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

November 1, 2024 **VIA ELECTRONIC FILING**

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

Re: In the Matter Minnesota Energy Resources Corporation's Petition for Approval of a Change in Demand Entitlement for its NNG System – November 1 Update

Docket No. G011/M-24-270

Dear Mr. Seuffert:

On August 1, 2024, Minnesota Energy Resources Corporation ("MERC" or the "Company") filed its Petition for Change in Demand Entitlement for its MERC-NNG purchased gas adjustment ("PGA") area. MERC submits this update to its August 1, 2024 Demand Entitlement filing.

In its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, the Minnesota Public Utilities Commission ("Commission") required that MERC explain changes made in its compliance petitions that are different from its original petitions, and provide a redline version of both petitions identifying changes. In accordance with the Commission's Order, MERC provides redlined changes in the attached Petition and has highlighted changes in the affected schedules.

As of the date of this filing, MERC has completed its purchases of future contracts and call options for the 2024-2025 winter period. The final financial hedge volumes and costs are shown in Attachments 5 and 11 (pages 1 and 3). The call option premium costs additionally flow through the spreadsheet in Attachment 4, pages 1 and 2, and in Attachment 8. Additionally, the rate comparisons in Attachment 4, page 1, have been updated to MERC's October 1, 2024, PGA rates, and a formula correction has been made to the summations of total demand costs and total demand rates per therm as shown on Attachment 4, page 2.

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.

Sincerely yours,

/s/Joylyn Hoffman Malueg
Joylyn Hoffman Malueg
Sr. Project Specialist
Minnesota Energy Resources Corporation

Enclosures
cc: Service List

ATTACHMENT A

November~~August~~ 1, 2024

To: Docket No. G011/M-24-270 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 24-270~~date of the filing~~.

ATTACHMENT B

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Valerie Means	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**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-24-270

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, 2024.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Valerie Means	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**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-24-270

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, 2024.

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 2024-2025 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

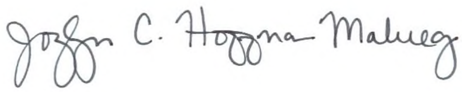
C. Date of the Filing and Proposed Effective Date

Date of filing: November~~August~~ 1, 2024
Proposed Effective Date: November 1, 2024

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
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(414) 221-4208

If additional information is required, please contact Joylyn Hoffman Malueg at (414) 221-4208.

DATED: November~~August~~ 1, 2024

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 C

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Valerie Means	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**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-24-270

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, 2024. 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 slightly decreased by 765 dekatherms (dth), or 0.26%, from the April 2, 2024 filing of the 2023-2024 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 2024-2025 Heating Season

	Reserve Margin 2024-2025 Heating Season	Reserve Margin 2023-2024 Heating Season	Change
NNG Zone EF	10.36%	10.07%	0.29%

For the Demand Entitlement filing effective November 1, 2024, the total Design-Day requirement for MERC NNG is 290,169 dth (Attachment 1). The difference between the total Design-Day requirement and total Design-Day capacity results in a 10.36% 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, 2024

See Attachment 12. As discussed in Attachment 12, MERC's 2024-2025 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 2023-2024.[4]

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 2024-2025 as compared to 2023-2024; therefore additional pipeline capacity was not required. Historically, ~~T~~the NNG Ventura North Generally Available Open Season has only allowed for Ventura as the receipt location, while the NNG West Leg Generally Available Open Season has historically only allowed for NBPL/NNG Welcome as the receipt location~~, therefore there were no other available options presented when bidding into the Open Season~~.

2. Other Demand Entitlement Changes

[4] Docket No. G011/M-24-155, *In the Matter of Minnesota Energy Resources Corporation's Petition for Approval of a Change in Demand Entitlement for its NNG System* (Jul. 16, 2024).

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 2,939 dth/day, with a corresponding decrease in the base component. This change does not result in an increase or decrease in demand entitlement levels. Additionally, there was a reduction of $10,082 in the annual costs for MERC-NBPL contract 101251 due to the calendar year in this 2024-2025 demand entitlement filing no longer containing an extra day due to the leap year.

E. Financial Option Units and Premiums

MERC has ~~started~~completed its purchases of future contracts and call options for the 2024-2025 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 2024-2025 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 2024-2025 winter is $3.4001~~3.6461~~/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 $2.1354~~2.4906~~/dth, which is ~~well~~ under 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 ~~push~~keep the strike price of the purchased call options up to an average of $5.7206~~7.1686~~/dth. Both the futures and option strike prices are ~~up slightly~~down from winter 2023-24. 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 2024 through March 2025 period. All 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, 2024. 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.[5]

[5] 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

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.

For the 2024-2025 heating season, MERC has calculated a reserve margin of 10.36%. As a result, MERC has taken action as laid out in the Capacity Release Plan filed on August 31, 2017, and approved by the Commission by Order dated May 8, 2018.

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. <u>MERC-NNG Future Capacity Outlook</u>

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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.

As discussed in MERC's November, 1, 2023 and April 1, 2024 updates in the 2023-2024 Demand Entitlement filing, MERC has continuously identified decreased reserve margins within different operating areas of the MERC-NNG system. While MERC-NNG has a surplus of 15,565 dth/day at a Total System level[6] through 2024-2025, 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 NNG Farmington area. The Rochester and NNG Farmington area 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 NNG Farmington area is not an operationally viable solution, nor allowed by NNG, for serving the Farmington area.

MERC's 10-year forecasted Peak (and Reserve) for the MERC-NNG Total System level as well as the operating area and gate station level, indicates system capacity shortages, with the NNG Farmington region being the bulk of the system shortage. On both an operating area and gate station level, and a MERC-NNG Total System level, MERC becomes short of its Peak + Reserve within the next 10 years.

Given MERC's focused efforts on ensuring reliability, MERC is looking at potential ways to meet the upcoming demand needs in the Farmington and Worthington areas. NNG has informed MERC that they do not have either discounted capacity, or the ability to realign capacity from other areas of the MERC system to the Farmington or Worthington areas. MERC expressed interest in NNG's 2025 Northern Lights Open Season, which would go in service November 1, 2025. As part of the 2025 Northern Lights Open Season process, NNG provided MERC a non-binding cost estimate to expand its system to meet the Company's needs in the

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

NNG Farmington area. NNG's cost estimate was a $250 million commitment for a 20 year contract, which equates to an annual increase of $12 million to the MERC-NNG demand costs.

As an alternative to an NNG expansion, MERC has investigated connections with another pipeline but there are no other interstate pipeline alternatives that are locationally viable, or that have open capacity to deliver to MERC's system in the Farmington or Worthington area. MERC is also analyzing the potential ability for Liquefied Natural Gas (LNG) peaking service in the Farmington area as well. MERC will continue to provide the Commission with updates on its efforts.

V. Conclusion

MERC respectfully requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2024.

DATED: November~~August~~ 1, 2024

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, 2024

		NNG
Design Day Requirement		290,169
Total Peak Day Entitlement		320,242
2023/24 Firm Peak Day Actual Sendout	1/15/2024	230,551
Firm Annual Throughput - Minnesota		25,743,791
No. of Firm Customers		212,522
Department Load Factor Calculation		30.59%

MINNESOTA ENERGY RESOURCES - NNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS

NOVEMBER 1, 2024

NNG

Pipeline Group	2023/24 Customer Count	Zone Total Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	Regression Total	Regression Adjustment	1/20 Requirements Regression Load	Firm/Interrupt. Contract Demand Units	Total
PEAK										
NNG	212,522	212,522	99	6,411	2,390	280,554	9,560	290,114	55	290,169
OFF PEAK										
NNG	212,522	212,522	55	6,411	2,390	158,314	9,560	167,874	55	167,929

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND PER CUSTOMER
NOVEMBER 1, 2024
NNG

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtu /Customer /Day
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
11/12	185,890	247,982	1.33

MINNESOTA ENERGY RESOURCES - NNG

SUMMER/WINTER USAGE - Dth
PROJECTED 12 MONTHS ENDING JUNE 2025

	NNG		
Class	**Summer Apr-Oct**	**Winter Nov-Mar**	**Total**
GS	6,627,384	19,108,988	25,736,372
Interruptible	770,402	1,089,367	1,859,770
Firm/Interruptible	3,378	4,042	7,420
Total	7,401,164	20,202,397	27,603,561

MINNESOTA ENERGY RESOURCES - NNG

ENTITLEMENT LEVELS

NOVEMBER 1, 2024

NNG

Capacity Type	*Summer* 2023-24 MMBtu	*Summer* Change MMBtu	*Summer* Proposed MMBtu	*April/October* 2023-24 MMBtu	*April/October* Change MMBtu	*April/October* Proposed MMBtu	*Winter* 2023-24 MMBtu	*Winter* Change MMBtu	*Winter* 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							290,934	(765)	290,169
Forecasted Design Day + 5% Reserve							305,481		304,677
Forecasted Design Day (Non-Heating Season)				167,204	725	167,929			
Capacity Surplus/Shortage to Design Day (Heating Season)							29,308	765	30,073
Capacity Surplus/Shortage to Design Day + 5% Reserve (Heating Season)							14,761		15,565
Non-Heating Season									
Capacity Surplus/Shortage				14,262	(725)	13,537			
*Not included in Heating Season Total entitlement									
Reserve Margin				8.53%	-0.47%	8.06%	10.07%	0.29%	10.36%

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
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All costs in $/Dth	Base Cost of Gas G011/MR-22-505 Mar 1, 2024	Demand Charge Demand Filing Apr 1, 2024	Most Recent PGA Oct 1, 2024	Proposed Effective Nov 1, 2024	Result of Proposed Change: Change from Last Rate Case	Change from Apr 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	$4.1220	$2.8929	$3.2949	($2.2477)	($0.8271)	13.90%	$0.4020
Demand Cost	$1.0107	$1.2580	$1.2580	$1.2853	$0.2746	$0.0273	2.17%	$0.0273
Commodity Margin	$3.2919	$3.2919	$3.2919	$3.2919	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.8452	$8.6719	$7.4428	$7.8721	($1.9731)	($0.7998)	5.77%	$0.4293
Avg Annual Cost	$842.75	$742.31	$637.10	$673.85	($168.90)	($68.46)	5.77%	$36.75
Effect of proposed commodity change on average annual bills:								$34.41
Effect of proposed demand change on average annual bills:								$2.34
2) Small C&I Firm, Class 2: Avg. Annual Use:		**781**	**Dth**					
Commodity Cost	$5.5426	$4.1220	$2.8929	$3.2949	($2.2477)	($0.8271)	13.90%	$0.4020
Demand Cost	$1.0107	$1.2580	$1.2580	$1.2853	$0.2746	$0.0273	2.17%	$0.0273
Commodity Margin	$2.5030	$2.5030	$2.5030	$2.5030	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$9.0563	$7.8830	$6.6539	$7.0832	($1.9731)	($0.7998)	6.45%	$0.4293
Avg Annual Cost	$7,072.97	$6,156.62	$5,196.70	$5,531.98	($1,540.99)	($624.64)	6.45%	$335.28
Effect of proposed commodity change on average annual bills:								$313.96
Effect of proposed demand change on average annual bills:								$21.32
3) Large C&I Firm Class 3: Avg. Annual Use:		**15,986**	**Dth**					
Commodity Cost	$5.5426	$4.1220	$2.8929	$3.2949	($2.2477)	($0.8271)	13.90%	$0.4020
Demand Cost	$1.0107	$1.2580	$1.2580	$1.2853	$0.2746	$0.0273	2.17%	$0.0273
Commodity Margin	$1.6890	$1.6890	$1.6890	$1.6890	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$8.2423	$7.0690	$5.8399	$6.2692	($1.9731)	($0.7998)	7.35%	$0.4293
Avg Annual Cost	$131,763.88	$113,007.15	$93,358.39	$100,221.31	($31,542.57)	($12,785.84)	7.35%	$6,862.92
Effect of proposed commodity change on average annual bills:								$6,426.49
Effect of proposed demand change on average annual bills:								$436.43
4) Small C&I Interruptible, Class 2: Avg. Annual Use:		**4,110**	**Dth**					
Commodity Cost	$5.5426	$4.1220	$2.8929	$3.2949	($2.2477)	($0.8271)	13.90%	$0.4020
Commodity Margin	$1.5047	$1.5047	$1.5047	$1.5047	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$7.0473	$5.6267	$4.3976	$4.7996	($2.2477)	($0.8271)	9.14%	$0.4020
Avg Annual Cost	$28,962.29	$23,124.05	$18,072.82	$19,724.92	($9,237.37)	($3,399.13)	9.14%	$1,652.10
Effect of proposed commodity change on average annual bills:								$1,652.10
5) Large C&I Interruptible, Class 3: Avg. Annual Use:		**22,091**	**Dth**					
Commodity Cost	$5.5426	$4.1220	$2.8929	$3.2949	($2.2477)	($0.8271)	13.90%	$0.4020
Commodity Margin	$1.2058	$1.2058	$1.2058	$1.2058	$0.0000	$0.0000	0.00%	$0.0000
Total Cost of Gas	$6.7484	$5.3278	$4.0987	$4.5007	($2.2477)	($0.8271)	9.81%	$0.4020
Avg Annual Cost	$149,080.93	$117,698.03	$90,545.61	$99,426.31	($49,654.62)	($18,271.71)	9.81%	$8,880.70
Effect of proposed commodity change on average annual bills:								$8,880.70

