MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	December 8, 2022	Agenda Item 4**
Company	All Regulated Gas Utilities	
Docket Nos.	**G-999/CI-21-135**	
	In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers	
	G-008/M-21-138	
	In the Matter of the Petition of CenterPoint Energy for Approval of a Recovery Process for Cost Impacts Due to February Extreme Gas Market Conditions.	
	G-004/M-21-235	
	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	
	G-002/CI-21-610	
	In the Matter of Petition of Northern States Power Company d/b/a Xcel Energy to Recover February 2021 Natural Gas Costs	
	G-011/CI-21-611	

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Recovery Process for Cost Impacts Due to February Extreme Gas Market Conditions

Issue	Should the Commission adopt any of the regulated gas utilities proposed gas practices?

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✓ Relevant Documents	Date
Docket No. G-999/CI-21-135	
Minnesota Public Utilities Commission – Order Disallowing Recovery of Certain Natural Gas Costs and Requiring Further Action	October 19, 2022
CenterPoint Energy, Great Plains Natural Gas Company, Xcel Energy, and Minnesota Energy Resources Corporation – Joint Comments	September 15, 2022
CenterPoint Energy – Comments	September 15, 2022
Great Plains Natural Gas Company – Comments	September 15, 2022
Xcel Energy – Comments	September 15, 2022
Minnesota Energy Resources Corporation – Comments	September 15, 2022
Department of Commerce – Comments	October 14, 2022
Office of the Attorney General – Comments	October 14, 2022
Citizens Utility Board of Minnesota – Comments	October 14, 2022
Center for Energy and the Environment – Comments	October 14, 2022
Docket No. G-008/M-21-138	
Minnesota Public Utilities Commission – Order Disallowing Recovery of Certain Natural Gas Costs and Requiring Further Action	October 19, 2022
Docket No. G-004/M-21-235	
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Docket No. G-002/CI-21-610	
Minnesota Public Utilities Commission – Order Disallowing Recovery of Certain Natural Gas Costs and Requiring Further Action	October 19, 2022

✓ **Relevant Documents**	**Date**
Docket No. G-011/CI-21-611	
Minnesota Public Utilities Commission – Order Adopting Settlement Agreement	October 19, 2022

I. Statement of the Issue

Should the Commission adopt any of the regulated gas utilities proposed gas practices?

II. Background

As listed above, on October 19, 2022 Order, the Minnesota Public Utilities Commission (Commission) issued four separate Orders pertaining to the four regulated natural gas utilities'[1] costs and actions related to the February 2021 cold weather (February Event). These orders instructed each utility to:

- Review their respective gas contracting, purchasing, hedging, storage, interruptible, customer communications, and other relevant practices and, by September 15, 2022, file a plan on how it will improve or modify its practices to protect ratepayers from extraordinary natural gas price spikes in the future.
- Identify the general timeframe it will take to implement the modifications, and, if the proposed change requires modification of tariff, proposed tariff language.
- Identify how integrated resource planning could facilitate ratepayer protection from price spikes and any statutory or rule changes that could be implemented to protect ratepayers from future price spikes.
- Provide an analysis of whether it considered filing a plan pursuant to Minn. Stat. § 216B. 167 (Performance-Based Gas Purchasing Plan) and its analysis of why they are not using the statute if it has chosen not to proceed with such a plan.
- Indicate how any proposed tariff, rule, or statutory changes are consistent with the Natural Gas Innovation Act (Minn. Stat. §§ 216B.2427 and 216B.2428).

On September 15, 2022, CenterPoint Energy (CenterPoint), Great Plains Natural Gas Company (Great Plains), Xcel Energy (Xcel), and Minnesota Energy Resources Corporation (MERC), collectively referred below as the Gas Utilities, jointly and individually filed answers and recommendations that addressed the Commission's Orders.

On October 14, 2022, the Department of Commerce, Division of Energy Resources (Department, DOC), the Office of the Attorney General (OAG), the Citizens Utility Board of Minnesota (CUB) and the Center for Energy and the Environment (CEE) filed comments responding to the utilities' September 15 filings.

[1] CenterPoint Energy (CenterPoint), Xcel Energy (Xcel), Minnesota Energy Resources Corp. (MERC) and Great Plains Natural Gas Co. (Great Plains).

III. Natural Gas Utilities – Gas Practices Filings

A. Joint Filing

The Gas Utilities jointly proposed several prospective initiatives regarding their gas practices.

1. Economic Trigger

To allow for economic curtailment of interruptible system sales customers, the Gas Utilities proposed implementation of an economic trigger ("two-prong trigger") that applies to specific pricing hub(s):

> The prior gas day (or multiple days in the case of weekends and holidays) settled Gas Daily index price at [any of the identified pricing hub(s) where the utility would purchase daily supplies]:
>
> 1. is greater than or equal to $50.00 per Dth; **and**
> 2. is greater than or equal to five times the weighted average cost of gas forecast for the month at issue in the utility's filed PGA for that month.

Due to the nature of the gas day and the fact that daily index prices are not published until after purchases have been made and trading has closed, the Gas Utilities proposed to initiate economic curtailments and other actions in response to extraordinary price spikes beginning the second gas day of a pricing event when the above trigger conditions occur.

2. Statute and Rule Changes

The Gas Utilities do not believe that changes to the AAA or PGA rules are needed at this time, nor have the Gas Utilities identified any specific rule changes at this time that would help to protect customers from daily gas price spikes. To the extent the Commission disagrees, the Gas Utilities requested that the Commission engage in a robust process as it did the last time rule changes were considered, especially considering all of the other policy discussions about natural gas regulation (e.g., the Natural Gas Innovation Act; the Future of Gas docket) currently pending.

3. Performance-Based Gas Purchasing Statute

The Gas Utilities noted that, in 1995, the Legislature passed Statute § 216B.167, authorizing the Commission to approve "performance-based gas purchasing" plans proposed by Minnesota's gas utilities according to the criteria set out in that section. The Gas Utilities stated that, with respect to setting benchmarks for natural gas commodity costs, one significant challenge with gas purchasing incentive mechanisms is the fact that the majority of natural gas commodity purchases are either through a) short- to medium-term contracts predominantly tied to some external market index, or b) from spot gas purchases where the price is set in the daily market. In both situations, the prices are established in the competitive gas supply marketplace. Additionally, there are a number of complex factors which affect the market price of gas supplies and are largely outside the control of the Gas Utilities. As a result of these circumstances, some jurisdictions which had implemented pilot gas cost mechanisms ultimately returned to pass-through recovery mechanisms. Those jurisdictions found that the incentive structure did not achieve lower gas prices as compared to a pass-through recovery mechanism and that pass-through mechanisms provided greater flexibility for utilities to react to market conditions and opportunities to meet customer needs.

B. CenterPoint Energy

CenterPoint stated that the pursuit of options that could mitigate against high or extraordinary prices should not jeopardize the safety or reliability of the gas system. In evaluating potential changes, it is also important to ensure the costs incurred to implement a modification are justified in light of the potential benefits or avoided exposure to potential risks. Compounding the difficulty of mitigating against volatility, the current market outlook for natural gas indicates prices are expected to remain high this winter season which has also increased the cost of many of the tools that can be used to mitigate volatility.

1. Natural Gas Market Outlook

Commodity prices for gas supplies in Minnesota are set in a nationwide, competitive marketplace and there are a number of factors that impact the market price of gas supplies, all of which are outside of CenterPoint's control. In recent years, the February Event notwithstanding, natural gas has traded at low prices, market volatility has been low, and the spread between summer and winter prices has been narrow. For the upcoming 2022-2023 winter, however, there are a number of factors that are expected to put upward pressure on market prices for natural gas, including:

- increased demand as the economy recovers from the pandemic;
- increased market volatility due to Russia's invasion of Ukraine and associated increases in liquefied natural gas (LNG) exports;
- low storage inventory levels due to high withdrawals in 2021-2022; and
- increased natural gas demand to support electric power generation.

The February Event occurred against a backdrop of average monthly prices of about $3.50/Dth. However, upcoming prices this winter are expected to range from $7.00 to $10.70/Dth for monthly baseload supply contracts (first-of-month (FOM) contracts). Gas purchased at daily prices could be far higher.

