January 22, 2026

Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Response to Reply Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G022/M-25-70

Dear Ms. Bergman:

Attached are the Response to Reply Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Petition for a Change in Contract Demand Entitlement.

The Petition was filed on March 31, 2025, by Greater Minnesota Gas.

In comments filed August 28, 2025, the Department deferred making recommendations on the following two topics until it has had an opportunity to review Greater Minnesota Gas Company's (GMG, the Company) reply comments:

- The Company's request to changes in its overall demand entitlement level.
- GMG's proposed reserve margin for the 2025-2026 heating season.

GMG filed its reply comments on September 5, 2025.

The Department now recommends the Commission approve the filing, after completing its review of the additional information provided in the Company's reply comments and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. Sydnie Lieb
Assistant Commissioner of Energy Regulatory Analysis

JK/LB/ar
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G022/M-25-70

I. INTRODUCTION

Pursuant to Minnesota Rules 7825.2910, subpart 2,[1] Greater Minnesota Gas (Greater Minnesota, GMG, or the Company) filed a petition requesting a change in its contract demand entitlement[2] (Petition) on March 31, 2025.

On August 28, 2025, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed comments. The Department's initial comments requested additional information and clarification prior to making a recommendation on the Company's proposals.

The Department requested GMG provide additional information in its reply comments regarding the following topics.

- An analysis comparing the present value of the costs of the Company's proposed purchase of 1,000 dth/day purchase of existing capacity on NNG and contracting for 1,000 dth/day of additional capacity via the 2027 Northern Lights Open Season.
- GMG's 2025-2026 proposed reserve margin given the question regarding the prudency of the 1,000 dth/day purchase referenced in the previous bullet point.
- Rate impact of NNG's 2025 FERC Rate Case.
- Any rate changes associated with existing agreements included in the 2025-2026 demand entitlement.
- The Department's estimate of the incremental expense resulting from the purchase of 500 dth of SMS and the date on which GMG will take service for the 200 dth/day of SMS from NNG.

The Department also noted in its comments that it had no further requests for information regarding GMG's 2025-2026 winter season design day calculation and no further comments or recommendations regarding the Company efforts regarding decarbonization/electrification on its design day calculation.

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[1] "Filing upon a change in demand. Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another."

[2] Also called entitlement, capacity, or transportation on the pipeline.

II. PROCEDURAL BACKGROUND

March 31, 2025	GMG submitted its petition requesting a change in its 2025-2026 Contract Demand Entitlement.[3]
May 30, 2025	GMG submitted its 2025-2026 Design Day.[4]
August 28, 2025	The Department filed its comments.[5]
September 5, 2025	GMG filed reply comments.[6]

III. ANALYSIS

A. GREATER MINNESOTA'S RESPONSES TO DEPARTMENT REQUESTS FOR ADDITIONAL INFORMATION

The Department's August 28, 2025, comments requested Greater Minnesota provide additional information on the following topics regarding the Company's proposed overall demand entitlement level for the 2025-2026 heating season:

- An estimate of the incremental expense associated with the purchase of 500 dth of SMS.
- The date on which GMG is proposing to take service for the additional 200 dth of SMS in its reply comments.
- The Company identify any changes in rates to existing agreements included in its 2025-2026 demand entitlement.
- Proposed rate changes resulting from Northern Natural Gas' (NNG) 2025 FERC rate case and provide an estimate of the impact of those proposed increases on GMG's average customer.

The Department also requested that the Company provide an analysis comparing the costs of the proposed purchase of this incremental 1,000 dth of existing firm capacity as opposed to purchasing a smaller amount of firm capacity through NNG's 2027 Northern Lights Open Season.[7]

GMG provided almost all the requested information in its Reply Comments. The Department reviews and discusses the information the Company provided in the following sections.

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[3] Request for a Change in Demand Units, Petition, March 31, 2025, Docket No. G022/M-25-70 (eDockets) 20253-217046-01 (hereinafter: Petition).
[4] Request for a Change in Demand Units, Compliance Filing, May 30, 2025, Docket No. G022/M-25-70 (eDockets) 20255-219437-01 (hereinafter Amended Petition).
[5] Request for a Change in Demand Units, Department, Comments, August 28, 2025, Docket No. G022/M-25-70 (eDockets) 20258-222525-01 (hereinafter: Department Comments).
[6] Request for a Change in Demand Units, Reply Comments, September 5, 2025, Docket No. G022/M-25-70 (eDockets) 20259-222753-01 (hereinafter: GMG Reply Comments).
[7] Department Comments, p. 12-13.

A.1 Proposed Overall Demand Entitlement Level, Design Day and Proposed Reserve Margin

GMG's 2025 Amended Petition included significant changes to these three items when compared to the Petition. The Department believes identifying those differences may help explain the Company's current request.

A.1.1 Petition

Greater Minnesota only identified a 60 dth increase in year-round firm pipeline capacity in its proposed overall demand entitlement in its filing on March 31,2025. Table 1 contains this information and is identical to a table GMG included in the Petition.

