



Minnesota Energy Resources Corporation
2685 145th Street West
Rosemount, MN 55068
www.minnesotaenergyresources.com

August 1, 2025

VIA ELECTRONIC FILING

Mike Bull
Interim Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

**PUBLIC DOCUMENT – TRADE
SECRET DATA HAS BEEN EXCISED**

Re: In the Matter Minnesota Energy Resources Corporation's Petition for
Approval of a Change in Demand Entitlement for its NNG System

Docket No. G011/M-25-68

Dear Mr. Bull:

In accordance with Minnesota Rules 7825.2910, subpart 2, please find enclosed Minnesota Energy Resources Corporation's (MERC's or the Company's) request to change demand entitlements for its Northern Natural Gas purchased gas adjustment area. Please note that any updated information will be provided with MERC's November 1, 2025 filing. MERC is also filing Excel and PDF versions of the attachments.

Pursuant to Minnesota Rule 7825.2910, subpart 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

The nonpublic version of the filing contains trade secret information. Specifically, the nonpublic version of the Petition contains information regarding MERC's ongoing negotiations regarding pipeline capacity, including the location, size and timing of needs and indicative pricing and contract terms that are not generally known to, and not readily ascertainable by competitors of MERC, who could obtain economic value from its disclosure. MERC maintains this information as secret. Accordingly nonpublic version of the filing contains data which qualifies as "Trade Secret Data" pursuant to Minnesota Statutes Section 13.37 Subdivision 1(b).

Please contact me at (414) 221-4208 if you have any questions regarding the information in this filing. Thank you for your attention to this matter.

Mr. Mike Bull
August 1, 2025
Page 2

Sincerely yours,

/s/Joylyn Hoffman Malueg
Joylyn Hoffman Malueg
Senior Project Specialist
Minnesota Energy Resources Corporation

Enclosures
cc: Service List

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben
Hwikwon Ham
Audrey Partridge
Joseph K. Sullivan
John A. Tuma

Chair
Commissioner
Commissioner
Commissioner
Commissioner

In the Matter of the Petition of Minnesota
Energy Resources Corporation for Approval of
a Change in Demand Entitlement for its NNG
System

Docket No. G011/M-25-68

FILING UPON CHANGE IN DEMAND

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

This filing includes the following attachments:

- Attachment A:** Notice of Availability.
- Attachment B:** One paragraph summary of the filing in accordance with Minn. R. 7829.1300, subp. 1.
- Attachment C:** Petition for Change in Demand with Attachments.
- Attachment D:** Certificate of Service and Service List.

The following information is provided in accordance with Minn. R. 7829.1300:

¹ MERC also serves certain of its Minnesota customers off of the Viking Gas Transmission, Great Lakes Gas Transmission, and Centra Pipeline systems. MERC requests approval of a demand entitlement change for the 2025-2026 heating season for its MERC-Consolidated PGA in a separate docket.

I. Summary of Filing

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing is attached.

II. Service

Pursuant to Minn. R. 7829.1300, subp. 2, MERC has served a copy of this filing on the Department of Commerce, Division of Energy Resources and the Office of the Attorney General — Residential Utilities Division. The summary of filing has been served on all parties on the attached service list. Additionally, pursuant to Minn. R. 7825.2910, subp. 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

III. General Filing Information

A. Name, Address, and Telephone Number of the Utility

Minnesota Energy Resources Corporation
2685 145th Street West
Rosemount, MN 55068
(651) 322-8901

B. Name, Address, Electronic Address, and Telephone Number of Attorney for the Utility

Kristin M. Stastny
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
KStastny@Taftlaw.com
(612) 977-8656


C. Date of the Filing and Proposed Effective Date

Date of filing: August 1, 2025
Proposed Effective Date: November 1, 2025

D. Statute Controlling Schedule for Processing the Filing

Minnesota Statutes and related rules do not provide an explicit time frame for action by the Commission. Under Minn. R. 7829.1400, initial comments are due within 30 days of filing, with reply comments due 10 days thereafter.

E. Signature, Electronic Address, and Title of Utility Employee Responsible for the Filing



Joylyn C. Hoffman Malueg
Senior Project Specialist
Joylyn.HoffmanMalueg@wecenergygroup.com
2685 145th Street West
Rosemount, MN 55068
(414) 221-4208

The nonpublic version of the filing contains trade secret information. Specifically, the nonpublic version of the Petition contains information regarding MERC's ongoing negotiations regarding pipeline capacity, including the location, size and timing of needs and indicative pricing and contract terms that are not generally known to, and not readily ascertainable by competitors of MERC, who could obtain economic value from its disclosure. MERC maintains this information as secret. Accordingly nonpublic version of the filing contains data which qualifies as "Trade Secret Data" pursuant to Minnesota Statutes Section 13.37 Subdivision 1(b). If additional information is required, please contact Joylyn Hoffman Malueg at (414) 221-4208.

DATED: August 1, 2025

Respectfully submitted,
MINNESOTA ENERGY RESOURCES
CORPORATION

By: /s/ Joylyn C. Hoffman Malueg
Joylyn C. Hoffman Malueg
2685 145th Street West
Rosemount, MN 55068
Telephone: (414) 221-4208

ATTACHMENT A

August 1, 2025

To: Docket No. G011/M-25-68 Service List

RE: Minnesota Energy Resources Corporation-NNG Petition for Approval of Change in Demand Entitlement

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation has filed a petition with the Minnesota Public Utilities Commission for approval of a change in demand entitlement for its NNG Purchased Gas Adjustment system.

To obtain copies, or if you have any questions, please contact:

Joylyn C. Hoffman Malueg
Minnesota Energy Resources Corporation
2685 145th Street West
Rosemount, MN 55068
(414) 221-4208

Please note that this filing is also available through the eDockets system maintained by the Minnesota Department of Commerce and the Minnesota Public Utilities Commission. You can access this document by going to eDockets through the websites of the Department of Commerce or the Public Utilities Commission or going to the eDockets homepage at:

<https://www.edockets.state.mn.us/EFiling/home.jsp>

Once on the eDockets homepage, this document can be accessed through the Search Documents link and by entering Docket Number 25-68.

**STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION**

**Katie J. Sieben
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**Chair
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In the Matter of the Petition of Minnesota
Energy Resources Corporation for Approval of
a Change in Demand Entitlement for its NNG
System

Docket No. G011/M-25-68

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation – NNG (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC customers served off of the Northern Natural Gas (NNG) system. MERC requests the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2025.

ATTACHMENT C

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben
Hwikwon Ham
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In the Matter of the Petition of Minnesota
Energy Resources Corporation for Approval
of a Change in Demand Entitlement for its
NNG System

Docket No. G011/M-25-68

PETITION OF MINNESOTA ENERGY RESOURCES CORPORATION-NNG FOR CHANGE IN
DEMAND

I. Introduction

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NNG (MERC or the Company), a subsidiary of WEC Energy Group, hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NNG customers served off the Northern Natural Gas interstate pipeline system. MERC requests the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2025. Included with this filing are the following Attachments:

Attachment 1: Design-Day Demand Summary

Attachment 2: Sales Forecast

Attachment 3: Current and Proposed Entitlement Levels

Attachment 4: Rate Impact of the Proposed Demand Change

Attachment 5: Financial Option Summary

Attachment 6: Winter Plan

Attachment 7: Entitlement History

Attachment 8: Change in Entitlement Levels and Related Demand Costs

Attachment 9: Actual Throughput and Design Day Forecast Estimated Throughput

Attachment 10: Customer Counts

Attachment 11: Hedging Summary

Attachment 12: Forecast Methodology

Through this filing, MERC also addresses compliance with the following Commission Orders:

- 1) the Commission's May 8, 2018, Order in Docket No. G011/M-15-895, which required MERC to provide a discussion of any capacity substitutions in its annual demand entitlement filings, and
- 2) Order Points 9 and 10 from the Commission's February 17, 2023 Order in Docket Nos. G999/CI-21-135 and G011/CI-21-611.²

II. Discussion

A. MERC's NNG Design-Day Requirements

Minnesota Rule 7825.2910, subpart 2(b) requires that a filing upon change in demand include the utility's Design-Day demand by customer class and the change in Design-Day demand, if any, necessitating the demand revision. The NNG Design-Day requirement has increased by 7,009 dekatherms (dth), or 2.4%, from the 2024-2025 heating season.

² Order Point 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 cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option. Order Point 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.

**Table 1: MERC Proposed NNG Reserve Margins
For the 2025-2026 Heating Season**

	Reserve Margin 2025-2026 Heating Season	Reserve Margin 2024-2025 Heating Season	Change
NNG Zone EF	7.76%	10.36%	-2.6%

For the Demand Entitlement filing effective November 1, 2025, the total Design-Day requirement for MERC NNG is 297,178 dth (Attachment 1). The difference between the total Design-Day requirement and total Design-Day capacity results in a 7.76% reserve margin (Attachment 3). As required by Order Point 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.

B. Gas Supply

Minnesota Rule 7825.2910, subpart 2, requires a description of Design-Day gas supply from all sources under the new level, allocation, or form of demand. This information is provided in Attachment 3.

C. Forecast Methodology for MERC Demand Entitlement November 1, 2025

See Attachment 12. As discussed in Attachment 12, MERC's 2025-2026 Design-Day Regression analysis utilizes daily telemetry data for all of the MERC-NNG customers.

III. Additional Filing Requirements

A. Daily Design-Day Estimate to Actual Comparison

In the 2007-2008 demand entitlement dockets,³ MERC agreed to include a daily estimate utilizing the Design-Day model, which is calculated in Attachment 9. The daily

³ Docket Nos. G007/M-07-1402; G007/M-07-1403; G007/M-07-1404; and G007/M-07-1405.

estimate is compared to actual consumption. The actual volumes are total throughput which includes interruptible and transportation volumes that are located behind MERC citygates. The Design-Day model only calculates firm volumes. MERC does not forecast on a daily/monthly basis utilizing the Design-Day model. The Design-Day model is utilized to calculate the theoretical peak day.

B. Average Customer Counts

In the 2007-2008 demand entitlement dockets, MERC agreed to include average customer counts which are provided in Attachment 10.

C. Balancing

Order Point 4 of the Commission's January 21, 2015, Order in MERC's 2010-2011 demand entitlement dockets, Docket Nos. G007/M-10-1166; G007/M-10-1167; G011/M-10-1168; and G011/M-10-1169, required that in future demand entitlement filings MERC 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. Additionally, in Docket No. G-999/AA-12-756, by Order dated November 14, 2013, the Commission ordered that "prospectively, all regulated natural gas utilities shall recover balancing service costs, and shall credit the utility's penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that can reasonably be implemented."

MERC subsequently revised its monthly PGA filings, beginning November 2013, to recover all balancing costs via the commodity portion of the PGA. MERC's 2014 AAA and true-up filings, as well as the 2014 Demand Entitlement filing, also reflected this change. The current MERC-NNG demand entitlement filing includes detailed evidence of the allocation of balancing costs to the commodity portion of the PGA in Attachment 4, page 2 of 2.

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

There are two types of demand entitlement changes. The first type 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.

1. Design-Day Deliverability Changes

As shown in Attachment 3, MERC-NNG's net Design-Day Deliverability is unchanged from 2024-2025.

The Commission's February 17, 2023 Order in Docket Nos. G-999/CI-21-135 and G-011/CI-21-611 Requiring Actions to Mitigate Impacts from Future Natural Gas Price Spikes, Setting Filing Requirements, and Initiating a Proceeding to Establish Gas Resource Planning Requirements, requires in Order Point 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 discussion of the tradeoff, including a comparison with the least-cost capacity option. As mentioned above, MERC does not have any change to net design-day deliverability for 2025-2026 as compared to 2024-2025.

2. Other Demand Entitlement Changes

MERC-NNG contract 112495 has a base and a variable component as outlined in the NNG's tariffs as approved by the Federal Energy Regulatory Commission (FERC). The base and variable components are set each year as a result 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, with a corresponding decrease in the base component. This change does not result in an increase or decrease in demand entitlement levels.

E. Financial Option Units and Premiums

MERC 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 (page 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.

In accordance with the Commission's April 9, 2021, Order in Docket No. G011/M-20-833 approving MERC's variance extension request to recover the costs of financial instruments through the PGA, MERC provides the following information:

- i. a list of all financial instruments purchased for the upcoming heating season (see Attachment 11);
- ii. the cost premium associated with each contract (see Attachment 5);
- iii. the size (in dth) of each contract (see Attachments 5 and 11);
- iv. the contract date (see Attachment 5);
- v. the contract price (see Attachment 11);
- vi. an attachment that details the projected total system sales estimates for the upcoming heating season, including all supporting data and assumptions used when calculating the sales forecast, and the total number of volumes hedged using financial instruments for the upcoming heating season (see Attachment 2 and Attachment 6, page 1 of 2); and
- vii. a detailed discussion of the anticipated benefits to ratepayers related to MERC's financial instrument contracts, discussed below.

The NNG 2025-2026 Winter Portfolio Hedging Plans - Minnesota Energy Resources Corporation for gas supply purchases is 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. Please see Attachment 11, page 1 of 3. As shown in Attachment 11, page 2 of 3, MERC projects the NNG storage WACOG to be \$2.8223/dth, an increase from last winter's WACOG. While MERC still continues 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. Both the futures and option strike prices are up from winter 2024-2025. If the NYMEX contract(s) settle above that price, the options are exercised and the MERC customer gas cost is capped at the average strike price. Please see Attachment 11, page 3 of 3. 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.