2. Modifications Implemented Since February Event

a. Procurement Practices

In response to the February Event, CenterPoint introduced a number of modifications and enhancements to its Gas Procurement Plan to further protect customers from the risk of extraordinary price volatility. Beginning with the most recent heating season 2021- 2022, CenterPoint implemented the following changes:

- **Increased baseload FOM index purchases**: By increasing baseload purchases, CenterPoint reduced the percentage of supply to be met through daily gas purchases.

Historically, CenterPoint based the volume of monthly baseload on the forecasted warmest daily load for the month. After the February Event, CenterPoint increased baseload to stabilize a portion of its "normal" weather scenario rather than the warmest weather scenario. The change accounted for a 5.9% increase in the total winter plan met by FOM index purchases.

- **Increased hedged baseload**: In 2021-2022, CenterPoint increased the volume of hedged baseload purchases to the maximum authorized under the Commission's 2020 Hedging Order to align with customer growth and to achieve the targeted stabilization rate.[2] By increasing baseload hedges, more of the portfolio is protected and CenterPoint has less reliance on daily gas purchases in the spot market. CenterPoint increased baseload hedges were 13% higher than the ones for the 2020-2021 heating season and accounting for a 2.1% increase in the total winter plan met by hedged baseload.

For the upcoming heating season 2022-2023, CenterPoint is implementing the following modifications and enhancements:

- **Continued increase in FOM index purchases**: CenterPoint is continuing to plan for a greater percentage of FOM baseload based on the "normal" weather scenario instead of the warmest weather scenario.
- **Continued increase in baseload hedges**: CenterPoint is continuing to plan for greater hedged baseload purchases to the maximum authorized under the Commission's 2020 Hedging Order.
- **Increased supply diversity**: By blending the FOM and gas daily index purchases between CenterPoint's primary receipt points on Northern Natural Gas (NNG) and Viking, CenterPoint has more optionality to purchase from different price indices and can maximize supply deliveries from the lower-priced index.
- **Hedging optimization**: CenterPoint is executing its hedging plan according to expert advice from Aegis Hedging, including heavily weighting the portfolio on fixed price products.
- **Increasing diversity of hedges**: CenterPoint has increased diversity of hedged supplies by adding hedged baseload at Demarc in addition to volumes delivered at Ventura.
- **Executing longer-term hedges**: To secure longer-term price protections and lower prices than the upcoming winter prices, CenterPoint has entered into some longer-term, two-year hedges effective April 2023.

[2] Commission January 13, 2020 Order, Docket No. G-008/M-19-699.

b. Customer Communications

CenterPoint has undertaken and is planning to continue a number of customer communication campaigns, including:

- **Heating season cold weather communications campaign**: CenterPoint has engaged in communications efforts to educate customers about the cause of higher natural gas bills and to raise awareness of available tools and programs such as My Energy Analyzer, levelized billing, energy efficiency tips, Conservation Improvement Programs (CIP), Gas Affordability Program (GAP), and Low-Income Home Energy Assistance (LIHEAP).
- **CIP campaign**: CenterPoint communicates with customers year-round about how to conserve energy and encourages participation in residential and business CIP offerings to help customers save energy and money.
- **Business customer engagement**: In addition to information about energy conservation, CenterPoint provides its commercial and industrial customers with monthly gas price updates to assist with budgeting, along with quarterly newsletters providing information on energy efficiency, natural gas costs, and natural gas technologies.

CenterPoint noted that it has generally not issued public requests for customers to voluntarily, immediately, and temporarily reduce their natural gas use as part of its normal gas supply planning. Instead, it has preserved such conservation requests for emergency situations. At this time, CenterPoint does not propose to take additional steps with respect to calls for voluntary customer conservation.

c. Short-Term Modifications

In response to the Commission's decisions in this matter, CenterPoint developed three possible modifications that, upon Commission approval, could be implemented during the upcoming heating season. Because some of them could jeopardize system reliability, CenterPoint requested a Commission directive to implement them. These modifications are:

- **Price-Based Withdrawals from Waterville Storage**: Beginning the day after the price-based trigger occurs, CenterPoint will plan to withdraw up to an additional 5,000 Dth/day above its current 50,000 Dth/day planned operational maximum withdrawal. However, real-time conditions may prevent CenterPoint from being able to actually achieve withdrawals above 50,000 Dth. Also, the NNG pipeline may not allow delivery of the additional 5,000 Dth to CenterPoint's distribution system.
- **Price-Based Dispatch of LNG Peak Shaving**: After January 20, CenterPoint will plan to dispatch up to 25 percent (18,000 Dth/day) of the total daily LNG capacity, beginning the day after the price-based trigger occurs. However, committing to dispatch this peaking resource on a planned basis reduces the volumes that are available during the gas day to address short-term needs and could result in the loss of service. Additionally, in the winter, it is not feasible to refill used LNG capacity which could result in LNG being unavailable to maintain reliability later in the heating season.

- **Price-Based Curtailment of System Sales Interruptible Customers**:[3] CenterPoint will curtail interruptible system sales customers beginning the day after price-based trigger occurs. CenterPoint warned that, because it does not have experience with price-based curtailments, it is difficult to accurately predict the expected level of customer compliance which could jeopardize service reliability to firm service customers and could require CenterPoint to procure emergency spot supplies or dispatch peak shaving resources.

CenterPoint noted that these modifications also come with the following risks: a) elimination of a tool to maintain reliability and b) timing of when price spike is known and duration of pricing event. Additionally, price-based curtailment has the following risks:

- **Dependency on curtailable volumes**: If volumes estimates are too low, it will not gain the full value of the economic curtailment. If they are too high, resulting in insufficient gas supply, CenterPoint risks the ability to maintain reliable service and also risks incurring pipeline imbalance penalties.
- **Dependency on compliance with price curtailment**: If for any reason customers continue to use gas during the pricing event, CenterPoint risks the ability to maintain reliable service and also risks incurring pipeline imbalance penalties.
- **Ensuring customers are not charged for price event**: Under the proposed tariff modifications, customers who are called to, and do, curtail for economic reasons will not be subject to surcharges imposed to recover cost of daily spot gas or swing gas purchased during the period the economic curtailment is in effect. While the cost impact of the price spike may be mitigated as a result of implementing economic curtailment of interruptible system sales customers, the costs that are incurred will be recovered from fewer customers.

d. Longer-Term Modifications

CenterPoint provided these longer-term alternatives and proposed to continue to evaluate these modifications, which would not be implemented until 2023-2024 or later.

i. Additional NNG Entitlement for Delivery from Waterville

CenterPoint is evaluating increasing its firm pipeline entitlements on NNG from 50,000 Dth/day to 55,000 Dth/day. If CenterPoint participates in NNG's 2023 open season, it anticipates such additional capacity could likely be available beginning in 2025

ii. Capacity Expansion at Waterville

A longer-term option to potentially increase storage capability and provide further price protection for customers may be to expand Waterville's working gas capacity and withdrawal capability. Based on initial assessment, there may be capability to expand the Waterville

[3] Proposed tariff revisions are reflected in Attachment E.

storage facility from the current working gas storage capacity of 2,000,000 Dth to up to approximately 2,600,000 Dth and increase the peak withdrawal rate when the storage field is near full from 50,000 Dth/day to up to approximately 65,000 Dth/day. Such upgrades would require extensive planning and engineering, modifications to various permits and additional capital investments. If the project was determined to be feasible and cost effective, and necessary permits and approvals could be obtained, such expansion could be in-service in approximately 2027, with initial scoping taking approximately one year to complete, and project planning, permitting, and construction estimated to take an additional four years.

iii. Additional Pipeline and Virtual Storage

Depending on available pricing and other contract terms, adding more virtual storage may be an attractive short-term option. Looking longer term, CenterPoint is continuing to evaluate options to contract for additional pipeline storage along with pipeline capacity that would be required to allow for the delivery of such stored gas to CenterPoint's system. CenterPoint will continue to evaluate options to increase pipeline contract storage, recognizing that any such increase will likely require a longer-term expansion of storage and pipeline facilities at significant cost.

iv. Peak Shaving

CenterPoint has evaluated options to modify its peak shaving facilities and use of those facilities to respond to extraordinary price spikes and is studying the feasibility of upgrading the LNG system to increase output beginning in 2025. Currently, the LNG facility is rated at a vaporization output of 72,000 Dth/day and preliminary engineering analysis shows that could be increased to 90,000 Dth/day with the replacement of the LNG vaporizers and supporting equipment. CenterPoint is also evaluating whether to modify the LNG liquefaction system to allow for refilling of LNG storage during the winter.

v. Interruptible Curtailments

As mentioned above, CenterPoint has proposed interim tariff modifications that would allow price-based curtailment if the two-prong trigger occurs. Longer term, CenterPoint proposed to evaluate potential modifications to its interruptible tariffs or the creation of a new interruptible service offering that could be implemented on a permanent basis to allow curtailments for economic purposes. Creating understandable and manageable criteria for price-based curtailments and corresponding criteria for returning interrupted customers to service are complex undertakings that could fundamentally change the nature and value of interruptible sales service.

vi. Gas Supply Contracting

CenterPoint attempted to negotiate more favorable terms to its gas supply contracts; however, they did not result in any major contractual term modifications for the upcoming winter season.