Table 1-RRC – Proposed Demand Entitlement for 2025-2026 Heating Season in Petition compared to 2024-2025 Commission Approved Demand Entitlement[8]

Approved Entitlement for 2024-2025 (Dth)	Proposed Entitlement for 2025-2026 (Dth)	Change from Previous Year (in Dth)	% Change from Previous Year
20,108	20,168	60	0.30%

GMG also provided an estimate of the Company's 2025-2026 design day in the Petition as well. Table 2 compares Greater Minnesota's approved 2024-2025 design day and the proposed design day included in the Petition.

Table 2-RRC – Proposed Design Day for 2025-2026 Heating Season in Petition compared to 2024-2025 Commission Approved Design Day[9]

Approved Design Day for 2024-2025 (Dth)	Initial Proposed Design Day for 2025-2026 (Dth)	Change from Previous Year (in Dth)	% Change from Previous Year
18,918	18,126	-792	-4.2%

The information in Table 3 identifies the Company's proposed reserve margin included in the Petition as well.

[8] Petition, p. 2.
[9] Petition, p. 3.

Table 3-RRC – Proposed Demand Entitlement, Design Day and Reserve Margin for 2025-2026 Heating Season Included in Petition[10]

2025-2026 Initial Proposed Entitlement, Design Day, Reserve and Reserve Margin	
Design Day	18,126
Demand Entitlement	20,168
Reserve	2,042
Reserve Margin	11.27%

The Department had not previously encountered a demand entitlement request that combined a lower design day estimate (-791 dth) than the prior year's design day combined with an increase in the current year's proposed demand entitlement (+60 dth).

After reviewing the information regarding GMG's acquisition of the additional 60 dth of capacity, the Department understood the Company's rationale for the proposed demand entitlement.

A.1.2 Amended Petition

In the Amended Petition, Greater Minnesota requested an increase of 1,060 dth of firm pipeline capacity while lowering its 2025-2026 design day compared to the initial filing and the 2024-2025 estimate even further.

Table 4 contains the demand-entitlement-related information and is identical to a table the Company included in the Amended Petition. Table 5 includes the design day related information.

Table 4-RRC – Proposed Demand Entitlement for 2025-2026 Heating Season Included in Amended Petition compared to 2024-2025 Commission Approved Demand Entitlement [11]

Approved Entitlement for 2024-2025 (Dth)	Proposed Entitlement for 2025-2026 (Dth)	Change from Previous Year (in Dth)	% Change from Previous Year
20,108	21,168	1,060	5.27%

GMG also provided an updated design day and reserve margin calculations in the Amended Petition as well. Table 5 recreates that table.

[10] *Ibid*.
[11] Amended Petition, p. 4.

Table 5-RRC – Proposed Design Day for 2025-2026 Heating Season in Amended Petition compared to 2024-2025 Commission Approved Design Day[12]

Approved Design Day for 2024-2025 (Dth)	Amended Proposed Design Day for 2025-2026 (Dth)	Change from Previous Year (in Dth)	% Change from Previous Year
18,918	18,045	-873	-4.6%

Table 6 summarizes the demand entitlement, design day, reserve and reserve margin included in the Amended Petition.

Table 6-RRC – Proposed Demand Entitlement, Design Day and Reserve Margin for 2025-2026 Heating Season Included in Amended Petition[13]

Amendedl 2025-2026 Proposed Entitlement, Design Day, Reserve and Reserve Margin	
Design Day	18,045
Demand Entitlement	21,168
Reserve	3,123
Reserve Margin	17.31%

The Amended Petition's lower design day estimate (-81 dth) and the proposed incremental increase in the current year's proposed demand entitlement (1,000 dth) as compared to those proposed in the Petition raised concern for the Department.[14, 15]

After reviewing GMG's explanation for the proposed purchase of 1,000 dth of additional firm pipeline capacity on NNG in the Amended Petition more closely, the Department realized that Greater Minnesota's position was that purchasing existing capacity priced at historical cost, even if the quantity of capacity was much higher than the Company would need for any short-term forecasted growth would be less costly than contracting with NNG to build additional capacity at NNG's current incremental cost, even if GMG was contracting for a smaller amount of incremental capacity at current cost or spreading those costs over a longer time.

The Department requested that Greater Minnesota provide an analysis that supports the Company's position in its Reply Comments.[16] Greater Minnesota did include that analysis in its Reply Comments.[17]

The Company estimated that ratepayers would benefit financially by $1.3 to $1.1 million over the next seven years because of the Company contracting for this additional 1,000 dth of existing capacity rather than purchasing the capacity on an incremental basis via NNG's Northern Lights Open Seasons in 2027 and 2029.

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[12] See Department Attachment 3, columns 4 through 6 for 2024-2025 and 2025-2026.
[13] Amended Petition, p.4 .
[14] Design day comparison calculation for Petition and Amended Petition: 18,126 dth – 18,045 dth = 81 dth.
[15] Demand entitlement calculation for Amended Petition and Petition: 1,060 dth – 60 dth = 1,000 dth.
[16] Department Comments, p. 16.
[17] GMG Reply Comments, p. 4, Attachment A.