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
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A. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE: 01-Nov-24

	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						$2.3949 /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-24

		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	23,137	5	$ 17.4170	=	$2,014,886	258,811,603	$ 0.00779
	TF12B (Max Rate) Summer	112495	23,137	7	$ 9.6760	=	$1,567,115	258,811,603	$ 0.00606
	TF12V (Max Rate)	112495	44,913	12	$ 15.4814	=	$8,343,793	258,811,603	$ 0.03224
	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						$33,266,129		**$ 0.12853**

NNG-GS Demand Current Cost of Gas/therm	**$ 0.12853**
NNG-GS Commodity Current Cost of Gas/therm	**$ 0.32949**
Total NNG-GS Current Cost of Gas/therm	**$ 0.45802**

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	$ 6.1230	=	$3,673,800	280,960,833	$ 0.01308
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						$14,390,074		$ 0.05122

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.

		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	$2.3949	$67,287,310	280,960,833	$ 0.23949
	Balancing Service	272,160	x	$4.2550	$1,158,041	280,960,833	$ 0.00412
	Physical Forward Start Premium				$555,750	280,960,833	$ 0.00198
	Call Option Premium				$397,979	280,960,833	$ 0.00142

(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))	$92,571,698	**$ 0.32949**

[1] Rate applies for new transport contract 142983

Attachment 5

MINNESOTA ENERGY RESOURCES - NNG

Financial Options

Heating Season 2024-2025

Units - Gas Daily Peaker Packages (Physical)

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

Premium - Gas Daily Peaker (Monthly Cost)

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

Units - Futures (Dth)

	November Contract Date	November Daily Volume	December Contract Date	December Daily Volume	January Contract Date	January Daily Volume	February Contract Date	February Daily Volume	March Contract Date	March Daily Volume	Term Total
1	05/23/24	1,955	05/22/24	2,667	05/20/24	2,445	05/17/24	3,071	05/15/24	1,919	362,585
2	06/24/24	1,676	06/18/24	2,401	05/20/24	272	06/07/24	2,457	06/03/24	1,919	261,398
3	07/25/24	1,676	07/23/24	2,134	06/13/24	2,716	07/18/24	2,457	07/16/24	1,919	328,856
4	08/07/24	1,676	07/23/24	267	07/22/24	2,716	08/20/24	2,457	08/26/24	1,919	269,831
5	09/24/24	1,676	08/13/24	2,134	08/15/24	2,445	09/11/24	2,457	09/06/24	1,645	311,992
6	10/16/24	1,676	09/19/24	2,134	09/17/24	2,445	10/10/24	2,457	10/07/24	1,645	311,992
7	01/00/00	-	10/14/24	2,134	10/11/24	2,445	01/00/00	-	01/00/00	-	143,347
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		10,333		13,871		15,484		15,357		10,968	1,990,000

Units - Call Options (Dth)

	November Contract Date	November Daily	December Contract Date	December Daily	January Contract Date	January Daily	February Contract Date	February Daily	March Contract Date	March Daily	Term Total
1	05/15/24	3,868	05/17/24	4,811	05/20/24	2,697	05/22/24	5,483	05/23/24	3,839	621,346
2	06/03/24	3,592	06/07/24	4,811	05/22/24	2,967	06/18/24	5,483	06/24/24	3,839	621,418
3	07/16/24	3,592	07/18/24	4,811	06/13/24	2,697	07/23/24	5,483	07/25/24	3,565	604,556
4	08/26/24	3,316	08/20/24	4,544	06/18/24	2,428	08/13/24	4,874	08/07/24	3,565	562,560
5	09/06/24	3,316	09/11/24	4,544	07/22/24	5,125	09/19/24	4,874	09/24/24	3,565	646,181
6	10/07/24	3,316	10/10/24	4,544	08/15/24	5,125	10/14/24	4,874	10/16/24	3,565	646,181
7	01/00/00	-	01/00/00	-	09/17/24	5,125	01/00/00	-	01/00/00	-	158,879
8	01/00/00	-	01/00/00	-	10/11/24	5,125	01/00/00	-	01/00/00	-	158,879
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		21,000		28,065		31,290		31,071		21,935	4,020,000

Premium - Call Option (Monthly Cost)

	November Option Premium	November Premium	December Option Premium	December Premium	January Option Premium	January Premium	February Option Premium	February Premium	March Option Premium	March Premium	Total Option Premium	Total Premium
1	$ 0.1000	$ 11,605	$ 0.1000	$ 14,914	$ 0.1000	$ 8,362	$ 0.1000	$ 15,353	$ 0.1000	$ 11,900	$ 0.1000	$ 62,135
2	$ 0.0980	$ 10,561	$ 0.1000	$ 14,914	$ 0.1000	$ 9,198	$ 0.1000	$ 15,353	$ 0.1000	$ 11,900	$ 0.0997	$ 61,926
3	$ 0.0970	$ 10,453	$ 0.1000	$ 14,914	$ 0.1000	$ 8,362	$ 0.1000	$ 15,353	$ 0.0990	$ 10,940	$ 0.0993	$ 60,022
4	$ 0.0980	$ 9,748	$ 0.0980	$ 13,804	$ 0.1000	$ 7,526	$ 0.1000	$ 13,647	$ 0.1000	$ 11,050	$ 0.0991	$ 55,775
5	$ 0.0920	$ 9,152	$ 0.0950	$ 13,381	$ 0.1000	$ 15,888	$ 0.0990	$ 13,511	$ 0.0990	$ 10,940	$ 0.0973	$ 62,871
6	$ 0.0970	$ 9,649	$ 0.0940	$ 13,241	$ 0.1000	$ 15,888	$ 0.1000	$ 13,647	$ 0.1000	$ 11,050	$ 0.0982	$ 63,475
7	$ -	$ -	$ -	$ -	$ 0.1000	$ 15,888	$ -	$ -	$ -	$ -	$ 0.1000	$ 15,888
8					$ 0.1000	$ 15,888	$ -	$ -			$ 0.1000	$ 15,888
9					$ -	$ -	$ -	$ -				$ -
10					$ -	$ -	$ -	$ -				$ -
11					$ -	$ -	$ -	$ -				$ -
12					$ -	$ -	$ -	$ -				$ -
Total	$ 0.0971	$ 61,168	$ 0.0979	$ 85,169	$ 0.1000	$ 97,000	$ 0.0998	$ 86,864	$ 0.0997	$ 67,779	$ 0.0990	$ 397,979

Units - Collar Floor (put)

No Puts were purchased.

MINNESOTA ENERGY RESOURCES - NNG

24/25 Winter Portfolio Plan - NNG MERC Hedging Plan

System	Purchase Month	Nov-24 Number Contracts	Nov-24 Contract Volume	Dec-24 Number Contracts	Dec-24 Contract Volume	Jan-25 Number Contracts	Jan-25 Contract Volume	Feb-25 Number Contracts	Feb-25 Contract Volume	Mar-25 Number Contracts	Mar-25 Contract Volume	Total Number Contracts	Total Contract Volume	Percent of Requirements
MN Requirements			3,156,840		4,375,717		4,879,197		4,356,573		3,434,070		20,202,397	20,202,397
Daily Average			105,228		141,152		157,393		155,592		110,776		133,791	
10%	Futures		315,684		437,572		487,920		435,657		343,407		2,020,240	
20%	Call		631,368		875,143		975,839		871,315		686,814		4,040,479	
30%	Storage		947,052		1,312,715		1,463,759		1,306,972		1,030,221		6,060,719	
40%	Index		1,262,736		1,750,287		1,951,679		1,742,629		1,373,628		8,080,959	
Futures														
Contracts	May-24	6	60,000	8	80,000	8	80,000	8	80,000	6	60,000	36	360,000	
	Jun-24	5	50,000	7	70,000	8	80,000	7	70,000	6	60,000	33	330,000	
	Jul-24	5	50,000	7	70,000	8	80,000	7	70,000	6	60,000	33	330,000	
	Aug-24	5	50,000	7	70,000	8	80,000	7	70,000	6	60,000	33	330,000	
	Sep-24	5	50,000	7	70,000	8	80,000	7	70,000	5	50,000	32	320,000	
	Oct-24	5	50,000	7	70,000	8	80,000	7	70,000	5	50,000	32	320,000	
	Total	31	310,000	43	430,000	48	480,000	43	430,000	34	340,000	199	1,990,000	**9.85%**
Call Options	May-24	11	110,000	15	150,000	17	170,000	15	150,000	12	120,000	70	700,000	
	Jun-24	11	110,000	15	150,000	16	160,000	15	150,000	12	120,000	69	690,000	
	Jul-24	11	110,000	15	150,000	16	160,000	15	150,000	11	110,000	68	680,000	
	Aug-24	10	100,000	14	140,000	16	160,000	14	140,000	11	110,000	65	650,000	
	Sep-24	10	100,000	14	140,000	16	160,000	14	140,000	11	110,000	65	650,000	
	Oct-24	10	100,000	14	140,000	16	160,000	14	140,000	11	110,000	65	650,000	
	Total	63	630,000	87	870,000	97	970,000	87	870,000	68	680,000	402	4,020,000	**19.90%**
Collars	May-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Jul-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Sep-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Oct-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Total	0	0	0	0	0	0	0	0	0	0	0	0	**0.00%**
Index (back financial)														
	Total		940,000		1,300,000		1,450,000		1,300,000		1,020,000		6,010,000	**29.75%**
Physical Hedges			0		0		0		0		0		0	
Storage			635,634		1,597,234		1,597,234		1,597,234		635,634		6,062,969	**30.01%**
Prepaid Obl			0		0		0		0		0		0	**0.00%**
			49.91%		66.21%		62.45%		66.50%		48.21%		59.76%	
Term Index		0	0	0	0	0	0	0	0	0	0		0	**0.00%**
		0	0	0	0	0	0	0	0	0	0		0	**0.00%**
Total NNG MN														
Futures													1,990,000	**9.85%**
Call Options													4,020,000	**19.90%**
Costing Collar													0	**0.00%**
Storage													6,062,969	**30.01%**
Prepaid Obl													0	**0.00%**
Term Index													0	**0.00%**
Month/Daily													8,129,428	**40.24%**
Total													20,202,397	**100.00%**