To mitigate the risk of future daily price spikes, CenterPoint also investigated whether it could incorporate non-ratable daily call options or call options priced at FOM index prices rather than gas daily index pricing into its gas procurement plan. In response to a Request for Proposal (RFP) seeking bids for these options, CenterPoint received only one bid for each; however, the price mitigation they offered did not justify the significant premiums.

In November 2021, the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Council (NERC) issued a report examining the impact the February Event.[4] Key Recommendation 7 (KR7), one of 28 recommendations, was for FERC to establish a forum to identify concrete actions to improve the reliability of the natural gas infrastructure system. In response to KR7, the NAESB Gas-Electric Harmonization Forum (NAESB Forum) held a kick-off meeting on August 30, 2022. The NAESB Forum intends to address thirteen topics identified in the November Report that fall into three categories:

- Measures to improve gas-electric information sharing for improved system performance during extreme cold weather emergencies.
- Measures to improve reliability of natural gas facilities during cold weather.
- Measures to improve the ability of generators to obtain fuel during extreme cold weather events when natural gas heating load and natural gas-fired generators are both in high demand for natural gas, at the same time that natural gas production may have decreased.[5]

The NAESB Forum will review identified challenges with the goal of developing:

- Concrete actions to increase reliability of natural gas infrastructure system necessary to support the Bulk Electric System.
- Plans for implementing actions.
- Deadlines for implementing actions.
- Identification of the entities responsible for implementing actions.[6]

CenterPoint stated that it is participating in the NAESB Forum and looks forward to the important discussion and resulting actions that can be taken nationwide to increase the reliability of natural gas infrastructure and the coordination between the natural gas and electric markets.

vii. Gas Supply Diversity and Purchasing

To potentially reduce risk of future gas price spikes that are concentrated at a particular pricing hub, CenterPoint is examining whether there are ways to further diversify its pricing hubs (NNG-Ventura, NNG-Demarc and Emerson). Over the long term, CenterPoint is examining

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[4]https://www.naesb.org/pdf4/ferc_nerc_regional_entity_staff_report_Feb2021_cold_weather_outages_111 621.pdf.

[5] https://www.naesb.org/pdf4/geh083022a1.pdf.

[6] *Id*. at 9.

whether it could use daily gas price data to forecast price spike risk when circumstances may give rise to another market price spike event

In the shorter term, CenterPoint is working with gas marketers to contract for delivery of gas supplies to NNG that would be priced a pricing hub other than Ventura. This type of delivered supply contract would introduce additional diversity to CenterPoint's portfolio. This type of contract modification could provide a quicker way to gain pricing hub diversification while CenterPoint evaluates the feasibility of obtaining pipeline capacity that would be needed to access gas supplies from the other pricing hubs. In the long-term, CenterPoint is also exploring adding additional transportation capacity on Viking to be able to make additional daily gas purchases from the Emerson pricing hub.

viii. Hedging

As mentioned above, CenterPoint has made a number of changes to its hedging portfolio since the February Event and plans to seek a variance of the Commission's 2020 Hedging Order[7] to increase the 26 Bcf hedging limit. Since CenterPoint has already executed its physical hedges for the upcoming 2022-2023 winter season, it plans to request the variance later this year or in early 2023, seeking Commission approval by mid-2023 to allow for implementation of changes in the 2023-2024 winter season.

ix. Demand Response Programs

CenterPoint noted that implementation of a natural gas demand response offering would require further analysis, stakeholder input, and Commission review and approval. To that end, it would be necessary for CenterPoint to evaluate: (1) how to replace or upgrade its existing metering infrastructure and meter reading protocols to provide more detailed real-time customer energy usage information (i.e., monthly usage data is not sufficient for a demand response program); (2) what level of participation CenterPoint could expect in a demand response program; and (3) how much energy usage reduction CenterPoint could count on. To implement such offerings, it would be necessary to determine the pricing of the offering and the price, frequency, and duration, of when CenterPoint could call upon demand response customers to suspend their natural gas usage.

CenterPoint Energy proposed to further explore the feasibility and benefits of natural gas demand response programs or other programs that would allow natural gas customers to respond to real-time pricing and proposed to evaluate opportunities for load research, such as through a demand response pilot, to collect additional information on the potential impacts of load control.

x. Investing in Local Supply, Energy Efficiency, and Carbon-Free Resources

[7] Commission's January 13, 2020 Order, Docket No. G-008/M-19-699.

CenterPoint is also exploring new technologies that can be implemented to lower overall customer demand and meet customer demand with local, in-state gas supply sources that are not subject to the natural gas price indices that spiked during the February Event. Increasing investment in energy efficiency and local supply resources such as renewable natural gas and hydrogen produced with carbon-free resources can help to insulate customers from price spikes in the gas market and also reduce greenhouse gas (GHG) emissions. CenterPoint plans to submit its first Innovation Plan under the NGIA in the first half of 2023 and is currently exploring pilots for energy efficiency and low and no carbon resources that will displace the need for geologic natural gas, avoiding GHG emissions and volatility in the gas market. As part of the development of its Innovation Plan, CenterPoint is evaluating whether pilots could be implemented to mitigate daily spot gas purchases. CenterPoint is also working with its partners to implement programming under the Minnesota Efficient Technology Accelerator (META) statute.

3. Natural Gas Integrated Resource Planning (IRP)

CenterPoint stated that its annual Gas Procurement Plan operates similarly to an IRP in that it shows CenterPoint's estimated load forecast, and the capacity and supply resources that will be used to meet that need for the upcoming heating season. Currently, very few jurisdictions use integrated resource planning for natural gas utilities. Rather, most jurisdictions use the types of proceedings used in Minnesota to regulate natural gas utility operations and investments. Capacity in the natural gas market is managed by the pipelines and commodity trading happens on separate exchanges or are bilaterally based on published indices or negotiated prices. As a result, there is not the same comprehensive overview and control of the market for both the commodity and the movement or storage of that commodity that exists in organized electric markets.

While a natural gas IRP process may provide insight for additional review of natural gas infrastructure, capacity, and supply planning, CenterPoint does not believe that an IRP would help to mitigate against extraordinary pricing events especially in the near term.

Since an IRP would not offer any new solutions that would lower gas daily prices or allow the utilities to reduce their daily spot market purchases, CenterPoint believes the Commission could consider integrated resource planning as part of its evaluation in Docket G-999/CI-21-565.[8]

The Commission could consider a process to review and approve CenterPoint's annual Gas Procurement Plan filing, which includes detailed information related to demand forecasting; the availability and use of storage contracts, including dispatching modeling and considerations; interruptible customer class curtailments; peak shaving facilities; incorporation of conservation impacts; the relationship between storage, curtailments, and peak shaving decisions; a discussion of geographic diversification of CenterPoint 's natural gas purchases; details regarding hedging including hedging analysis, alternative scenarios, and approach; as well as

[8] In the Matter of a Commission Evaluation of Changes to Natural Gas Utility Regulatory and Policy Structures to Meet State Greenhouse Gas Reduction Goals.

other topics. Such a change would require the Commission to establish new filing timelines and review processes that would allow parties to understand and approve CenterPoint's procurement and implementation strategy before heating seasons begin.