The Commission's February 17, 2023 Order in Docket Nos. G-999/CI-21-135 and G-011/CI-21-611 Requiring Actions to Mitigate Impacts from Future Natural Gas Price Spikes, Setting Filing Requirements, and Initiating a Proceeding to Establish Gas Resource Planning Requirements, requires in Order Point 10 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) the forecasted minimum, average, and maximum day load requirements, and C) the expected mix of baseload, storage, and spot supply on those days. 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.

F. PGA Cost Recovery

MERC proposes to begin recovering the costs associated with the change in demand-related costs in its monthly PGA effective November 1, 2025. Rate impacts associated with this change can be found on Attachment 4, page 1.

G. Impacts of Telemetry

Throughout the course of 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. MERC's process requires an evaluation of the system capability before a customer is allowed to switch to firm. As a result, the firm volumes associated with a customer switch fall within the Design-Day parameters and do not impact demand entitlement levels.

H. Rochester Project Compliance

The Commission's May 8, 2018, Order in Docket No. G011/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.⁴

As discussed in Docket No. G011/M-19-496, the second tranche of additional capacity resulting from the NNG upgrades related to the Rochester Project approved in Docket No. G011/M-15-895 became available on November 1, 2019. This additional capacity is included for recovery through the commodity portion of the PGA, in accordance with the Commission's May 5, 2017, Order Approving Rochester Project and Granting Rider Recovery with Conditions.

⁴ 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.

With respect to capacity substitutions related to the additional Rochester Project capacity, as discussed in MERC's August 31, 2017, Capacity Release Plan, MERC received Commission approval to expand its service into the communities of Balaton and Esko (Docket Nos. G011/M-16-654 and G011/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. Additionally, in Docket No. G011/M-18-460, MERC received Commission approval, by order dated March 29, 2019, to extend service into Pengilly. MERC 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. No additional capacity substitutions have occurred. MERC will provide updates on future capacity substitutions in future Demand Entitlement filings and updates.

IV. MERC-NNG Capacity Releases

As part of the Rochester Expansion Project, MERC has taken action 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. For the 2025-2026 heating season, MERC has calculated a reserve margin of 7.76% and will post its excess capacity for this coming heating season, totaling 8,205 dth/day (as shown in Attachment 3), for release to the market in the September 2025 timeframe.

V. MERC-NNG Impacts of Interstate Pipeline Rate Cases

On July 1, 2025, Northern Natural Gas (NNG) filed a Section 4 rate case with FERC. 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. Since the result of the rate case is unknown at this time, MERC has held rates at current levels for determining its demand rate in this proceeding. In accordance with Minn. R. 7825.2910, MERC will reflect actual rate increases in its monthly PGA filing when those rates go into effect.

VI. MERC-NNG Future Capacity Outlook

As discussed in MERC's 2023-2024 and 2024-2025 Demand Entitlement filings⁵, MERC has identified decreased reserve margins within different operating areas of the MERC-NNG system, as well as at a Total System level.⁶ While MERC-NNG has a Total System surplus of 8,205 dth/day for the 2025-2026 heating season, within [TRADE SECRET DATA BEGINS...
... TRADE SECRET DATA ENDS], MERC-NNG is not expected to have enough capacity to meet its 5% reserve margin at a Total System level. Further, there are operating areas of MERC-NNG that have excess capacity, such as the Rochester area, but other operating areas that are very short on capacity, such as the MERC gates in the Farmington area (as an example). The Rochester and Farmington areas have different laterals on the NNG system and are therefore not integrated. Since they are not served by the same NNG lateral, utilizing the excess Rochester capacity to serve the Farmington area is not an operationally viable solution, nor allowed by NNG. Reliability during winter season continues to be MERCs primary concern, and contracting for adequate capacity will mitigate the potential event of insufficient pressures on the distribution system to meet MERC's customer's needs.

Observing that MERC-NNG currently has operating areas with insufficient capacity to meet the Peak (and Reserve) need, and that MERC Total System level shortages are

⁵ Docket Nos. G011/M-23-359 and G011/M-24-270, respectively.

⁶ As shown on Attachment 3, Capacity Surplus/Shortage to Design Day + 5% Reserve (Heating Season).


forecasted to occur within [TRADE SECRET DATA BEGINS...... TRADE SECRET DATA ENDS], the Company has evaluated various options to meet its needs. To best evaluate option scales and economics, MERC forecasted its Peak (and Reserve) needs for a 10 year period. A 10-year historic growth rate for the MERC-NNG system 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 also scaled down the remainder of the 10-year timeframe by 50 percent once again. See Table 2 below.

Table 2: MERC-NNG Growth Rate Assumptions

<i>Heating Season (Nov-Mar)</i>	<i>YoY Growth Rate</i>
2026-2029	1.27%
2029-2032	0.64%
2032-2036	0.32%

MERC 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. For all of these options, except for contracting for current NNG available capacity, there are significant facilities, workforce, regulatory filings, etc. that are necessary. MERC has looked to meet its 10 year forecasted need in order to manage the costs via economies of scale, particularly with the required facilities that are necessary for any project. Having to do one project for a 10 year period, as opposed to three smaller projects, for example, is much more cost effective. However, when projects such as these occur, there will be years in which MERC will have excess capacity, over the peak plus 5% reserve. MERC will release excess capacity over its reserve needs, as stated above in Section IV.

1. LNG

MERC analyzed the potential ability for LNG peaking service to meet the Total System needs, or even operating system needs. The area that MERC-NNG has its largest shortage of capacity is around [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS]. 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 needs for more capacity were. The LNG facility would connect directly to NNG's interstate pipeline system, as opposed to MERC's distribution system, which would allow the gas to get to more MERC locations of need. MERC 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. The total costs for this alternative option of placing the LNG facility outside of the populated area was not economically, nor operationally feasible.

2. Currently Available NNG Capacity

MERC [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS] of NNG capacity to meet identified areas of need, primarily around [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS] 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 it sold as part of the Open Season would be at a rate [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS]. At that time, MERC was still analyzing

other alternatives for meeting its needs and as a result of the [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS] expansion rate, did not commit to purchasing any capacity at that time.

MERC also [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS] of 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 it sold as part of the Open Season would be at a rate of [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS].

3. Pipeline Alternatives

The areas that MERC is short of capacity are currently all served by NNG. Geographically, 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 not only require the typical expansion facilities of additional compression and looping to account for additional demand, but would also 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 extraordinary. Additionally, Great Lakes Gas Transmission, Viking Gas Transmission, and Northern Border Pipeline are all sold out of their capacity into the MERC service territory. As a result, pipeline alternatives were not deemed feasible.

4. NNG Pipeline Expansion

As mentioned above, MERC [TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS]. After NNG's response of not being able to provide any available capacity at tariff rate, they provided

MERC a preliminary cost estimate for a negotiated rate for pipeline capacity made available via an expansion project. MERC's portion of the expansion project would be for

[TRADE SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA ENDS] to

meet the identified needs as discussed above, and would [TRADE SECRET DATA BEGINS...

[REDACTED] ... TRADE SECRET DATA ENDS], which aligns with MERC's forecast for

Total System shortage of Peak Day plus 5% reserve. The expected annual capacity costs for

the expansion capacity will be [TRADE SECRET DATA BEGINS... [REDACTED]

[REDACTED] ... TRADE SECRET DATA ENDS] for a [TRADE SECRET DATA BEGINS... [REDACTED]

[REDACTED] ... TRADE SECRET DATA ENDS] commitment. This initial cost estimate was considered

along the alternatives detailed above, and is considered to be the most cost effective, and

reliable solution of those alternatives. Therefore, MERC is moving forward with the [TRADE

SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET DATA

ENDS] expansion project to meet the forecasted capacity need shortage. MERC [TRADE

SECRET DATA BEGINS... [REDACTED] ... TRADE SECRET

DATA ENDS]. NNG will assess all their customer's volumes and respond with a new rate

estimate now 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. The PA will include a

condition that [TRADE SECRET DATA BEGINS... [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] ... TRADE SECRET DATA ENDS] is still in progress

and MERC will provide an update in the November 1 filing of the 2025-2026 MERC-NNG

Demand Entitlement Filing.

VII. Conclusion

MERC respectfully requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2025.

DATED: August 1, 2025

Respectfully submitted,

MINNESOTA ENERGY RESOURCES
CORPORATION

By: /s/ Joylyn C. Hoffman Malueg
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MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND SUMMARY

NOVEMBER 1, 2025

NNG

Design Day Requirement		297,178
Total Peak Day Entitlement		320,242
2024/25 Firm Peak Day Actual Sendout	1/20/2025	244,679
Firm Annual Throughput - Minnesota		26,180,034
No. of Firm Customers		213,567
Department Load Factor Calculation		29.31%

MINNESOTA ENERGY RESOURCES - NNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS

NOVEMBER 1, 2025

NNG

Pipeline Group	2024/25 Customer Count	Zone Total Customer Count	1/20 Design DDD	Regression Factors		Regression Total	Regression Adjustment	1/20 Requirements Regression Load	Firm/Interrupt. Contract Demand Units	Total
				Intercept	Slope					

PEAK										
NNG	213,567	213,567	99	9,359	2,549	282,406	14,718	297,123	55	297,178

OFF PEAK										
NNG	213,567	213,567	55	9,359	2,549	159,777	14,718	174,495	55	174,550

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND PER CUSTOMER

NOVEMBER 1, 2025

NNG

<u>Heating Season</u>	<u>No. of Firm Customers</u>	<u>Design Day Requirements</u>	<u>MMBtu /Customer /Day</u>
25/26	213,567	297,178	1.39
24/25	212,522	290,169	1.37
23/24	209,362	290,934	1.39
22/23	208,405	291,250	1.40
21/22	206,351	282,710	1.37
20/21	204,781	280,796	1.37
19/20	201,190	277,376	1.38
18/19	198,628	273,842	1.38
17/18	197,991	267,783	1.35
16/17	195,311	262,324	1.34
15/16	192,016	259,076	1.35
14/15	189,078	273,917	1.45
13/14	189,254	258,913	1.37
12/13	187,545	239,325	1.28

MINNESOTA ENERGY RESOURCES - NNG

SUMMER/WINTER USAGE - Dth
PROJECTED 12 MONTHS ENDING JUNE 2026

NNG

<u>Class</u>	<u>Summer Apr-Oct</u>	<u>Winter Nov-Mar</u>	<u>Total</u>
GS	6,115,132	20,062,692	26,177,824
Interruptible	598,584	965,053	1,563,637
Firm/Interruptible	861	1,349	2,210
Total	6,714,577	21,029,094	27,743,671

MINNESOTA ENERGY RESOURCES - NNG

ENTITLEMENT LEVELS

NOVEMBER 1, 2025

NNG

<u>Capacity Type</u>	<i>Summer</i>			<i>April/October</i>			<i>Winter</i>		
	2024-25 MMBtu	Change MMBtu	Proposed MMBtu	2024-25 MMBtu	Change MMBtu	Proposed MMBtu	2024-25 MMBtu	Change MMBtu	Proposed MMBtu
TF-12 Base & Variable	84,116	0	84,116	84,116	0	84,116	84,116	0	84,116
TF5	0	0	0	0	0	0	36,275	0	36,275
TFX - 12	91,815	0	91,815	91,815	0	91,815	91,815	0	91,815
TFX - 5	0	0	0	0	0	0	104,501	0	104,501
TFX- (Apr/Oct) Offpeak*	0	0	0	2,000	0	2,000	0	0	0
NBPL	50,000	0	50,000	50,000	0	50,000	50,000	0	50,000
Northwest Gas (Windom)	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500
Northwestern Energy (Ortonville)	1,035	0	1,035	1,035	0	1,035	1,035	0	1,035
NNG Zone Delivery Call Option	0	0	0	0	0	0	0	0	0
Total	179,466	0	179,466	181,466	0	181,466	320,242	0	320,242
Heating Season									
Forecasted Design Day-Adjusted							290,169	7,009	297,178
Forecasted Design Day + 5% Reserve							304,677		312,037
Forecasted Design Day (Non-Heating Season)				167,929	6,621	174,550			
Capacity Surplus/Shortage to Design Day (Heating Season)							30,073	(7,009)	23,064
Capacity Surplus/Shortage to Design Day + 5% Reserve (Heating Season)							15,565		8,205
Non-Heating Season									
Capacity Surplus/Shortage				13,537	(6,621)	6,916			
*Not included in Heating Season Total entitlement									
Reserve Margin				8.06%	-4.10%	3.96%	10.36%	-2.60%	7.76%

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2025

NNG

All costs in \$/Dth	Base Cost of Gas G011/MR-22-505 Mar 1, 2024	Demand Charge Demand Filing Nov 1, 2024	Most Recent PGA Jul 1, 2025	Proposed Effective Nov 1, 2025	Result of Proposed Change			
					Change from Last Rate Case	Change from Nov 1, 2024 Demand Filing	Change from Last PGA %	Change from Last PGA \$