MINNESOTA ENERGY RESOURCES - NNG

NNG WINTER PLAN
NOVEMBER 2024 THROUGH MARCH 2025

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

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
	123822	5/15/2024	NNG/GLGT Carlton	24,972	24,972	24,972	24,972	24,972	3,770,772
	123823	5/15/2024	NNG/GLGT Grand Rapids	6,000	6,000	6,000	6,000	6,000	906,000
	123824	5/15/2024	NNG-TCPL/NNG Beatrice	5,540	5,540	5,540	5,540	5,540	836,540
	123825	5/15/2024	NNG-NBPL/NNG Ventura	-	19,000	19,000	19,000	-	1,710,000
	123826	5/15/2024	NNG-NNG Field/Demarc	10,000	10,000	10,000	10,000	10,000	1,510,000
	123827	5/15/2024	NNG-NNG Field/Demarc	10,000	10,000	10,000	10,000	10,000	1,510,000
	123828	5/15/2024	NNG-NNG Field/Demarc	12,000	12,000	12,000	12,000	12,000	1,812,000
	123829	5/15/2024	NNG-NNG Field/Demarc	-	10,371	10,371	10,371	-	933,390
	123821	5/15/2024	NBPL at Spring Creek TP	10,000	10,000	10,000	10,000	10,000	1,510,000
			TOTAL	**78,512**	**107,883**	**107,883**	**107,883**	**78,512**	**14,498,702**
GAS DAILY PACKAGES									
Physical Call Option	123830	5/15/2024	NNG NBPL/NNG Ventura	-	10,000	10,000	10,000	-	
Physical Call Option	123831	5/15/2024	NNG NBPL/NNG Ventura	-	10,000	10,000	10,000	-	
Physical Call Option	123833	5/15/2024	NNG NBPL/NNG Ventura	-	10,000	10,000	10,000	-	
FOM PRICED CALL PACKAGES									
Physical Call Option	122402	3/14/2024	NNG-NBPL/NNG Various	40,000	40,000	40,000	40,000	40,000	

STORAGE Injection Month	K#118657 Volume Injected	Open Volume Injected	Total Volume Injected
May - balance forward	2,581,735	0	2,581,735
June	725,490	0	725,490
July	549,673	0	549,673
August	549,673	0	549,673
Sept	925,490	0	925,490
Oct (est)	867,939	0	867,939
Total	**6,200,000**	**0**	**6,200,000**

MINNESOTA ENERGY RESOURCES - NNG

NNG WINTER PLAN - SUPPLY MIX
NOVEMBER 2024 THROUGH MARCH 2025

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-TCPL/NNG Beatrice	5,540	5,540	5,540	5,540	5,540	5,540
Monthly Index	Baseload	Ventura	NNG-NBPL/NNG Ventura	-	19,000	19,000	19,000	19,000	-
Monthly Index	Baseload	Nymex LDS	NNG-NNG Field/Demarc	10,000	10,000	10,000	10,000	10,000	10,000
Monthly Index	Baseload	Demarc	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	12,000	12,000	12,000	12,000	12,000	12,000
Monthly Index	Baseload	Demarc	NNG-NNG Field/Demarc	-	10,371	10,371	10,371	10,371	-
Monthly Index	Baseload	Ventura	NBPL at Spring Creek TP	10,000	10,000	10,000	10,000	10,000	10,000
Daily Index	Call/Swing	Ventura	NNG NBPL/NNG Ventura	-	10,000	10,000	10,000	10,000	-
Daily Index	Call/Swing	Ventura	NNG NBPL/NNG Ventura	-	10,000	10,000	10,000	10,000	-
Daily Index	Call/Swing	Ventura	NNG NBPL/NNG Ventura	-	10,000	10,000	10,000	10,000	-
Monthly Index	Call/Swing	Ventura	NNG-NBPL/NNG Various	40,000	40,000	40,000	40,000	40,000	40,000
			TOTAL BASELOAD	**78,512**	**107,883**	**107,883**	**107,883**	**107,883**	**78,512**
			TOTAL CALL/SWING (MONTH INDEX)	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**
			TOTAL CALL/SWING (DAILY INDEX)	**-**	**30,000**	**30,000**	**30,000**	**30,000**	**-**
			TOTAL STORAGE WITHDRAWAL	**113,074**	**113,074**	**113,074**	**113,074**	**59,267**	**59,267**

SUPPLY MIX - MAX DAY	Nov	Dec	Jan	Feb (1-14)	Feb (15-28)	Mar
DEMAND	**210,653**	**290,169**	**290,169**	**290,169**	**290,169**	**206,319**
BASELOAD	78,512	107,883	107,883	107,883	107,883	78,512
CALL/SWING	-	69,960	69,960	69,960	70,000	40,000
STORAGE WITHDRAWAL	132,141	113,074	113,074	113,074	59,267	59,267
SPOT SUPPLY (DAILY PURCHASE)	-	-	-	-	53,784	28,540
TOTAL SUPPLY	**210,653**	**290,917**	**290,917**	**290,917**	**290,934**	**206,319**
% MONTHLY PRICE	37%	51%	51%	51%	37%	38%
% DAILY PRICE	0%	10%	10%	10%	25%	14%
% STORAGE WACOG	63%	39%	39%	39%	20%	29%

SUPPLY MIX - AVERAGE DAY	Nov	Dec	Jan	Feb (1-14)	Feb (15-29)	Mar
DEMAND	**104,217**	**138,818**	**166,291**	**146,248**	**146,248**	**113,561**
BASELOAD	78,512	107,883	107,883	107,883	107,883	78,512
CALL/SWING	-	-	-	-	-	-
STORAGE WITHDRAWAL	25,705	30,935	58,408	38,365	38,365	35,049
SPOT SUPPLY (DAILY PURCHASE)	-	-	-	-	-	-
TOTAL SUPPLY	**104,217**	**138,818**	**166,291**	**146,248**	**146,248**	**113,561**
% MONTHLY PRICE	75%	78%	65%	74%	74%	69%
% DAILY PRICE	0%	0%	0%	0%	0%	0%
% STORAGE WACOG	25%	22%	35%	26%	26%	31%

SUPPLY MIX - MINIMUM DAY	Nov	Dec	Jan	Feb (1-14)	Feb (15-29)	Mar
DEMAND	**26,994**	**54,980**	**89,907**	**69,395**	**69,395**	**45,042**
BASELOAD	78,512	107,883	107,883	107,883	107,883	78,512
CALL/SWING	-	-	-	-	-	-
STORAGE WITHDRAWAL	-	-	-	-	-	-
SPOT SUPPLY (DAILY PURCHASE)	-	-	-	-	-	-
NNG SMS INJECT (-)	(22,680)	(22,260)	-	-	-	(16,563)
STORAGE INJECT (-)	(26,192)	(26,192)	(17,993)	(15,856)	(15,856)	(26,192)
REMAINING SUPPLY (LONG GAS)	2,646	4,451	(17)	22,632	22,632	(9,285)
% MONTHLY PRICE	100%	100%	100%	100%	100%	100%
% DAILY PRICE	0%	0%	0%	0%	0%	0%
% STORAGE WACOG	0%	0%	0%	0%	0%	0%

Attachment 7

MINNESOTA ENERGY RESOURCES - NNG

	2020-2021 NNG	2021-2022 NNG	2022-2023 NNG	2023-2024 NNG	2024-2025 NNG	Proposed Change
Design Day	280,796	282,710	291,250	290,934	290,169	(765)
Customer Requirements moving to Transportation						
Adjusted Design Day						
Design Day Percentages	32.69%	28.90%	29.71%	28.53%	30.59%	2.06%
Total Design Day Capacity (includes non-recallable capacity)	314,349	313,756	313,756	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	310,814	310,221	310,221	316,707	316,707	0
Factors for All Winter Capacity	100.00%	100.00%	100.00%	100.00%	100.00%	
Direct Assigned Entitlements in PGA						
TF12B	46,006	21,492	33,714	37,650	34,711	(2,939)
TF12V	38,703	62,624	50,402	46,466	49,405	2,939
TF5	36,275	36,275	36,275	36,275	36,275	0
TFX12	85,329	85,329	85,329	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 *	50,000	0	0	0	0	0
NBPL *	50,000	50,000	50,000	50,000	50,000	0
Total Direct Assignments	314,349	313,756	313,756	320,242	320,242	0
LP Peak Shaving						0
Total Design Day Capacity	314,349	313,756	313,756	320,242	320,242	0
Total Annual Transportation	173,573	172,980	172,980	179,466	179,466	0
Total Seasonal Transportation	140,776	140,776	140,776	140,776	140,776	0
Total Percent Seasonal	44.8%	44.9%	44.9%	44.0%	44.0%	0.0%
Reserve Margin	11.95%	10.98%	7.73%	10.36%	10.36%	0.0%
Total Design Day Capacity w/ contract demand	314,349	313,756	313,756	320,242	320,242	0
Factors	32.69%	28.90%	29.71%	28.53%	30.59%	2.06%
Other Entitlements not included in Peak Day Deliverability						
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	113,075	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

Attachment 8

MINNESOTA ENERGY RESOURCES - NNG

Change in Costs due to November 1, 2024 Change in Entitlement Levels and Related Demand Costs

Costs Assigned In Demand	Contract	2023/24 Entitlements	2024/25 Entitlements	Entitlement Change	Months	2024/25 Rate	2023/24 Total Annual Cost	2024/25 Total Annual Cost	Total Annual Cost Change
TF12B (Max Rate) Winter	112495	26,076	23,137	(2,939)	5	$17.4170	$2,270,828	$2,014,886	($255,943)
TF12B (Max Rate) Summer	112495	26,076	23,137	(2,939)	7	$9.6760	$1,766,180	$1,567,115	($199,064)
TF12V (Max Rate)	112495	41,974	44,913	2,939	12	$15.4814	$7,797,795	$8,343,793	$545,998
TF5 (Max Rate)	112495	16,183	16,183	0	5	$25.7990	$2,087,526	$2,087,526	$0
TF5 (Rochester Capped)	112495	20,092	20,092	0	5	$15.1530	$1,522,270	$1,522,270	$0
TF12B (Rochester Capped)	112495	11,574	11,574	0	12	$7.5776	$1,052,438	$1,052,438	$0
TF12V (Rochester Capped)	112495	4,492	4,492	0	12	$9.0926	$490,128	$490,128	$0
TFX12 (Max Rate)	112486	8,750	8,750	0	12	$16.3939	$1,721,360	$1,721,360	$0
TFX Apr (Max Rate)	112486	2,000	2,000	0	1	$9.6760	$19,352	$19,352	$0
TFX Oct (Max Rate)	112486	2,000	2,000	0	1	$9.6760	$19,352	$19,352	$0
TFX (Rochester Capped)	112486	2,072	2,072	0	12	$9.6288	$239,410	$239,410	$0
TFX5 (Max Rate)	112486	62,549	62,549	0	5	$25.7990	$8,068,508	$8,068,508	$0
TFX5 (Rochester Capped)	112486	16,939	16,939	0	5	$15.1530	$1,283,383	$1,283,383	$0
TFX12 (Discount)	111866	1,283	1,283	0	12	$4.8640	$74,886	$74,886	$0
TFX12 (Discount)	111866	8,271	8,271	0	12	$5.4720	$543,107	$543,107	$0
TFX12 (Discount)	111866	11,921	11,921	0	12	$7.6025	$1,087,553	$1,087,553	$0
TFX5 (Discount)	111866	379	379	0	5	$4.8640	$9,217	$9,217	$0
TFX5 (Discount)	111866	2,445	2,445	0	5	$5.4720	$66,895	$66,895	$0
TFX5 (Discount)	111866	22,189	22,189	0	5	$15.1392	$1,679,619	$1,679,619	$0
TFX (Max Rate)	141673/142983	6,486	6,486	0	12	$16.3939	$336,206	$1,275,970	$939,764
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							$32,235,374	$33,266,129	$1,030,755

