. Minnesota Energy Resources Corp. – Initial Petition

MERC-NNG serves customers located along the Northern Natural Gas interstate pipelines.

MERC's Petition proposed two demand entitlement changes. The first is Design-Day deliverability, which quantifies the amount of available firm transportation and storage capacity during winter peak periods. The second alters the capacity portfolio and PGA costs to be recovered.

As shown in in Table 4, MERC proposed to decrease its design-day requirement by 765 dekatherms (Dth) to 290,169 Dth/day.

Table 4: MERC-NNG Design-Day Levels

Pipeline	2023-2024 Design-Day (Dth)	2024-2025 Proposed Design-Day (Dth)	Design-Day Changes (Dth)	Change From Previous Year (%)
NNG	290,934	290,169	(765)	-0.26%

Regarding capacity, MERC's 2024-2025 design-day deliverability of 320,242 Dth/day is unchanged,[32] which results in a 10.36 percent estimated reserve margin.[33]

MERC noted that, as of November 2019, additional NNG upgrade capacity from the Rochester Project became available and allowed the Company to absorb additional firm load and utilize existing capacity without paying for incremental pipeline investments. The Rochester Project capacity is included for recovery in the commodity portion of the PGA.

Regarding capacity substitutions, MERC has previously received approval to expand its service into Balaton, Esko and Pengilly.[34]

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[32] Petition, Attachment 3, which reflects separate summer and winter demand entitlements.

[33] Petition, at 3.

[34] Commission Order dated March 29, 2019, in Docket No. G-011/M-18-460.

MERC indicated a 15,565 Dth/day surplus capacity on NNG through 2024-2025,[35] and acknowledged that some operating areas, such as Rochester, have excess capacity and others, such as Farmington and Worthington, are short. MERC is looking at potential ways to meet demand in the Farmington and Worthington areas and will provide appropriate updates to the Commission.

MERC included average customer counts[36] and daily throughput estimates utilizing the Design-Day model to calculate the theoretical peak day and compare to actual consumption.[37] However, MERC does not utilize the Design-Day model to forecast daily/monthly consumption.

Compared to July 2024 PGA rates, MERC's proposed entitlement changes would increase yearly residential demand costs by approximately $0.0235 per Dth or $2.01 per customer, while decreasing commodity costs by $0.0164 per Dth or $1.40 per customer. MERC requested, effective November 1, 2024, cost recovery of the associated demand costs through its monthly PGA.[38] MERC's Petition also includes the balancing costs allocation to the commodity portion of the PGA.[39]

The Company's 2024-2025 hedging strategy covers up to 60 percent of normal winter volumes; up to 30 percent through physical storage; and 30 percent through financial instruments (10 percent futures, 20 percent options) and includes future contracts and call options for the winter period.[40] The weighted average price of purchased futures contracts is $3.6461 per Dth.[41]

During the NNG Ventura and NNG West Leg Open Seasons, only the Ventura and NBPL (Northern Border Pipeline) / NNG Welcome receipt points were available, thus there were no other alternative options presented.

The Commission's February 17, 2023 Order in the Uri Dockets required MERC provide the following in its relevant, annual forward-looking gas planning or hedging filings:[42]

- Expected supply mix across different load and weather conditions throughout each

[35] Petition, Attachment 3, Capacity Surplus/Shortage to Design Day + 5% Reserve (Heating Season).

[36] Petition, Attachment 10.

[37] Petition, Attachment 9.

[38] Petition, Attachment 4.

[39] Petition, Attachments 4, 8.

[40] Petition, Attachments 5 and 11 detail the volumes and costs.

[41] Petition, Attachment 11, at 1.

[42] Docket No's. G-999/CI-21-135 and G-011/CI-21-611.

month of the upcoming winter season
- Forecasted minimum, average, and maximum day load requirements
- Expected mix of baseload, storage, and spot supply on those days

MERC supplied this information for November 2024 through March 2025.[43] Except for the December through February months, load estimates were based on the previous three years in which the Design Day represented the maximum load.

2. Department of Commerce – Comments

The Department's initial comments focused on MERC's design-day requirements and compliance with the January 17, 2024 Commission Order,[44] while withholding a final recommendation until after MERC provided its November 1, 2024 update.