The Department then re-created the Company's analysis as a check and then modified GMG's analysis such that the Company only purchased 500 dth of incremental capacity in 2027 and the remaining 500 dth of incremental capacity in 2029.[18] Table 7-RRC contains that analysis. The Department considers that to be a more reasonable assumption given Greater Minnesota's current customer growth rate. The Department's estimate of the savings associated with the 1,000 dth purchase as compared to pursuing the capacity via the Northern Lights process are $1.2 million assuming 2025 NNG rates and $0.9 million assuming 2026 NNG Initial Interim rates.

Table DOC-7-RRC – Summary of GMG and Department Net Present Value Analysis of GMG's Propose 1,000 dth Purchase and Acquiring 1,000 dth of Incremental Capacity via Northern Lights 2027 ($)

Line No	GMG Estimate - 2025 NNG Rates	Net Present Value	Attachment DOC-1-RRC Ref.
1.	1,000 Dth Purchase	$886,772	Table 1 tab, Cell 16 Q
2.	Northern Lights 2027	$2,241,970	Table 1 tab, Cell 28 Q
3.	Difference (Line 2- Line 1)	**$1,355,198**	Table 1 tab, Cell 30 Q
	GMG Estimate - 2026 NNG Initial Interim Rates		
4.	1,000 Dth Purchase	$1,800,799	Table 1 tab, Cell 43 Q
5.	Northern Lights 2027	$2,867,368	Table 1 tab, Cell 56 Q
6.	Difference (Line 5- Line 4)	**$1,066,570**	Table 1 tab, Cell 30 Q
	DOC Estimate - 2025 NNG Rates	**Net Present Value**	
7.	1,000 Dth Purchase	$886,772	Mod. Table 1 tab, Cell16Q
8.	Northern Lights 2027	$2,121,369	Mod. Table 1 tab, Cell 28 Q
9.	Difference (Line 8- Line 7)	$1,234,597	Mod. Table 1 tab, Cell 30 Q
	DOC Estimate - 2026 NNG Initial Interim Rates		
10.	1,000 Dth Purchase	$1,800,799	Mod. Table 1 tab, Cell 43 Q
11.	Northern Lights 2027	$2,746,767	Mod.Table 1 tab, Cell 56 Q
12.	Difference (Line 1- Line 10)	$945,968	Mod. Table 1 tab, Cell 30 Q

While that change did lower the Net Present Values (NPVs) of the Northern Lights scenarios, it didn't lower them sufficiently to justify that option being preferable financially to GMG's ratepayers. The difference in NPV under both scenarios for the Northern Lights option decreased $120,602. This lowered the benefit to ratepayers of the existing capacity option using current rates to $1,234,597 from GMG's original estimate of $1,355,198. That same decrease for the NNG Increase scenario decreased by the benefit to ratepayers of the existing capacity option using current rates to $945,968 from GMG's original estimate of $1,066,570.

Thus, the Department concludes that GMG's proposal to purchase the incremental 1,000 dth of firm pipeline capacity on NNG is financially beneficial to ratepayers given the alternative and recommends the Commission approve the request. By extension, this approval of that increase would increase the Company's reserve margin to 17.31 percent and the Department recommends that Commission approve that reserve margin as well.

[18] See Attachment DOC-1-RRC.

The Department also notes that it is providing updated information on GMG's proposed 2025-2026 Demand Entitlement and Design-Days in Attachments DOC-2-RRC and DOC 3-RRC.

A.1.3 Other Topics

i. Incremental System Management Service (SMS) on NNG

Regarding the Department's request as to the date on which GMG would take service for the additional 200 dth of SMS, the Company explained that it would take that service in November 2025 for the duration of the winter season or five months.[19] Hence, the Department estimates the annual incremental costs associated with that 500 dth of SMS under current rates given that make-up would be $583,050. Table DOC-8-RRC includes that calculation.

Table DOC-8-RRC – Annual Cost of 300 dth Year-Round SMS and 200 dth Winter-Season SMs – Estimated Additional Cost

Line No.	Res. Chg/Day	Qty	Daily Cost	# of Days per Month	Monthly Exp.	# of Months	Annual Exp.
1.	$ 4.225	300	$ 1,268	30	$ 38,025	12	$ 456,300
2.	$ 4.225	200	$ 845	30	$ 25,350	5	$ 126,750
3.	Annual Cost						$ 583,050
4.	Summer Season Monthly Cost				$ 38,025	7	$ 266,175
5.	Winter Season Monthly Cost				$ 63,375	5	$ 316,875
6.	Annual Cost						$ 583,050

The monthly summer season SMS expense would be $38,025 and the winter season expense would be $63,375. The Department has no further comments regarding GMG's proposed SMS expenses since those costs are recovered via the Purchased Gas Adjustment (PGA).

ii. Potential Rate Increases to Existing Agreements

GMG also discussed proposed rate changes on existing contracts that may occur, specifically noting the current NNG rate case.[20] The Company didn't provide an estimate of the rate/bill impacts at the customer level resulting from that potential rate increase.

NNG did proposed new interim rates for its 2025 rate case in a filing it made at FERC on January 5th, 2026. The effective date for those revised interim rates was January 8, 2026. According to information on NNG's website:

> Northern will be filing a motion to implement the suspended tariff rates associated with Docket No. RP-989 to be effective January 1, 2026. In

[19] GMG Reply Comments at p. 2.
[20] GMG Reply Comments, p. 2-3.