1) General Service Residential: Avg. Annual Use:		86	Dth					
Commodity Cost	\$5.5426	\$3.2949	\$2.2815	\$2.2395	(\$3.3031)	(\$1.0554)	-1.84%	(\$0.0420)
Demand Cost	\$1.0107	\$1.2853	\$1.2853	\$1.2903	\$0.2796	\$0.0050	0.39%	\$0.0050
Commodity Margin	\$3.2919	\$3.2919	\$3.2919	\$3.2919	\$0.0000	\$0.0000	0.00%	\$0.0000
Total Cost of Gas	\$9.8452	\$7.8721	\$6.8587	\$6.8217	(\$3.0235)	(\$1.0504)	-0.54%	(\$0.0370)
Avg Annual Cost	\$842.75	\$673.85	\$587.10	\$583.94	(\$258.81)	(\$89.91)	-0.54%	(\$3.17)
Effect of proposed commodity change on average annual bills:								(\$3.60)
Effect of proposed demand change on average annual bills:								\$0.43

2) Small C&I Firm, Class 2: Avg. Annual Use:		781	Dth					
Commodity Cost	\$5.5426	\$3.2949	\$2.2815	\$2.2395	(\$3.3031)	(\$1.0554)	-1.84%	(\$0.0420)
Demand Cost	\$1.0107	\$1.2853	\$1.2853	\$1.2903	\$0.2796	\$0.0050	0.39%	\$0.0050
Commodity Margin	\$2.5030	\$2.5030	\$2.5030	\$2.5030	\$0.0000	\$0.0000	0.00%	\$0.0000
Total Cost of Gas	\$9.0563	\$7.0832	\$6.0698	\$6.0328	(\$3.0235)	(\$1.0504)	-0.61%	(\$0.0370)
Avg Annual Cost	\$7,072.97	\$5,531.98	\$4,740.51	\$4,711.62	(\$2,361.35)	(\$820.36)	-0.61%	(\$28.90)
Effect of proposed commodity change on average annual bills:								(\$32.80)
Effect of proposed demand change on average annual bills:								\$3.90

3) Large C&I Firm Class 3: Avg. Annual Use:		15,986	Dth					
Commodity Cost	\$5.5426	\$3.2949	\$2.2815	\$2.2395	(\$3.3031)	(\$1.0554)	-1.84%	(\$0.0420)
Demand Cost	\$1.0107	\$1.2853	\$1.2853	\$1.2903	\$0.2796	\$0.0050	0.39%	\$0.0050
Commodity Margin	\$1.6890	\$1.6890	\$1.6890	\$1.6890	\$0.0000	\$0.0000	0.00%	\$0.0000
Total Cost of Gas	\$8.2423	\$6.2692	\$5.2558	\$5.2188	(\$3.0235)	(\$1.0504)	-0.70%	(\$0.0370)
Avg Annual Cost	\$131,763.88	\$100,221.31	\$84,020.80	\$83,429.30	(\$48,334.58)	(\$16,792.01)	-0.70%	(\$591.49)
Effect of proposed commodity change on average annual bills:								(\$671.42)
Effect of proposed demand change on average annual bills:								\$79.93

4) Small C&I Interruptible, Class 2: Avg. Annual Use:		4,110	Dth					
Commodity Cost	\$5.5426	\$3.2949	\$2.2815	\$2.2395	(\$3.3031)	(\$1.0554)	-1.84%	(\$0.0420)
Commodity Margin	\$1.5047	\$1.5047	\$1.5047	\$1.5047	\$0.0000	\$0.0000	0.00%	\$0.0000
Total Cost of Gas	\$7.0473	\$4.7996	\$3.7862	\$3.7442	(\$3.3031)	(\$1.0554)	-1.11%	(\$0.0420)
Avg Annual Cost	\$28,962.29	\$19,724.92	\$15,560.15	\$15,387.54	(\$13,574.75)	(\$4,337.38)	-1.11%	(\$172.61)
Effect of proposed commodity change on average annual bills:								(\$172.61)

5) Large C&I Interruptible, Class 3: Avg. Annual Use:		22,091	Dth					
Commodity Cost	\$5.5426	\$3.2949	\$2.2815	\$2.2395	(\$3.3031)	(\$1.0554)	-1.84%	(\$0.0420)
Commodity Margin	\$1.2058	\$1.2058	\$1.2058	\$1.2058	\$0.0000	\$0.0000	0.00%	\$0.0000
Total Cost of Gas	\$6.7484	\$4.5007	\$3.4873	\$3.4453	(\$3.3031)	(\$1.0554)	-1.20%	(\$0.0420)
Avg Annual Cost	\$149,080.93	\$99,426.31	\$77,038.99	\$76,111.16	(\$72,969.77)	(\$23,315.16)	-1.20%	(\$927.83)
Effect of proposed commodity change on average annual bills:								(\$927.83)

Note: Average Annual Use based on 2023 MERC Gas Rate Design in Docket GR-22-504

Note: Rates do not include the ACA adjustment.

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2025

NNG

A. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE:						01-Nov-25
	Contract #(s)	Tariff-Summer (7 mths)	Tariff-Winter (5 mths)	Wt. Annual	GRI	Total
TF-12B	112495	\$ 9.6760	\$ 17.4170	\$12.9014	\$0.0000	\$12.9014
TF-12B Rochester Capped	112495	\$ 5.6830	\$ 10.2300	\$7.5776	\$0.0000	\$7.5776
TF-12V Rochester Capped	112495	\$ 5.6830	\$ 13.8660	\$9.0926	\$0.0000	\$9.0926
TF-12V	112495	\$ 9.6760	\$ 23.6090	\$15.4814	\$0.0000	\$15.4814
TF-5	112495	\$ -	\$ 25.7990	\$25.7990	\$0.0000	\$25.7990
TF-5 Rochester Capped	112495	\$ -	\$ 15.1530	\$15.1530	\$0.0000	\$15.1530
TFX ¹	112486/141673/142983	\$ 9.6760	\$ 25.7990	\$16.3939	\$0.0000	\$16.3939
TFX Rochester Capped	112486	\$ 5.6830	\$ 15.1530	\$9.6288	\$0.0000	\$9.6288
TFX-5	112486	\$ -	\$ 25.7990	\$25.7990	\$0.0000	\$25.7990
TFX-5 Rochester Capped	112486	\$ -	\$ 15.1530	\$15.1530	\$0.0000	\$15.1530
TFX Rochester	112486	\$ 37.1175	\$ 37.1175	\$37.1175	\$0.0000	\$37.1175
TFX Rochester II	112486	\$ 10.7714	\$ 10.7714	\$10.7714	\$0.0000	\$10.7714
TFX - Discount	111866	\$ 2.2192	\$ 15.1392	\$7.6025	\$0.0000	\$7.6025
TFX - Discount	111866	\$ 4.8640	\$ 4.8640	\$4.8640	\$0.0000	\$4.8640
TFX - Discount	111866	\$ 5.4720	\$ 5.4720	\$5.4720	\$0.0000	\$5.4720
Gas Cost						\$1.3815 /Dth

B. ANNUAL SALES -- As approved in Docket No. G011/MR-22-505		
Total MERC NNG Annual Sales		280,960,833
Total MERC NNG Firm Sales		258,811,603

C. MERC-NNG'S CURRENT COST OF GAS EFFECTIVE:						01-Nov-25	
	Contract #(s)	Monthly Entitlements (Dth)	Months	Rate \$/Dth	Contract Costs	Total MERC NNG Firm Sales	Rate/Therm
1. NNG-GS	TF12B (Max Rate) Winter	112495	18,984	5	\$ 17.4170	\$1,653,222	258,811,603 \$ 0.00639
	TF12B (Max Rate) Summer	112495	18,984	7	\$ 9.6760	\$1,285,824	258,811,603 \$ 0.00497
	TF12V (Max Rate)	112495	49,066	12	\$ 15.4814	\$9,115,324	258,811,603 \$ 0.03522
	TF5 (Max Rate)	112495	16,183	5	\$ 25.7990	\$2,087,526	258,811,603 \$ 0.00807
	TF5 (Rochester Capped)	112495	20,092	5	\$ 15.1530	\$1,522,270	258,811,603 \$ 0.00588
	TF12B (Rochester Capped)	112495	11,574	12	\$ 7.5776	\$1,052,438	258,811,603 \$ 0.00407
	TF12V (Rochester Capped)	112495	4,492	12	\$ 9.0926	\$490,128	258,811,603 \$ 0.00189
	TFX12 (Max Rate)	112486	8,750	12	\$ 16.3939	\$1,721,360	258,811,603 \$ 0.00665
	TFX Apr (Max Rate)	112486	2,000	1	\$ 9.6760	\$19,352	258,811,603 \$ 0.00007
	TFX Oct (Max Rate)	112486	2,000	1	\$ 9.6760	\$19,352	258,811,603 \$ 0.00007
	TFX (Rochester Capped)	112486	2,072	12	\$ 9.6288	\$239,410	258,811,603 \$ 0.00093
	TFX5 (Max Rate)	112486	62,549	5	\$ 25.7990	\$8,068,508	258,811,603 \$ 0.03118
	TFX5 (Rochester Capped)	112486	16,939	5	\$ 15.1530	\$1,283,383	258,811,603 \$ 0.00496
	TFX12 (Discount)	111866	1,283	12	\$ 4.8640	\$74,886	258,811,603 \$ 0.00029
	TFX12 (Discount)	111866	8,271	12	\$ 5.4720	\$543,107	258,811,603 \$ 0.00210
	TFX12 (Discount)	111866	11,921	12	\$ 7.6025	\$1,087,553	258,811,603 \$ 0.00420
	TFX5 (Discount)	111866	379	5	\$ 4.8640	\$9,217	258,811,603 \$ 0.00004
	TFX5 (Discount)	111866	2,445	5	\$ 5.4720	\$66,895	258,811,603 \$ 0.00026
	TFX5 (Discount)	111866	22,189	5	\$ 15.1392	\$1,679,619	258,811,603 \$ 0.00649
	TFX (Max Rate)	141673/142983	6,486	12	\$ 16.3939	\$1,275,970	258,811,603 \$ 0.00493
	Windom		2,500	12	\$ -	\$0	258,811,603 \$ -
	Northwestern Energy		1,035	12	\$ 8.0000	\$99,360	258,811,603 \$ 0.00038
	Total Demand Cost					\$33,394,705	\$ 0.12903
	NNG-GS Demand Current Cost of Gas/therm						\$ 0.12903
	NNG-GS Commodity Current Cost of Gas/therm						\$ 0.22395
	Total NNG-GS Current Cost of Gas/therm						\$ 0.35298
2. NNG - General Service, Interruptible, Firm/Interruptible - Commodity							
	Contract #(s)	Monthly Entitlement (Dth)	Months	Rate (\$/Dth)	Contract Costs	Total MERC NNG Annual Sales	Rate (\$/therm)
FDD - Reservation	118657	107,524	12	\$ 3.2345	\$4,173,437	280,960,833	\$ 0.01485
FDD - Storage Cycle	118657	1,239,864	5	\$ 0.6731	\$4,172,763	280,960,833	\$ 0.01485
FDD - Reservation	118657	5,550	12	\$ 3.2758	\$218,168	280,960,833	\$ 0.00078
FDD - Storage Cycle	118657	64,000	5	\$ 0.6818	\$218,176	280,960,833	\$ 0.00078
FDD - Reservation	open	0	0	\$ -	\$0	280,960,833	\$ -
FDD - Storage Cycle	open	0	0	\$ -	\$0	280,960,833	\$ -
FDD - Reservation	open	0	0	\$ -	\$0	280,960,833	\$ -
FDD - Storage Cycle	open	0	0	\$ -	\$0	280,960,833	\$ -
(a) Firm Deferred Delivery Storage Contracts					\$8,782,544		\$ 0.03126
Per Docket No. G-007/M-07-1402-05 dated August 6, 2014, storage demand charges will be allocated through the commodity charge effective 11/1/2014.							
	Contract #(s)	Monthly Entitlement (Dth)	Months	Rate (\$/Dth)	Contract Costs	Total MERC NNG Annual Sales	Rate (\$/therm)
NBPL	101251	50,000	12	\$ 5.3578	\$3,214,660	280,960,833	\$ 0.01144
TFX12 (Rochester)	112486	10,500	12	\$ 37.1175	\$4,676,805	280,960,833	\$ 0.01665
TFX12 (Rochester II)	112486	34,500	12	\$ 10.7714	\$4,459,360	280,960,833	\$ 0.01587
TFX12 (SE MN Expansion)	112486	8,032	12	\$ 16.3939	\$1,580,110	280,960,833	\$ 0.00562
(b) Delivery Contracts to be recovery via Commodity					\$13,930,934		\$ 0.04958
Per Docket No. G-011/M-15-895 dated May 5, 2017, recovery of the costs associated with Rochester and SE MN Expansion is via commodity.							
	Contract #(s)	Annual Sales (Dth)	Rate (\$/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate (\$/therm)	
(c) Remaining Costs to be Recovered via Commodity	Commodity	28,096,083	x	\$1.3815	\$38,814,739	280,960,833 \$ 0.13815	
Balancing Service		272,160	x	\$4.2550	\$1,158,041	280,960,833 \$ 0.00412	
Physical Forward Start Premium				\$101,250	280,960,833	\$ 0.00036	
Call Option Premium				\$134,926	280,960,833	\$ 0.00048	
(d) NNG-General Service, Interruptible, Firm/Interruptible: Total Commodity Current Cost of Gas/therm (i.e. Sum of Costs from Sections (a), (b), and (c))					\$62,922,434	\$ 0.22395	

MINNESOTA ENERGY RESOURCES - NNG

Financial Options Heating Season 2025-2026

Units - Gas Daily Peaker Packages (Physical)

<u>November</u>		<u>December</u>		<u>January</u>		<u>February</u>		<u>March</u>		<u>Total</u>	<u>Term</u>
<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Daily</u>	<u>Term</u>
<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Total</u>	<u>Total</u>
N/A		N/A		N/A		N/A		N/A			