The Department noted that, similar to previous demand entitlement filings, MERC used the Ordinary Least Squares (OLS) regression and December 2021 through February 2024 heating season data for its design-day analysis.

To estimate daily heating season consumption for each weather station, MERC conducted six separate regression models such as Adjusted Heating Degree Days (AHDD)[45] and various other determinants (e.g., month, day of the week, holiday). The Department determined that, except for Ortonville, MERC's regression models and determinant coefficients were appropriate and reasonable. While MERC used a negative intercept term in its regression model for Ortonville, the Department nonetheless concluded that the Company complied with previous Commission Orders.[46]

While MERC's combined regression analyses resulted in a 280,554 Dth/day design-day estimate, the Company determined a 290,169 Dth/day[47] throughput was more appropriate because it factored in a volume risk adjustment and a higher confidence level.[48]

Prior to MERC's 2019 demand entitlement filing, the Company's planning objective was based on the coldest day (highest AHDD) for its regional regression models. The Department noted that, in January to February 2019, the state of Minnesota experienced a cold outbreak unlike any experienced since the 1995-1996 heating season. As a result, MERC now considers the day

[43] Petition, Attachment 6, at 3.

[44] Docket No. G-011/M-23-358.

[45] AHDD incorporates the impacts of wind into the weather determinant used to estimate peak day consumption. MERC has historically used AHDD in its design-day analysis.

[46] Commission Order dated April 28, 2016, in Docket No. G-011/M-15-723.

[47] Petition, Attachment 1, at 2.

[48] Petition, Attachment 12, at 6.

prior to the coldest day (AHDD65-1) when determining whether a specific date represents the planning objective for a weather station. MERC's Petition provided the following explanation:[49]

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

Table 5 indicates MERC's planning objective data for its design-day analysis. Except for the Worthington station, MERC's planning objective did not occur during the 2021 – 2024 data period.

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

* Combined PGA weather station.

The Department also noted that MERC's telemetry program made it possible for interruptible customers to have daily metered data, thus MERC no longer needed to estimate peak-day impact for interruptible customers.

The Department determined that MERC's correcting its regression models for autocorrelation complied with the February 4, 2015 Commission Orders[50] and recommended approval of MERC's design-day analysis.

3. Minnesota Energy Resources Corp. – Reply Comments

MERC agreed with the Department's recommendations on the Design-Day analyses for the NNG area.

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[49] Petition, Attachment 12, at 4.

[50] Docket No's. G-011/M-12-1192, G-011/M-12-1193, G-011/M-12-1194, and G-011/M-12-1195.

4. Minnesota Energy Resources Corp. – Compliance Filing

In accordance with April 28, 2016 Commission Orders,[51] MERC provided redline and highlighted attachments and schedules that explained changes to its Petition.

MERC noted that, for the 2024-2025 winter season, it had completed future contract and call option purchases. The weighted average price of futures contracts changed from $3.6461 to $3.4011 per Dth, while the strike price of purchased call options changed from $7.1686 to $5.7206 per Dth. MERC's final hedge volumes and costs are noted in Attachments 5 and 11, while MERC's updated October 1, 2024 PGA rates and call option premium costs are noted in Attachments 4 and 8.

MERC indicated no changes to 2024-2025 design-day deliverability and that, historically, NNG Ventura North and West Leg Open Seasons have only allowed Ventura and NBPL/NNG Welcome as receipt locations.

5. Department of Commerce – Supplemental Reply Comments

The Department noted that, compared to October 2024 PGA rates, MERC's proposed entitlement changes would increase yearly residential demand costs by approximately $0.0273 per Dth or $2.34 per customer, while increasing yearly commodity costs by $0.4020 per Dth or $34.41 per customer. Regarding bill impacts by customer class, MERC indicated the following: [52]

- Annual bill increase of $2.34 related to demand costs, or approximately 2.17 percent, for the average General Service customer consuming 86 dekatherms.
- Annual bill increase of $21.32 related to demand costs, or approximately 2.17 percent, for the average Small Volume firm customer consuming 781 dekatherms.
- Annual bill increase of $436.43 related to demand costs, or approximately 2.17 percent, for the average Large Volume firm customer consuming 15,986 dekatherms.
- No demand cost impacts related to MERC-NNG's interruptible rate classes.