> furtherance of settlement discussions, Northern is also proposing to implement lower interim rates compared to filed rates for the market area and the field area. Northern's proposed interim rates reflect an approximately 17% reduction below the Market Area filed rates and a 29% reduction below the Field Area filed rates.[21]

It also appears that settlement negotiations are ongoing.

The Department also asked Great Plains Natural Gas to provide an estimate of the rate/bill impacts resulting from NNG original proposed interim rates in an information request issued in that company's 2025-2026 Demand Entitlement filing. Great Plains assumed a 35 percent rate increase in the analysis it provided in its response.[22] That analysis identified an annual cost impact from a potential NNG rate case settlement to be approximately $72 for a Great Plains residential customer using 90 dekatherms of natural gas annually.

While this analysis was not developed for GMG, if one adjusts the calculation for GMG's average residential customer usage of 80 dekatherms per year per customer, it does provide an admittedly rough estimate of a $64 annual cost increase a GMG residential customer might face.

A.2 Proposed PGA Cost-Recovery Proposal

The demand entitlement amounts listed in Department Attachment 2 represent the demand entitlements for which the Company's firm customers would pay. In Attachment D, page 1 of its Amended Petition, the Company compared its 2025 PGA to its expected proposed 2025 demand entitlement level as a means of calculating the bill impact.[23] According to the Company, Greater Minnesota's demand entitlement proposal would result in the following annual rate impacts:

- Annual bill increase of $10.56, or approximately 2.18 percent, for the average Residential customer consuming 85.8 dth annually; and
- Annual bill increase of $101.73, or approximately 2.18 percent, for the average Commercial and Industrial Firm customer consuming 826.7 dth annually.

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[21] Northern Natural Gas Update 1: Rate Case – Interim Rates and Deferred Collection Agreement, December 29, 2025.
[22] *In the Matter of Great Plains Natural Gas Company's Demand Entitlement Filing,* Great Plains Natural Gas Company, Reply Comments, October 13, 2025, Docket No. G004/M-25-71, (eDockets 202510-223861-01).
[23] Attachment D of the Amended Petition at 2 lists the "Total Rate Impact of Contract Demand Entitlement Change as of June 1, 2025 (as compared to March 2025). That table includes the June 2025 Demand Cost of $1.8194/dth. Greater Minnesota did provide the calculation of the June 2025 Demand Cost on that page, but did not identify it. Department staff reviewed the Company's June 2025 PGA filing to verify that information. See eDockets (20257-220731-05).

A.3 Electrification and Decarbonization Efforts

In its Comments, the Department noted that it has asked discovery related to GMG's efforts to quantify the effects of electrification and decarbonization efforts on its forecasted demand. The Department concluded that Greater Minnesota did not attempt to quantify those impacts explicitly in its 2025-2026 demand entitlement filing and noted that these issues might be addressed in the Commission's Gas Integrated Resource Plan or Future of Gas proceedings.[24]

GMG noted in its Reply Comments that the Company's sales forecasting efforts will capture the impact of any electrification or decarbonization efforts made by its customers. Greater Minnesota stated that even if the Company had not attempted to explicitly identify those effects, they would still be reflected in GMG's sales forecast due to the Company's use of actual degree day information in its sales forecast.

The Department appreciates GMG's discussion of this issue and notes that the goal of its review was to determine if the Company had made any explicit changes to its sales forecast to account for those changes.

A.4 Compliance with Reporting Requirements included Relevant Commission Orders

In its comments, the Department stated that it would provide a review of GMG's efforts to comply with the reporting requirement included in relevant Commission orders in supplemental comments.

The Department's review only identified two Orders that included specific information requirements in addition to those included in rules. In its Order in Greater Minnesota 2017-2018 Demand Entitlement filing the Commission:

- Approved Greater Minnesota's proposed level of demand entitlement and proposed recovery of demand costs effective November 1, 2017; and
- Required the Company to undertake the following in future demand entitlement filings:
    - Use a constant annual average residential usage estimate for the purpose of estimating rate impact on a going-forward basis:
    - Perform separate regression analyses by service area, using area-specific weather stations, as soon as there is sufficient consumption and customer data for the results to be relied upon.
    - Estimate its design day using data from at least three heating seasons when appropriate. If the results of these calculations are not acceptable, the Company shall fully explain its decision to use a shorter estimation period in its initial filing; and

[24] Docket Nos. G008, G002, G011/CI-23-117 and G999/CI-21-565.

- Maintain, on a going-forward basis, a two-part design day process involving both regression analysis and mathematical analysis based on the Company's historical all-time peak-day send-out. [25]

In its Order in Greater Minnesota's 2020-2021 demand entitlement filing, the Commission included an additional reporting requirement/directive:

- Required Greater Minnesota Gas to maintain a minimum reserve margin of 5% on a going forward basis for the heating season or fully explain any decision to use a reserve margin of less than 5%.

Greater Minnesota included all the information required in its filing regarding its sales forecast and the Company's proposed reserve margin is well more than the 5% threshold. Hence, the Department concludes GMG has complied with the Commission's reporting requirements.