Premium - Gas Daily Peaker (Monthly Cost)

<u>November</u>		<u>December</u>		<u>January</u>		<u>February</u>		<u>March</u>		<u>Total</u>	<u>Premium</u>
<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>
<u>Premium</u>	<u>Cost</u>	<u>Premium</u>	<u>Cost</u>	<u>Premium</u>	<u>Cost</u>	<u>Premium</u>	<u>Cost</u>	<u>Premium</u>	<u>Cost</u>	<u>Premium</u>	<u>Cost</u>
N/A		N/A		N/A		N/A		N/A			

Units - Futures (Dth)

<u>November</u>		<u>December</u>		<u>January</u>		<u>February</u>		<u>March</u>		<u>Term</u>
<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Total</u>
<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	
1 05/16/25	1,657	05/22/25	3,149	05/16/25	3,431	05/22/25	1,181	05/16/25	2,129	353,214
2 06/13/25	1,657	06/24/25	2,887	06/13/25	3,167	05/22/25	1,772	06/13/25	1,863	345,000
3 01/00/00	-	01/00/00	-	01/00/00	-	06/24/25	2,658	01/00/00	-	73,929
4 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
5 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
6 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
7 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
8 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
9 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
Total	3,314		6,036		6,598		5,611		3,992	772,143

Units - Call Options (Dth)

<u>November</u>		<u>December</u>		<u>January</u>		<u>February</u>		<u>March</u>		<u>Term</u>
<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Contract</u>	<u>Daily</u>	<u>Total</u>
<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	<u>Date</u>	<u>Volume</u>	
1 05/16/25	3,278	05/22/25	4,996	05/16/25	2,908	05/22/25	4,983	05/16/25	3,426	589,105
2 06/13/25	3,278	06/24/25	4,996	05/22/25	2,908	06/24/25	4,983	06/13/25	3,426	589,105
3 01/00/00	-	01/00/00	-	06/13/25	2,908	01/00/00	-	01/00/00	-	90,150
4 01/00/00	-	01/00/00	-	06/24/25	2,908	01/00/00	-	01/00/00	-	90,150
5 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
6 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
7 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
8 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
9 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
10 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
11 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
12 01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
Total	6,556		9,992		11,632		9,966		6,853	1,358,512

Premium - Call Option (Monthly Cost)

<u>November</u>		<u>December</u>		<u>January</u>		<u>February</u>		<u>March</u>		<u>Total</u>	<u>Premium</u>
<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>	<u>Option</u>	<u>Premium</u>
<u>Premium</u>		<u>Premium</u>		<u>Premium</u>		<u>Premium</u>		<u>Premium</u>		<u>Premium</u>	
1 \$ 0.1000	\$ 9,833	\$ 0.0990	\$ 15,333	\$ 0.1000	\$ 9,015	\$ 0.0970	\$ 13,534	\$ 0.1000	\$ 10,622	\$ 0.0990	\$ 58,337
2 \$ 0.1000	\$ 9,833	\$ 0.1000	\$ 15,487	\$ 0.1000	\$ 9,015	\$ 0.0990	\$ 13,813	\$ 0.0980	\$ 10,410	\$ 0.0994	\$ 58,559
3 \$ -	\$ -	\$ -	\$ -	\$ 0.1000	\$ 9,015	\$ -	\$ -	\$ -	\$ -	\$ 0.1000	\$ 9,015
4 \$ -	\$ -	\$ -	\$ -	\$ 0.1000	\$ 9,015	\$ -	\$ -	\$ -	\$ -	\$ 0.1000	\$ 9,015
5 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	\$ -
6 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	\$ -
7 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	\$ -
8 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	\$ -
9 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
11 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
12 \$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total \$ 0.1000	\$ 19,667	\$ 0.0995	\$ 30,820	\$ 0.1000	\$ 36,060	\$ 0.0980	\$ 27,348	\$ 0.0990	\$ 21,031	\$ 0.0993	\$ 134,926

Units - Collar Floor (put)

No Puts were purchased.

Attachment 6
Page 2 of 3

MINNESOTA ENERGY RESOURCES - NNG

NNG WINTER PLAN

NOVEMBER 2025 THROUGH MARCH 2026

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Daily Volumes				Monthly Total
					Nov	Dec	Jan	Feb	
No Physical Fixed Price Hedges					-	-	-	-	-
Total Actual Fixed/Option Physical									

INDEX

Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
133292	6/5/2025	NNG/GLGT Carlton	24,972	24,972	24,972	24,972	24,972	3,770,772
133294	6/5/2025	NNG/GLGT Grand Rapids	6,000	6,000	6,000	6,000	6,000	906,000
133291	6/5/2025	NNG-TCPL/NNG Beatrice	5,540	5,540	5,540	5,540	5,540	836,540
133297	6/5/2025	NNG-NBPL/NNG Ventura	-	10,000	10,000	10,000	-	900,000
133298	6/5/2025	NNG-NBPL/NNG Ventura	-	7,000	7,000	7,000	-	630,000
133299	6/5/2025	NNG-NBPL/NNG Ventura	-	10,000	10,000	10,000	-	900,000
133301	6/5/2025	NNG-NNG Field/Denmarc	15,000	15,000	15,000	15,000	15,000	2,265,000
133305	6/5/2025	NNG-NNG Field/Denmarc	10,000	10,000	10,000	10,000	10,000	1,510,000
133306	6/5/2025	NNG-NNG Field/Denmarc	3,500	3,500	3,500	3,500	3,500	528,500
133307	6/5/2025	NNG-NNG Field/Denmarc	-	3,000	3,000	3,000	-	270,000
133308	6/5/2025	NNG-NNG Field/Denmarc	-	5,100	5,100	5,100	-	459,000
133309	6/5/2025	NNG-NNG Field/Denmarc	-	5,000	5,000	5,000	-	450,000
133313	6/5/2025	NBPL at Port of Morgan	10,000	10,000	10,000	10,000	10,000	1,510,000

GAS DAILY PACKAGES

Physical Call Option

FOM PRICED CALL PACKAGES

Physical Call Option

Physical Call Option

TOTAL

TOTAL

14,935,812

STORAGE

Injection

Month

May - balance forward

June

July (est)

August (est)

Sept (est)

Oct (est)

Total

K#118657	Volume Injected	Open Volume Injected	Total Volume Injected
1,832,026	0	1,832,026	1,832,026
357,781	0	357,781	357,781
1,053,595	0	1,053,595	1,053,595
1,053,595	0	1,053,595	1,053,595
1,019,608	0	1,019,608	1,019,608
883,395	0	883,395	883,395
6,200,000	0	6,200,000	6,200,000

K#118657	Volume Injected	Open Volume Injected	Total Volume Injected
1,832,026	0	1,832,026	1,832,026
357,781	0	357,781	357,781
1,053,595	0	1,053,595	1,053,595
1,053,595	0	1,053,595	1,053,595
1,019,608	0	1,019,608	1,019,608
883,395	0	883,395	883,395
6,200,000	0	6,200,000	6,200,000

K#118657	Volume Injected	Open Volume Injected	Total Volume Injected
1,832,026	0	1,832,026	1,832,026
357,781	0	357,781	357,781
1,053,595	0	1,053,595	1,053,595
1,053,595	0	1,053,595	1,053,595
1,019,608	0	1,019,608	1,019,608
883,395	0	883,395	883,395
6,200,000	0	6,200,000	6,200,000

K#118657	Volume Injected	Open Volume Injected	Total Volume Injected
1,832,026	0	1,832,026	1,832,026
357,781	0	357,781	357,781
1,053,595	0	1,053,595	1,053,595
1,053,595	0	1,053,595	1,053,595
1,019,608	0	1,019,608	1,019,608
883,395	0	883,395	883,395
6,200,000	0	6,200,000	6,200,000

K#118657	Volume Injected	Open Volume Injected	Total Volume Injected
1,832,026	0	1,832,026	1,832,026
357,781	0	357,781	357,781
1,053,595	0	1,053,595	1,053,595
1,053,595	0	1,053,595	1,053,595
1,019,608	0	1,019,608	1,019,608
883,395	0	883,395	883,395
6,200,000	0	6,200,000	6,200,000

MINNESOTA ENERGY RESOURCES - NNG

NNG WINTER PLAN - SUPPLY MIX
NOVEMBER 2025 THROUGH MARCH 2026

Monthly vs. Daily Pricing		Term Deal Type	Index Location	Receipt Point	Nov	Dec	Jan	Feb (1-14)	Feb (15-28)	Mar
Monthly Index	Baseload	Nymex LDS	NNG/GLGT Carlton		24,972	24,972	24,972	24,972	24,972	24,972
Monthly Index	Baseload	Nymex LDS	NNG/GLGT Grand Rapids		6,000	6,000	6,000	6,000	6,000	6,000
Monthly Index	Baseload	Nymex LDS	NNG-TCLP/NNG Beatrice		5,540	5,540	5,540	5,540	5,540	5,540
Monthly Index	Baseload	Nymex LDS	NNG-NBPL/NNG Ventura		-	10,000	10,000	10,000	10,000	-
Monthly Index	Baseload	Nymex LDS	NNG-NBPL/NNG Ventura		-	7,000	7,000	7,000	7,000	-
Monthly Index	Baseload	Nymex LDS	NNG-NBPL/NNG Ventura		-	10,000	10,000	10,000	10,000	-
Monthly Index	Baseload	Nymex LDS	NNG-NNG Field/Demarc		15,000	15,000	15,000	15,000	15,000	15,000
Monthly Index	Baseload	Nymex LDS	NNG-NNG Field/Demarc		10,000	10,000	10,000	10,000	10,000	10,000
Monthly Index	Baseload	Nymex LDS	NNG-NNG Field/Demarc		3,500	3,500	3,500	3,500	3,500	3,500
Monthly Index	Baseload	Nymex LDS	NNG-NNG Field/Demarc		-	3,000	3,000	3,000	3,000	-
Monthly Index	Baseload	Nymex LDS	NNG-NNG Field/Demarc		-	5,100	5,100	5,100	5,100	-
Monthly Index	Baseload	Nymex LDS	NNG-NNG Field/Demarc		-	5,000	5,000	5,000	5,000	-
Monthly Index	Baseload	Nymex LDS	NBPL at Port of Morgan TP		10,000	10,000	10,000	10,000	10,000	10,000
Daily Index	Call/Swing	Nymex LDS	NNG NBPL/NNG Ventura		-	15,000	15,000	15,000	15,000	15,000
Monthly Index	Call/Swing	Nymex LDS	NNG NBPL/NNG Ventura		15,000	15,000	15,000	15,000	15,000	15,000
Monthly Index	Call/Swing	Nymex LDS	NNG-NBPL/NNG Various		40,000	40,000	40,000	40,000	40,000	40,000
TOTAL BASELOAD					75,012	115,112	115,112	115,112	115,112	75,012
TOTAL CALLSWING (MONTH INDEX)					55,000	55,000	55,000	55,000	55,000	55,000
TOTAL CALLSWING (DAILY INDEX)					-	15,000	15,000	15,000	15,000	-
TOTAL STORAGE WITHDRAWAL					113,074	113,074	113,074	113,074	59,267	59,267
SUPPLY MIX - MAX DAY										
DEMAND		Nov	Dec	Jan	Feb (1-14)	Feb (15-28)	Mar			
		210,653	297,178	297,178	297,178	297,178	195,782			
BASELOAD		75,012	115,112	115,112	115,112	115,112	75,012			
CALLSWING		22,507	68,992	68,992	68,992	68,992	70,000			
STORAGE WITHDRAWAL		113,074	113,074	113,074	113,074	113,074	59,267			
SPOT SUPPLY (DAILY PURCHASE)		-	-	-	-	-	6,483			
TOTAL SUPPLY		210,653	297,178	297,178	297,178	297,178	195,782			
% MONTHLY PRICE		46%	57%	57%	57%	57%	66%			
% DAILY PRICE		0%	5%	5%	5%	23%	3%			
% STORAGE WACOG		54%	38%	38%	38%	20%	30%			
SUPPLY MIX - AVERAGE DAY										
DEMAND		Nov	Dec	Jan	Feb (1-14)	Feb (15-28)	Mar			
		98,502	156,733	177,227	155,408	155,408	108,705			
BASELOAD		75,012	115,112	115,112	115,112	115,112	75,012			
CALLSWING		-	-	-	-	-	-			
STORAGE WITHDRAWAL		23,490	41,621	62,115	40,296	40,296	33,683			
SPOT SUPPLY (DAILY PURCHASE)		-	-	-	-	-	-			
TOTAL SUPPLY		98,502	156,733	177,227	155,408	155,408	108,705			
% MONTHLY PRICE		76%	73%	65%	74%	74%	69%			
% DAILY PRICE		0%	0%	0%	0%	0%	0%			
% STORAGE WACOG		24%	27%	35%	26%	26%	31%			
SUPPLY MIX - MINIMUM DAY										
DEMAND		Nov	Dec	Jan	Feb (1-14)	Feb (15-28)	Mar			
		26,994	54,980	89,907	68,707	68,707	35,250			
BASELOAD		75,012	115,112	115,112	115,112	115,112	75,012			
CALLSWING		-	-	-	-	-	-			
STORAGE WITHDRAWAL		-	-	-	-	-	-			
SPOT SUPPLY (DAILY PURCHASE)		-	-	-	-	-	-			
NNG SMS INJECT (-)		(21,826)	(22,260)	-	-	-	(13,570)			
STORAGE INJECT (-)		(26,192)	(26,192)	(17,993)	(15,856)	(15,856)	(26,192)			
REMAINING SUPPLY (LONG GAS)		-	11,680	7,212	30,549	30,549	-			
% MONTHLY PRICE		100%	100%	100%	100%	100%	100%			
% DAILY PRICE		0%	0%	0%	0%	0%	0%			
% STORAGE WACOG		0%	0%	0%	0%	0%	0%			

