MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**February 5, 2026**		**Agenda Item 6***
Company	Great Plains Natural Gas Co.		
Docket No.	G-004/M-25-71		
	In the Matter of Great Plains Natural Gas Co.'s Petition for Approval of Changes in Contract Demand Entitlement for the 2025-2026 Winter Heating Season		
Issues	Should the Commission approve Great Plains' proposed demand entitlement levels and cost changes?		
Staff	Justin Andringa	justin.andringa@state.mn.us	651-539-1079

✓ **Relevant Documents**	**Date**
Great Plains – Initial Filing	July 1, 2025
Department of Commerce – Comments	October 2, 2025
Great Plains – Reply Comments	October 13, 2025
Great Plains – Informational Update	October 31, 2025
Department of Commerce – Supplemental Comments	November 17, 2025
Great Plains – Supplemental Reply Comments	November 21, 2025

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I. BACKGROUND

On July 1, 2025, Great Plains Natural Gas Co. (Great Plains or the Company) filed its annual Demand Entitlement Petition requesting Commission approval to change levels of demand for natural gas pipeline capacity and recovery of associated costs for the 2025–2026 winter heating season.

On October 2, 2025, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed its initial comments, recommending that the Commission approve the Company's design-day estimate, while deferring recommendations on the proposed demand entitlement and reserve margin until after Great Plains filed its Reply Comments and Informational Update. Additionally, the Department requested that Great Plains address capacity releases, as well as Northern Natural Gas' (NNG) proposed rate changes in its 2025 Federal Energy Regulatory Commission (FERC) rate case.

On October 13, 2025, Great Plains filed Reply Comments, noting its intervention in the NNG rate case and reporting that settlement discussions are ongoing. Additionally, Great Plains stated that it is soliciting bids for capacity release on Viking Gas Transmission (VGT), with the results to be included in its supplemental demand entitlement filing on or before November 1, 2025.

On October 31, 2025, Great Plains filed its Informational Update, detailing the Company's updated demand entitlement volumes and costs, as well as updated VGT capacity release pricing.

On November 17, 2025, the Department filed Supplemental Comments and recommended approval of Great Plains' proposed demand entitlement level and reserve margin, and to allow recovery of associated demand costs.

On November 21, 2025, Great Plains filed Supplemental Comments, indicating its acceptance of the Department's recommendations.

II. LEGAL STANDARDS

Minnesota (Minn) Rules (R) part (pt.) 7825.2910, subpart 2, requires gas utilities to make a filing whenever there is a change to demand-related entitlement services provided by a supplier or transporter of natural gas.[1]

III. DISCUSSION

[1] See *7825.2910 FILING BY GAS UTILITIES.* Minnesota Administrative Rules. https://www.revisor.mn.gov/rules/7825.2910/#rule.7825.2910.2

A. Great Plains – Initial Filing

Great Plains has various interstate pipeline transportation contracts (demand entitlements) to transport its natural gas supply for retail services to its customers. To assure continued reliability of firm natural gas supply deliveries to its customers, each year Great Plains reviews and updates these contracts as needed.

In this annual demand entitlement petition (Petition), Great Plains requested approval for capacity changes in these interstate pipeline transportation entitlements and certain demand-related contract costs, and to implement the rate impact of these changes through its Purchased Gas Adjustment (PGA) for charges effective November 1, 2025.

Great Plains proposed no change from its currently effective demand entitlement of 34,436 dekatherms per day (Dth/day)[2], which includes an 8,000 Dth/day capacity release on VGT.[3] Great Plains successfully released variable VGT capacity during the 2024–2025 heating season due to the dynamic needs of the now completed Wahpeton Expansion Project, generating total credits of $745,345.[4] In the current petition, Great Plains does not intend to release any capacity on NNG, as its reserve margin is 7.98%.

Great Plains' firm transportation service portfolio provides a maximum delivery quantity (MDQ) of 57,436 Dth/day, consisting of 42,436 Dth/day deliverable to Great Plains' city gates and 15,000 Dth/day of supplemental capacity to transport gas from the supply market to the demand market.[5]

Based on a winter design day of 31,892 dekatherms (Dth),[6] Great Plains projected a 7.98% reserve margin[7] for the heating season effective November 1, 2025.

As shown in Table 1, Great Plains estimates that the proposed demand costs would increase a residential customer's annual bill by $60.94, or 8.7% and a commercial customer's annual bill by $327.22, or 9.3%.

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[2] Upon review, Staff discovered a discrepancy between the demand entitlement amount approved in the previous year and amount proposed in the current proceeding. See Staff Comments at 16 for further information.