Given the additional information GMG provided in Reply Comments, the Department recommends the Commission accept GMGs proposed 2025-2026 demand entitlement level.

IV. RECOMMENDATIONS

The Department recommends the Commission approve Greater Minnesota's proposed 2025-2026:

- demand entitlement level.
- design-day estimate.
- reserve margin.

[25] *In the Matter of a Request by Greater Minnesota Gas, Inc. for Approval of a Change in Contract Demand Entitlement Units Effective November 1, 2017*, Public Utilities Commission, Order, June 13, 2019, Docket No. G022/M-17-399, (eDockets) 20196-153536-01, at 1-2, hereinafter "17-399 Order."

Attachment DOC-3-RRC

Detail of Greater Minnesota Gas' Annual Design Day, Demand Entitlements, and Reserve Margins 1996-2025

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving + Peak Shaving			Reserve Margin
Heating Season	(1) Number of Design Day Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Mcf)	(5) Change from Previous Year	(6) % Change From Previous Year	Heating Season Total Entitlement (Mcf)	(8) Change from Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2025-2026 (Estimate)	11,614	500	4.50%	18,045	-873	-4.61%	21,168	1,060	5.27%	17.31%
2024-2025 (3/3125)	11,114	303	2.80%	18,918	1,846	10.81%	20,108	1,000	5.23%	6.29%
2023-2024 (2/29/2024)	10,811	397	3.81%	17,072	1,105	6.92%	19,108	1,500	8.52%	11.93%
2022-2023 (1/31/2023)	10,414	443	4.44%	15,967	610	3.97%	17,608	0	0.00%	10.28%
2021-2022 (2/2022)	9,971	453	4.76%	15,357	298	1.98%	17,608	2,000	12.81%	14.66%
2020-2021 (2/14/2021)	9,518	455	5.02%	15,059	815	5.72%	15,608	333	2.18%	3.65%
2019-2020 (2/13/20)	9,063	562	6.61%	14,244	1,540	12.12%	15,275	1,166	8.26%	7.24%
2018-2019 (1/29/19)	8,501	591	7.47%	12,704	755	6.32%	14,109	1,500	11.90%	11.06%
2017-2018 (12/31/17)	7,910	532	7.21%	11,949	1,131	10.45%	12,609	(750)	-5.61%	5.52%
2016-2017 (1/31/17)	7,378	735	11.06%	10,818	(308)	-2.77%	13,359	850	6.80%	23.49%
2015-2016 (1/31/2016)	6,643	791	13.52%	11,126	2,157	24.05%	12,509	2,850	29.51%	12.43%
2014-2015 (2/28/15)	5,852	547	10.31%	8,969	904	11.21%	9,659	300	3.21%	7.69%
2013-2014 (1/31/14)	5,305	531	11.12%	8,065	3,101	62.47%	9,359	4,150	79.67%	16.04%
2012-2013	4,774	558	13.24%	4,964	273	5.82%	5,209	165	3.27%	4.94%
2011-2012	4,216	319	8.19%	4,691	241	5.42%	5,044	0	0.00%	7.53%
2010-2011	3,897	175	4.70%	4,450	796	21.78%	5,044	500	11.00%	13.35%
2009-2010	3,722	162	4.55%	3,654	(628)	-14.67%	4,544	300	7.07%	24.36%
2008-2009	3,560	182	5.39%	4,282	566	15.23%	4,244	244	6.10%	-0.89%
2007-2008	3,378	170	5.30%	3,716	166	4.68%	4,000	350	9.59%	7.64%
2006-2007	3,208	237	7.98%	3,550	750	26.79%	3,650	350	10.61%	2.82%
2005-2006	2,971	290	10.82%	2,800	255	10.02%	3,300	300	10.00%	17.86%
2004-2005	2,681	336	14.33%	2,545	545	27.25%	3,000	600	25.00%	17.88%
2003-2004	2,345	181	8.36%	2,000	(200)	-9.09%	2,400	(200)	-7.69%	20.00%
2002-2003	2,164	300	16.09%	2,200	400	22.22%	2,600	400	18.18%	18.18%
2001-2002	1,864	301	19.26%	1,800	400	28.57%	2,200	500	29.41%	22.22%
2000-2001	1,563	393	33.59%	1,400	300	27.27%	1,700	300	21.43%	21.43%
1999-2000	1,170	279	31.31%	1,100	250	29.41%	1,400	150	12.00%	27.27%
1998-1999	891	289	48.01%	850	350	70.00%	1,250	750	150.00%	47.06%
1997-1998	602	339	128.90%	500	200	66.67%	500	200	66.67%	0.00%
1996-1997	263	263		300	0		300	300		0.00%
Average Change Per Year:	5,245	387	15.61%	7,437	612	16.76%	8,282	720	18.63%	13.77%

Attachment DOC-3-RRC

Detail of Greater Minnesota Gas' Annual Design Day, Demand Entitlements, and Reserve Margins 1996-2025