MINNESOTA ENERGY RESOURCES - NNG

	2021-2022 NNG	2022-2023 NNG	2023-2024 NNG	2024-2025 NNG	2025-2026 NNG	Proposed Change
Design Day	282,710	291,250	290,934	290,169	297,178	7,009
Customer Requirements moving to Transportation						
Adjusted Design Day						
Design Day Percentages	28.90%	29.71%	28.53%	30.59%	29.31%	-1.28%
Total Design Day Capacity (includes non-recallable capacity)	313,756	313,756	320,242	320,242	320,242	0
Less: Windom	2,500	2,500	2,500	2,500	2,500	0
Less: Northwestern Energy	1,035	1,035	1,035	1,035	1,035	0
Total Design Day Capacity NNG Pipeline	310,221	310,221	316,707	316,707	316,707	0
Factors for All Winter Capacity	100.00%	100.00%	100.00%	100.00%	100.00%	
<u>Direct Assigned Entitlements in PGA</u>						
TF12B	21,492	33,714	37,650	34,711	30,558	(4,153)
TF12V	62,624	50,402	46,466	49,405	53,558	4,153
TF5	36,275	36,275	36,275	36,275	36,275	0
TFX12	85,329	85,329	91,815	91,815	91,815	0
TFX(5)	104,501	104,501	104,501	104,501	104,501	0
TFX(5) (12-V)						0
TFX (April Only)	2,000	2,000	2,000	2,000	2,000	0
TFX (October Only)	2,000	2,000	2,000	2,000	2,000	0
Windom	2,500	2,500	2,500	2,500	2,500	0
Northwestern Energy	1,035	1,035	1,035	1,035	1,035	0
NNG Zone Delivery Call Option	0	0	0	0	0	0
Bison	0	0	0	0	0	0
NBPL	50,000	50,000	50,000	50,000	50,000	0
Total Direct Assignments	313,756	313,756	320,242	320,242	320,242	0
LP Peak Shaving						0
Total Design Day Capacity	313,756	313,756	320,242	320,242	320,242	0
Total Annual Transportation	172,980	172,980	179,466	179,466	179,466	0
Total Seasonal Transportation	140,776	140,776	140,776	140,776	140,776	0
Total Percent Seasonal	44.9%	44.9%	44.0%	44.0%	44.0%	0.0%
Reserve Margin	10.98%	7.73%	10.36%	10.36%	7.76%	-2.6%
Total Design Day Capacity w/ contract demand	313,756	313,756	320,242	320,242	320,242	0
Factors	28.90%	29.71%	28.53%	30.59%	29.31%	-1.28%
<u>Other Entitlements not included in Peak Day Deliverability</u>						
TFX Oct	2,000	2,000	2,000	2,000	2,000	0
TFX Apr	2,000	2,000	2,000	2,000	2,000	0
FDD Storage Reservation	113,075	113,075	113,074	113,074	113,074	0
FDD Storage Capacity	1,303,864	1,303,864	1,303,864	1,303,864	1,303,864	0
FDD Maximum Storage Quantity	6,519,321	6,519,321	6,519,321	6,519,321	6,519,321	0
SMS	22,680	22,680	22,680	22,680	22,680	0

MINNESOTA ENERGY RESOURCES - NNG

Change in Costs due to November 1, 2025 Change in Entitlement Levels and Related Demand Costs

Costs Assigned in Demand		2024/25	2025/26	Entitlement	2025/26	2024/25	2025/26	Total Annual Cost	2025/26	Total Annual Cost
Contract	Entitlements	Entitlements	Entitlements	Change	Months	Rate	Rate	Total Annual Cost	Entitlement	Change
TF12B (Max Rate) Winter	23,137	18,984	(4,153)	5	\$17,4170	\$2,014,886	\$1,653,222	\$361,664)		
TF12B (Max Rate) Summer	23,137	18,984	(4,153)	7	\$9,6760	\$1,567,115	\$1,285,824	\$281,291)		
TF12V (Max Rate)	44,913	49,066	4,153	12	\$15,4814	\$8,343,793	\$9,115,324	\$771,531		
TF5 (Max Rate)	16,183	16,183	0	5	\$25,7990	\$2,087,526	\$2,087,526	\$0		
TF5 (Rochester Capped)	20,092	20,092	0	5	\$15,1530	\$1,522,270	\$1,522,270	\$0		
TF12B (Rochester Capped)	11,574	11,574	0	12	\$7,5776	\$1,052,438	\$1,052,438	\$0		
TF12V (Rochester Capped)	4,492	4,492	0	12	\$9,0926	\$490,128	\$490,128	\$0		
TFX12 (Max Rate)	8,750	8,750	0	12	\$16,3939	\$1,721,360	\$1,721,360	\$0		
TFX Apr (Max Rate)	2,000	2,000	0	1	\$9,6760	\$19,352	\$19,352	\$0		
TFX Oct (Max Rate)	2,000	2,000	0	1	\$9,6760	\$19,352	\$19,352	\$0		
TFX (Rochester Capped)	2,072	2,072	0	12	\$9,6288	\$239,410	\$239,410	\$0		
TFX5 (Max Rate)	62,549	62,549	0	5	\$25,7990	\$8,068,508	\$8,068,508	\$0		
TFX5 (Rochester Capped)	16,939	16,939	0	5	\$15,1530	\$1,283,383	\$1,283,383	\$0		
TFX12 (Discount)	1,283	1,283	0	12	\$4,8640	\$74,886	\$74,886	\$0		
TFX12 (Discount)	8,271	8,271	0	12	\$5,4720	\$543,107	\$543,107	\$0		
TFX12 (Discount)	11,921	11,921	0	12	\$7,6025	\$1,087,553	\$1,087,553	\$0		
TFX5 (Discount)	379	379	0	5	\$4,8640	\$9,217	\$9,217	\$0		
TFX5 (Discount)	2,445	2,445	0	5	\$5,4720	\$66,895	\$66,895	\$0		
TFX5 (Discount)	22,189	22,189	0	5	\$15,1392	\$1,679,619	\$1,679,619	\$0		
TFX (Max Rate)	6,486	6,486	0	12	\$16,3939	\$1,275,970	\$1,275,970	\$0		
Windom	2,500	2,500	0	12	\$0,0000	\$0	\$0	\$0		
Northwestern Energy	1,035	1,035	0	12	\$8.00	\$99,360	\$99,360	\$0		
Total Demand Cost						\$33,266,129	\$33,394,705	\$128,576		

Costs Assigned in Commodity		2024/25	2025/26	Entitlement	2025/26	2024/25	2025/26	Entitlement	2025/26	Entitlement
Upstream	Entitlement	Entitlement	Entitlement	Change	Months	Rate/Dth	Rate/Dth	Total Cost	Entitlement	Change
Surcharges:										
Storage (FDD)										
FDD - Reservation	107,524	107,524	0	12	\$	3,2345	\$4,173,437	\$4,173,437	\$0	
FDD - Storage Cycle	1,239,864	1,239,864	0	5	\$	0.6731	\$4,172,763	\$4,172,763	\$0	
FDD - Reservation	5,550	5,550	0	12	\$	3,2758	\$218,168	\$218,168	\$0	
FDD - Storage Cycle	64,000	64,000	0	5	\$	0.6818	\$218,176	\$218,176	\$0	
FDD - Reservation	0	0	0	12	\$	-	\$0	\$0	\$0	
FDD - Storage Cycle	0	0	0	5	\$	-	\$0	\$0	\$0	
FDD - Reservation	0	0	0	12	\$	-	\$0	\$0	\$0	
FDD - Storage Cycle	0	0	0	5	\$	-	\$0	\$0	\$0	
Pbeline										
NBPL										
TFX12 (Rochester)	50,000	50,000	0	12	\$5,3578	\$3,673,800	\$3,214,660	\$459,140)		
TFX12 (Rochester II)	10,500	10,500	0	12	\$37,1175	\$4,676,805	\$4,676,805	\$0		
TFX12 (SE MN Expansion)	34,500	34,500	0	12	\$10,7714	\$4,459,360	\$4,459,360	\$0		
Balancing Service	8,032	8,032	0	12	\$16,3939	\$1,580,110	\$1,580,110	\$0		
Physical Forward Start Premium	272,160	272,160	0	1	\$4,2550	\$1,158,041	\$1,158,041	\$0		
Financial Call Option Premium						\$555,750	\$101,250	\$454,500)		
Total Commodity Costs						\$397,979	\$134,926	\$263,054)		
						\$25,284,388	\$24,107,695	\$1,176,694)		

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
7/1/24	1	0	0	1	0	166,270	9,981
7/2/24	2	0	1	0	1	184,171	11,108
7/3/24	0	0	0	0	0	195,158	9,359
7/4/24	2	0	0	0	0	167,371	9,801
7/5/24	2	0	0	0	0	182,643	9,795
7/6/24	0	0	0	0	0	177,721	9,359
7/7/24	0	0	0	0	0	183,860	9,359
7/8/24	0	0	0	0	0	199,855	9,359
7/9/24	0	0	0	0	0	195,163	9,359
7/10/24	0	0	0	0	0	197,576	9,359
7/11/24	0	0	0	0	0	190,776	9,359
7/12/24	0	0	0	0	0	180,615	9,359
7/13/24	0	0	0	0	0	173,957	9,359
7/14/24	0	0	0	0	0	188,352	9,359
7/15/24	0	0	0	0	0	186,222	9,359
7/16/24	3	0	0	0	0	194,464	10,127
7/17/24	8	0	2	3	2	188,419	14,850
7/18/24	1	0	0	0	0	182,544	9,502
7/19/24	0	0	0	0	0	181,820	9,359
7/20/24	0	0	0	0	0	182,793	9,359
7/21/24	0	0	0	0	0	189,698	9,359
7/22/24	0	0	0	0	0	200,433	9,359
7/23/24	9	0	0	0	1	196,180	12,013
7/24/24	3	0	0	0	0	180,159	10,228
7/25/24	0	0	0	0	0	177,776	9,359
7/26/24	0	0	0	0	0	176,884	9,359
7/27/24	0	0	0	0	0	169,186	9,359
7/28/24	0	0	0	0	0	178,010	9,359
7/29/24	0	0	0	0	0	186,317	9,359
7/30/24	0	0	0	0	0	182,827	9,359
7/31/24	0	0	0	0	0	177,479	9,359
8/1/24	0	0	0	0	0	177,886	9,359
8/2/24	0	0	0	0	0	188,193	9,359
8/3/24	0	0	0	0	0	170,813	9,359
8/4/24	1	0	0	0	0	165,519	9,505
8/5/24	7	2	0	0	2	170,814	13,205

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
8/6/24	3	0	2	2	1	177,874	12,721
8/7/24	3	0	0	0	0	185,606	10,096
8/8/24	8	1	5	6	4	179,390	19,490
8/9/24	10	4	7	7	6	162,325	25,805
8/10/24	3	0	6	1	3	157,757	17,120
8/11/24	2	0	0	0	0	167,128	9,803
8/12/24	0	0	0	2	0	182,390	9,786
8/13/24	0	0	0	0	0	163,253	9,359
8/14/24	0	0	0	0	0	165,783	9,359
8/15/24	0	0	0	0	0	138,571	9,359
8/16/24	0	0	0	0	0	133,359	9,359
8/17/24	0	0	0	0	0	132,018	9,359
8/18/24	3	0	0	0	0	133,547	10,079
8/19/24	0	0	0	0	0	140,330	9,359
8/20/24	5	0	1	2	1	139,841	12,655
8/21/24	1	0	4	0	2	149,378	13,974
8/22/24	0	0	0	0	0	176,406	9,359
8/23/24	1	0	0	0	0	176,100	9,502
8/24/24	0	0	0	0	0	162,733	9,359
8/25/24	0	0	0	0	0	185,257	9,359
8/26/24	0	0	0	0	0	198,320	9,359
8/27/24	1	0	0	1	0	204,230	9,653
8/28/24	4	0	0	0	0	188,740	10,431
8/29/24	3	0	0	0	0	191,920	10,268
8/30/24	1	0	0	0	0	181,024	9,511
8/31/24	0	0	0	0	0	159,640	9,359
9/1/24	9	1	6	6	5	158,692	21,725
9/2/24	3	0	4	1	2	161,630	15,476
9/3/24	1	0	3	0	1	177,782	12,811
9/4/24	0	0	0	0	0	183,192	9,359
9/5/24	10	0	4	5	3	188,525	18,258
9/6/24	18	8	11	8	10	175,295	35,779
9/7/24	9	5	8	3	6	162,417	25,857
9/8/24	1	0	4	0	2	146,319	14,751
9/9/24	0	0	0	0	0	155,575	9,359
9/10/24	0	0	0	0	0	163,014	9,359