The Department recommended that, effective November 1, 2024, MERC's recovery of its proposed demand costs through its monthly PGA be approved.

The Department summarized and noted that, to provide adequate capacity for areas forecasted to be short of design day needs, during two Open Seasons held in March 2024, MERC purchased an additional 4,777 Dth/day capacity at NNG's tariffed TFX (max rate) rate.[53] MERC indicated the acquired capacity was favorable to a pipeline expansion, which would have cost

[51] Docket No's. G-011/M-15-722, G-011/M-15-723, and G-011/M-15-724.

[52] MERC Update, Attachment 4, at 1.

[53] MERC 2023-2024 Heating Season Capacity Update Petition, at 2, in Docket No. G-011/M-24-155.

approximately $250 million over 20 years. The increased capacity results in 320,242 Dth of proposed demand entitlement[54] and a $1,030,755 increase in demand costs.[55]

Table 6 indicates MERC-NNG's proposed reserve margin.

Table 6: MERC-NNG Reserve Margin

Pipeline	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
NNG	320,242	290,169	30,073	10.36%	1.93%

The Department determined that MERC's proposed 320,242 Dth demand entitlement and 10.36 percent reserve margin is driven by large natural gas projects including Rochester and is acceptable.

As shown in Table 7, the Department indicated that MERC included Rochester Project demand costs in the commodity portion of the PGA and summarized its bill impacts, by class.

Table 7: Comparison of October 2024 PGA Commodity Cost to November 2024 PGA Proposal by Customer Class

Customer Class	Annual Difference ($/yr/customer)	Percentage change
Residential	$34.41	13.90%
Small Commercial	$313.96	13.90%
Large Commercial	$6,426.49	13.90%
Small Interruptible	$1,652.10	13.90%
Large Interruptible	$8,880.70	13.90%

Regarding capacity substitutions, MERC noted that the second phase of Rochester Project capacity entered service on November 1, 2019. While no capacity substitutions have occurred recently, MERC will continue to provide updates in future demand entitlement filings.[56] The Department concluded that MERC complied with the Rochester Project Commission Order.[57]

The Department determined that MERC's Petition complied with Order Points 9 and 10 of the Commission's February 17, 2023 Order[58] while indicating that the prudency of MERC's actions

54 Petition, Attachment 3.

55 Petition, Attachment 8.

56 Petition, at 9.

57 Commission Order dated May 8, 2018, in Docket No. G-011/M-15-895.

58 Docket No's. G-999/CI-21-135 and G-011/CI-21-611.

to minimize natural gas costs will be evaluated when the Company files its annual automatic adjustment (AAA) report and true-up on September 1, 2025.

6. Minnesota Energy Resources Corp. – Supplemental Reply Comments

MERC requested approval of its proposed 320,242 Dth demand entitlement and, effective November 1, 2024, recovery of associated costs through the monthly PGA.

V. STAFF COMMENTS

Staff concurs with the Department's recommendations to approve MERC-Consolidated and MERC NNG's proposed demand entitlement levels, design-day analysis and associated costs recovery through the monthly PGA.

VI. DECISION OPTIONS

<u>MERC Consolidated PGA area</u>

1. Approve recovery of MERC's demand costs in the Consolidated territories through the monthly PGA effective November 1, 2024. [MERC, Department]

2. Accept MERC's proposed total entitlement level of 64,429 dekatherms in the Consolidated territories. [MERC, Department]

3. Approve MERC's Design-Day analysis for the Consolidated territories. [MERC, Department]

<u>MERC NNG PGA area</u>

4. Approve recovery of MERC's demand costs in the Northern Natural Gas territory through the monthly PGA effective November 1, 2024. [MERC, Department]

5. Accept MERC's proposed total entitlement level of 320,242 dekatherms in the Northern Natural Gas territory. [MERC, Department]

6. Approve MERC's Design-Day analysis for the Northern Natural Gas territory. [MERC, Department]