Firm Peak Day Sendout

Heating Season *	(11) Firm Peak Day Send out (Mcf)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per DD Customer (7)/(1)	Peak Day Sendout per DD Customer (11)/(1)
2025-2026	Unavailable			0.269	1.5537	1.8226	Unavailable
2024-2025	15,139	2,128	16.36%	0.107	1.7022	1.8092	1.3622
2023-2024	13,011	(756)	-5.49%	0.188	1.5791	1.7675	1.2035
2022-2023	13,767	1,156	9.17%	0.158	1.5332	1.6908	1.3220
2021-2022	12,611	288	2.34%	0.226	1.5402	1.7659	1.2648
2020-2021	12,323	634	5.42%	0.058	1.5822	1.6398	1.2947
2019-2020	11,689	(1,634)	-12.26%	0.114	1.5717	1.6854	1.2897
2018-2019	13,323	2,963	28.60%	0.165	1.4944	1.6597	1.5672
2017-2018	10,360	1,114	12.05%	0.083	1.5106	1.5941	1.3097
2016-2017	9,246	(249)	-2.62%	0.344	1.4663	1.8107	1.2532
2015-2016	9,495	1,126	13.45%	0.208	1.6748	1.8830	1.4293
2014-2015	8,369	489	6.21%	0.118	1.5326	1.6505	1.4301
2013-2014	7,880	2,855	56.82%	0.244	1.5203	1.7642	1.4854
2012-2013	5,025	1,368	37.41%	0.051	1.0398	1.0911	1.0526
2011-2012	3,657	(248)	-6.35%	0.084	1.1127	1.1964	0.8674
2010-2011	3,905	251	6.87%	0.152	1.1419	1.2943	1.0021
2009-2010	3,654	(374)	-9.29%	0.239	0.9817	1.2208	0.9817
2008-2009	4,028	(72)	-1.76%	(0.011)	1.2028	1.1921	1.1315
2007-2008	4,100	550	15.49%	0.084	1.1001	1.1841	1.2137
2006-2007	3,550	738	26.24%	0.031	1.1066	1.1378	1.1066
2005-2006	2,812	285	11.28%	0.168	0.9424	1.1107	0.9465
2004-2005	2,527	185	7.90%	0.170	0.9493	1.1190	0.9426
2003-2004	2,342	587	33.45%	0.171	0.8529	1.0235	0.9987
2002-2003	1,755	747	74.11%	0.185	1.0166	1.2015	0.8110
2001-2002	1,008	(180)	-15.15%	0.215	0.9657	1.1803	0.5408
2000-2001	1,188	291	32.44%	0.192	0.8957	1.0877	0.7601
1999-2000	897	95	11.85%	0.256	0.9402	1.1966	0.7667
1998-1999	802	397	98.02%	0.449	0.9540	1.4029	0.9001
1997-1998	405	233	135.47%	0.000	0.8306	0.8306	0.6728
1996-1997	172	172					
Average Change Per Year:	6,388	535	21.00%	0.159	1.241	1.421	1.1038

GMG Estimates

Attachment DOC-1-RRC GMG Table from Reply Comments

Net Present Value Impact of Additional Capacity

Discount Rate
8.0%

1,000 Dth Purchase — Using Current Rates

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0								$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 48,380**	$ 48,380	=P8/((1+$R$4)^B8)
Nov 25 - Oct 26	1	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 149,104	=P9/((1+$R$4)^B9)
Nov 26 - Oct 27	2	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 138,059	=P10/((1+$R$4)^B10)
Nov 27 - Oct 28	3	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 127,832	=P11/((1+$R$4)^B11)
Nov 28 - Oct 29	4	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 118,363	=P12/((1+$R$4)^B12)
Nov 29 - Oct 30	5	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 109,596	=P13/((1+$R$4)^B13)
Nov 30 - Oct 31	6	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 101,477	=P14/((1+$R$4)^B14)
Nov 31 - Oct 32	7	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 93,961	=P15/((1+$R$4)^B15)
															$ 886,772	

Northern Lights — Using Current Rates

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 0	
Nov 25 - Oct 26	1	$ -	$ 1,826,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,826,000**	$ 1,690,741	=P21/((1+$R$4)^B21)
Nov 26 - Oct 27	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 0	=P22/((1+$R$4)^B22)
Nov 27 - Oct 28	3	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 127,832	=P23/((1+$R$4)^B23)
Nov 28 - Oct 29	4	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 118,363	=P24/((1+$R$4)^B24)
Nov 29 - Oct 30	5	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 109,596	=P25/((1+$R$4)^B25)
Nov 30 - Oct 31	6	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 101,477	=P26/((1+$R$4)^B26)
Nov 31 - Oct 32	7	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 93,961	=P27/((1+$R$4)^B27)
															$2,241,970	

Difference (Northern Lights less 1,000 Dth Purchase) with current rates — **$1,355,198**

1,000 Dth Purchase — Using Northern Natural Gas Rate Increase

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0								$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 48,380**	$ 48,380	=P35/((1+$R$4)^B35)
Nov 25 - Oct 26	1	$ 23,609	$ 23,609	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 303,585**	$ 281,097	=P36/((1+$R$4)^B36)
Nov 26 - Oct 27	2	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 294,694	=P37/((1+$R$4)^B37)
Nov 27 - Oct 28	3	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 272,865	=P38/((1+$R$4)^B38)
Nov 28 - Oct 29	4	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 252,653	=P39/((1+$R$4)^B39)
Nov 29 - Oct 30	5	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 233,938	=P40/((1+$R$4)^B40)
Nov 30 - Oct 31	6	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 216,609	=P41/((1+$R$4)^B41)
Nov 31 - Oct 32	7	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 200,564	=P42/((1+$R$4)^B42)
															$1,800,799	