[3] Great Plains Initial Filing, July 1, 2025, Exhibit B at 1.

[4] *Id.* at 3.

[5] Supplemental capacity transports natural gas from the Northern Border Pipeline/NNG pipeline interconnect at Ventura to the NNG/VGT interconnect at Chisago. Any deliveries made against these contracts must simultaneously be received against a VGT agreement.

[6] Great Plains Initial Filing, July 1, 2025, Exhibit B at 1.

[7] *Id.,* Exhibit A.

Table 1: Great Plains' Proposed Demand Cost Impacts – Initial Filing[8]

Filing Date	Residential Customer (81.2 Dth)	Total Change Residential (%)	Firm General Customer (436.0 Dth)	Total Change Firm General (%)
July 1, 2025	$60.94	8.7	$327.22	9.3

Great Plains noted that the largest rate impact for the 2025–2026 heating season will likely result from NNG's recently announced rate case,[9] which seeks recovery of costs associated with its asset-modernization efforts. A full breakout of Great Plains' proposed demand costs are detailed in Table 2 below.

[8] Great Plains Initial Filing, July 1, 2025 at 5.

[9] NNG filed on July 1, 2025. Rates effective January 1, 2026. Great Plains will update with known changes in subsequent filings.

Table 2 – Great Plains' Proposed Demand Costs[10]

Interstate Pipelines	Dth/Day	Rates	Months	Demand Cost
Viking Firm				
FT-A - Zone 1-1 (Cat. 3)	8,000	$5.6200	12	$539,520
FT-A - Zone 1-1 (Cat. 3)	5,000	$5.6200	12	$337,200
FT-A - Seasonal (Cat. 3)	2,000	$5.6200	5	$56,200
FT-A - Zone 1-1 (Cat. 3)	5,000	$5.6200	12	$337,200
FT-A - Zone 1-1 (Cat. 3)	3,291	$5.6200	12	$221,945
FT-A - Capacity Release	(8,000)	$6.3250	12	$(607,200)
Northern Natural Firm				
TFX - Summer	13,000	$9.6760	7	$880,516
TFX - Winter	13,000	$25.7990	5	$1,676,935
TFX Seasonal (November-March)	2,000	$25.7990	5	$257,990
TF12 Base - Summer	5,703	$9.6760	7	$386,276
TF12 Base - Winter	5,703	$17.4170	5	$496,646
TF12 Variable - Summer	5,242	$9.6760	7	$355,051
TF12 Variable - Winter	5,242	$23.6090	5	$618,792
TFX - Winter	7,200	$25.7990	5	$928,764
TFX - Annual (Summer Rate)	3,000	$9.6760	7	$203,196
TFX - Annual (Winter Rate)	1,000	$25.7990	5	$128,995
FDD-1 Reservation	4,640	$3.2345	12	$180,097
Interruptible Demand Credit				$(356,006)
Total Demand Charges				$6,642,117

Pursuant to NNG's FERC tariff, NNG adjusts the MDQ associated with the TF12 Base and TF12 Variable effective November 1st of each year, based on the amount of capacity used during the preceding May through September period. Currently, the adjustment is pending; but it is typically insignificant. The changes in the TF12 Base and TF12 Variable for the 2025-2026 heating season will be finalized in Great Plains' November 1, 2025 supplemental filing.

Accordingly, Great Plains requested approval to begin recovering the associated demand costs through the Company's monthly PGA effective November 1, 2025.

[10] Great Plains Initial Filing, July 1, 2025 at 4.

In response to Commission Orders in Docket No.'s G-004/M-22-310,[11] G-004/M-23-262[12] and G-004/M-24-234,[13] Great Plains provided additional information regarding the new VGT FT-A 5-year and 10-year contracts. Great Plains' responses are summarized as follows:[14]

- Customer #4 elected to relocate outside of Minnesota.
- Great Plains cannot turn back the excess VGT-FT-A 3,291 Dth/day capacity without penalty.
- Great Plains could choose to forego renewal of any expiring 2027 FT-A capacity in the future.
- Great Plains does decrease its excess transportation capacity via capacity release mechanisms offered by VGT. This practice has proven successful for several years.
- Since November 1, 2022, a total of 524,285 Dth has been scheduled using contract AF0505. The coinciding Emerson purchases may otherwise have been executed at Ventura.
- Since November 1, 2022, none of the supplemental capacity has been reallocated to NNG delivery because of using the new VGT FT-A contract. NNG quoted the cost to be approximately $5.3 million for such reallocation, which Great Plains deemed would be unduly prohibitive.