Costs Assigned In Commodity		2023/24 Entitlements	2024/25 Entitlement	Entitlement Change	Months	2024/25 Rate/Dth	2023/24 Total Annual Cost	Entitlement Total Cost	Entitlement Change
Upstream Surcharges:									
Storage (FDD)									
FDD - Reservation	118657	107,524	107,524	0	12	$ 3.2345	$4,173,437	$4,173,437	$0
FDD - Storage Cycle	118657	1,239,864	1,239,864	0	5	$ 0.6731	$4,172,763	$4,172,763	$0
FDD - Reservation	118657	5,550	5,550	0	12	$ 3.2758	$218,168	$218,168	$0
FDD - Storage Cycle	118657	64,000	64,000	0	5	$ 0.6818	$218,176	$218,176	$0
FDD - Reservation	open	0	0	0	12	$ -	$0	$0	$0
FDD - Storage Cycle	open	0	0	0	5	$ -	$0	$0	$0
FDD - Reservation	open	0	0	0	12	$ -	$0	$0	$0
FDD - Storage Cycle	open	0	0	0	5	$ -	$0	$0	$0
Pipeline									
NBPL	101251	50,000	50,000	0	12	$6.1230	$3,683,882	$3,673,800	($10,082)
TFX12 (Rochester)	112486	10,500	10,500	0	12	$37.1175	$4,676,805	$4,676,805	$0
TFX12 (Rochester II)	112486	34,500	34,500	0	12	$10.7714	$4,459,360	$4,459,360	$0
TFX12 (SE MN Expansion)	112486	8,032	8,032	0	12	$16.3939	$1,580,110	$1,580,110	$0
Balancing Service		272,160	272,160	0	1	$4.2550	$1,158,041	$1,158,041	$0
Physical Forward Start Premium							$750,750	$555,750	($195,000)
Financial Call Option Premium							$401,771	$397,979	($3,791)
Total Commodity Costs							$25,493,262	$25,284,388	($208,873)

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024

NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
7/1/23	0	0	0	0	0	178,199	**6,411**
7/2/23	0	0	0	0	0	176,543	**6,411**
7/3/23	0	0	0	0	0	180,087	**6,411**
7/4/23	0	0	0	0	0	168,770	**6,411**
7/5/23	8	0	0	7	2	180,399	**10,352**
7/6/23	2	0	6	2	3	186,753	**13,817**
7/7/23	0	0	4	9	3	178,081	**12,870**
7/8/23	5	0	2	4	2	166,109	**10,403**
7/9/23	0	0	0	0	0	159,043	**6,411**
7/10/23	7	0	0	0	1	159,740	**8,237**
7/11/23	5	0	0	3	1	179,667	**8,644**
7/12/23	4	0	2	0	1	186,877	**9,843**
7/13/23	0	0	0	0	0	188,025	**6,411**
7/14/23	0	0	0	0	0	189,546	**6,411**
7/15/23	5	0	0	0	1	156,522	**7,817**
7/16/23	3	0	2	2	2	162,205	**10,191**
7/17/23	4	0	4	3	3	193,788	**13,016**
7/18/23	1	0	0	0	0	186,496	**6,548**
7/19/23	4	0	0	0	0	184,749	**7,377**
7/20/23	0	0	0	1	0	186,370	**6,553**
7/21/23	0	0	0	0	0	187,514	**6,411**
7/22/23	0	0	0	0	0	175,280	**6,411**
7/23/23	0	0	0	0	0	182,269	**6,411**
7/24/23	0	0	0	0	0	189,310	**6,411**
7/25/23	0	0	0	0	0	193,308	**6,411**
7/26/23	0	0	0	0	0	197,959	**6,411**
7/27/23	0	0	0	0	0	197,033	**6,411**
7/28/23	1	0	0	0	0	191,604	**6,551**
7/29/23	5	0	0	0	1	172,432	**7,675**
7/30/23	3	0	0	0	0	143,801	**7,095**
7/31/23	0	0	0	0	0	172,104	**6,411**
8/1/23	0	0	0	0	0	187,042	**6,411**
8/2/23	0	0	0	0	0	205,994	**6,411**
8/3/23	0	0	0	0	0	204,608	**6,411**
8/4/23	0	0	0	0	0	191,206	**6,411**
8/5/23	0	0	0	0	0	167,491	**6,411**

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
8/6/23	0	0	0	3	0	170,994	**7,262**
8/7/23	0	0	0	0	0	198,774	**6,411**
8/8/23	0	0	0	0	0	199,460	**6,411**
8/9/23	5	0	0	0	1	202,519	**7,667**
8/10/23	0	0	0	0	0	194,273	**6,411**
8/11/23	2	0	0	0	0	185,521	**6,820**
8/12/23	2	0	0	0	0	181,415	**6,823**
8/13/23	2	0	1	1	1	178,437	**7,732**
8/14/23	6	2	5	6	4	183,734	**16,787**
8/15/23	0	0	0	0	0	183,130	**6,411**
8/16/23	0	0	0	0	0	163,525	**6,411**
8/17/23	7	0	5	2	3	179,896	**14,463**
8/18/23	0	0	0	0	0	161,048	**6,411**
8/19/23	0	0	0	0	0	167,707	**6,411**
8/20/23	0	0	0	0	0	169,292	**6,411**
8/21/23	2	0	0	0	0	182,253	**6,844**
8/22/23	3	0	0	0	0	190,775	**7,269**
8/23/23	4	0	0	0	0	200,468	**7,398**
8/24/23	0	0	0	0	0	200,200	**6,411**
8/25/23	0	0	0	0	0	177,511	**6,411**
8/26/23	14	1	1	5	3	161,530	**13,072**
8/27/23	6	0	2	0	1	170,833	**9,772**
8/28/23	0	0	0	0	0	192,190	**6,411**
8/29/23	5	0	0	0	1	177,388	**7,788**
8/30/23	3	0	1	0	1	182,675	**8,274**
8/31/23	0	0	0	0	0	155,979	**6,411**
9/1/23	0	0	0	0	0	167,344	**6,411**
9/2/23	0	0	0	0	0	160,385	**6,411**
9/3/23	0	0	0	0	0	158,665	**6,411**
9/4/23	0	0	0	0	0	186,442	**6,411**
9/5/23	0	0	0	0	0	182,176	**6,411**
9/6/23	10	3	5	10	5	170,728	**19,381**
9/7/23	14	7	12	4	9	183,807	**29,019**
9/8/23	8	0	2	0	2	179,260	**10,329**
9/9/23	3	0	0	2	0	163,735	**7,492**
9/10/23	8	2	6	8	5	148,519	**18,657**

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
9/11/23	8	1	5	5	4	123,707	**16,228**
9/12/23	22	10	11	10	12	119,862	**33,943**
9/13/23	16	7	8	4	8	121,485	**25,690**
9/14/23	4	0	0	0	0	122,010	**7,379**
9/15/23	5	3	8	5	6	144,282	**20,262**
9/16/23	12	3	5	9	6	136,359	**19,804**
9/17/23	9	3	7	6	6	138,865	**20,644**
9/18/23	7	0	0	0	1	167,765	**8,366**
9/19/23	6	0	0	0	1	181,023	**8,071**
9/20/23	0	0	0	0	0	186,141	**6,411**
9/21/23	0	0	0	0	0	192,347	**6,411**
9/22/23	3	0	0	2	0	184,536	**7,545**
9/23/23	7	0	0	6	1	150,013	**9,696**
9/24/23	8	0	0	4	1	175,551	**9,523**
9/25/23	9	3	2	6	3	195,680	**14,090**
9/26/23	4	1	2	2	2	197,471	**10,619**
9/27/23	5	0	1	4	1	186,751	**9,505**
9/28/23	6	0	1	0	1	165,828	**9,162**
9/29/23	5	0	0	0	1	151,868	**7,780**
9/30/23	3	0	0	0	0	159,476	**7,121**
10/1/23	3	0	0	0	0	158,358	**7,108**
10/2/23	0	0	0	0	0	183,824	**6,411**
10/3/23	0	0	0	0	0	177,454	**6,411**
10/4/23	11	5	7	8	7	192,619	**22,812**
10/5/23	16	12	11	16	13	158,925	**36,533**
10/6/23	24	18	20	28	20	184,413	**55,024**
10/7/23	24	18	18	18	18	198,694	**50,317**
10/8/23	25	17	19	18	19	193,715	**51,526**
10/9/23	24	19	24	24	22	234,449	**59,786**
10/10/23	23	17	24	18	21	230,845	**56,238**
10/11/23	26	13	14	14	15	207,441	**42,438**
10/12/23	18	18	21	23	20	211,446	**54,094**
10/13/23	21	20	20	21	20	205,153	**54,787**
10/14/23	23	19	21	21	20	202,009	**54,948**
10/15/23	20	18	21	21	20	195,302	**54,124**
10/16/23	30	14	21	18	19	240,234	**52,809**

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
10/17/23	18	12	13	10	13	210,358	**36,851**
10/18/23	17	11	12	14	13	212,336	**36,670**
10/19/23	19	13	21	14	18	237,753	**48,384**
10/20/23	17	8	10	6	10	203,751	**29,544**
10/21/23	17	16	22	20	19	218,298	**52,591**
10/22/23	16	14	19	17	17	207,032	**46,314**
10/23/23	14	9	8	8	9	212,914	**27,321**
10/24/23	16	12	4	16	9	230,778	**29,051**
10/25/23	21	11	9	14	12	231,129	**34,150**
10/26/23	24	16	12	23	16	214,456	**44,878**
10/27/23	35	36	38	45	38	272,233	**96,053**
10/28/23	43	37	39	42	39	284,325	**99,340**
10/29/23	43	37	41	42	40	288,433	**102,170**
10/30/23	44	38	41	45	41	311,625	**104,043**
10/31/23	44	38	45	46	43	306,269	**108,524**
11/1/23	40	34	38	35	37	311,295	**94,190**
11/2/23	33	31	29	28	30	297,427	**78,741**
11/3/23	41	26	26	30	28	288,814	**74,000**
11/4/23	37	24	24	25	26	265,771	**67,842**
11/5/23	27	17	16	13	17	215,117	**47,079**
11/6/23	30	22	21	21	22	258,006	**58,981**
11/7/23	33	25	24	23	25	272,418	**67,063**
11/8/23	30	25	28	26	27	247,204	**71,278**
11/9/23	34	26	27	29	28	263,681	**72,269**
11/10/23	33	31	37	36	34	291,076	**88,627**
11/11/23	33	25	31	22	28	248,943	**74,498**
11/12/23	26	17	22	21	21	229,727	**56,105**
11/13/23	22	16	21	13	19	234,977	**51,308**
11/14/23	20	14	18	20	17	217,865	**46,952**
11/15/23	19	13	13	15	14	219,929	**40,159**
11/16/23	25	19	24	27	23	245,077	**61,134**
11/17/23	34	28	33	31	31	275,831	**80,989**
11/18/23	30	21	23	22	23	260,405	**61,716**
11/19/23	28	19	21	20	21	232,846	**56,394**
11/20/23	29	24	29	32	28	245,721	**72,283**
11/21/23	39	34	40	41	38	275,248	**97,375**

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MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
11/22/23	43	31	35	32	34	245,614	**87,838**
11/23/23	52	48	48	54	49	281,025	**123,692**
11/24/23	48	44	46	49	46	313,377	**116,071**
11/25/23	45	41	43	50	43	295,361	**110,160**
11/26/23	52	48	53	50	51	303,325	**128,175**
11/27/23	64	57	65	54	61	372,576	**152,693**
11/28/23	54	47	55	41	51	321,540	**128,304**
11/29/23	32	29	33	31	31	281,533	**81,282**
11/30/23	41	37	37	44	38	306,429	**97,322**
12/1/23	42	37	41	40	40	310,103	**101,989**
12/2/23	36	36	37	39	37	283,855	**94,277**
12/3/23	35	35	38	39	37	298,259	**93,974**
12/4/23	35	36	39	38	37	281,359	**95,889**
12/5/23	43	39	43	35	41	306,879	**104,626**
12/6/23	36	29	33	27	32	259,808	**81,688**
12/7/23	29	25	25	19	25	218,673	**65,141**
12/8/23	29	25	28	31	27	245,530	**71,877**
12/9/23	42	40	44	53	44	296,307	**110,653**
12/10/23	47	43	46	47	45	338,874	**114,695**
12/11/23	48	41	46	42	44	317,718	**111,647**
12/12/23	49	42	46	45	45	340,261	**114,229**
12/13/23	40	32	34	35	34	292,477	**87,907**
12/14/23	29	24	26	25	26	250,984	**67,845**
12/15/23	31	26	29	27	28	276,534	**74,017**
12/16/23	33	30	31	36	31	256,636	**81,536**
12/17/23	51	44	48	44	46	279,520	**117,515**
12/18/23	55	48	57	48	53	356,542	**132,515**
12/19/23	40	35	42	39	39	318,939	**100,346**
12/20/23	39	32	35	36	34	300,766	**88,561**
12/21/23	34	32	34	33	33	295,369	**85,598**
12/22/23	30	26	27	30	28	266,752	**72,397**
12/23/23	26	21	24	29	24	222,630	**63,667**
12/24/23	23	18	17	29	19	207,860	**52,520**
12/25/23	29	23	28	35	27	223,720	**71,787**
12/26/23	33	33	39	39	36	301,608	**93,117**
12/27/23	35	34	37	40	36	305,076	**92,681**