4. Statutory and Rule Changes

Other than the sales tax exemption mentioned above, the Gas Utilities have carefully reviewed applicable rules and statutes, including the Commission's PGA rules, and continue to believe they are reasonable.

5. Performance Based Gas Purchasing Plans Under Minn. Stat. 216B.167

As discussed in the Gas Utilities' Joint Filing, commodity prices for gas supplies used in Minnesota are set in a nationwide, competitive marketplace and there are a number of factors that impact the market price of gas supplies, all of which are outside the control of the Gas Utilities. As a result, CenterPoint has continued to utilize the PGA pass-through recovery provided for under the Commission's PGA rules. That mechanism provides greater flexibility for CenterPoint to react to market conditions and opportunities to meet customer needs, while also ensuring CenterPoint procures reasonably priced natural gas supplies in light of market conditions and customer needs.

C. Xcel Energy

1. Gas Contracting

Effective November 1, 2022, Xcel acquired an incremental 22,000 Dth/day of backhaul firm transportation entitlement on Viking which provides Xcel with additional access to gas supplies from the Chicago gas markets. Xcel historically has used delivered supply from a producer or marketer, typically sourced from the Emerson Hub to fill a portion of its design day needs. This additional capacity increases Xcel's geographic supply diversity

Xcel also acquired 30,000 Dth/day of firm transportation entitlement on Viking for next year (i.e., the 2023-2024 hearing season). This entitlement requires additional construction by Viking; therefore, it will be unavailable until December 1, 2023. This capacity will transport gas supplies on a firm basis from the Emerson Hub to various locations in Minnesota and North Dakota. The additional firm pipeline capacity will improve Xcel's ability to reliably access gas quantities from the Emerson Hub.

2. Purchasing

a. Xcel's Purchasing Practices

For the 2021-2022 heating season, Xcel purchased 12% more baseload supply from December 2021 through February 2022. While baseload purchases continue to be based on numerous factors, Xcel currently plans to evaluate the appropriateness of purchasing incremental baseload amounts for each month. On forecasting, at the time of Winter Storm Uri, Xcel used a blend of two third-party weather forecasts as inputs to the gas model; however, it now incorporates its own internal weather forecast. At this time, Xcel anticipates buying approximately the same level of baseload over the upcoming winter but will make any appropriate adjustments to those anticipated baseload quantities on a monthly basis.

Xcel noted that buying more baseload gas than necessary can lead to operational concerns and issues that, over the long-term, can outweigh any potential benefit of buying additional baseload gas. Purchasers of baseload gas must accept delivery of the daily contract quantity every day, even if baseload purchases exceed actual load. Therefore, any gas not used by customers must either be placed in storage or become subject to substantial pipeline penalties. Storage contracts and tariff restrictions limit the ability to rely on storage injections and, during winter months, storage inventories must be reduced. Further, substantial pipeline penalties provide a strong incentive for purchasers to stay "in balance" with their pipelines and not have excess baseload supplies. Thus, if Xcel purchases too much gas for its low demand days, it has limited options available which creates the potential of significant cost to customers.

b. Industry Practices – the NAESB Standard Contract

Xcel stated that it purchases gas supply using the standard NAESB contract (which was accepted by FERC and codified in FERC Regulations). That standard contract contains a very flexible force majeure provision that excuses seller performance during freezing weather conditions which many sellers used during the February Event. Xcel is trying to make policy change on the standard NAESB contract itself and, on July 11, 2022, its Senior Director of Federal Regulatory Affairs presented to the NARUC Committee on Gas on the force majeure provisions in the NAESB contract and recommended solutions like asking NAESB to convene a proceeding to reevaluate its force majeure language or at least provide more clarification around certain phrases within the force majeure contract provision. To date, NARUC has not taken action on this issue. Contemporaneously, Southwest Power Pool, in which buyers and suppliers of natural gas were also dramatically impacted by Winter Storm Uri, has also been developing suggested revisions to the NAESB force majeure provision and is working with other trade groups like Edison Electric Institute to build a consensus approach.

Xcel also discussed the NAESB's August 30, 2022 meeting mentioned above and stated that it will continue participating in that forum.

c. Hedging

Xcel annually reviews its hedging program but the current regulatory review process contemplates infrequent or after-the-fact reviews. As discussed below, Xcel believes it might be in the public interest to develop a different or additional type of regulatory review and welcomes Commission and stakeholder feedback on this issue.

Xcel's financial hedging program is currently designed to insure against sharp upward price movements in the monthly market for baseload gas. Because the program is focused on monthly prices increasing over future month's forecasted prices, Xcel does not expect it to insure against daily price spikes. Although it continually surveys the financial hedging market, Xcel has not identified counterparties that are willing to offer daily financial products at any significant quantity.

Xcel noted that its currently approved hedging plan has worked well during periods of stable gas prices, this year's gas prices raise a policy choice about our hedging programs, and it would be beneficial to have a more regular and expeditious manner to get feedback from interested stakeholders. When the Commission approved Xcel's most recent hedging variance in early 2020, the approved budget (of hedging costs that can pass through the PGA) was sufficient to hedge the targeted 25% of the annual winter quantity requirements. As the price of gas has increased (the price of natural gas on September 1, 2022, was $9.16 per Dth), the approved dollar budget covers significantly less than 25% of current annual winter quantity requirements. Therefore, in preparation for this heating season, Xcel was faced with the choice to either: (1) adhere to the approved dollar budget and hedge a lower percentage of its annual winter quantity requirements; (2) exceed its budget and risk those costs being disallowed in a future AAA; (3) or seek an amendment to the hedging variance, which may not be completed quickly enough in order to incorporate the feedback into Xcel's hedging transactions that generally take place from April to October. Ultimately, Xcel decided to adhere to the approved dollar budget resulting in a lower percentage of its annual winter quantity requirements in part due to the conclusion that the financial hedge tools being offered are generally overpriced for the benefits received.

Based on this recent example, Xcel believes it would be beneficial to create an expedited regulatory process to obtain feedback from stakeholders and the Commission on policy issues like the one above. Xcel invited feedback from stakeholders on whether such an expedited process is feasible, or if not, their view of how it should address policy choices such as this in the future.

d. Storage

Xcel is interested in procuring additional storage; however, demand for storage outpaces its availability and the storage that is currently available is father away from Xcel's service territory meaning that there are additional transportation costs and constraints to get the natural gas from storage to its distribution system. In its annual Contract Demand Entitlements filing, Xcel will continue to keep stakeholders apprised of its efforts in obtaining additional cost-effective storage.

e. Peak-Shaving

Starting at the beginning of the 2023-2024 heating season, Xcel expects to use LNG stored in its Wescott facility in situations where the price of gas reaches extraordinary levels, like they did during the February Event, while maintaining sufficient inventory to meet Design Day and operational requirements. If the two-prong trigger is met, Xcel will operate Wescott up to its maximum deliverable capacity of 156,000 Dth/day.

Use of the facility for economic dispatch will depend on the LNG inventory levels at the time of the event. Xcel will, first and foremost, maintain inventory levels that support the system during a design day event or other operational needs. Because some work was done on the plant's equipment during the summer of 2022, liquefication for the upcoming heating season was limited. Therefore, Xcel does not expect to have sufficient additional inventory to economically dispatch Wescott during the 2022-2023 heating season. However, over time, Xcel plans to build and maintain inventory for price mitigation operations. Xcel explained that it has focused its economic dispatch on Wescott because of the smaller capacity and the time and price uncertainty of replacement fuel at Sibley and Maplewood propane facilities.

Xcel noted that interruptible customers do not pay for the peaking plants because they are a capacity resource. As Xcel nears its distribution system demand capacity, interruptible customers are called on to curtail so that the full capacity of the peaking plants and distribution system may be used to serve firm customers' peak needs. Interruptible customers are penalized for their consumption of natural gas and their use of the system in the event they do not comply. Because of this, Xcel believes it is important to use the same trigger for economic dispatch of the plants and economic curtailment of interruptible customers; otherwise, Xcel would need to reallocate costs to ensure different customer classes are fairly paying for the infrastructure they use.

f. Interruptible Customers

Xcel is requesting approval to change to its interruptible tariffs[9] to make clear it clear that it plans to economically curtail customers when the two-prong trigger occurs. The tariff change can be effective as soon as it is approved; however, to avoid possible customer confusion and frustration, Xcel requested that the tariff change become effective at the end of the 2022-2023 heating season (i.e., April 1, 2023).