Additionally, in response to Commission Orders in Docket No.'s G-004/M-21-135 and G-004/M-21-235,[15] Great Plains responded as follows:[16]

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[11] *In the Matter of the Petition by Great Plains Natural Gas Co. for Approval of its Demand Entitlement for the 2022-2023 Winter Heating Season*, ORDER, November 26, 2024, Ordering Paragraph 2.

[12] *In the Matter of the Petition by Great Plains Natural Gas Co. for Approval of its Demand Entitlement for the 2023-2024 Winter Heating Season*, ORDER, November 26, 2024, Ordering Paragraph 2.

[13] *In the Matter of Great Plains Natural Gas Co.'s Petition for Approval of Changes in Contract Demand Entitlements for the 2024-2025 Winter Heating Season*, ORDER, May 19, 2025, Ordering Paragraph 5.

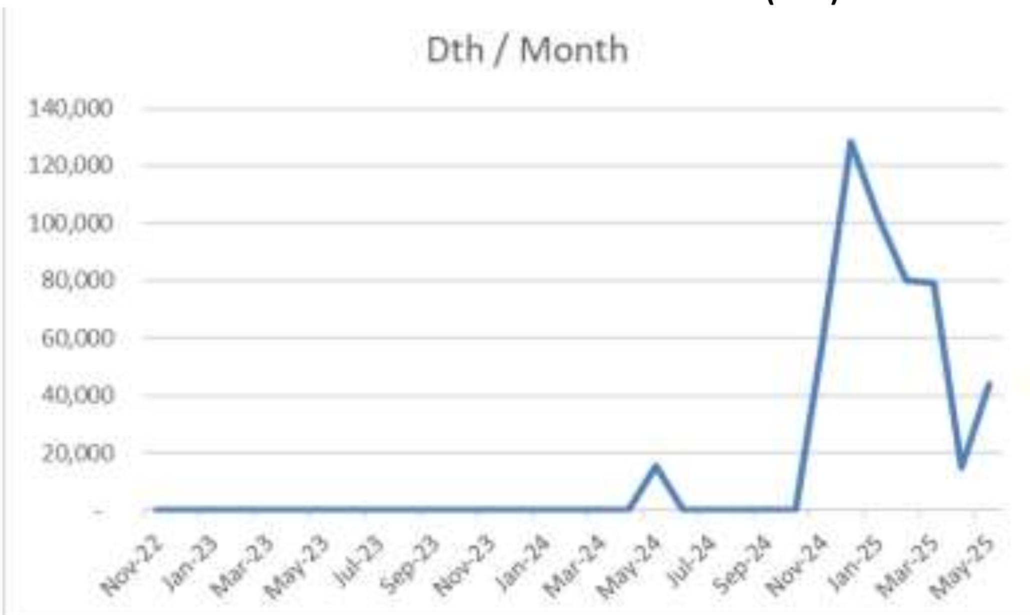
[14] Great Plains Initial Filing, July 1, 2025, at 5-6 and Exhibit B at 1.

[15] *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers*, and *In the Matter of the Petition by Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co., for Approval of Rule Variances to Recover High Natural Gas Costs from February 2021,* ORDER REQUIRING ACTIONS TO MITIGATE IMPACTS FROM FUTURE NATURAL GAS PRICE SPIKES, SETTING FILING REQUIREMENTS, AND INITIATING A PROCEEDING TO ESTABLISH GAS RESOURCE PLANNING REQUIREMENTS, Ordering Paragraph 9, February 17, 2023.

[16] Great Plains Initial Filing, July 1, 2025 at 7.

Pursuant to proceedings, hearings, and filings, Great Plains maintains a regionally diverse portfolio making nearly equal purchases from all three of its major trading locations. With that in mind, Great Plains has increased its monthly use of VGT capacity. For example, the following table displays use of AF0505 since November 2022.

Table 3: Great Plains' use of AF0505 Contract (VGT)[17]



This increase of utilization does not strictly relate to either base or spot purchases. It does, however, demonstrate that Great Plains recognizes that opportunities for less expensive supply can be found at Emerson versus other locations.

B. Department of Commerce – Comments

The Department reviewed the reasonableness of Great Plains' proposed demand entitlement levels, design-day requirements, proposed reserve margin, PGA cost recovery proposal, and compliance with previous Commission orders.