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MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
12/28/23	39	37	42	42	40	297,004	**101,470**
12/29/23	35	33	37	33	35	270,025	**90,671**
12/30/23	45	42	44	45	44	273,857	**110,451**
12/31/23	48	43	46	49	45	315,791	**115,093**
1/1/24	47	44	47	45	46	303,816	**115,205**
1/2/24	40	37	39	41	39	311,785	**98,584**
1/3/24	49	41	41	46	42	325,921	**107,922**
1/4/24	50	40	45	46	44	330,224	**111,557**
1/5/24	41	36	39	38	38	304,093	**97,553**
1/6/24	46	39	43	52	43	289,503	**109,300**
1/7/24	56	43	46	50	47	305,498	**117,716**
1/8/24	45	40	43	51	43	296,763	**108,739**
1/9/24	45	42	47	62	47	303,503	**118,576**
1/10/24	43	45	51	61	49	295,852	**123,754**
1/11/24	61	60	59	73	61	335,190	**151,821**
1/12/24	68	65	68	86	69	344,111	**171,928**
1/13/24	76	76	85	97	82	378,014	**203,372**
1/14/24	81	75	85	87	82	387,408	**202,138**
1/15/24	82	75	83	92	81	393,970	**200,085**
1/16/24	73	70	77	77	74	367,097	**183,689**
1/17/24	73	62	66	62	65	373,486	**162,613**
1/18/24	72	67	72	76	71	399,926	**176,096**
1/19/24	74	69	77	80	75	427,990	**184,504**
1/20/24	69	66	75	78	72	387,531	**177,830**
1/21/24	55	54	60	61	58	331,270	**144,650**
1/22/24	45	39	41	42	41	308,112	**104,187**
1/23/24	40	36	37	39	37	298,807	**95,145**
1/24/24	36	32	34	35	34	283,679	**87,676**
1/25/24	32	30	34	34	32	288,766	**83,973**
1/26/24	34	30	33	38	33	278,389	**84,659**
1/27/24	37	34	38	36	37	295,316	**94,106**
1/28/24	35	37	39	32	37	296,924	**94,539**
1/29/24	34	28	30	31	30	252,297	**78,420**
1/30/24	36	31	36	37	35	285,028	**89,249**
1/31/24	27	24	27	27	26	260,755	**68,451**
2/1/24	35	28	30	28	30	261,573	**77,515**

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MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
2/2/24	39	33	40	32	37	256,193	**94,275**
2/3/24	41	36	35	36	36	270,550	**92,517**
2/4/24	36	28	29	34	30	288,098	**78,494**
2/5/24	24	27	27	31	27	280,931	**71,527**
2/6/24	29	20	25	25	24	244,709	**63,548**
2/7/24	30	22	28	21	26	248,151	**67,483**
2/8/24	31	26	27	33	28	261,990	**73,229**
2/9/24	49	41	43	39	43	304,132	**108,092**
2/10/24	45	37	42	39	40	306,433	**102,683**
2/11/24	43	34	38	37	37	291,775	**95,048**
2/12/24	42	31	35	34	34	306,790	**87,999**
2/13/24	42	35	33	33	34	307,067	**88,727**
2/14/24	41	39	38	47	39	286,157	**100,502**
2/15/24	57	51	52	47	52	341,130	**130,135**
2/16/24	63	60	64	62	63	348,854	**156,348**
2/17/24	45	50	54	56	52	301,691	**130,507**
2/18/24	45	39	43	39	42	318,577	**105,600**
2/19/24	40	37	33	31	35	301,029	**89,854**
2/20/24	28	32	28	26	29	282,235	**75,824**
2/21/24	29	26	27	22	26	273,402	**69,036**
2/22/24	32	27	27	27	28	238,067	**72,324**
2/23/24	54	42	44	41	44	318,702	**111,398**
2/24/24	41	33	40	30	37	251,238	**95,297**
2/25/24	38	27	27	29	28	256,199	**74,211**
2/26/24	25	18	17	20	18	222,372	**50,287**
2/27/24	57	44	47	67	49	329,934	**123,969**
2/28/24	64	57	61	54	59	374,219	**147,584**
2/29/24	50	29	32	25	32	262,587	**83,058**
3/1/24	26	22	26	27	25	238,782	**65,916**
3/2/24	27	16	17	16	17	201,135	**48,194**
3/3/24	33	13	17	24	18	217,257	**50,153**
3/4/24	40	35	38	39	37	297,467	**95,407**
3/5/24	33	27	30	31	30	274,076	**76,973**
3/6/24	33	21	26	26	25	231,707	**66,081**
3/7/24	41	32	27	38	31	270,171	**80,305**
3/8/24	43	39	39	44	40	294,716	**102,440**

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MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
3/9/24	44	36	41	38	39	270,848	**100,603**
3/10/24	33	28	30	25	29	225,407	**76,044**
3/11/24	16	13	9	12	11	185,829	**33,407**
3/12/24	19	11	12	17	13	206,591	**38,031**
3/13/24	23	11	9	11	12	201,823	**34,418**
3/14/24	32	20	25	27	24	229,480	**64,949**
3/15/24	30	22	23	26	24	206,918	**63,445**
3/16/24	46	35	36	38	37	232,844	**95,488**
3/17/24	52	45	47	53	47	302,936	**119,639**
3/18/24	44	39	42	43	41	282,049	**105,316**
3/19/24	46	36	34	35	36	265,249	**93,289**
3/20/24	53	43	42	46	44	325,812	**112,026**
3/21/24	45	37	37	38	38	320,620	**97,253**
3/22/24	50	42	48	50	47	317,531	**118,240**
3/23/24	46	39	41	45	42	287,512	**105,896**
3/24/24	44	38	39	39	39	277,052	**100,392**
3/25/24	45	35	31	47	35	299,305	**90,869**
3/26/24	54	49	47	58	50	335,663	**124,899**
3/27/24	51	47	48	48	48	336,352	**120,839**
3/28/24	45	38	36	36	38	301,591	**96,076**
3/29/24	38	31	25	26	28	261,440	**73,792**
3/30/24	33	28	26	33	28	258,086	**73,914**
3/31/24	30	26	27	35	28	252,817	**73,653**
4/1/24	34	28	36	36	33	269,549	**85,232**
4/2/24	36	32	38	31	35	278,393	**89,745**
4/3/24	31	26	33	35	31	258,733	**80,037**
4/4/24	32	24	30	24	28	261,263	**72,425**
4/5/24	31	19	26	22	24	202,864	**64,127**
4/6/24	28	19	22	19	21	206,050	**57,703**
4/7/24	27	25	27	26	26	241,676	**69,457**
4/8/24	28	22	24	28	24	232,737	**64,723**
4/9/24	21	15	18	17	17	201,393	**48,007**
4/10/24	17	8	11	13	11	187,854	**32,515**
4/11/24	19	15	21	24	19	200,185	**51,746**
4/12/24	25	15	22	16	20	195,557	**53,515**
4/13/24	14	0	0	0	2	161,738	**10,084**

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MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
4/14/24	20	4	4	11	7	188,326	**22,517**
4/15/24	14	6	6	0	6	179,573	**21,845**
4/16/24	28	19	17	13	18	218,149	**50,545**
4/17/24	26	18	21	18	20	222,001	**54,882**
4/18/24	30	26	27	30	27	226,531	**71,350**
4/19/24	39	36	35	35	36	236,363	**92,083**
4/20/24	30	27	33	33	31	237,175	**80,266**
4/21/24	17	15	21	16	18	177,202	**50,237**
4/22/24	14	8	12	12	11	177,580	**32,229**
4/23/24	26	19	23	22	22	180,705	**58,455**
4/24/24	29	17	19	10	18	194,450	**50,045**
4/25/24	18	9	12	10	11	167,484	**33,576**
4/26/24	19	15	15	17	15	196,353	**43,383**
4/27/24	25	13	12	16	14	171,477	**40,321**
4/28/24	37	21	19	21	22	215,641	**58,185**
4/29/24	31	20	23	23	23	239,876	**60,776**
4/30/24	22	7	8	11	9	205,778	**29,024**
5/1/24	18	9	9	13	11	199,633	**31,744**
5/2/24	26	16	20	15	19	225,278	**51,396**
5/3/24	13	7	6	11	8	192,534	**25,314**
5/4/24	22	14	19	18	18	197,080	**48,565**
5/5/24	13	6	10	10	9	172,206	**27,382**
5/6/24	12	0	2	4	3	154,510	**13,335**
5/7/24	20	4	7	13	8	174,422	**26,315**
5/8/24	19	3	2	6	5	190,713	**17,248**
5/9/24	25	9	14	10	13	197,114	**37,338**
5/10/24	17	4	8	7	8	168,927	**24,510**
5/11/24	3	0	3	0	2	163,406	**10,327**
5/12/24	7	0	0	0	1	173,440	**8,147**
5/13/24	14	5	7	9	7	190,803	**23,582**
5/14/24	17	4	8	1	7	177,554	**22,859**
5/15/24	19	1	0	6	3	180,293	**13,163**
5/16/24	16	3	7	3	6	194,149	**21,233**
5/17/24	10	0	0	0	1	154,667	**9,113**
5/18/24	3	0	0	3	1	161,265	**8,137**
5/19/24	3	1	2	4	2	164,293	**10,493**

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
5/20/24	8	0	0	0	1	157,555	**8,617**
5/21/24	15	3	5	7	6	142,295	**19,727**
5/22/24	18	2	6	5	6	150,314	**21,084**
5/23/24	7	0	0	0	1	141,266	**8,250**
5/24/24	25	6	9	13	10	138,658	**30,943**
5/25/24	4	0	0	2	1	127,299	**8,126**
5/26/24	11	4	13	2	9	134,064	**27,653**
5/27/24	10	7	8	8	8	140,008	**25,266**
5/28/24	14	7	11	10	10	149,710	**30,322**
5/29/24	15	2	7	0	5	143,324	**19,150**
5/30/24	4	0	0	0	0	138,367	**7,393**
5/31/24	2	1	2	3	2	133,614	**10,249**
6/1/24	7	0	3	0	2	131,364	**11,848**
6/2/24	0	0	0	0	0	123,905	**6,411**
6/3/24	0	0	0	0	0	143,608	**6,411**
6/4/24	3	0	0	0	0	146,645	**7,250**
6/5/24	3	0	0	0	0	130,104	**7,134**
6/6/24	12	1	4	2	3	150,060	**14,352**
6/7/24	3	0	0	0	0	167,106	**7,279**
6/8/24	3	0	3	1	2	158,951	**10,469**
6/9/24	16	3	4	3	5	137,234	**18,201**
6/10/24	6	0	3	0	2	150,843	**10,997**
6/11/24	5	0	0	0	1	152,223	**7,672**
6/12/24	0	0	0	0	0	158,986	**6,411**
6/13/24	3	0	0	0	0	166,971	**7,110**
6/14/24	6	0	0	0	1	155,386	**7,907**
6/15/24	5	0	0	0	1	129,458	**7,815**
6/16/24	1	0	0	0	0	152,168	**6,548**
6/17/24	5	0	0	0	1	160,858	**7,799**
6/18/24	0	0	0	0	0	166,932	**6,411**
6/19/24	6	0	2	2	2	180,126	**10,304**
6/20/24	8	0	0	3	1	166,945	**9,297**
6/21/24	5	0	0	0	1	161,382	**7,807**
6/22/24	11	0	0	0	1	160,948	**9,340**
6/23/24	1	0	0	0	0	162,813	**6,548**
6/24/24	0	0	0	0	0	168,107	**6,411**