Xcel noted that, in the last several years, it made a number of adjustments to its interruptible tariff language and the penalty structure for curtailment non-compliance; however, full compliance continues to be a challenge. Xcel added it feels that, under its tariff language, it has the authority to curtail for a variety of reasons, including economic purposes. Nevertheless, it believes it is reasonable to add a trigger for economic curtailment so that customers are well informed and to provide transparency.

g. Customer Communications

Pursuant to the Commission's August 30, 2021 Order in Docket No. G-999/CI-21-135, on November 1, 2021, and as shown below, Xcel filed a communication plan that included multiple means of customer outreach, including phone calls, text messages, emails, and social media. [10]

[9] Proposed tariff revisions are reflected in Attachment A.

[10] Staff notes that the other gas utilities also filed their communications plans on the same date.

PROPOSED COMMUNICATIONS TACTICS

Communications Channel	Customer Type
News release	All/general public
Webpage on xcelenergy.com with homepage banner	All/general public
Social media: Facebook and Twitter posts	All/general public
Automated phone call	Commercial and industrial natural gas customers
Email	All natural gas customers, for whom we have an email on file and permission to email*
Text messages	All natural gas customers, for whom we have contact info and permission to text**
Upfront recorded message on customer service line	All callers to call center
Messaging provided to external-facing employees	For sharing with large customers, communities, stakeholders

* Emails may be delivered over 24-hour period to manage inbound customer phone call volume
** Due to Telephone Consumer Protection Act (TCPA) laws, Xcel Energy may only utilize text messages for communications to customers who proactively opt in to receiving text messages from us. Currently, customers may only opt in to receive text messages specifically related to outage and/or payment information related to their account. At this time, we do not have the ability to offer additional options so customers could choose to receive text messages related to topics such as bill increases or conservation requests. However, we are working to include these options for all customers in the future.

To date, the communication plan has not been commented on by any stakeholder or approved by the Commission's Executive Secretary. While it was contemplated, Xcel does not believe specific Commission action is needed with regard to the plan. Xcel has been prepared since the November 1, 2021 filing to implement this communications plan should gas prices exceed the two-prong trigger.

h. Other Relevant Practices

Since Winter Storm Uri, Xcel has looked for different types of natural gas supply deals that can protect customers from extraordinary natural gas price spikes. Xcel found and purchased a peaking supply deal for last heating season that protected a small quantity of gas from Winter Storm Uri type price and cost of approximately $1.3 million. Xcel included that cost in its Contract Demand Entitlements filing for the 2021 heating season and noted that, in its February 14, 2022 Comments, the Department concluded "[t]he Department will not comment on each individual contract but has reviewed the filings and can confirm that Xcel's proposal is not unreasonable."[11]

[11] Docket No. G-002/M-21-589.

Xcel continues to search for similar opportunities; however, it has been unable to find one for the current heating season.

3. Integrated Resource Planning

Xcel believes that integrated natural gas resource planning should be discussed, but that the Commission and stakeholders should take the time in currently open policy dockets, such as the Future of Gas[12] and the NGIA dockets, to get the details right. Xcel highlighted that its Contract Demand Entitlements gives parties important and valuable information on its gas transportation and storage contracting efforts that could inform IRPs.

4. Statutory or Rule Changes

Xcel has not identified or proposed any statutory or rule changes.

5. Performance-Based Gas Purchasing Plan under Minn. Stat. § 216B.167

Throughout the years, Xcel has considered whether to propose a plan under Minn. Stat. § 216B.167, but has not done so because it had difficulty identifying benchmarks that would provide more protection to customers than the existing PGA rules. Based on its experience and evaluation of performance-based mechanisms in other states, it takes years and considerable stakeholder engagement to get mechanisms correct since they need to account for the uncertainty of forecasting costs over a longer term than is customary. If the Commission is interested in pursuing a performance-based purchasing mechanism further, Xcel is willing to participate in such discussions; however, such a mechanism would likely take a long time to develop well.

D. Great Plains Natural Gas Co.

Great Plains stated that, to ensure Great Plains' customers receive the most reliable and economical supply of natural gas to heat their homes and run their businesses, its Gas Supply personnel performs an extensive review and analyses of gas procurement and contracting practices before each heating season. With that in mind, Great Plains makes changes each year based on the lessons learned from prior heating seasons and predicted challenges for upcoming heating seasons. Gas Supply's annual proposal is presented to an internal oversight committee for review and approval.

For example, for the 2022-2023 heating season, Great Plains intends to leverage its transportation capacity, for both base and swing Supplies, on Viking Gas Transmission (VGT) to take advantage of the current Canadian to U.S. price differential and reducing its purchases on Northern Natural Gas (NNG). This pricing differential may or may not continue beyond the upcoming heating season, which is why Great Plains' annual evaluation occurs.

[12] Xcel noted that integrated resource planning is an identified topic of discussion in the Future of Gas docket.

1. Gas Supply Planning

Based on its experience during the February Event, Great Plains undertook a review of its gas contracting and purchasing practices, including storage and highlighted improvements and modifications that are intended to mitigate customers' exposure to extraordinary natural gas price spikes in the future.

Great Plains increased its peak winter-month Base Supply during the 2021-2022 Heating Season (November through March) and plans to purchase Base Supply at a rate of 80% of normalized core demand during the 2022-2023 Heating Season. Prior to the February Event, Great Plains targeted Base Supply of approximately 50%-60%, with available storage providing an additional supply of 10-20%. These changes reduce Great Plains' exposure to spot or daily gas prices, which can be more volatile.

With respect to storage, historically, Great Plains planned to uniformly withdraw storage each day during the months of December through February, reserving an appropriate remainder storage balance for use in March and April. During the 2021-2022 Heating Season, however, Great Plains shifted to using storage more as a price mitigation tool and did not prescriptively withdraw storage during the earlier winter months on a set schedule and instead preserved its storage levels for use during the colder winter months where demand increases and prices are often higher. Great Plains will continue this practice during the 2022-2023 Heating Season.

The strategy of increasing Base Supply and upward storage flexibility has reduced exposure to the Day/Spot markets. At the same time, this strategy of providing additional "insurance" against exposure to extreme price spikes has resulted in potential risks that may result in higher costs to customers over time; however, Great Plains believes these modifications to its practices will protect ratepayers from extraordinary natural gas price spikes in the future.

2. Financial Hedging

At this time, Great Plains has not identified a cost-effective financial hedging strategy that will effectively mitigate exposure to spot market or daily index prices.

3. Peak Shaving

While Great Plains does not currently have peak-shaving facilities, it has considered whether peaking facilities could serve as a replacement for transportation capacity or be used for price mitigation; however, Great Plains' relatively small and remote communities make peak shaving facilities an inefficient use of capital. To ensure productive use of capital, the ideal location for peak shaving facilities resides in more densely populated areas where dollars spent on facilities can benefit a larger number of customers. In the past, Great Plains did have peak-shaving facilities; however, they were retired about a decade ago due to their age, their condition and their increasing operating costs. Additionally, operational concerns limited the number of times the facilities were used. An economic analysis which supported Great Plains' decision to retire those peak-shaving facilities was completed and provided to the Commission in the request for authority to retire these facilities.

4. Economic Curtailment

To incorporate economic curtailment into interruptible tariffs, a two-prong economic trigger has been developed. Great Plains' current tariffs do not specifically address economic curtailments and customers have not been informed as to what constitutes an economic curtailment; therefore, Great Plains has proposed tariffs revisions.[13]

Great Plains noted that it does not have experience with customer compliance related to economic curtailments so it will have to monitor customer actions and may find it necessary to implement further changes to its tariffs.