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
9/11/24	0	0	0	0	0	168,458	9,359
9/12/24	0	0	0	0	0	165,932	9,359
9/13/24	0	0	0	0	0	181,043	9,359
9/14/24	0	0	0	0	0	153,480	9,359
9/15/24	0	0	0	0	0	156,901	9,359
9/16/24	0	0	0	0	0	163,616	9,359
9/17/24	0	0	0	0	0	158,766	9,359
9/18/24	0	0	0	0	0	167,721	9,359
9/19/24	0	0	0	0	0	169,047	9,359
9/20/24	3	0	0	0	0	176,195	10,091
9/21/24	5	0	0	2	1	168,528	11,173
9/22/24	15	5	11	11	10	179,317	33,736
9/23/24	10	3	10	5	7	180,249	27,464
9/24/24	9	0	4	6	4	184,685	18,627
9/25/24	2	0	2	0	1	176,410	12,298
9/26/24	0	0	0	0	0	181,888	9,359
9/27/24	0	0	0	0	0	180,112	9,359
9/28/24	2	0	0	0	0	172,025	9,789
9/29/24	3	0	0	0	0	172,404	10,262
9/30/24	6	0	2	3	2	188,447	13,753
10/1/24	14	9	12	10	11	180,443	37,440
10/2/24	7	0	6	4	4	178,998	19,366
10/3/24	21	12	9	15	12	182,565	39,606
10/4/24	11	7	9	9	9	155,391	31,719
10/5/24	9	0	0	3	1	145,086	12,700
10/6/24	21	12	18	17	16	179,414	51,382
10/7/24	18	7	11	9	10	201,300	35,572
10/8/24	15	5	7	5	7	192,702	27,473
10/9/24	13	4	7	0	6	191,880	24,958
10/10/24	6	0	1	0	1	184,772	11,649
10/11/24	12	4	6	13	7	193,030	26,265
10/12/24	21	11	16	11	15	197,195	46,607
10/13/24	28	24	26	25	25	210,556	73,953
10/14/24	29	24	29	30	28	257,252	79,517
10/15/24	29	22	28	26	26	251,004	75,937
10/16/24	20	16	21	18	19	222,870	57,626

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
10/17/24	8	5	12	4	8	200,396	30,624
10/18/24	6	2	5	0	4	202,593	18,517
10/19/24	15	3	1	6	4	182,161	18,946
10/20/24	6	0	0	0	1	179,781	10,946
10/21/24	5	0	0	0	1	192,923	10,636
10/22/24	13	5	10	14	9	197,721	32,636
10/23/24	23	16	22	18	20	225,308	60,228
10/24/24	19	13	16	17	15	204,820	48,396
10/25/24	26	19	23	26	22	232,947	66,463
10/26/24	22	17	20	21	19	193,711	58,969
10/27/24	17	9	15	10	13	184,570	42,554
10/28/24	11	1	5	5	4	187,791	19,710
10/29/24	12	0	0	3	2	183,964	13,582
10/30/24	26	19	9	30	16	205,764	50,257
10/31/24	36	32	28	34	31	277,717	87,720
11/1/24	33	27	31	26	29	259,200	84,185
11/2/24	24	18	21	19	20	227,525	60,782
11/3/24	21	15	16	17	16	225,496	51,006
11/4/24	19	13	13	21	14	232,475	46,179
11/5/24	29	27	26	29	27	262,500	78,463
11/6/24	23	23	24	27	24	259,073	70,828
11/7/24	25	23	24	25	24	256,337	70,286
11/8/24	24	17	19	16	19	241,138	56,617
11/9/24	23	17	22	21	20	242,484	61,224
11/10/24	26	23	25	26	25	224,292	71,887
11/11/24	32	27	33	32	31	257,587	87,986
11/12/24	29	28	31	28	29	253,550	84,053
11/13/24	25	24	26	25	25	263,497	73,335
11/14/24	29	24	28	30	27	276,920	78,739
11/15/24	26	20	24	22	22	244,536	66,286
11/16/24	21	21	27	24	24	226,264	70,969
11/17/24	29	23	26	24	25	255,084	74,061
11/18/24	25	20	20	23	21	245,663	62,601
11/19/24	28	28	32	38	31	266,549	87,845
11/20/24	35	40	44	49	42	314,473	116,523
11/21/24	32	33	36	41	35	301,236	98,665

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
11/22/24	33	32	35	33	34	297,418	95,505
11/23/24	36	28	29	30	30	263,184	85,235
11/24/24	34	30	31	41	32	262,769	91,131
11/25/24	45	46	47	49	46	334,452	127,686
11/26/24	48	44	43	45	44	332,196	121,893
11/27/24	44	46	46	49	46	319,393	127,578
11/28/24	54	54	58	58	56	318,957	152,722
11/29/24	64	59	62	61	61	360,414	164,565
11/30/24	63	60	61	58	61	370,287	164,119
12/1/24	51	56	56	52	55	364,520	149,392
12/2/24	49	52	54	62	53	360,026	145,418
12/3/24	46	45	49	48	47	315,951	130,326
12/4/24	60	54	57	57	57	382,381	153,448
12/5/24	51	51	55	59	54	377,321	146,574
12/6/24	42	38	42	39	41	298,862	113,029
12/7/24	31	25	28	26	27	250,805	78,304
12/8/24	32	31	29	25	29	241,518	84,463
12/9/24	43	40	41	46	41	308,143	114,234
12/10/24	53	51	53	55	53	330,245	143,790
12/11/24	81	71	72	71	73	389,413	194,994
12/12/24	75	68	68	64	68	391,797	183,777
12/13/24	65	59	60	59	60	352,267	163,076
12/14/24	44	41	40	41	41	316,993	113,708
12/15/24	35	33	36	35	35	282,637	98,422
12/16/24	42	37	39	41	39	292,527	108,732
12/17/24	49	43	45	47	45	342,951	124,192
12/18/24	59	48	47	51	49	354,762	134,961
12/19/24	60	51	51	58	53	354,026	144,629
12/20/24	66	58	61	60	60	391,560	163,353
12/21/24	56	57	61	54	59	347,411	158,545
12/22/24	45	41	44	42	43	303,046	118,124
12/23/24	47	38	36	44	39	321,302	108,387
12/24/24	45	39	40	42	40	306,470	112,121
12/25/24	40	39	41	38	40	289,375	110,656
12/26/24	35	33	33	33	33	271,139	94,533
12/27/24	31	30	30	33	30	261,002	86,995

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
12/28/24	37	28	31	26	30	271,960	86,803
12/29/24	34	32	34	29	33	284,644	93,590
12/30/24	40	38	35	41	37	275,645	104,145
12/31/24	49	46	48	50	48	284,368	131,062
1/1/25	57	53	55	49	54	346,498	146,993
1/2/25	63	57	56	54	57	367,742	154,145
1/3/25	73	64	65	64	66	382,977	176,706
1/4/25	75	64	65	69	66	372,260	178,348
1/5/25	69	62	66	69	65	369,607	175,658
1/6/25	61	55	57	58	57	364,612	154,005
1/7/25	58	56	58	59	57	341,960	155,388
1/8/25	56	55	57	58	56	332,128	153,229
1/9/25	50	47	52	46	49	296,807	134,934
1/10/25	52	46	48	49	48	318,717	131,279
1/11/25	52	46	48	46	47	283,054	129,964
1/12/25	72	64	67	68	67	371,113	179,690
1/13/25	81	74	73	69	74	368,936	197,343
1/14/25	70	69	71	65	70	362,160	186,598
1/15/25	56	50	56	49	54	305,210	145,972
1/16/25	38	34	41	36	38	259,665	106,968
1/17/25	57	51	52	54	52	292,103	142,794
1/18/25	83	78	76	77	77	363,197	206,804
1/19/25	87	80	82	77	81	397,756	216,662
1/20/25	94	85	87	88	87	425,386	231,799
1/21/25	80	70	77	69	74	366,204	198,480
1/22/25	67	58	59	59	60	329,262	161,459
1/23/25	74	63	67	64	66	362,745	177,608
1/24/25	59	52	56	45	54	297,293	146,378
1/25/25	57	55	58	59	57	303,832	155,080
1/26/25	52	49	51	53	51	290,774	138,701
1/27/25	43	39	43	38	41	276,693	113,678
1/28/25	43	31	32	33	33	248,772	93,472
1/29/25	46	34	38	31	37	281,309	103,755
1/30/25	34	27	26	27	27	242,112	78,862
1/31/25	49	35	36	40	38	268,075	105,584
2/1/25	50	40	44	37	43	288,186	118,414

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

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Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
2/2/25	47	34	32	38	35	271,638	98,195
2/3/25	70	60	58	65	61	349,084	163,700
2/4/25	67	65	64	64	65	375,093	174,568
2/5/25	58	54	54	56	55	323,763	149,307
2/6/25	67	60	58	52	59	336,390	159,083
2/7/25	57	51	49	45	50	315,245	136,265
2/8/25	66	61	63	66	63	316,257	170,191
2/9/25	63	59	64	56	61	331,645	165,684
2/10/25	74	67	64	72	67	361,818	179,748
2/11/25	79	67	66	69	68	386,680	183,549
2/12/25	73	70	74	77	73	384,716	195,528
2/13/25	70	68	72	71	70	375,098	188,146
2/14/25	61	55	57	52	56	313,528	152,390
2/15/25	68	61	60	74	63	305,986	169,701
2/16/25	79	76	78	78	77	354,222	206,520
2/17/25	82	81	87	88	84	412,501	224,689
2/18/25	78	75	78	84	78	403,937	207,380
2/19/25	69	71	73	78	73	389,338	194,787
2/20/25	59	57	63	66	61	350,973	164,663
2/21/25	56	53	62	62	59	297,673	158,667
2/22/25	39	42	48	40	44	245,133	122,423
2/23/25	32	28	32	23	30	195,297	85,490
2/24/25	31	26	28	29	28	209,257	80,186
2/25/25	28	23	28	26	26	202,254	76,740
2/26/25	28	23	27	26	26	199,087	74,601
2/27/25	33	23	29	24	27	214,375	77,788
2/28/25	54	43	44	45	45	270,648	123,077
3/1/25	57	46	50	48	49	282,785	134,815
3/2/25	42	36	39	32	37	248,629	104,752
3/3/25	26	24	20	19	22	203,860	64,969
3/4/25	39	36	34	51	37	264,610	103,310
3/5/25	49	46	50	49	49	290,028	133,162
3/6/25	43	35	38	32	37	270,808	102,695
3/7/25	44	31	32	37	33	245,728	94,735
3/8/25	31	25	30	31	28	216,752	81,852
3/9/25	23	19	22	22	21	199,630	62,837

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

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Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
3/10/25	28	22	21	26	23	208,372	67,034
3/11/25	40	30	30	35	31	245,897	89,114
3/12/25	30	19	21	20	21	227,081	64,160
3/13/25	26	16	17	15	17	180,254	52,974
3/14/25	22	7	8	17	11	159,482	36,143
3/15/25	44	44	43	49	44	254,631	121,577
3/16/25	45	38	42	41	41	259,966	114,115
3/17/25	36	19	20	16	21	217,955	62,774
3/18/25	36	27	23	30	27	227,253	76,977
3/19/25	43	38	44	47	42	294,187	117,297
3/20/25	33	29	40	30	34	242,012	97,196
3/21/25	45	32	32	34	34	251,033	95,755
3/22/25	48	37	37	34	38	235,441	105,303
3/23/25	42	36	37	42	38	254,656	105,332
3/24/25	39	29	31	27	31	251,799	87,749
3/25/25	32	24	27	26	26	237,120	76,444
3/26/25	27	20	21	21	22	220,039	64,276
3/27/25	25	13	13	13	14	193,366	45,738
3/28/25	40	13	7	7	12	197,960	41,103
3/29/25	43	33	33	39	35	235,188	97,832
3/30/25	42	39	41	42	40	259,398	112,590
3/31/25	35	29	33	35	32	267,431	91,513
4/1/25	36	34	36	37	35	274,849	99,580
4/2/25	40	32	26	34	30	274,443	86,944
4/3/25	34	30	31	33	31	283,869	89,213
4/4/25	34	26	27	33	28	243,116	80,971
4/5/25	35	32	35	35	34	251,727	96,419
4/6/25	34	26	28	28	28	233,471	80,165
4/7/25	44	36	40	39	39	273,914	108,823
4/8/25	31	27	29	24	28	236,135	80,873
4/9/25	33	16	19	10	19	218,676	57,176
4/10/25	32	21	23	25	24	237,189	69,785
4/11/25	19	18	24	16	21	209,217	62,482
4/12/25	15	8	10	3	9	164,619	32,050
4/13/25	18	10	14	11	13	186,717	41,976
4/14/25	33	26	24	30	26	217,697	76,527