*2025 calculations at current rates, 2026 and beyond at proposed T12 Variable Rates

Northern Lights — Using Northern Natural Gas Rate Increase

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 0	
Nov 25 - Oct 26	1	$ -	$ 1,826,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,826,000**	$ 1,690,741	=P49/((1+$R$4)^B49)
Nov 26 - Oct 27	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	$ 0	=P50/((1+$R$4)^B50)
Nov 27 - Oct 28	3	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 272,865	=P51/((1+$R$4)^B51)
Nov 28 - Oct 29	4	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 252,653	=P52/((1+$R$4)^B52)
Nov 29 - Oct 30	5	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 233,938	=P53/((1+$R$4)^B53)
Nov 30 - Oct 31	6	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 216,609	=P54/((1+$R$4)^B54)
Nov 31 - Oct 32	7	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 200,564	=P55/((1+$R$4)^B55)
															$2,867,368	

*CIAC paid in December 2026 to NNG.

*Rates used are proposed T12 Variable Rates

Difference (Northern Lights less 1,000 Dth Purchase) with NNG proposed rates — **$1,066,570**

NOTE: In the Formula references, the "P" refers to the Total column for the respective row, the "$R$4" refers to the cell that reflects the discount rate of 8%, and the "B" refers to the Year column for the repetive row.

ATTACHMENT DOC-1-RRC Modified Table 1
Net Present Value Impact of Additional Capacity

Discount Rate
8.0%

1,000 Dth Purchase — Using Current Rates

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0								$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 48,380**	$ 48,380	=P8/((1+$R$4)^B8)
Nov 25 - Oct 26	1	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 149,104	=P9/((1+$R$4)^B9)
Nov 26 - Oct 27	2	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 138,059	=P10/((1+$R$4)^B10)
Nov 27 - Oct 28	3	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 127,832	=P11/((1+$R$4)^B11)
Nov 28 - Oct 29	4	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 118,363	=P12/((1+$R$4)^B12)
Nov 29 - Oct 30	5	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 109,596	=P13/((1+$R$4)^B13)
Nov 30 - Oct 31	6	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 101,477	=P14/((1+$R$4)^B14)
Nov 31 - Oct 32	7	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 93,961	=P15/((1+$R$4)^B15)
															$ 886,772	

Northern Lights — Using Current Rates

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 0**	$ 0	
Nov 25 - Oct 26	1	$ -	$ 913,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 913,000**	$ 845,370	=P21/((1+$R$4)^B21)
Nov 26 - Oct 27	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 0**	$ 0	=P22/((1+$R$4)^B22)
Nov 27 - Oct 28	3	$ 18,660	$ 931,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 1,074,032**	$ 852,601	=P23/((1+$R$4)^B23)
Nov 28 - Oct 29	4	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 118,363	=P24/((1+$R$4)^B24)
Nov 29 - Oct 30	5	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 109,596	=P25/((1+$R$4)^B25)
Nov 30 - Oct 31	6	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 101,477	=P26/((1+$R$4)^B26)
Nov 31 - Oct 32	7	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 18,660	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 161,032**	$ 93,961	=P27/((1+$R$4)^B27)
															$2,121,369	
Difference (Northern Lights less 1,000 Dth Purchase) with current rates															**$1,234,597**	**$120,602**

1,000 Dth Purchase — Using Northern Natural Gas Rate Increase

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0								$ 9,676	$ 9,676	$ 9,676	$ 9,676	$ 9,676	**$ 48,380**	$ 48,380	=P35/((1+$R$4)^B35)
Nov 25 - Oct 26	1	$ 23,609	$ 23,609	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 303,585**	$ 281,097	=P36/((1+$R$4)^B36)
Nov 26 - Oct 27	2	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 294,694	=P37/((1+$R$4)^B37)
Nov 27 - Oct 28	3	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 272,865	=P38/((1+$R$4)^B38)
Nov 28 - Oct 29	4	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 252,653	=P39/((1+$R$4)^B39)
Nov 29 - Oct 30	5	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 233,938	=P40/((1+$R$4)^B40)
Nov 30 - Oct 31	6	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 216,609	=P41/((1+$R$4)^B41)
Nov 31 - Oct 32	7	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 200,564	=P42/((1+$R$4)^B42)
															$1,800,799	

*2025 calculations at current rates, 2026 and beyond at proposed T12 Variable Rates