5. Customer Communications

Communications to Great Plains' firm customers regarding curtailment of their usage during economic pricing events has been discussed; however, a comprehensive plan that will provide tangible benefits has not yet been developed. At this time, based on its planned purchasing and contracting procedures for the upcoming 2022-2023 Heating Season, Great Plains' only exposure to daily price spikes is the quantity of gas between Base Supply and the days' firm demand. Upon determination that a pricing event has materialized, Great Plains will increase storage reduce that exposure by deploying its full storage quantity. Great Plains may opt to appeal to firm customers to reduce their natural gas usage during a pricing event; however, Great Plains cannot quantify the benefit of such appeals and ultimately must purchase sufficient gas to meet the expected needs of its customers.

Great Plains noted that its interconnected gas system includes the town of Wahpeton, North Dakota and a relatively significant portion of its interruptible customers, including those with a significant portion of interruptible volumes, are located in Wahpeton. Great Plains' North Dakota tariff does not specifically address economic curtailments; therefore, economic curtailment of North Dakota interruptible customers is not currently an option.

6. Time Frame

As described above, Great Plains made modifications to its gas purchasing and storage plans during the 2021-2022 Heating Season and plans to make further modifications during the 2022-2023 Heating Season. Such changes do not require tariff changes.

Proposed modifications to its tariffs to establish the terms and conditions under which Great Plains may curtail interruptible customers have been included for approval with the intention of having those modifications in place for the 2022-2023 Heating Season.

7. Integrated Resource Planning

The most effective way to protect customers from exposure to extraordinary pricing is to employ options which reduce natural gas demand (e.g., curtailment) and/or supplement market supply (e.g., storage gas). These considerations are factored into Great Plains' gas supply planning, which is similar to an IRP.

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[13] Proposed tariff revisions are reflected in Exhibit 1.

Implementing a formal IRP process would likely result in a significant investment of time and resources for all stakeholders, the Commission, the Department, the gas utilities and other interested parties and achieve uncertain benefits. Unless such plans are filed as informational filings, to ensure customers are getting the benefit of an IRP, the timeliness of the process must be prioritized so that approval occurs prior to the heating season. Given the current workload and compressed timeframe required, an effective IRP process may be difficult to achieve.

8. Performance-Based Gas Purchasing Plan

Great Plains has not submitted a performance-based gas purchasing plan for Commission consideration and approval under the above referenced statute. Given its size, Great Plains usually looks to other Minnesota gas utilities' activities to see if their experience could provide a useful model to use. In this case, Great Plains was unaware of any other utilities availing themselves of a performance-based gas purchasing plan and, therefore, did not explore further.

Great Plains' gas supply procurement objective has been, and continues to be, to obtain the lowest cost of gas for its natural gas customers. Adding a performance-based incentive would not change that objective but, given the fact that the price of gas is dictated by a national marketplace, it would create challenges in finding performance metrics to which all parties would agree. Additionally, since Great Plains competes with other fuel sources, it has every incentive to keep gas costs (which make up nearly 75% of a customers' average monthly bill) as low as reasonably possible without the need for a performance-based gas purchasing plan that does not have an established track-record in Minnesota.

9. Natural Gas Innovation Act

Other than the utilities commitment to continue to pursue a sales tax exemption for the February Event surcharge for residential heating customers, no statutory or rule changes have been identified by the utilities. With respect to Great Plains' proposed Tariff changes to implement economic curtailment, such changes do not implicate the NGIA.

E. Minnesota Energy Resources Corporation

1. Gas Contracting

MERC reviewed its contracts to determine whether modifications could be incorporated to provide additional protection in the event of market price spikes and did not identify any modifications that could be reasonably or cost-beneficially incorporated into these agreements, MERC noted it will continue to evaluate whether any contract modifications could be incorporated in the future.

For the 2022-2023 winter heating season, MERC issued RFPs to approximately 65 suppliers, seeking bids on approximately 40 products. As part of this process, MERC issued RFPs to obtain information as to availability and pricing for additional products that could provide greater protection for customers against the impacts of future price spikes. For example, MERC requested bids on call options priced at the FOM index rather than daily pricing. However, MERC did not receive any bids for this requested product.

MERC also requested bids for summer priced winter call option contracts in both its 2021-2022 and 2022-2023 RFPs; however, no bids were received.

2. Gas Purchasing

MERC purchases all of its term supply through the RFP process by purchasing baseload, call, and asset management agreement (AMA) products.[14] MERC has increased its total baseload supply priced at FOM each winter including 2020-2021, 2021-2022, and 2022-2023. In particular, MERC has increased its baseload purchases priced at FOM index prices each year and decreased planned daily purchases.

3. Storage

MERC utilizes storage to provide natural gas deliverability during periods of high demand and for operational flexibility in balancing the system. In addition to operational benefits, storage provides a physical price hedge for customers by reducing the amount of gas purchased in the winter and by purchasing in the summer for delivery at a later date.

MERC has pipeline storage contracts with ANR and NNG. The ANR storage is only deliverable to the MERC's Consolidated PGA system and the NNG storage is only deliverable to MERC's NNG PGA system.

On the Consolidated PGA system, effective April 1, 2022, MERC increased its ANR storage by 5,000 Dth/day. MERC's ANR storage contract is a ratcheted service and provides for a maximum storage quantity of 1,004,300 Dth and a maximum daily withdrawal of 20,086 Dth/day.

On the NNG PGA system, NNG's contracted storage capacity is currently fully subscribed. If additional storage becomes available, MERC will evaluate the viability and cost-effectiveness for customers within the gas supply portfolio.

4. Hedging

MERC's hedging strategy covers approximately 30% of normal expected winter volumes through financial instruments – approximately 10% futures and 20% options. Natural gas market prices are up considerably over recent historical prices, with significantly greater market volatility. The increases in overall gas market prices and volatility have pushed the strike price of purchased call options up as well.

MERC has determined it will continue to utilize financial futures and financial call options, as part of its hedging portfolio and continues to review the availability of other products that could be implemented to help hedge against winter price spikes.

5. Peak Shaving

In 2021, MERC reviewed the feasibility of including peak shaving as part of its gas supply portfolio and determined that, due to limitations on customer demand and limitations for

[14] AMAs are agreements where a counterparty provides gas supply and manages transportation assets. The utility agrees to receive and pay for the gas delivered and release all applicable transportation assets to the Asset Manager.

moving peak shaving supplies to other areas of the distribution system, it would not be feasible to incorporate peak shaving resources at most locations on MERC's distribution system. While the Rochester area might have sufficient customer demand to support peak shaving, MERC continues to have capacity reserve margins for pipeline capacity serving Rochester. Therefore, peak shaving is not needed at this time.

6. Interruptible Curtailments

Similar to the other gas utilities to allow for economic curtailment, MERC proposed making changes to its tariffs[15] and proposed using the same two-prong trigger system. The only difference is that MERC proposed to apply these triggers separately for each of its two PGAs: MERC-Consolidated and MERC-NNG.

7. Customer Communications

Through bill inserts, its website and on social media, MERC routinely engages with customers regarding steps they can take to manager their energy usage and bills and provides customers with information regarding conservation programs, energy savings tips, and information to access available resources such as LIHEAP and GAP.

Beyond such communications, MERC has evaluated the feasibility of issuing conservation requests in response to price spikes, to ask customers to voluntarily reduce their natural gas use in order to mitigate the impacts of the daily price spike. On November 1, 2021, the Gas Utilities, including MERC, submitted a compliance filing detailing the reasons such conservation requests would not provide a reasonable mechanism to mitigate the impacts of price spikes. Notably, conservation requests are voluntary, making it difficult or impossible to forecast how such requests will impact daily supply needs across MERC's system over each 24-hour gas day.

Also, due to the structure and timing of daily natural gas purchases, MERC did not propose to take any further steps with respect to calls for voluntary customer conservation at this time.

8. Other Relevant Practices

a. Daily Forecasting

MERC has updated its available forecasting tools with the goal of being able to more easily identify changes to transportation customer gas deliveries. To achieve this objective, MERC has removed its largest electric generation transportation customer from the historic data used to forecast daily customer requirements. Isolating the large electric generation transportation customer from the remainder of transportation customer information will help highlight when transportation customer nominations change significantly, which may indicate transportation deviations from historical actuals. This will help to improve forecasting of the gas supply needs for sales customers.