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

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Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
4/15/25	32	23	27	21	26	203,761	75,083
4/16/25	28	17	17	4	17	186,438	52,760
4/17/25	19	6	6	8	8	162,180	28,515
4/18/25	32	20	23	29	24	193,047	70,205
4/19/25	28	20	24	20	23	207,641	66,925
4/20/25	24	20	25	26	23	197,740	69,207
4/21/25	18	15	19	10	17	187,668	51,430
4/22/25	27	5	10	9	10	164,344	35,546
4/23/25	21	8	7	12	9	167,237	32,664
4/24/25	22	20	15	23	18	179,919	55,220
4/25/25	25	18	24	21	22	181,328	65,528
4/26/25	19	10	13	14	13	162,400	42,714
4/27/25	16	9	7	11	9	156,379	32,934
4/28/25	20	8	9	11	10	167,111	35,516
4/29/25	28	17	20	18	20	181,541	59,417
4/30/25	22	5	9	6	9	155,749	31,905
5/1/25	17	11	12	16	13	158,343	42,327
5/2/25	29	21	22	22	22	175,231	66,216
5/3/25	12	8	13	10	11	148,892	37,775
5/4/25	18	0	3	3	4	137,168	18,510
5/5/25	11	0	6	1	4	149,645	20,425
5/6/25	2	0	0	0	0	142,371	9,829
5/7/25	23	6	6	5	8	146,041	28,879
5/8/25	24	5	9	2	8	146,192	30,786
5/9/25	3	0	0	0	0	138,840	10,279
5/10/25	16	0	1	0	2	133,848	15,201
5/11/25	0	0	0	0	0	129,088	9,359
5/12/25	0	0	0	0	0	139,467	9,359
5/13/25	0	0	0	0	0	137,626	9,359
5/14/25	6	0	0	0	1	144,740	11,154
5/15/25	9	0	0	4	1	139,670	12,855
5/16/25	18	16	13	25	16	150,759	49,297
5/17/25	23	21	21	23	21	165,220	64,144
5/18/25	26	18	14	14	17	150,977	51,487
5/19/25	30	17	15	20	18	162,174	54,347
5/20/25	31	24	24	22	25	189,920	71,926

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
5/21/25	26	20	19	24	21	177,695	62,028
5/22/25	19	9	14	15	13	157,565	42,528
5/23/25	19	9	12	7	11	147,038	37,606
5/24/25	19	8	9	12	10	140,146	35,391
5/25/25	14	5	6	9	7	130,800	27,122
5/26/25	9	0	3	6	3	132,856	16,636
5/27/25	8	6	8	11	8	145,598	29,398
5/28/25	5	8	12	12	10	160,161	35,673
5/29/25	0	0	3	6	2	145,194	14,211
5/30/25	3	0	0	1	0	137,339	10,416
5/31/25	11	0	0	0	1	139,898	12,404
6/1/25	3	0	0	0	0	143,108	10,088
6/2/25	0	0	0	0	0	139,269	9,359
6/3/25	10	6	8	8	8	148,746	29,332
6/4/25	8	0	1	2	1	150,075	12,767
6/5/25	0	0	0	0	0	145,823	9,359
6/6/25	8	0	0	2	1	143,062	12,237
6/7/25	3	0	2	0	1	131,266	12,184
6/8/25	10	3	2	5	4	124,402	19,056
6/9/25	8	4	7	8	7	135,046	26,211
6/10/25	3	0	0	0	0	126,584	10,102
6/11/25	6	0	0	0	1	132,773	11,137
6/12/25	15	4	1	0	3	141,780	17,508
6/13/25	17	12	3	0	7	143,870	27,179
6/14/25	14	7	0	1	4	135,319	19,246
6/15/25	11	0	0	0	1	136,606	12,446
6/16/25	4	0	0	0	0	138,041	10,417
6/17/25	0	0	0	0	0	131,528	9,359
6/18/25	0	0	0	0	0	137,679	9,359
6/19/25	4	0	0	0	0	143,584	10,394
6/20/25	2	0	0	0	0	138,138	9,812
6/21/25	0	0	0	0	0	138,078	9,359
6/22/25	4	0	0	0	0	141,836	10,417
6/23/25	2	0	0	0	0	147,279	9,812
6/24/25	2	0	0	0	0	146,037	9,787
6/25/25	10	0	0	0	1	137,194	12,198

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2024 through June 30, 2025

NNG

Design Day:

Base	9,359
Variable	2,549

Date	11.04% Cloquet Adjusted HDD	31.68% Minneapolis Adjusted HDD	46.53% Rochester Adjusted HDD	10.75% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through- Put *	Estimated Firm Through- Put **
6/26/25	10	3	0	0	2	146,057	14,315
6/27/25	5	0	0	0	1	152,660	10,803
6/28/25	0	0	0	0	0	151,867	9,359
6/29/25	0	0	0	0	0	142,361	9,359
6/30/25	0	0	0	0	0	149,540	9,359
6/30/24	7	0	4	0	3	156,135	15,827
Totals	9,285	7,493	8,003	8,017	7,985	81,773,649	23,779,058

* Volumes include interruptible and transportation volumes, NorthWest Energy not included.

** Design Model numbers are used to calculate firm volumes only

MINNESOTA ENERGY RESOURCES - NNG

Customer Counts by PG&C Class - July 1, 2024 through June 30, 2025

Tariff Rate Class	Rate Designation	Jul-24 Customers	Aug-24 Customers	Sep-24 Customers	Oct-24 Customers	Nov-24 Customers	Dec-24 Customers	Jan-25 Customers	Feb-25 Customers	Mar-25 Customers	Apr-25 Customers	May-25 Customers	Jun-25 Customers	Annual Average Customers
GS- Residential	MERC000001	185,844	193,329	192,820	193,032	193,806	195,692	195,964	195,663	195,533	196,185	195,995	195,224	194,091
Residential Farm Taps	MERC001206	1,087	1,244	956	1,550	833	1,248	1,153	1,027	1,170	1,021	1,333	1,042	1,139
Firm Class 1	MERC000005	7,197	7,528	7,585	7,571	8,027	8,245	8,350	8,237	8,257	8,317	8,195	7,939	7,954
Firm Class 2	MERC001221	9,909	10,389	10,366	10,326	9,876	9,888	9,902	10,064	9,898	9,934	9,904	9,851	10,026
Firm Class 3	MERC001231	51	52	52	52	50	50	65	61	57	56	55	57	55
Firm Class 4	MERC001241	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Class 5	MERC001251	0	0	0	0	0	0	0	0	0	0	0	0	0
GS-C&I <1,500 therms/yr (Small) Emmons, IA	MERC000013	2	2	2	2	2	2	2	2	2	2	2	2	2
GS-C&I >1,500 therms/yr (Large) Emmons, IA	MERC000014	1	1	1	1	1	1	1	1	1	1	1	1	1
Agricultural Grain Dryer Class 1	MERC001217	74	96	64	91	80	79	74	78	79	77	77	75	79
Agricultural Grain Dryer Class 2	MERC001227	66	101	44	95	76	72	69	74	72	72	71	74	74
Agricultural Grain Dryer Class 3	MERC001237	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Class 2	MERC001222	196	177	147	156	160	150	143	151	148	149	141	151	156
Interruptible Class 3	MERC001232	48	39	37	37	37	35	39	37	36	35	35	39	38
Interruptible Class 4	MERC001242	0	0	0	0	0	0	0	0	0	0	2	1	0
Interruptible Class 5	MERC001252	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptible Class 2	MERC001223	1	1	1	1	1	1	1	1	1	1	1	1	1
Firm/Interruptible Class 3	MERC001233	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptible Class 4	MERC001243	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptible Class 5	MERC001253	0	0	0	0	0	0	0	0	0	0	0	0	0
Farm Tap Class 1	MERC001216	93	99	92	141	53	136	111	111	118	97	142	101	108
Farm Tap Class 2	MERC001226	186	196	182	252	118	216	161	192	190	210	178	182	189
Farm Tap Class 3	MERC001236	2	3	4	3	2	4	2	4	3	2	4	2	3
Interruptible Electric Generation Class 1	MERC001218	7	6	6	6	6	6	6	6	6	6	6	6	6
Interruptible Electric Generation Class 2	MERC001228	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		204,765	213,262	212,359	213,318	213,128	215,825	216,045	215,708	215,570	216,165	216,143	214,746	213,919

MINNESOTA ENERGY RESOURCES - NNG
Projected Hedges Oct - November 2025 through March 2026

Future Contracts WACOG

Future Contracts											
10,000 @Contract											
Order Number	Purchase Date	Trade Number	Trade Volume	Trade Price	Sale Price	Cost	Pre-Purchase Cost	Pre-Purchase Per Unit	Pre-Purchase Volume	Pre-Purchase Price	Pre-Purchase Cost
1	09/16/25	132741	6	60.000	\$ 4,200	\$ 253,740	\$ -	\$ -	6	60.000	\$ 253,740
2	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
3	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
4	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
5	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
6	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
7	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
8	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
9	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
10	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
11	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
12	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
13	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
14	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
15	09/16/25	133445	6	60.000	\$ 4,100	\$ 246,120	\$ -	\$ -	6	60.000	\$ 246,120
Total			12			\$ 2,537,400	\$ -	\$ -	12		\$ 2,537,400
NNG	09/16/25	29	82.69%	99.420	\$ 4,1655	\$ 414,170	\$ -	\$ -	29	82.69%	\$ 414,170
Other Cons	09/16/25	6	17.14%	20.571	\$ 4,1655	\$ 86,690	\$ -	\$ -	6	17.14%	\$ 86,690
Total		35	100.00%	120.000	\$ 4,1655	\$ 499,860	\$ -	\$ -	35	100.00%	\$ 499,860
Order Number	Purchase Date	Trade Number	Trade Volume	Trade Price	Sale Price	Cost	Pre-Purchase Cost	Pre-Purchase Per Unit	Pre-Purchase Volume	Pre-Purchase Price	Pre-Purchase Cost
1	09/22/25	133002	4	40.000	\$ 4,530	\$ 186,360	\$ -	\$ -	4	40.000	\$ 186,360
2	09/22/25	133003	6	60.000	\$ 4,530	\$ 271,800	\$ -	\$ -	6	60.000	\$ 271,800
3	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
4	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
5	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
6	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
7	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
8	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
9	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
10	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
11	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
12	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
13	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
14	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
15	09/24/25	133736	9	90.000	\$ 4,790	\$ 431,130	\$ -	\$ -	9	90.000	\$ 431,130
Total			19			\$ 3,863,220	\$ -	\$ -	19		\$ 3,863,220
NNG	09/24/25	43	82.69%	157.115	\$ 4,6801	\$ 783,317	\$ -	\$ -	43	82.69%	\$ 783,317
Other Cons	09/24/25	9	17.31%	32.885	\$ 4,6801	\$ 86,630	\$ -	\$ -	9	17.31%	\$ 86,630
Total		52	100.00%	190.000	\$ 4,6801	\$ 869,950	\$ -	\$ -	52	100.00%	\$ 869,950

* Prices from 7/2/2025 NYMEX market close

MINNESOTA ENERGY RESOURCES - NNG

Projected Storage Cost - November 2025 through March 2026

Month/ Year	K#118657 NNG Storage (Dth)	Total NNG Storage (Dth)	Projected NNG WACOG	K#118657 NNG Storage Cost		Total NNG Storage Cost	ANR Storage GLGT/VGT (Dth)	ANR Storage GLGT/VGT WACOG	ANR Storage GLGT/VGT Cost
Nov-25	585,000	585,000	\$ 2.8223	\$ 1,651,065		\$ 1,651,065	90,000	\$ 2.9649	\$ 266,840
Dec-25	1,470,000	1,470,000	\$ 2.8223	\$ 4,148,830		\$ 4,148,830	248,000	\$ 2.9649	\$ 735,291
Jan-26	1,470,000	1,470,000	\$ 2.8223	\$ 4,148,830		\$ 4,148,830	310,000	\$ 2.9649	\$ 919,114
Feb-26	1,470,000	1,470,000	\$ 2.8223	\$ 4,148,830		\$ 4,148,830	196,000	\$ 2.9649	\$ 581,117
Mar-26	585,000	585,000	\$ 2.8223	\$ 1,651,065		\$ 1,651,065	56,000	\$ 2.9649	\$ 166,033
Total	5,580,000	5,580,000		\$ 15,748,621		\$ 15,748,621	900,000		\$ 2,668,395

Month/ Year	NNG Storage Volume (Dth)	NNG Index Price	NNG Index Cost	Month/ Year	ANR Storage Volume (Dth)	Emerson Index Price	Emerson Market Cost
Nov-25	585,000	\$ 3.6530	\$ 2,137,005	Nov-25	90,000	\$ 2.9980	\$ 269,820
Dec-25	1,470,000	\$ 5.1035	\$ 7,502,145	Dec-25	248,000	\$ 3.5610	\$ 883,128
Jan-26	1,470,000	\$ 6.2790	\$ 9,230,130	Jan-26	310,000	\$ 3.8540	\$ 1,194,740
Feb-26	1,470,000	\$ 6.0525	\$ 8,897,175	Feb-26	196,000	\$ 3.5600	\$ 697,760
Mar-26	585,000	\$ 3.7255	\$ 2,179,418	Mar-26	56,000	\$ 3.1030	\$ 173,768
Total	5,580,000		\$ 29,945,873	Total	900,000		\$ 3,219,216
Storage Savings (Cost):			\$ 14,197,252				\$ 550,821

*Indexes and projected WACOG based on 7/3/2025 market prices and actual wacog through 6/2025.

rejected Hedged Cost - November 2025 through March 2026

[illegible]

*Prices from 7/02/2025 NYMEX market close

**Attachment 12: Forecast Methodology for MERC Demand Entitlement
Effective November 1, 2025**

1. Peak-day

a. Purpose

Gather data and perform analysis used in the “Petition for Change in Demand” for MERC, otherwise known as the “MERC Demand Entitlement Filings.”

b. Background

MERC customers are served by four pipelines¹

1. VGT - Viking Gas Transmission system
2. NNG - Northern Natural Gas pipeline
3. GLGT - Great Lakes Gas Transmission pipeline
4. Centra - Centra pipeline

Weather data is obtained from eight weather stations: International Falls, Bemidji, Cloquet, Fargo, Minneapolis, Rochester, Worthington, and Ortonville.