Attachment 9

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
NNG

Design Day:	
Base	6,411
Variable	2,390

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 **
6/25/24	0	0	0	0	0	173,865	**6,411**
6/26/24	8	0	0	0	1	171,019	**8,498**
6/27/24	1	0	0	0	0	164,912	**6,548**
6/28/24	0	0	0	0	0	160,201	**6,411**
6/29/24	14	2	3	7	5	154,697	**17,257**
6/30/24	7	0	4	0	3	156,135	**12,475**
Totals	8,519	6,557	7,244	7,448	7,189	82,575,221	19,525,862

* Volumes include interruptible and transportation volumes, NorthWest Energy not included.
** Design Model numbers are used to calculate firm volumes only

Attachment 10
NNG

MINNESOTA ENERGY RESOURCES - NNG

Customer Counts by PGAC Class - July 1, 2023 through June 30, 2024

Tariff Rate Class	Rate Designation	Jul-23 Customers	Aug-23 Customers	Sep-23 Customers	Oct-23 Customers	Nov-23 Customers	Dec-23 Customers	Jan-24 Customers	Feb-24 Customers	Mar-24 Customers	Apr-24 Customers	May-24 Customers	Jun-24 Customers	Annual Average Customers
GS- Residential	MERC000001	189,950	189,967	189,905	190,178	192,386	193,681	193,229	193,096	194,349	194,604	194,672	200,493	193,042
Residential Farm Taps	MERC001206	945	1,485	1,153	1,210	1,209	827	1,509	1,116	1,081	1,088	1,247	1,018	1,157
Firm Class 1	MERC000005	7,421	7,472	7,373	7,422	7,438	7,646	7,592	7,572	7,578	7,716	7,593	7,919	7,562
Firm Class 2	MERC001221	10,218	10,213	10,222	10,210	10,341	10,456	10,419	10,420	10,443	10,408	10,395	10,889	10,386
Firm Class 3	MERC001231	52	60	60	59	58	53	52	54	53	45	51	56	54
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	67	95	64	106	69	71	92	79	74	73	65	94	79
Agricultural Grain Dryer Class 2	MERC001227	47	85	60	87	50	82	83	58	70	74	64	59	68
Agricultural Grain Dryer Class 3	MERC001237	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Class 2	MERC001222	169	169	120	190	158	154	161	148	157	160	139	121	154
Interruptible Class 3	MERC001232	42	40	32	48	40	40	36	33	40	38	34	34	38
Interruptible Class 4	MERC001242	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Class 5	MERC001252	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptilbe Class 2	MERC001223	1	1	1	1	1	1	1	1	1	0	2	0	1
Firm/Interruptilbe Class 3	MERC001233	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptilbe Class 4	MERC001243	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptilbe Class 5	MERC001253	0	0	0	0	0	0	0	0	0	0	0	0	0
Farm Tap Class 1	MERC001216	90	134	107	118	114	81	137	100	102	120	111	97	109
Farm Tap Class 2	MERC001226	175	243	192	213	220	169	246	179	182	232	193	206	204
Farm Tap Class 3	MERC001236	2	2	2	3	3	3	3	3	3	3	2	4	3
Interruptible Electric Generation Class 1	MERC001218	6	6	5	8	5	6	7	3	8	7	6	5	6
Interruptible Electric Generation Class 2	MERC001228	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		209,187	209,973	209,300	209,857	212,093	213,274	213,571	212,866	214,145	214,570	214,577	220,998	212,867

MINNESOTA ENERGY RESOURCES - NNG

Projected Hedged Cost - November 2024 through March 2025

Futures Contracts WACOG

Futures 10,000 Dth/contract

Nov-24

Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/23/24	124075	7	70,000	$ 3.4100	$ 238,700	$ 2.3670	$ 165,690	$ 73,010		$ -	$ 238,700
2	06/24/24	125215	6	60,000	$ 3.2970	$ 197,820	$ 2.3670	$ 142,020	$ 55,800		$ -	$ 197,820
3	07/25/24	126123	6	60,000	$ 2.6710	$ 160,260	$ 2.3670	$ 142,020	$ 18,240		$ -	$ 160,260
4	08/07/24	126359	6	60,000	$ 2.5990	$ 155,940	$ 2.3670	$ 142,020	$ 13,920		$ -	$ 155,940
5	09/24/24	127616	6	60,000	$ 2.8260	$ 169,560	$ 2.3670	$ 142,020	$ 27,540		$ -	$ 169,560
6	10/16/24	128204	6	60,000	$ 2.4320	$ 145,920	$ 2.3670	$ 142,020	$ 3,900		$ -	$ 145,920
7						$ -	$ 2.3670	$ -	$ -		$ -	$ -
8						$ -	$ 2.3670	$ -	$ -		$ -	$ -
9						$ -	$ 2.3670	$ -	$ -		$ -	$ -
10						$ -	$ 2.3670	$ -	$ -		$ -	$ -
11						$ -	$ 2.3670	$ -	$ -		$ -	$ -
12						$ -	$ 2.3670	$ -	$ -		$ -	$ -
13						$ -	$ 2.3670	$ -	$ -		$ -	$ -
14						$ -	$ 2.3670	$ -	$ -		$ -	$ -
15						$ -	$ 2.3670	$ -	$ -		$ -	$ -
Total			37	370,000		$ 1,068,200		$ 875,790	$ 192,410		$ -	$ 1,068,200
						$ 2.8870		$ 2.3670	$ 0.5200		$ -	$ 2.8870
NNG	31	83.78%	31	310,000	$ 2.8870	$ 894,978	$ 2.3670	$ 733,770	$ 161,208	$ -	$ -	$ 894,978
Other-Cons	6	16.22%	6	60,000	$ 2.8870	$ 173,222	$ 2.3670	$ 142,020	$ 31,202	$ -	$ -	$ 173,222
Total	37	100.0%	37	370,000	$ 2.8870	$ 1,068,200	$ 2.3670	$ 875,790	$ 192,410	$ -	$ -	$ 1,068,200

Dec-24

Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/22/24	124036	10	100,000	$ 3.6400	$ 364,000	$ 2.8410	$ 284,100	$ 79,900		$ -	$ 364,000
2	06/18/24	124941	9	90,000	$ 3.7550	$ 337,950	$ 2.8410	$ 255,690	$ 82,260		$ -	$ 337,950
3	07/23/24	126008	8	80,000	$ 3.3500	$ 268,000	$ 2.8410	$ 227,280	$ 40,720		$ -	$ 268,000
4	07/23/24	126009	1	10,000	$ 3.3510	$ 33,510	$ 2.8410	$ 28,410	$ 5,100		$ -	$ 33,510
5	08/13/24	126476	8	80,000	$ 3.3330	$ 266,640	$ 2.8410	$ 227,280	$ 39,360		$ -	$ 266,640
6	09/19/24	127458	8	80,000	$ 3.0000	$ 240,000	$ 2.8410	$ 227,280	$ 12,720		$ -	$ 240,000
7	10/14/24	128056	8	80,000	$ 2.9520	$ 236,160	$ 2.8410	$ 227,280	$ 8,880		$ -	$ 236,160
8						$ -	$ 2.8410	$ -	$ -		$ -	$ -
9						$ -	$ 2.8410	$ -	$ -		$ -	$ -
10						$ -	$ 2.8410	$ -	$ -		$ -	$ -
11						$ -	$ 2.8410	$ -	$ -		$ -	$ -
12						$ -	$ 2.8410	$ -	$ -		$ -	$ -
13						$ -	$ 2.8410	$ -	$ -		$ -	$ -
14						$ -	$ 2.8410	$ -	$ -		$ -	$ -
15						$ -	$ 2.8410	$ -	$ -		$ -	$ -
Total			52	520,000		$ 1,746,260		$ 1,477,320	$ 268,940		$ -	$ 1,746,260
						$ 3.3582		$ 2.8410	$ 0.5172		$ -	$ 3.3582
NNG	43	82.69%	43	430,000	$ 3.3582	$ 1,444,023	$ 2.8410	$ 1,221,630	$ 222,393	$ -	$ -	$ 1,444,023
Other-Cons	9	17.31%	9	90,000	$ 3.3582	$ 302,237	$ 2.8410	$ 255,690	$ 46,547	$ -	$ -	$ 302,237
Total	52	100.0%	52	520,000	$ 3.3582	$ 1,746,260	$ 2.8410	$ 1,477,320	$ 268,940	$ -	$ -	$ 1,746,260

Jan-25

Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/20/24	123931	9	90,000	$ 3.8960	$ 350,640	$ 3.1160	$ 280,440	$ 70,200		$ -	$ 350,640
2	05/20/24	123932	1	10,000	$ 3.8950	$ 38,950	$ 3.1160	$ 31,160	$ 7,790		$ -	$ 38,950
3	06/13/24	124819	10	100,000	$ 4.0920	$ 409,200	$ 3.1160	$ 311,600	$ 97,600		$ -	$ 409,200
4	07/22/24	125950	10	100,000	$ 3.9750	$ 397,500	$ 3.1160	$ 311,600	$ 85,900		$ -	$ 397,500
5	08/15/24	126552	9	90,000	$ 3.9800	$ 358,200	$ 3.1160	$ 280,440	$ 77,760		$ -	$ 358,200
6	09/17/24	127297	9	90,000	$ 3.9820	$ 358,380	$ 3.1160	$ 280,440	$ 77,940		$ -	$ 358,380
7	10/11/24	127940	9	90,000	$ 3.6640	$ 329,760	$ 3.1160	$ 280,440	$ 49,320		$ -	$ 329,760
8						$ -	$ 3.1160	$ -	$ -		$ -	$ -
9						$ -	$ 3.1160	$ -	$ -		$ -	$ -
10						$ -	$ 3.1160	$ -	$ -		$ -	$ -
11						$ -	$ 3.1160	$ -	$ -		$ -	$ -
12						$ -	$ 3.1160	$ -	$ -		$ -	$ -
13						$ -	$ 3.1160	$ -	$ -		$ -	$ -
14						$ -	$ 3.1160	$ -	$ -		$ -	$ -
15						$ -	$ 3.1160	$ -	$ -		$ -	$ -
Total	Total		57	570,000		$ 2,242,630		$ 1,776,120	$ 466,510		$ -	$ 2,242,630
						$ 3.9344		$ 3.1160	$ 0.8184		$ -	$ 3.9344
NNG	48	84.21%	48	480,000	$ 3.9344	$ 1,888,531	$ 3.1160	$ 1,495,680	$ 392,851	$ -	$ -	$ 1,888,531
Other-Cons	9	15.79%	9	90,000	$ 3.9344	$ 354,099	$ 3.1160	$ 280,440	$ 73,659	$ -	$ -	$ 354,099
Total	57	100.0%	57	570,000	$ 3.9344	$ 2,242,630	$ 3.1160	$ 1,776,120	$ 466,510	$ -	$ -	$ 2,242,630

Feb-25

Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/17/24	123905	10	100,000	$ 3.7260	$ 372,600	$ 3.0270	$ 302,700	$ 69,900		$ -	$ 372,600
2	06/07/24	124703	8	80,000	$ 3.7520	$ 300,160	$ 3.0270	$ 242,160	$ 58,000		$ -	$ 300,160
3	07/18/24	125875	8	80,000	$ 3.3960	$ 271,680	$ 3.0270	$ 242,160	$ 29,520		$ -	$ 271,680
4	08/20/24	126679	8	80,000	$ 3.3290	$ 266,320	$ 3.0270	$ 242,160	$ 24,160		$ -	$ 266,320
5	09/11/24	127203	8	80,000	$ 3.1840	$ 254,720	$ 3.0270	$ 242,160	$ 12,560		$ -	$ 254,720
6	10/10/24	127928	8	80,000	$ 3.2130	$ 257,040	$ 3.0270	$ 242,160	$ 14,880		$ -	$ 257,040
7						$ -	$ 3.0270	$ -	$ -		$ -	$ -
8						$ -	$ 3.0270	$ -	$ -		$ -	$ -
9						$ -	$ 3.0270	$ -	$ -		$ -	$ -
10						$ -	$ 3.0270	$ -	$ -		$ -	$ -
11						$ -	$ 3.0270	$ -	$ -		$ -	$ -
12						$ -	$ 3.0270	$ -	$ -		$ -	$ -
13						$ -	$ 3.0270	$ -	$ -		$ -	$ -
14						$ -	$ 3.0270	$ -	$ -		$ -	$ -
15						$ -	$ 3.0270	$ -	$ -		$ -	$ -
Total			50	500,000		$ 1,722,520		$ 1,513,500	$ 209,020		$ -	$ 1,722,520
						$ 3.4450		$ 3.0270	$ 0.4180		$ -	$ 3.4450
NNG	43	86.00%	43	430,000	$ 3.4450	$ 1,481,367	$ 3.0270	$ 1,301,610	$ 179,757	$ -	$ -	$ 1,481,367
Other-Cons	7	14.00%	7	70,000	$ 3.4450	$ 241,153	$ 3.0270	$ 211,890	$ 29,263	$ -	$ -	$ 241,153
Total	50	100.0%	50	500,000	$ 3.4450	$ 1,722,520	$ 3.0270	$ 1,513,500	$ 209,020	$ -	$ -	$ 1,722,520