1. Design-day Requirements

The Department noted that Great Plains calculated a projected design-day requirement of 31,892 Dth/day, consisting of 14,209 Dth/day for firm customers served via city gates interconnected with VGT and 17,683 Dth/day for firm customers on the NNG system.
As shown in Table 4, the Department also compared Great Plains' current design-day levels to its proposed levels.

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[17] Great Plains Initial Filing, July 1, 2025 at 7.

Table 4 - Great Plains' Design-Day Levels[18]

Pipeline & Area	2024-2025 Design-day (Dth/day)	Proposed 2025-2026 Design-day (Dth/day)	Change (Dth/day)	Percent Change
Crookston	3,769	3,836	67	1.78%
North-4	10,260	10,373	113	1.10%
Total Viking	***14,029***	***14,209***	***180***	***2.88%***[19]
South District				
Total NNG	***17,649***	***17,683***	***34***	***0.19%***
Grand Total	**31,678**	**31,892**	**214**	**3.07%**[20]

The Department noted that Great Plains used the same design day method that the Commission has consistently approved in the Company's demand entitlement dockets since Docket No. G-004/M-03-303.

2. Regression Analysis

The Department noted that, in prior demand entitlement proceedings, both the Department and Commission Staff raised concerns that Great Plains' design-day method might under-estimate the natural gas requirements on a peak day for the South and North Districts.[21]

The Department noted the issue of serial correlation and its potential impact, observing that while Great Plains partially complied with the Commission's Order in Docket No. G-004/M-16-557 by checking its models for autocorrelation, it did not adjust the models to correct for serial correlation. In this filing, the Department made the necessary corrections, resulting in a total system design-day estimate of 31,254 Dth/day – approximately -638 Dth/day, or -2% lower than Great Plains' proposed estimate of 31,892 Dth/day. Given the small difference, the Department concluded that Great Plains' models remain suitable for design day planning.

Additionally, Great Plains experienced a peak of 30,686 Dth during the 2022–2023 heating season, its second highest in recent history, which remained below the 35,159 Dth design-day for that season.

Based on the foregoing discussion, the Department recommended that the Commission accept

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[18] Department Comments, October 2, 2025 at 5.

[19] Staff notes a discrepancy. The Change (Dth/day) of 180 divided by the Previous Design-day (Dth/day) of 14,029 equals 1.28%, not 2.88%.

[20] Staff notes a discrepancy. The Change (Dth/day) of 214 divided by the Previous Design-day (Dth/day) of 31,678 equals 0.68%, not 3.07%.

[21] Department Comments, October 2, 2025 at 5.

the Company's proposed design-day methodology.

3. Great Plains' Proposed Overall Demand Entitlement Level

The Department reviewed the Company's proposed 2025–2026 demand entitlement levels. As shown in Table 5, the Viking and NNG entitlement levels remain unchanged from 2024–2025.

Table 5 - Comparison of Great Plains' Current and Proposed Demand Entitlements[22]

Pipeline	2024-2025 Entitlement (Dth/day)	Proposed 2025-2026 Entitlement (Dth/day)	Change (Dth/day)	Percent Change
VGT	15,291	15,291	-	0.00%
NNG	19,145	19,145	-	0.00%
Total	**34,436**	**34,436**	**-**	**0.00%**

4. Effects of Electrification-Decarbonization on Great Plains' 2025–2026 Heating Season Design Day

The Department noted that, during the Commission's review of CenterPoint Energy's 2024–2025 demand entitlement filing, Commissioners' questions focused on efforts to incorporate electrification and/or decarbonization in its design day analysis, specifically in the design day regression analyses and annual sales forecast.

In response, the Department issued information requests (IR or IRs) seeking detailed information on these topics.[23]

IR #6 inquired whether Great Plains had incorporated any process to estimate the impact of electric heat pumps on its 2025–2026 design day projections for the residential customer class. Great Plains provided the following response:[24]

> Great Plains does not have a process in place to estimate the installations or effects of heat pumps or other electrification technologies for any class of customers. Therefore, Great Plains is not incorporating an analysis or adjustment for electrification technologies in its design day calculations. The main reason being that Great Plains has a small service territory mainly located in rural areas.

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22 Department Comments, October 2, 2025 at 4.

23 The Department issued IRs 1 through 18 on August 11, 2025. IRs 6 through 16 were related to this question.

24 Attachment DOC-2 includes Great Plains' response to IR 6.

> The Company has very low growth rate and has not seen any significant demand changes from customers relating to electrification.