For analytical purposes, data is subdivided, analyzed, and regressed by the following nine demand areas:

	Pipeline	PGA	Weather Station(s)
1	Centra	MERC Consolidated	International Falls
2	GLGT	MERC Consolidated	Bemidji
3	GLGT	MERC Consolidated	Cloquet
4	VGT	MERC Consolidated	Fargo
5	NNG	MERC NNG	Cloquet
6	NNG	MERC NNG	Minneapolis
7	NNG	MERC NNG	Ortonville
8	NNG	MERC NNG	Rochester
9	NNG	MERC NNG	Worthington

¹ MERC acquired Interstate Power & Light Company's Minnesota natural gas operations and customers in 2015. The Commission's Order Approving Sale Subject to Conditions in Docket No. G-001,011/PA-14-107 required MERC to maintain the transitioned customers on a separate PGA (MERC-NNG-Albert Lea). Pursuant to the Commission's Order in Docket No. G011/GR-15-736, the NNG and NNG-Albert Lea PGAs were consolidated effective July 1, 2017. MERC now submits only two demand entitlement petitions (NNG and Consolidated) for each heating season.

2. Analytical Approach

a. Summary

1. Obtain daily weather data for each weather station.
2. Obtain daily total throughput volumes by pipeline and by weather station.
3. Obtain daily large volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station (Data A).
4. Obtain daily small volume interruptible volumes by pipeline and by weather station (Data B).
5. Calculate daily “firm” volumes by subtracting both Data A and Data B from total throughput volumes.
6. Perform quality control on volumetric data (e.g., identify missing or bad reads, and, to the extent possible, fix missing or bad reads).
7. Perform firm peak day regressions. In response to comments from the Minnesota Department of Commerce, Division of Energy Resources (Department):
 - a. Incorporate a methodology to mitigate the impact of autocorrelation.
 - b. Provide a reasonable explanation whenever a regression model is selected that does not have an intercept.
8. Add back Daily Firm Capacity (DFC) customer selections.

3. Process

The Peak Day Process consisted of:

- I. Data Preparation
- II. Regression Generation of Net Daily Metered Volumes
- III. Volume Risk Adjustments
- IV. Adjusting the Regression Results to a Firm Peak Day Estimate
- V. Firm Peak Day Estimate Gate Station Allocation

i. The **Data Preparation** consisted of:

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.

Determine the most recent three years of December through February daily total metered throughput by pipeline and by weather station.

Determine the most recent three years of December through February daily large volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station (Data A).

Determine the most recent three years of December through February daily small volume interruptible volumes by pipeline and by weather station (Data B).

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.

Subtract both Data A and Data B daily meter readings for all three December through February years from the total throughput for each pipeline and each weather station.

Use the resulting net daily metered volumes for regressions. Examples of transportation, interruptible, and joint interruptible meter readings subtracted are paper mills, direct-connects, taconites, and off-system end users. See "Adjusting the Regression Results to a Firm Peak Day Estimate" below.

Each daily weather station data file was searched to find the coldest Adjusted Heating Degree Day (AHDD65) since January 1996. Many weather stations experienced historically cold weather in the January/February 1996 time period; without inclusion of that additional data from January/February 1996, AHDD65 were materially lower and not reflective of MERC's capacity needs. The coldest AHDD65 data since 1996 is included in the table below, along with the AHDD65 conditions on the day prior ("AHDD65-1").

<u>Station</u>	<u>Date</u>	<u>Avg. Temp</u>	<u>Avg. Wind</u>	<u>HDD65</u>	<u>AHDD65</u>	<u>AHDD65-1</u>
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

This data by weather station was then compared to the AHDD65 data used in the previous demand entitlement filing:

<u>Station</u>	<u>Date</u>	<u>Avg. Temp</u>	<u>Avg. Wind</u>	<u>HDD65</u>	<u>AHDD65</u>	<u>AHDD65-1</u>
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	1/18/1996	-8	32	73	96	74
Ortonville	1/14/2009	-21	11	86	96	86

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. Following is the data by weather station that was ultimately used in MERC's current analysis:

<u>Station</u>	<u>Date</u>	<u>Avg. Temp</u>	<u>Avg. Wind</u>	<u>HDD65</u>	<u>AHDD65</u>	<u>AHDD65-1</u>
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

ii. The **Regression Generation of Net Daily Metered Volumes** consisted of:

For each of the pipelines and weather stations:

1. Gather the net daily metered volumes and weather station data including AHDD65.²
2. Add indicator variables for day-type and month. Day-type variables are used to isolate load that changes by day of the week, such as commercial or industrial customers who may change their consumption on weekends when they run fewer shifts. Month indicator variables are used to isolate load that changes based on winter months, such as businesses that are open extra hours in December and resume normal operating hours in January.
3. Perform ordinary least squares linear regressions for the 3-year time frame using the AHDD65 weather variable and the significant indicator variables.
4. In response to comments from the Department, the regression methodology incorporates a process to mitigate the impact of autocorrelation. See section below on autocorrelation.

² Temperature and weather data were obtained from DTN (formerly Schneider Electric) via DataMaxx then converted to HDD65 and AHDD65 in an Excel spreadsheet by MERC – Gas Supply. Temperature and wind data is the 24-hour average based on the 9am to 9am gas day.

5. In response to comments from the Department, provide an explanation whenever we choose to use a regression model that does not have an intercept.
6. Summarize the Baseload and Use/AHDD65 and Use/Prior Day AHDD65 from each regression.
7. Calculate a point estimate from each regression based on the baseload value plus the Use/AHDD65 coefficient times the coldest AHDD65 since January 1996 and the Use/Prior Day AHDD65 coefficient times the AHDD65 on the day prior to the coldest AHDD65 since January 1996.

iii. **Volume Risk Adjustments**

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. An appropriate volume risk adjustment was determined for each regression group by multiplying the standard error of each regression analysis (sigma) by a factor needed to attain a desired confidence level. The desired confidence level chosen was 97.5%.

iv. **Adjusting the Regression Results to a Firm Peak Day Estimate** consisted of:

1. **Add back DFC customer selections**

While transportation, interruptible, and joint interruptible customer volumes were removed (as described above), in order to determine firm peak day load, daily firm capacity volumes needed to be added back. Reporting from the billing system provided historical monthly DFC data for the joint service customers from the prior winter that showed the volume that each customer has selected to receive as firm service from MERC each month. Based on direction from the Company's Gas Supply department, the Joint Firm/ Interruptible customers who were relying on MERC to provide peak day firm supply were identified and their daily firm

capacity volumes were summed by month for each pipeline. The total volumes were then added back to the regression results.

v. **Firm Peak Day Estimate Gate Station Allocation:**

After the data is subdivided, analyzed, and regressed to the nine demand areas, the data is further subdivided to each Gate Station within each of the nine demand areas. To provide a firm peak day estimate for each Gate Station, the following steps are taken:

1. The previous winter's actual historical throughout, by Gate Station, is gathered.
2. Estimated transportation, interruptible, and joint interruptible customer volumes are allocated to each Gate Station. The allocation is determined by which Gate Station has the closest geographical location to the customer.
3. For each Gate Station, using the last winter's data, the estimated coincidental transportation and interruptible Gate Station non-firm throughput total for the same date of the Gate Station's total throughput peak is then subtracted from the total throughput peak value in order to calculate an estimated coincidental peak firm value for each Gate Station.

$$\text{Gate Total Throughput Peak} - \text{Same Date Location-based estimated Non-Firm Total Throughput} = \text{Coincidental Gate Station Firm Estimate}$$

4. Each of the calculated coincidental peak firm values at each Gate Station are then divided by the new demand area total of the coincidental firm peak day estimates, and then multiplied by the initial demand area firm peak day total.

$$\left[\frac{\text{Coincidental Gate Station Firm Estimate}}{\text{Total Demand Area Coincidental Firm Estimate}} \right] \times \text{Regression Demand Area Firm Estimate}$$

By having the coincidental peak day estimates as a ratio of the initial demand area estimates, the Gate Station peak day estimates continue to maintain the initial demand area estimates that resulted from the regression analyses in steps i. through iv. above.

Exhibit 1
Pipeline and Weather Station Regression Notes

A. Large Volume Transportation, Interruptible, and Joint Interruptible Customers

GLGT Paper Mills =

Blandin mapped to Bemidji
Sappi and USG mapped to Cloquet

VGT Lamb Weston mapped to Fargo

NNG Taconites / Direct Connects =

CCI EMPIRE IND DEL PT 2 TILDEN mapped to Cloquet
CCI NORTHSORE mapped to Cloquet
UNITED TACONITE (was EVELETH TACONITE) mapped to Cloquet
HIBBING TACONITE CO. mapped to Cloquet
U.S. STEEL #1 & #2 mapped to Cloquet
NATIONAL STEEL PELLET mapped to Cloquet
COTTAGE GROVE TBS LS POWER mapped to Minneapolis
INLAND STEEL mapped to Cloquet

NNG OSEU (End Users) =

ARKEMA INC. mapped to Rochester
MAYO Clinic 1 Fairmont mapped to Worthington
MAYO Clinic 2 (Franklin Htg) mapped to Rochester
MAYO Clinic 3 (St Mary's) mapped to Rochester
ARCHER DANIELS MIDLAND, CO. mapped to Minneapolis
ASSOCIATED MILK PRODUCTS, INC. mapped to Rochester
Hawkins Inc. mapped to Minneapolis
CORRECTIONAL CTR mapped to Minneapolis
DAIRY FARMERS OF AMERICA mapped to Rochester
Dick's Sanitation mapped to Minneapolis
KEMPS LLC mapped to Rochester
KERRY BIO-SCIENCE mapped to Rochester
LAKESIDE mapped to Rochester
MILK SPECIALTIES mapped to Worthington
LAND O'LAKES mapped to Rochester
PRO-CORN mapped to Rochester

SWIFT mapped to Worthington
SENECA FOODS-ROCHESTER mapped to Rochester
ENGINEERED POLYMERS mapped to Cloquet
SANDSTONE FEDERAL CORRECTIONAL INSTITUTE mapped to Cloquet
Agra Resources(Exol) mapped to Rochester
Halcon Corporation mapped to Rochester
REG ALBERT LEA, LLC mapped to Rochester
Zinpro North Branch mapped to Minneapolis

B. Daily Firm Capacity

VGT

DETROIT LAKES MIDDLE SCHOOL
ROSSMAN SCHOOL

GLGT

NORTHLAND APTS

NNG

HENDRICKS HOSPITAL
BRAND FX BODY INC

4. Autocorrelation Review

The Commission's February 4, 2015, Order in MERC's 2012-2013 demand entitlement dockets³ required MERC to check its regression models for autocorrelation and correct the model if autocorrelation is present and to provide a reasonable explanation of its use of no-intercept models if it chooses to use one again in the future.

In a regression analysis, using time series data, autocorrelation of the errors is a problem. Autocorrelation of the errors, which themselves are unobserved, can generally be detected because it produces autocorrelation in the observable residuals. (Errors are also known as "error terms" in econometrics.) Autocorrelation violates the ordinary least squares (OLS) assumption that the error terms are uncorrelated. While it does not bias the OLS coefficient estimates, the standard errors tend to be underestimated (and the t-scores overestimated) when the autocorrelations of the errors at low lags are positive. The traditional

³ Docket Nos. G011/M-12-1192, G011/M-12-1193, G011/M-12-1194, and G011/M-12-1195

test for the presence of first-order autocorrelation is the Durbin–Watson statistic or, if the explanatory variables include a lagged dependent variable, Durbin's h statistic. To correct for this use, MERC used the Yule-Walker estimation method within the SAS software package to employ an AR(1) regression which then showed that the Durbin–Watson statistics are all either close to 2 or above.

5. Design-Day Model

Order Point 5 of the Commission's January 21, 2015, Order in MERC's 2010-2011 demand entitlement dockets⁴ required that in future demand entitlement filings, MERC provide (1) the determinants used in its Design-Day models that account for each and every impact on usage associated with economic conditions, and (2) a detailed explanation of each and every cause of unexpected changes in usage that might impact the Design-Day calculation, and what, if any, modifications the Company made to its Design-Day numbers. MERC does not forecast its Design Day using economic variables. Additionally, there were no unexpected changes in the Design-Day forecast.

6. Verification of Regression Analysis Results

Order Point 10 of the Commission's April 28, 2016, Order in Docket No. G011/M-15-722 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 the May

⁴ Docket Nos. G007/M-10-1166, G007/M-10-1167, G011/M-10-1168, and G011/M-10-1169

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.

7. Albert Lea Telemetry Data

Order Point 11 of 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 has worked with the Department to ensure its design day regression analysis for the NNG-PGA is reasonable. As of this filing, MERC has completed installation of telemetry for its former MERC-Albert Lea customers and has sufficient data for these customers to utilize in the Design Day analysis. For this 2025-2026 Design-Day, MERC has utilized daily telemetry data for all of the MERC-NNG customers.

ATTACHMENT D

In the Matter of the Petition of Minnesota
Energy Resources Corporation for Approval
of a Change in Demand Entitlement for its
NNG System

Docket No. G011/M-25-68

CERTIFICATE OF SERVICE

I, Colleen T. Sipiorski, hereby certify that on the 1st day of August, 2025, on behalf of Minnesota Energy Resources Corporation (MERC) I electronically filed a true and correct copy of MERC's Petition for Approval of a Change in Demand Entitlement on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

Dated this 1st day of August, 2025.

/s/ Colleen T. Sipiorski

Colleen T. Sipiorski

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