[15] Proposed tariff revisions are reflected in Attachment A.

b. Transportation Tariffs Modifications

MERC is evaluating potential changes to its transportation tariffs that could be implemented to ensure transportation customers deliver the volumes they intend to use. MERC, as a local distribution company, is responsible for daily balancing of the interconnections or town boarder stations between MERC's distribution system and the interstate pipeline. As a result, all daily imbalances caused by transportation customers are a portion of MERC's imbalance on the pipeline.

Based on MERC's ongoing review of potential modifications that could be incorporated into the Company's transportation tariffs, MERC plans to propose potential tariff modifications in a future general rate case proceeding for Commission review.

c. Market Reform

Similar to other gas utilities, MERC had been participating in the NAESB forum mentioned above.

d. Statutory or Rule Changes

Other than continuing to advocate for the sales tax exemption related to the Market Event surcharge, MERC had no additional recommendations.

e. Minn. Stat. §216B.2427 and 216B.2428

MERC stated that the proposed tariff and statutory changes are consistent with the NGIA and neither the proposed interruptible tariff modifications nor pursuit of the sales tax exemption will impact future NGIA filings.

f. Integrated Resource Planning

MERC stated that the development and implementation of a natural gas IRP framework would require significant time and resources and would not be likely to result in any new gas commodity alternatives that could be implemented to reduce price risk exposure or pricing volatility. Further, gas supply procurement decisions generally must be made on a very short timeframe, with contracts awarded within a matter of minutes to days of bids being received in order to lock in offered pricing and other terms. Market volatility and changes in market product offerings also makes long-term planning for natural gas commodity difficult.

Similar to other utilities, MERC stated that, to the extent the Commission wishes to further evaluate the parameters and potential benefits of an IRP, further evaluation could occur in Docket No. G-999/CI-21-565.

g. Performance-Based Gas Purchasing

Similar to other utilities, MERC stated that commodity prices for gas supplies used in Minnesota are set in a nationwide, competitive marketplace and there are a number of factors that affect the market price of gas supplies, all of which are outside the control of the Gas Utilities; therefore, MERC supports continued use of the current PGA mechanism.

IV. Parties' Comments

A. Minnesota Department of Commerce

1. Gas Supply Contracting

The Department noted that the Gas Utilities contend that they have been unsuccessful in altering their gas supply contracts or acquiring new contracts that would reasonably protect against a spot price spike. The Department appreciates that the Gas Utilities are actors in a broader market without unilateral control over all its aspects. Furthermore, spot price spikes reflect a risk that is inherently challenging to mitigate perfectly. The Department recommended that the Gas Utilities should continue to pursue and explore non-standard contracting options that could provide greater protection against daily price spikes. To the extent those options come at a cost premium (as they likely would), the benefit of reduced risk or greater price certainty must exceed the associated cost premium.

The Department also recommended that the Gas Utilities participate in the NAESB Forum and other relevant efforts to track and pursue reforms that would be beneficial to their customers. One possible reform item would be improvements to the force majeure language in the standard NAESB contract. Although gas supply cuts or failures were not a major issue for the Gas Utilities in the February Event, they represent a supply uncertainty and risk going forward.

2. Gas Purchasing

a. Baseload Purchases

Each of the Gas Utilities described purchasing a greater portion of its overall supply needs with baseload. The Department supports this practice and, in the prudence review, had noted that greater levels of baseload were possible for each Gas Utility. Higher volume baseload purchases directly offset the required volume of spot or daily purchases, which represent the portion of gas supply exposed to the risk of a short-term price spike. Baseload can be purchased at a monthly index (FOM) or at an otherwise agreed upon fixed price. Going into a month, the Gas Utilities cannot be certain whether the baseload price will result in higher or lower than the average price of spot or daily gas for that month. However, the potential premium comes with the benefit of assurance that the Gas Utility avoids excessive costs associated with a price spike on the additional volume supplied via baseload.

b. Xcel Baseload Procurement and Forecasting

The Department described Xcel's plans to incorporate greater amounts of baseload purchases as vague. In the prudence review, the Department had serious concerns with Xcel's forecasting of its minimum load and its level of baseload procurement. Xcel's lack of a commitment to procuring additional baseload and its description of numerous obstacles that may limit it from doing so are concerning, especially in light of the other Gas Utilities ability to make such commitments. On a prospective basis, it remains unclear if Xcel is procuring a reasonable amount of baseload or whether it is reasonably forecasting minimum load, which is an important factor in procuring baseload.

c. Supply Diversity

During the February Event, prices spiked to various degrees across the pricing hubs relevant to the Minnesota Gas Utilities. Most notably, Canadian gas supply priced at the Emerson hub was much less expensive than supply priced at the more southern hubs of Ventura and Demarc. Although the Department understands that supply diversity is connected to long-term pipeline capacity positions, there broadly exists some capability for the Gas Utilities to adjust their supply diversity given their existing pipeline capacity, and the Department supports the Gas Utilities doing so.

Over the longer term, the Department recommends the Gas Utilities include supply diversity as one of many considerations taken when reviewing, modifying, or expanding their pipeline capacity. As a part of their Contract Demand Entitlement filings, the Department recommended the Gas Utilities discuss how changes to their pipeline capacity affect their supply diversity. If pipeline capacity comes at a cost premium but increases supply diversity, the Gas Utilities should provide a meaningful cost/benefit discussion of the tradeoff including a comparison with the least-cost capacity option.

d. Supply Reserve Margin

Despite being a significant topic in the prudence review, none of the Gas Utilities discussed their practices related to their supply reserve margins. A supply reserve margin reflects the practice of intentionally acquiring gas supply at a level slightly higher than forecasted load requirements for a particular day. A supply reserve margin is utilized to manage the risk, and avoid the associated costs, of inadequate supply caused by forecast uncertainty and supply failures. Although the Department recognizes the general practice of carrying a supply reserve margin, the Department disagrees with the Gas Utilities' position that a supply reserve margin defied after-the-fact explanation or quantification and that a reasonable supply reserve margin could be as large as 30%.

The Department does not seek to require a prescriptive supply reserve margin position. Nevertheless, the Gas Utilities' practices related to a supply reserve margin are directly relevant to spot price spike exposure. Procuring 10% to 30% supply reserve margins when such quantities cannot be justified or explained should not be an acceptable practice. The Department recommended the Gas Utilities commit to improving their supply reserve margin practices to minimize these quantities to the greatest extent possible and be prepared to explain the level of their supply reserve margins in the future.

3. Hedging

The Department understands that hedges that would be effective for spot price spikes have been generally unavailable or prohibitively expensive but supports the Gas Utilities continuing to explore for future opportunities. the Department recommended the Gas Utilities expand their relevant annual, forward-looking gas planning or hedging filings to illustrate their expected supply mix across different load and weather conditions throughout the winter. Specifically, the Gas Utilities should provide, for each month of the upcoming winter season, the forecasted minimum, average, and maximum day load requirements and the expected mix of baseload, storage, and spot supply on those days. This information will complement the Gas Utilities overall hedging percentage targets with the exposure to spot prices on a daily basis throughout the winter months.

4. Storage

The Department understands that additional storage is not readily available for the Gas Utilities because existing storage in the region is fully subscribed. While additional storage could provide a greater ability to mitigate winter spot price spike exposure, it also represents a significant long-term, fixed expense that must be borne by customers. Adding significant storage capacity would be a major decision that would need to be fully evaluated under the Commission's existing processes. Mitigation of spot price spikes is only one benefit of storage additions, and as such, should not be considered in isolation during these decisions. Other factors, including other associated benefits in combination with spot price mitigation and the operational needs of the Gas Utilities would need to justify the fixed cost investment

Given the difficulty and expense of acquiring additional storage, the Department's focus is on the Gas Utilities maximizing the use of their existing storage. An important lesson from the February Event is that the Gas Utilities are more exposed to a spot price spike because storage capability has eroded by late winter. Generally speaking, storage is most effective when inventory levels are full going into the winter. As storage inventories are withdrawn, the maximum daily usage of storage ratchets down. Late February appears to be particularly problematic because the potential for extreme cold weather is still relatively high. In its comments, Great Plains discussed changes to its storage withdrawals throughout the winter to maintain greater withdrawal capability for the later part of the season.