The Department noted that Great Plains' responses to IRs #7 through #15 each referenced its response to IR #6, with no additional information provided in the individual responses.[25]

In IR #16, the Department asked whether Great Plains had identified or initiated conversations with any Minnesota electric utilities regarding the potential sharing of interstate pipeline capacity during extreme weather events. Great Plains responded that it had not.[26]

Following its review of the potential impacts of electrification and decarbonization on Great Plains' 2025–2026 design day, the Department determined that no adjustment was warranted and issued no recommendation.

5. Proposed Reserve Margin

As shown in Table 6, the Department summarized Great Plains' reserve margin calculations for 2019–2026 and noted that the Company proposed to increase its 2025–2026 reserve margin to 7.98%.

Table 6 - Great Plains' Reserve Margin, 2019–2026 (%)[27]

Heating Season	Design Day (Dth/day) (a)	Total Entitlement (Dth/day) (b)	Reserve Margin (c) = (b-a)/a
2019-2020	34,066	36,945	8.45%
2020-2021	33,922	37,145	9.50%
2021-2022	34,398	39,145	13.80%
2022-2023	35,159	38,145	8.49%
2023-2024	34,975	38,145	9.03%
2024-2025	31,678	34,145	7.79%
2025-2026	31,892	34,436	7.98%

The Department concluded that the Company likely has sufficient capacity to ensure firm reliability on a peak day and noted that the requested reserve margin appears acceptable and within the historical range in which the Company has operated since the 2006–2007 heating season.[28]

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[25] Attachment DOC-3 includes Great Plains' responses to IRs 7-15.

[26] Attachment DOC-4 includes Great Plains' response to IR 16.

[27] Department Comments, October 2, 2025, Table 4 at 10.

[28] *Id.*, Exhibit 2.

The Department further noted that, as shown in Table 7, VGT's supply/demand conditions and year-round firm capacity rates have enabled the Company to generate more revenue from releasing excess capacity during the five-month heating season than the cost of holding that capacity year-round under Viking's tariffed rates. The net revenue from these capacity release transactions, calculated as capacity release income minus the year-round tariffed cost, is credited to ratepayers.[29] During the 2024–2025 heating season, the Company released 8,000 Dth/day of VGT capacity and credited ratepayers $745,345.

Table 7 – Great Plains Capacity Releases during the Winter Season Months Revenue, Costs and Net Benefit to Ratepayers by year, 2022 – 2025[30]

Year	Amount of Capacity Released (Dth) (a)	VGT tariffed rate ($/Dth) (b)	Cost of VGT Capacity Released ($/yr)[31] (c)	Avg Winter Season Capacity Release Rate ($/Dth) (d)	Total Winter Season Capacity Release Revenue (Nov-Mar)[32] (e)	Net Benefit to Ratepayers ($/yr)[33] (f)
2022	4,291	$3.806	$195,979	$13.594	$291,657	$95,679
2023	4,291	$3.806	$195,979	$16.476	$353,484	$157,505
2024	8,000	$5.620	$559,145	$18.633	$745,300[34]	$186,155
3 Yr Avg	5,527	$4.600	$305,137	$17.098	$472,528	$167,390
2025	8,000	$5.620	$539,520	$17.098	$683,914	$144,394

For the 2025–2026 heating season, VGT's higher firm capacity rate ($5.62 versus $3.806) reduces the forecasted credit to an amount below the three-year average ($144,394 versus $167,390). Concurrently, the Department did not recommend any change to Great Plains' proposal to release 8,000 Dth of capacity.

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[29] Income = Revenue – Expenses. In this instance, the revenue term in the equation is equal to the revenue generated from the winter season capacity release sales minus the expense or cost resulting from maintaining this capacity under VGT's tariffed rates for the entire year.

[30] All information presented in Table 6 was derived from Great Plains' annual demand entitlement filings or updates, with the exception for the calculation of cost of VGT capacity released, total winter season capacity release revenue (Nov-May), and calculation of the net benefit to ratepayers. The Department's estimated capacity release rate for the 2025-2026 heating season is the average of the previous of three years. Calculation: ($472,528/5,527 Dth)/5 months = $17.098 Dth/month.

[31] (a x b x 12) = c

[32] (a x d x 5) = e

[33] (e – c) = f

[34] Staff notes that the 2024 Capacity Release Revenue is $745,345, as previously stated above. Staff determined this to be of no impact to the Department's underlying analysis.

6. PGA Cost Recovery Proposal

The Department noted that Great Plains' demand entitlement proposal would result in the following estimated annual rate impacts for customers:[35]

- An annual bill increase of $60.94 or approximately 8.7%, for the average residential customer using 81.2 Dth annually; and
- An annual bill increase of $327.22 or approximately 9.3%, for the average firm general service customer consuming 436 Dth annually.[36]

The Department observed that firm pipeline capacity is constrained due to full subscription in the Upper Midwest, as well as recent filings by existing pipelines, such as NNG, to increase their currently tariffed rates.