Mar-25

Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/15/24	123814	7	70,000	$ 3.2180	$ 225,260	$ 2.8010	$ 196,070	$ 29,190		$ -	$ 225,260
2	06/03/24	124421	7	70,000	$ 3.2490	$ 227,430	$ 2.8010	$ 196,070	$ 31,360		$ -	$ 227,430
3	07/16/24	125805	7	70,000	$ 3.0920	$ 216,440	$ 2.8010	$ 196,070	$ 20,370		$ -	$ 216,440
4	08/26/24	126876	7	70,000	$ 2.9670	$ 207,690	$ 2.8010	$ 196,070	$ 11,620		$ -	$ 207,690
5	09/06/24	127138	6	60,000	$ 2.9510	$ 177,060	$ 2.8010	$ 168,060	$ 9,000		$ -	$ 177,060
6	10/07/24	127844	6	60,000	$ 3.1800	$ 190,800	$ 2.8010	$ 168,060	$ 22,740		$ -	$ 190,800
7						$ -	$ 2.8010	$ -	$ -		$ -	$ -
8						$ -	$ 2.8010	$ -	$ -		$ -	$ -
9						$ -	$ 2.8010	$ -	$ -		$ -	$ -
10						$ -	$ 2.8010	$ -	$ -		$ -	$ -
11						$ -	$ 2.8010	$ -	$ -		$ -	$ -
12						$ -	$ 2.8010	$ -	$ -		$ -	$ -
13						$ -	$ 2.8010	$ -	$ -		$ -	$ -
14						$ -	$ 2.8010	$ -	$ -		$ -	$ -
15						$ -	$ 2.8010	$ -	$ -		$ -	$ -
Total			40	400,000		$ 1,244,680		$ 1,120,400	$ 124,280		$ -	$ 1,244,680
						$ 3.1117		$ 2.8010	$ 0.3107		$ -	$ 3.1117
NNG	34	85.00%	34	340,000	$ 3.1117	$ 1,057,978	$ 2.8010	$ 952,340	$ 105,638	$ -	$ -	$ 1,057,978
Other-Cons	6	15.00%	6	60,000	$ 3.1117	$ 186,702	$ 2.8010	$ 168,060	$ 18,642	$ -	$ -	$ 186,702
Total	40	100.0%	40	400,000	$ 3.1117	$ 1,244,680	$ 2.8010	$ 1,120,400	$ 124,280	$ -	$ -	$ 1,244,680

Total

Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			43	430,000	$ 3.6074	$ 1,551,200	$ 2.8581	$ 1,229,000	$ 322,200	$ -	$ -	$ 1,551,200
2			31	310,000	$ 3.5558	$ 1,102,310	$ 2.7971	$ 867,100	$ 235,210	$ -	$ -	$ 1,102,310
3			39	390,000	$ 3.3989	$ 1,325,580	$ 2.8696	$ 1,119,130	$ 206,450	$ -	$ -	$ 1,325,580
4			32	320,000	$ 3.3155	$ 1,060,960	$ 2.8758	$ 920,260	$ 140,700	$ -	$ -	$ 1,060,960
5			37	370,000	$ 3.3140	$ 1,226,180	$ 2.8648	$ 1,059,960	$ 166,220	$ -	$ -	$ 1,226,180
6			37	370,000	$ 3.2220	$ 1,192,140	$ 2.8648	$ 1,059,960	$ 132,180	$ -	$ -	$ 1,192,140
7			17	170,000	$ 3.3289	$ 565,920	$ 2.9866	$ 507,720	$ 58,200	$ -	$ -	$ 565,920
8				-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9				-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10												
11												
12												
13												
14												
15												
Total			236	2,360,000		$ 8,024,290		$ 6,763,130	$ 1,261,160		$ -	$ 8,024,290
						$ 3.4001		$ 2.8657	$ 0.5344		$ -	$ 3.4001
NNG	199	84.32%	199	1,990,000	$ 3.4001	$ 6,766,245	$ 2.8657	$ 5,702,809	$ 1,063,436	$ -	$ -	$ 6,766,245
Other-Cons	37	15.68%	37	370,000	$ 3.4001	$ 1,258,045	$ 2.8657	$ 1,060,321	$ 197,724	$ -	$ -	$ 1,258,045
Total	236	100.0%	236	2,360,000	$ 3.4001	$ 8,024,290	$ 2.8657	$ 6,763,130	$ 1,261,160	$ -	$ -	$ 8,024,290

*Prices from 10/16/2024 NYMEX market close

Minnesota Energy Resources Corporation
2024-2025 Demand Entitlement
MERC-NNG
November 1, 2024

MINNESOTA ENERGY RESOURCES - NNG

Projected Storage Cost - November 2024 through March 2025

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-24	635,634			635,634	$ 2.1354	$ 1,357,304			$ 1,357,304	90,000	$ 2.1787	$ 196,082
Dec-24	1,597,234			1,597,234	$ 2.1354	$ 3,410,661			$ 3,410,661	248,000	$ 2.1787	$ 540,316
Jan-25	1,597,234			1,597,234	$ 2.1354	$ 3,410,661			$ 3,410,661	279,000	$ 2.1787	$ 607,855
Feb-25	1,597,234			1,597,234	$ 2.1354	$ 3,410,661			$ 3,410,661	196,000	$ 2.1787	$ 427,024
Mar-25	635,634			635,634	$ 2.1354	$ 1,357,304			$ 1,357,304	89,000	$ 2.1787	$ 193,904
Total	6,062,970			6,062,970		$ 12,946,592			$ 12,946,592	902,000		$ 1,965,180

Month/ Year	NNG Storage Volume (Dth)	NNG Index Price	NNG Index Cost
Nov-24	635,634	$ 2.2795	$ 1,448,928
Dec-24	1,597,234	$ 3.6585	$ 5,843,481
Jan-25	1,597,234	$ 5.1360	$ 8,203,394
Feb-25	1,597,234	$ 5.0645	$ 8,089,192
Mar-25	635,634	$ 2.7960	$ 1,777,233
Total	6,062,970		$ 25,362,226
Storage Savings (Cost):			$ 12,415,634

Month/ Year	ANR Storage Volume (Dth)	Emerson Index Price	Emerson Market Cost
Nov-24	90,000	$ 1.7170	$ 154,530
Dec-24	248,000	$ 2.3960	$ 594,208
Jan-25	279,000	$ 2.6510	$ 739,629
Feb-25	196,000	$ 2.7420	$ 537,432
Mar-25	89,000	$ 2.3960	$ 213,244
Total	902,000		$ 2,239,043
			$ 273,863

*Indexes and projected WACOG based on 10/16/24 market prices and actual wacog through 9/2024

Minnesota Energy Resources Corporation
2024-2025 Demand Entitlement
MERC-NNG
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Attachment 11
Page 3 of 3

MINNESOTA ENERGY RESOURCES - NNG

Projected Hedged Cost - November 2024 through March 2025

Call/Put Options WACOG

Call/Put Options 10,000 Dth/contract

Nov-24														
Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle*	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/15/24	123816	14	140,000	$ 4.1500	$ 581,000	$ 2.3670	$ 331,380	$ 2.3670	$ 331,380	$ -	$ 0.1000	$ 14,000	$ 345,380
2	06/03/24	124420	13	130,000	$ 4.6500	$ 604,500	$ 2.3670	$ 307,710	$ 2.3670	$ 307,710	$ -	$ 0.0980	$ 12,740	$ 320,450
3	07/16/24	125804	13	130,000	$ 3.6000	$ 468,000	$ 2.3670	$ 307,710	$ 2.3670	$ 307,710	$ -	$ 0.0970	$ 12,610	$ 320,320
4	08/26/24	126877	12	120,000	$ 3.0500	$ 366,000	$ 2.3670	$ 284,040	$ 2.3670	$ 284,040	$ -	$ 0.0980	$ 11,760	$ 295,800
5	09/06/24	127137	12	120,000	$ 3.0000	$ 360,000	$ 2.3670	$ 284,040	$ 2.3670	$ 284,040	$ -	$ 0.0920	$ 11,040	$ 295,080
6	10/07/24	127843	12	120,000	$ 3.0000	$ 360,000	$ 2.3670	$ 284,040	$ 2.3670	$ 284,040	$ -	$ 0.0970	$ 11,640	$ 295,680
7						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 2.3670	$ -	$ -	$ -	$ -	$ -
Total			76	760,000		$ 2,739,500		$ 1,798,920		$ 1,798,920	$ -		$ 73,790	$ 1,872,710
						$ 3.6046		$ 2.3670		$ 2.3670	$ -		$ 0.0269	$ 2.4641
NNG	63	82.89%	63	630,000	$ 3.6046	$ 2,270,901	$ 2.3670	$ 1,491,210	$ 2.3670	$ 1,491,210	$ -	$ 0.0971	$ 61,168	$ 1,552,378
Other-Cons	13	17.11%	13	130,000	$ 3.6046	$ 468,599	$ 2.3670	$ 307,710	$ 2.3670	$ 307,710	$ -	$ 0.0971	$ 12,622	$ 320,332
Total	76	100.0%	76	760,000	$ 3.6046	$ 2,739,500	$ 2.3670	$ 1,798,920	$ 2.3670	$ 1,798,920	$ -	$ 0.0971	$ 73,790	$ 1,872,710

Dec-24														
Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle*	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/17/24	123904	18	180,000	$ 5.8000	$ 1,044,000	$ 2.8410	$ 511,380	$ 2.8410	$ 511,380	$ -	$ 0.1000	$ 18,000	$ 529,380
2	06/07/24	124704	18	180,000	$ 6.1000	$ 1,098,000	$ 2.8410	$ 511,380	$ 2.8410	$ 511,380	$ -	$ 0.1000	$ 18,000	$ 529,380
3	07/18/24	125874	18	180,000	$ 4.7500	$ 855,000	$ 2.8410	$ 511,380	$ 2.8410	$ 511,380	$ -	$ 0.1000	$ 18,000	$ 529,380
4	08/20/24	126678	17	170,000	$ 4.2500	$ 722,500	$ 2.8410	$ 482,970	$ 2.8410	$ 482,970	$ -	$ 0.0980	$ 16,660	$ 499,630
5	09/11/24	127202	17	170,000	$ 3.7500	$ 637,500	$ 2.8410	$ 482,970	$ 2.8410	$ 482,970	$ -	$ 0.0950	$ 16,150	$ 499,120
6	10/10/24	127927	17	170,000	$ 3.6500	$ 620,500	$ 2.8410	$ 482,970	$ 2.8410	$ 482,970	$ -	$ 0.0940	$ 15,980	$ 498,950
7						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 2.8410	$ -	$ -	$ -	$ -	$ -
Total			105	1,050,000		$ 4,977,500		$ 2,983,050		$ 2,983,050	$ -		$ 102,790	$ 3,085,840
						$ 4.7405		$ 2.8410		$ 2.8410	$ -		$ 0.0207	$ 2.9389
NNG	87	82.86%	87	870,000	$ 4.7405	$ 4,124,214	$ 2.8410	$ 2,471,670	$ 2.8410	$ 2,471,670	$ -	$ 0.0979	$ 85,169	$ 2,556,839
Other-Cons	18	17.14%	18	180,000	$ 4.7405	$ 853,286	$ 2.8410	$ 511,380	$ 2.8410	$ 511,380	$ -	$ 0.0979	$ 17,621	$ 529,001
Total	105	100.0%	105	1,050,000	$ 4.7405	$ 4,977,500	$ 2.8410	$ 2,983,050	$ 2.8410	$ 2,983,050	$ -	$ 0.0979	$ 102,790	$ 3,085,840