Northern Lights — Using Northern Natural Gas Rate Increase

	Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Total	NPV	Formula
Jun 25 - Oct 25	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 0**	$ 0	
Nov 25 - Oct 26	1	$ -	$ 913,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 913,000**	$ 845,370	=P49/((1+$R$4)^B49)
Nov 26 - Oct 27	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 0**	$ 0	=P50/((1+$R$4)^B50)
Nov 27 - Oct 28	3	$ 43,682	$ 956,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 1,256,731**	$ 997,634	=P51/((1+$R$4)^B51)
Nov 28 - Oct 29	4	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 252,653	=P52/((1+$R$4)^B52)
Nov 29 - Oct 30	5	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 233,938	=P53/((1+$R$4)^B53)
Nov 30 - Oct 31	6	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 216,609	=P54/((1+$R$4)^B54)
Nov 31 - Oct 32	7	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 43,682	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	$ 17,903	**$ 343,731**	$ 200,564	=P55/((1+$R$4)^B55)
															$2,746,767	
Difference (Northern Lights less 1,000 Dth Purchase) with NNG proposed rates															**$945,968**	**$120,602**

*CIAC paid in December 2026 to NNG.
*Rates used are proposed T12 Variable Rates

NOTE: In the Formula references, the "P" refers to the Total column for the respective row, the "$R$4" refers to the cell that reflects the discount rate of 8%, and the "B" refers to the Year column for the respetive row.

Attachment DOC- 2-RRC Historical and Proposed Demand Entitlements 2023-2026

2023-2024 Heating Season	Quantity (Mcf)	Change in Quantity
TF 12 (Nov.-Oct.)	210	0
TF-7 (Oct.-Apr.)	665	0
TFX-5 (Nov.-Mar.)	6,344	0
TFX-5 (Nov.-Mar.)	90	0
TF 12 (Nov.-Oct.)	500	0
TF 12 (Nov.-Oct.)	500	0
TFX-5 (Nov.-Mar.)	349	0
TF 12 (Nov.-Oct.)	817	0
TF 12 (Nov.-Oct.)	333	0
TFX5 (Nov.-Mar.)	1000	0
TF 12 (Oct.-Sept.)	1000	1000
TF 12 (Nov.-Oct.)	500	500
FT-A Viking	1,400	0
FT-A Viking	1,200	0
FT-A Viking	2,200	0
FT-A Viking	1,000	0
FT-A Viking	1,000	0
SMS	3,500	1,000
Total Demand Entitlement	19,108	1,500
Total Transportation	19,108	1,500
Total Annual Transportation		0
Total Seasonal Transport	19,108	1,500
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	100.00%	0.00%

2024-2025 Heating Season	Quantity (Mcf)	Change in Quantity
TF 12 (Nov.-Oct.)	210	0
TF-7 (Oct. - Apr.)	665	0
TFX-5 (Nov.-Mar.)	6,344	0
TFX-5 (Nov.-Mar.)	90	0
TF 12 (Nov.-Oct.)	500	0
TF 12 (Nov.-Oct.)	500	0
TFX-5 (Nov.-Mar.)	349	0
TF 12 (Nov.-Oct.)	817	0
TF 12 (Nov.-Oct.)	333	0
TFX5 (Nov.-Mar.)	1000	0
TF 12 (Oct.-Sept.)	1000	0
TF 12 (Nov.-Oct.)	500	0
TF 12 (Nov.-Oct.)	1,000	1,000
FT-A Viking	1,400	0
FT-A Viking	1,200	0
FT-A Viking	2,200	0
FT-A Viking	1,000	0
FT-A Viking	1,000	0
SMS	3,500	0
Total Demand Entitlement	20,108	1,000
Total Transportation	20,108	1,000
Total Annual Transportation		0
Total Seasonal Transport	20,108	1,000
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	100.00%	0.00%

2025-2026 Heating Season	Quantity (Mcf)	Change in Quantity
TF 12 (Nov.-Oct.)	210	0
TF-7 (Oct. - Apr.)	665	0
TFX-5 (Nov.-Mar.)	6,344	0
TFX-5 (Nov.-Mar.)	90	0
TF 12 (Nov.-Oct.)	500	0
TF 12 (Nov.-Oct.)	500	0
TFX-5 (Nov.-Mar.)	349	0
TF 12 (Nov.-Oct.)	817	0
TF 12 (Nov.-Oct.)	333	0
TFX5 (Nov.-Mar.)	1000	0
TF 12 (Oct.-Sept.)	1000	0
TF 12 (Nov.-Oct.)	500	0
TF 12 (Nov.-Oct.)	1,000	0
TF 12 (Apr.-Mar.)	60	60
TF 12 (Apr.-Mar.)	1,000	1,000
FT-A Viking	1,400	0
FT-A Viking	1,200	0
FT-A Viking	2,200	0
FT-A Viking	1,000	0
FT-A Viking	1,000	0
SMS	4,000	500
Total Demand Entitlement	21,168	1,060
Total Transportation	21,168	1,060
Total Annual Transportation		0
Total Seasonal Transport	21,168	1,060
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	100.00%	0.00%

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Response to Reply Comments

Docket No. G022/M-25-70

Dated this **22nd** day of **January 2026**

/s/Sharon Ferguson

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Lane PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	M-25-70
2	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-70
3	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-70
4	Robin	Burke	rburke@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	M-25-70
5	Cody	Chilson	cchilson@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	M-25-70
6	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-70
7	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	M-25-70
8	Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	M-25-70
9	Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	M-25-70
10	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-70