The Department noted that NNG filed a Section 4 rate case with FERC in Docket RP25-989, proposing a $1.1 billion increase to recover costs associated with asset modernization investments that have not yet been reflected in rates. NNG's proposal includes an 85% increase in Northern's Market Rates, and a 48% increase in storage reservation and capacity rates. The proposed rates will take effect on January 1, 2026, subject to refund.[37]

In response to questions regarding the potential residential bill impact if FERC were to approve an overall 35% increase for NNG, Great Plains estimated an annual increase of $72 for a residential customer consuming 90 Dth. The Department relied on the 35 percent assumption, as FERC approved a comparable increase in Northern's most recent rate case.[38]

The Department requested that Great Plains address any information received from NNG concerning the proposed rate changes and provide, in its Reply Comments, an estimate of the impact on the average customer by class.

7. Compliance with Previous Commission Orders

The Department determined that Great Plains complied with the Commission's previous order requirements.[39] The review considered matters including Great Plains' new VGT FT-A 10-year contract, an existing 5,000 Dth/day contract, and supply diversity.

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[35] Great Plains Initial Filing, July 1, 2025 at Exhibit C.

[36] Staff notes that annual consumption of 81.2 and 436 Dth would be extraordinarily low. Staff interpreted Great Plains filing to mean that, for *monthly* consumptions of 81.2 and 436 Dth, the *annual* impact would be $60.94 and $327.22, respectively. Staff does not consider this clarification to impact any of the Department's underlying analysis.

[37] See Attachment DOC-5.

[38] Attachment DOC-6 includes Great Plains' response to IR 18.

[39] See page 5 of BP for Docket No's as well as footnotes 11, 12, 13 and 15.

Additionally, the Department requested that Great Plains continue to provide the required supply diversity information in future demand entitlement filings. If there are no changes to pipeline capacity affecting supply diversity, Great Plains was asked to explicitly confirm this in its filing.

C. Great Plains – Reply Comments

Great Plains indicated of intervening in the NNG rate case, and that settlement discussions are ongoing and subject to confidentiality agreements. The Company reiterated its estimate that a 35% rate increase would result in an annual cost impact of $72 for a residential customer using 90 Dth.[40]

Additionally, Great Plains stated it would solicit bids for VGT capacity releases, with the results to be included in the supplemental demand entitlement filing on or before November 1, 2025.

D. Great Plains – Informational Update

Great Plains' Informational Update presented the Company's demand entitlement volumes and the associated costs to be charged to ratepayers, as shown in Table 8. The total demand charges reflect a reduction of nearly $500,000 compared to Great Plains' Initial Filing.[41]

[40] Attachment DOC-6 includes Great Plains' response to IR 18.

[41] $6,642,117 (Great Plains' Initial Filing) minus $6,145,785 (Great Plains' Informational Update) = $496,332.

Table 8 – Great Plains' Updated Demand Costs[42]

Interstate Pipelines	Dth/Day	Rates	Months	Demand Cost
Viking Firm				
FT-A - Zone 1-1 (Cat. 3)	8,000	$5.6200	12	$539,520
FT-A - Zone 1-1 (Cat. 3)	5,000	$5.6200	12	$337,200
FT-A - Seasonal (Cat. 3)	2,000	$5.6200	5	$56,200
FT-A - Zone 1-1 (Cat. 3)	5,000	$5.6200	12	$337,200
FT-A - Zone 1-1 (Cat. 3)	3,291	$5.6200	12	$221,945
FT-A - Capacity Release	(8,000)	$28.4119	5	$(1,136,476)
Northern Natural Firm				
TFX - Summer	13,000	$9.6760	7	$880,516
TFX - Winter	13,000	$25.7990	5	$1,676,935
TFX Seasonal (November-March)	2,000	$25.7990	5	$257,990
TF12 Base - Summer	5,498	$9.6760	7	$372,391
TF12 Base - Winter	5,498	$17.4170	5	$478,793
TF12 Variable - Summer	5,447	$9.6760	7	$368,936
TF12 Variable - Winter	5,447	$23.6090	5	$642,991
TFX - Winter	7,200	$25.7990	5	$928,764
TFX - Annual (Summer Rate)	3,000	$9.6760	7	$203,196
TFX - Annual (Winter Rate)	1,000	$25.7990	5	$128,995
FDD-1 Reservation	4,640	$3.2345	12	$180,097
Interruptible Demand Credit				$(329,408)
Total Demand Charges				$6,145,785

Great Plains received favorable offers for the proposed release of 8,000 Dth VGT capacity. The released FT-A capacity will be priced at an average of $28.4119 per Dth over a five-month period.