Jan-25														
Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle*	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/20/24	123930	10	100,000	$ 7.7500	$ 775,000	$ 3.1160	$ 311,600	$ 3.1160	$ 311,600	$ -	$ 0.1000	$ 10,000	$ 321,600
2	05/22/24	124037	11	110,000	$ 7.7500	$ 852,500	$ 3.1160	$ 342,760	$ 3.1160	$ 342,760	$ -	$ 0.1000	$ 11,000	$ 353,760
3	06/13/24	124820	10	100,000	$ 8.2500	$ 825,000	$ 3.1160	$ 311,600	$ 3.1160	$ 311,600	$ -	$ 0.1000	$ 10,000	$ 321,600
4	06/18/24	124939	9	90,000	$ 7.6500	$ 688,500	$ 3.1160	$ 280,440	$ 3.1160	$ 280,440	$ -	$ 0.1000	$ 9,000	$ 289,440
5	07/22/24	125951	19	190,000	$ 6.5000	$ 1,235,000	$ 3.1160	$ 592,040	$ 3.1160	$ 592,040	$ -	$ 0.1000	$ 19,000	$ 611,040
6	08/15/24	126551	19	190,000	$ 5.7500	$ 1,092,500	$ 3.1160	$ 592,040	$ 3.1160	$ 592,040	$ -	$ 0.1000	$ 19,000	$ 611,040
7	09/17/24	127296	19	190,000	$ 4.8500	$ 921,500	$ 3.1160	$ 592,040	$ 3.1160	$ 592,040	$ -	$ 0.1000	$ 19,000	$ 611,040
8	10/11/24	127938	19	190,000	$ 4.7500	$ 902,500	$ 3.1160	$ 592,040	$ 3.1160	$ 592,040	$ -	$ 0.1000	$ 19,000	$ 611,040
9						$ -	$ -	$ -	$ 3.1160	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 3.1160	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 3.1160	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 3.1160	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 3.1160	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 3.1160	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 3.1160	$ -	$ -	$ -	$ -	$ -
Total	Total		116	1,160,000		$ 7,292,500		$ 3,614,560		$ 3,614,560	$ -		$ 116,000	$ 3,730,560
						$ 6.2866		$ 3.1160		$ 3.1160	$ -		$ 0.0159	$ 3.2160
NNG	97	83.62%	97	970,000	$ 6.2866	$ 6,098,039	$ 3.1160	$ 3,022,520	$ 3.1160	$ 3,022,520	$ -	$ 0.1000	$ 97,000	$ 3,119,520
Other-Cons	19	16.38%	19	190,000	$ 6.2866	$ 1,194,461	$ 3.1160	$ 592,040	$ 3.1160	$ 592,040	$ -	$ 0.1000	$ 19,000	$ 611,040
Total	116	100.0%	116	1,160,000	$ 6.2866	$ 7,292,500	$ 3.1160	$ 3,614,560	$ 3.1160	$ 3,614,560	$ -	$ 0.1000	$ 116,000	$ 3,730,560

Feb-25														
Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle*	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/22/24	124038	18	180,000	$ 8.9000	$ 1,602,000	$ 3.0270	$ 544,860	$ 3.0270	$ 544,860	$ -	$ 0.1000	$ 18,000	$ 562,860
2	06/18/24	124940	18	180,000	$ 9.1500	$ 1,647,000	$ 3.0270	$ 544,860	$ 3.0270	$ 544,860	$ -	$ 0.1000	$ 18,000	$ 562,860
3	07/23/24	126007	18	180,000	$ 7.2500	$ 1,305,000	$ 3.0270	$ 544,860	$ 3.0270	$ 544,860	$ -	$ 0.1000	$ 18,000	$ 562,860
4	08/13/24	126475	16	160,000	$ 6.9000	$ 1,104,000	$ 3.0270	$ 484,320	$ 3.0270	$ 484,320	$ -	$ 0.1000	$ 16,000	$ 500,320
5	09/19/24	127457	16	160,000	$ 5.3000	$ 848,000	$ 3.0270	$ 484,320	$ 3.0270	$ 484,320	$ -	$ 0.0990	$ 15,840	$ 500,160
6	10/14/24	128055	16	160,000	$ 5.1500	$ 824,000	$ 3.0270	$ 484,320	$ 3.0270	$ 484,320	$ -	$ 0.1000	$ 16,000	$ 500,320
7						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 3.0270	$ -	$ -	$ -	$ -	$ -
Total			102	1,020,000		$ 7,330,000		$ 3,087,540		$ 3,087,540	$ -		$ 101,840	$ 3,189,380
						$ 7.1863		$ 3.0270		$ 3.0270	$ -		$ 0.0139	$ 3.1268
NNG	87	85.29%	87	870,000	$ 7.1863	$ 6,252,059	$ 3.0270	$ 2,633,490	$ 3.0270	$ 2,633,490	$ -	$ 0.0998	$ 86,864	$ 2,720,354
Other-Cons	15	14.71%	15	150,000	$ 7.1863	$ 1,077,941	$ 3.0270	$ 454,050	$ 3.0270	$ 454,050	$ -	$ 0.0998	$ 14,976	$ 469,026
Total	102	100.0%	102	1,020,000	$ 7.1863	$ 7,330,000	$ 3.0270	$ 3,087,540	$ 3.0270	$ 3,087,540	$ -	$ 0.0998	$ 101,840	$ 3,189,380

Mar-25														
Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle*	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/23/24	124074	14	140,000	$ 8.5500	$ 1,197,000	$ 2.8010	$ 392,140	$ 2.8010	$ 392,140	$ -	$ 0.1000	$ 14,000	$ 406,140
2	06/24/24	125216	14	140,000	$ 7.5500	$ 1,057,000	$ 2.8010	$ 392,140	$ 2.8010	$ 392,140	$ -	$ 0.1000	$ 14,000	$ 406,140
3	07/25/24	126124	13	130,000	$ 5.8500	$ 760,500	$ 2.8010	$ 364,130	$ 2.8010	$ 364,130	$ -	$ 0.0990	$ 12,870	$ 377,000
4	08/07/24	126358	13	130,000	$ 5.9000	$ 767,000	$ 2.8010	$ 364,130	$ 2.8010	$ 364,130	$ -	$ 0.1000	$ 13,000	$ 377,130
5	09/24/24	127614	13	130,000	$ 5.3500	$ 695,500	$ 2.8010	$ 364,130	$ 2.8010	$ 364,130	$ -	$ 0.0990	$ 12,870	$ 377,000
6	10/16/24	128203	13	130,000	$ 4.5000	$ 585,000	$ 2.8010	$ 364,130	$ 2.8010	$ 364,130	$ -	$ 0.1000	$ 13,000	$ 377,130
7						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 2.8010	$ -	$ -	$ -	$ -	$ -
Total			80	800,000		$ 5,062,000		$ 2,240,800		$ 2,240,800	$ -		$ 79,740	$ 2,320,540
						$ 6.3275		$ 2.8010		$ 2.8010	$ -		$ 0.0158	$ 2.9007
NNG	68	85.00%	68	680,000	$ 6.3275	$ 4,302,700	$ 2.8010	$ 1,904,680	$ 2.8010	$ 1,904,680	$ -	$ 0.0997	$ 67,779	$ 1,972,459
Other-Cons	12	15.00%	12	120,000	$ 6.3275	$ 759,300	$ 2.8010	$ 336,120	$ 2.8010	$ 336,120	$ -	$ 0.0997	$ 11,961	$ 348,081
Total	80	100.0%	80	800,000	$ 6.3275	$ 5,062,000	$ 2.8010	$ 2,240,800	$ 2.8010	$ 2,240,800	$ -	$ 0.0997	$ 79,740	$ 2,320,540

Total														
Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle*	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			74	740,000	$ 7.0257	$ 5,199,000	$ 2.8262	$ 2,091,360	$ 2.8262	$ 2,091,360	$ -	$0.1000	$ 74,000	$ 2,165,360
2			74	740,000	$ 7.1068	$ 5,259,000	$ 2.8363	$ 2,098,850	$ 2.8363	$ 2,098,850	$ -	$0.0996	$ 73,740	$ 2,172,590
3			72	720,000	$ 5.8521	$ 4,213,500	$ 2.8329	$ 2,039,680	$ 2.8329	$ 2,039,680	$ -	$0.0993	$ 71,480	$ 2,111,160
4			67	670,000	$ 5.4448	$ 3,648,000	$ 2.8297	$ 1,895,900	$ 2.8297	$ 1,895,900	$ -	$0.0991	$ 66,420	$ 1,962,320
5			77	770,000	$ 4.9039	$ 3,776,000	$ 2.8669	$ 2,207,500	$ 2.8669	$ 2,207,500	$ -	$0.0973	$ 74,900	$ 2,282,400
6			77	770,000	$ 4.5221	$ 3,482,000	$ 2.8669	$ 2,207,500	$ 2.8669	$ 2,207,500	$ -	$0.0982	$ 75,620	$ 2,283,120
7			19	190,000	$ 4.8500	$ 921,500	$ 3.1160	$ 592,040	$ 3.1160	$ 592,040	$ -	$0.1000	$ 19,000	$ 611,040
8			19	190,000	$ 4.7500	$ 902,500	$ 3.1160	$ 592,040	$ 3.1160	$ 592,040	$ -	$0.1000	$ 19,000	$ 611,040
9														
10														
11														
12														
13														
14														
15														
Total			479	4,790,000		$ 27,401,500		$13,724,870		$13,724,870	$ -		$ 474,160	$ 14,199,030
						$ 5.7206		$ 2.8653		$ 2.8653	$ -		1.73%	$ 2.9643
NNG	402	83.92%	402	4,020,000	$ 5.7333	$23,047,913	$ 2.8666	$11,523,570	$ 2.8666	$11,523,570	$ -	$0.0990	$ 397,979	$ 11,921,549
Other-Cons	77	16.08%	77	770,000	$ 5.6540	$ 4,353,587	$ 2.8588	$ 2,201,300	$ 2.8588	$ 2,201,300	$ -	$0.0989	$ 76,181	$ 2,277,481
Total	479	100.0%	479	4,790,000	$ 5.7206	$ 27,401,500	$ 2.8653	$13,724,870	$ 2.8653	$13,724,870	$ -	$ 0.0990	$ 474,160	$ 14,199,030

*Prices from 10/16/2024 NYMEX market close

Attachment 12: Forecast Methodology for MERC Demand Entitlement Effective November 1, 2024

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 pipelines[1]

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").

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

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

Station	Date	Avg. Temp	Avg. Wind	HDD65	AHDD65	AHDD65-1
Bemidji	2/1/1996	-34	8	99	107	94
Cloquet	2/2/1996	-31	7	96	103	100
Fargo	1/18/1996	-16	34	81	109	85
International Falls	2/2/1996	-34	8	99	107	107
Minneapolis	2/2/1996	-25	8	90	97	92
Rochester	2/2/1996	-27	10	92	101	94
Worthington	1/18/1996	-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:

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

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.

Gate Total Throughput Peak – Same Date Location-based estimated Non-Firm Total Throughput = 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 intial demand area estimates, the Gate Station peak day estimates continue to maintain the intial 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 NORTHSHORE 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 dockets[3] 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 dockets[4] 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 2024-2025 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-24-270

CERTIFICATE OF SERVICE

I, Colleen T. Sipiorski, hereby certify that on the 1st day of November~~August~~, 2024, 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 November~~August~~, 2024.

/s/ Colleen T. Sipiorski
Colleen T. Sipiorski

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