The Company also provided the final allocation of NNG TF Base and TF Variable entitlements. The TF12 Base allocation decreased by 205 Dth to 5,498 Dth/day while the TF12 Variable allocation increased by 205 Dth to 5,447 Dth/day.

Great Plains reported that its 2025-2026 heating season capacity reserve margin remained unchanged at 7.98% and noted the following demand rate impacts, as shown in Table 9.

42 Great Plains' Informational Update, October 31, 2025 at 2.

Table 9: Great Plains' Proposed Demand Cost Impacts – Supplemental Filing

Filing Date	Residential Customer (81.2 Dth)	Total Change Residential (%)	Firm General Customer (436.0 Dth)	Total Change Firm General (%)
November 1, 2025	$46.60	7.6[43]	$250.22	8.2[44]

E. Department of Commerce – Supplemental Comments

The Department reviewed Great Plains' Informational update, and, as shown in Table 10, updated its analysis of the Company's capacity releases and resulting net benefits to ratepayers for the 2022-2025 winter heating seasons.

Table 10 – Great Plains Capacity Releases during the Winter Season Months, Revenue, Costs and Net Benefit to Ratepayers by year – 2022 – 2025[45]

Year	Amount of Capacity Released (Dth) (a)	VGT tariffed rate ($/Dth) (b)	Cost of VGT Capacity Released ($/yr)[46] (c)	Avg Winter Season Capacity Release Rate ($/Dth) (d)	Total Winter Season Capacity Release Revenue (Nov-Mar)[47] (e)	Net Benefit to Ratepayers ($/yr)[48] (f)
2022	4,291	$3.806	$195,979	$13.594	$291,657	$95,679
2023	4,291	$3.806	$195,979	$16.476	$353,484	$157,505
2024	8,000	$5.620	$559,145	$18.633	$745,300[49]	$186,155
3 Yr Avg	5,527	$4.600	$305,137	$17.098	$472,528	$167,390
2025	8,000	$5.620	$539,520	$28.412	$1,136,476	$596,956

For 2025, the Department projected $1,136,476 in capacity release revenue and $596,956 in

43 Great Plains did not perform this calculation in the Supplemental Filing, at 3. In the Initial filing, at 5, the denominator was taken from Exhibit C - Average Annual Cost of Gas, Current Rates. Staff calculated in the same manner in the supplemental filing for consistency, as follows: $46.60 / $615.60 (average annual cost of gas) = 7.6%.

44 See previous footnote. $250.22 / $3,062.93 = 8.2%.

45 All the information in Table 9 was taken from Great Plains' annual demand entitlement filings or updates except for the calculation of cost of VGT capacity released, total winter season capacity release revenue (Nov-Mar), and calculation of the net benefit to ratepayers.

46 (a x b x 12) = c

47 (a x d x 5) = e

48 (e – c) = f

49 See Footnote 34 above.

net benefit to ratepayers from Great Plains' sale of the additional 8,000 Dth of contracted capacity for the 2025–2026 winter season.

Additionally, the Department summarized Great Plains' proposed gas demand costs, as presented in its July 1 Petition, October 1 PGA filing, November 2025 Update, and the January 2026 potential impacts of NNG's rate case, as shown in Table 11.

Table 11 – Great Plains Actual and Forecasted Demand Cost of Gas for November 2025 and January 2026 (Assuming 35% NNG residential rate increase)[50]

Date Filed	Cost per Dth.	Annual Usage	Annual Cost	Variance ($)	Variance (%)
1-Jul-25	$2.3638[51]	81.2	$191.94	NA	NA
1-Oct-25	$1.6133[52]	81.2	$131.00	$60.94	NA
1-Nov-25	$2.1872[53]	81.2	$177.60	$46.60	35.6%
1-Jan-26	$3.1638[54]	81.2	$256.90[55]	$79.30	44.7%

The Department noted that Great Plains' updated demand change represents an increase of $0.57390/Dth or 35.6%, in a residential customer's annual demand cost compared to rates effective October 1, 2025. However, the updated rates also reflect a 7.5% decrease[56] from those proposed in the July 1, 2025 initial filing, due to increased revenues from the sale of excess Viking capacity.

The Department concluded that Great Plains' November 1, 2025 proposed demand rate is reasonable and recommended approval, while making no recommendation regarding the potential NNG rate increase effective January 1, 2026.

Based on its review and analysis of the information in the record, the Department recommended that the Commission:

- Accept Great Plains' proposed level of demand entitlement;

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50 Department Supplemental Comments, November 17, 2025 at 4.

51 Great Plains' Initial Petition, July 1, 2025, Exhibit C at 1. Forecasted demand cost of gas for November 2, 2025.

52 Great Plains' Informational Update, November 1, 2025, Exhibit C at 1. Actual demand cost of gas for October 1, 2025.

53 *Id.* Forecasted demand cost of gas for November 1, 2025.

54 DOC-6 includes Great Plains' estimate of the residential customer bill increase resulting from a 35% increase in NNG's rates. The Department then prorated that increase to reflect an annual usage of 81.2 Dth.

55 Staff notes the calculation based on DOC-6 as follows: $72/90 Dth = $0.80/Dth. $0.80 * 81.2 Dth = $64.96, which represents the annual cost difference from Great Plains' July 1 filing.

56 Calculations: $191.94 - $177.60 = $14.24. ($14.24 / $191.94 = 7.5%).

- Accept Great Plains' proposed design day estimate for the 2025-2026 heating season;
- Accept Great Plains' proposed reserve margin;
- Approve Great Plains' cost-recovery proposal for recovering demand entitlement costs through the PGA effective November 1, 2025;
- Accept Great Plains' efforts to comply with additional reporting requirements included in Commission Orders regarding demand entitlement.

F. Great Plains – Supplemental Reply Comments

Great Plains agreed with the Department's recommendations and stated that it will continue to comply with any additional demand entitlement reporting requirements.

IV. STAFF COMMENTS

As shown in Table 4 of this briefing paper, Great Plains is proposing an increase in its overall design day compared to 2024–2025. The Department noted a 2.88% increase for Viking supply and a 3.07% overall increase in Great Plains' design day. However, Staff calculated the percent increase as 1.28% for Viking and 0.68% overall for Great Plains, based on use of the appropriate denominator.

With respect to total demand entitlement quantity, Staff notes that, based on Great Plains' supplemental filing in the 2024-2025 proceeding[57] and the Commission's Order approving the Company's demand entitlement for the prior year, the authorized quantity for the 2024-2025 period is 35,436 Dth/day.[58] Accordingly, the Company's proposed demand entitlement of 34,436 Dth/day for the 2025–2026 period represents a *decrease* of 1,000 Dth/day. The Commission may wish to confirm its understanding of the 2025-2026 demand entitlement quantity and reserve margin with the Company and the Department and, if necessary, require Great Plains to submit a compliance filing reflecting the correct information.

Great Plains' Initial Petition proposed an annual demand cost increase of $60.94 for a residential customer using 81.2 Dth. In its supplemental update, the proposed annual increase is $46.60, representing a $14.24 decrease from the Initial Petition.

Additionally, Staff notes that CenterPoint indicated in its current demand entitlement proceeding that, if a settlement is not reached in NNG's rate case, interim rates would take effect on January 1, 2026.[59]

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[57] Great Plains Additional Informational Update, November 27, 2024, Exhibit B at 1. Docket No. G-004/M-24-234.

[58] *In the Matter of Great Plains Natural Gas Co.'s Petition for Approval of Changes in Contract Demand Entitlements for the 2024-2025 Winter Heating Season.* Docket No. G-004/M-24-234. ORDER, at Ordering Paragraph 1 (May 19, 2025).

[59] *In the Matter of CenterPoint Energy Minnesota Gas' Request for Change in Demand Units.* CenterPoint Reply Comments, September 26, 2025 at 3. Docket No. G-008/M-25-72.

After reviewing the analysis, Staff finds that Great Plains has provided appropriate information to support its proposed demand entitlement levels and cost changes and agrees with the Department's recommendations for approval.

V. DECISION OPTIONS

1. Approve Great Plains' proposed level of demand entitlements for the 2025-2026 winter heating season as indicated by Great Plains in its Supplemental Filing. [Great Plains, Department]

2. Accept Great Plains' proposed design day estimate for the 2025-2026 heating season. [Great Plains, Department]

3. Accept Great Plains' proposed reserve margin for the 2025-2026 heating season. [Great Plains, Department]

4. Effective November 1, 2025, allow Great Plains to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA). [Great Plains, Department]

5. Accept Great Plains' efforts to comply with additional reporting requirements included in Commission Orders regarding demand entitlement. [Great Plains, Department]