Given those factors, the Department recommended the other Gas Utilities explain if there are modifications to storage inventory management that could preserve withdrawal capabilities for the later winter and the ramifications of such a strategy.

a. CenterPoint's Waterville Storage

The Department supports CenterPoint's proposal to incorporate an additional 10% of storage withdrawals from Waterville into its daily purchasing plans.

5. Interruptible Customers

a. Economic Trigger

As the Gas Utilities correctly describe, their proposed economic trigger is only useful in avoiding impacts for price spikes that extend to a second natural gas trading day. The proposed economic trigger amounts to waiting for a price spike to occur and then reacting based on the assumption the price spike will continue for subsequent days. Utilizing curtailments and peak shaving in a purely reactive fashion following the occurrence of a price spike severely limits the usefulness of their mitigation potential. If a price spike does persist for more than one trading day, then a reactive action is warranted and necessary. The February Event illustrated that the majority of the economic impact was incurred based on purchases made on the first trading day. Although that price spike was unprecedented, its occurrence means the Gas Utilities should be on alert for another large price spike in the future.

The Department understands that a spot price spike cannot be perfectly forecasted in advance and is not guaranteed to have occurred until after the Gas Utilities' purchases have already been made. However, the Gas Utilities are regular and sophisticated actors in the market and are well suited to gauge the risk and volatility in the market that would lead to a high likelihood of a price spike occurring.

The Department noted that a simple, robotic economic trigger that would provide better protection and benefit for ratepayers. However, the inherent nature of a price spike does not lend itself to a prescriptive trigger. A price spike is sudden and transient. If a price spike is expected to extend beyond a single trading day, then the trigger can be used as a guide for mitigating economic harm. However, the Gas Utilities should not reflexively react to a price spike if it has clearly passed and will not continue. Accordingly, the Gas Utilities need to proactively trigger economic action with the understanding that there is a reasonable probability of a price spike but one is not guaranteed to occur. Neither the Department nor the Commission can prescribe the details of the Gas Utilities' day-to-day operations. Rather, the Gas Utilities maintain the burden to act prudently such that customers only pay for reasonably incurred costs. The proposed economic trigger should not be justification for the Gas Utilities failing to take other reasonable actions to protect customers in future event.

b. Other Interruptible Customer Issues

The Department supports the Gas Utilities pursuing strategic curtailment to mitigate spot price risk. Xcel, MERC, and Great Plains' comments each suggest that they intend to curtail all of their interruptible customers for economic purposes. In contrast, CenterPoint identified specific classes of customers that it would curtail for economic purposes. In the near term, the Department supports the concept of focusing (to the extent possible) economic curtailments on the interruptible customer classes that are the best candidates for economic curtailments. This approach is in concert with the Department's recommendation from the prudence review which was based on a partial curtailment targeted at the customers the Gas Utilities had the most comfort and experience with curtailing.

In the longer term, the Department recommended that the Gas Utilities explore the development of new interruptible service offerings that are designed to allow for a reasonable degree of economic curtailments by the Gas Utilities. It is reasonable for the Gas Utilities to utilize their existing offerings for economic purposes this winter, but it may be beneficial to design new offerings based on the Gas Utilities' experience with economic curtailments or the greater flexibility those might provide. Certain customers may prefer to pay more for service that is interrupted less and only for reliability purposes (but still not firm service), but other customers may be interested in paying less for service that is flexible for further interruptions for economic purposes as well.

6. Peak Shaving

The Gas Utilities are proposing to apply the same economic trigger to economic curtailment of interruptible customers and peak shaving. Thus, the discussion in the previous section related to the economic trigger is equally applicable to peak shaving.

a. CenterPoint

CenterPoint proposed to begin economic dispatch of its peak shaving facilities for the upcoming winter with certain limitations. Specifically, it proposed to limit dispatch 25% of the daily capability of its LNG plant and only do so after January 20 but did not justify either of these strict, bright-line limitations and also discusses relevant factors that make them inappropriate.

During the February Event, CenterPoint did not dispatch its peak shaving facilities. The relative lateness in the winter and effectively full fuel inventory meant that CenterPoint could be assured its LNG plant would have fuel in the unlikely event of an even later winter Design Day. If CenterPoint were to find itself in similar circumstances this winter, it should not rigidly impose a 25% LNG limit. CenterPoint should use the circumstances of the event, the prevailing winter, and the status of its fuel inventory to inform its dispatch decision. In an attachment, CNP describes that it is evaluating development of a probabilistic model to weigh the tradeoff of LNG fuel inventory versus the probability of subsequent Design Day events. The Department agrees that the correct analysis is to weigh the remaining inventory of LNG fuel versus the probability for subsequent Design Day conditions that would require LNG dispatch for reliability. LNG fuel needs to be available for use on Design Day conditions, if those manifest. If a fully developed model cannot be developed prior to this winter, the basic tradeoff can still be evaluated and acted upon.

b. Xcel

Xcel proposed to use potentially the entire capability of its LNG facility for economic dispatch but not until the winter of 2023-24. because it has been limited on filling its LNG facility over the summer, implying that its inventory level will be too limited to allow for economic dispatch this winter. Based on Xcel's description, it is unclear what the fuel inventory position of the LNG plant will be or the specific circumstances surrounding any fuel inventory limitations. Besides the lack of clarity pertaining to why Xcel cannot begin economic dispatch this winter, the same tradeoff of fuel inventory versus the probability of future Design Day events applies for Xcel. If

Xcel finds itself in the late winter with significant unused LNG fuel and the prospect of price spike, economic dispatch is likely warranted.

7. Customer Communications

The Gas Utilities presented a range of limited to no changes with respect to customer communications. CenterPoint and MERC describe their ongoing, regular customer communication campaigns but states it will not explore economic conservation requests further. They argue that such requests should be reserved for emergency situations. Xcel explained that it will make economic conservation requests in accordance with its November 1, 2021 filing whenever the economic trigger is reached. Great Plains stated that it may make economic conservation requests of its customers. All of the Gas Utilities explain that the response of an economic conservation request would be difficult to gauge in advance in order to avoid purchasing spot gas. Nevertheless, the Department agreed with Xcel's approach of engaging in economic conservation requests in anticipation of extreme spot price spikes and studying customer responses. If such requests manifest, then the Gas Utilities can learn to anticipate customer's responses and potentially translate that anticipation into avoided spot gas purchases

8. Integrated Resource Planning

The Department agreed that a Gas IRP would largely duplicate other existing dockets and the Gas Utilities' description of the differences between the gas and electric industries. Therefore, the Department recommended that there be no pursuit a Gas IRP as a tool to prevent against future price spikes.

9. Statutory Or Rule Changes to Prevent Future Price Spikes

The Gas Utilities jointly noted that they supported legislation adopting a sales tax exemption for the February Event for residential heating customers, but it did not pass in the 2022 Legislative Session. They also stated that they reviewed existing statutes and rules, focusing especially on the AAA and PGA rules but did not recommend any changes. The Department does not have any recommendations independent of the Gas Utilities at this time.

10. Performance Based Gas Purchasing Plan

The Department generally agreed with the Gas Utilities that, because the statute was passed in the 1990s, it may not reflect the current nature of the natural gas industry. How the statute is structured and its goals may need a refreshed look. However, if the Commission believes there is an opportunity to structure an incentive plan under this statute, the Department will participate in any proceeding initiated by the Commission.

11. Natural Gas Innovation Act

Innovation plans under NGIA and examination of regulatory changes under the Future of Gas docket focus on GHG emission reductions in the natural gas utility sector. Specifically, innovation plans center around development and deployment of alternative fuel resources to displace conventional natural gas. To the extent that the fuel resource practices highlighted in Docket No. 21-135 (21-135) impact efforts to displace conventional natural gas via utility innovation plans, or vice versa, some overlap between the two dockets might exist. For example, CenterPoint hypothesized a scenario where renewable natural gas developed under an innovation plan might be stored to supplement supplies during a pricing event. While 21-135 and innovation plans focus on fuel resources, the scope of the Future of Gas docket contemplates any regulatory and policy changes that could further gas utility participation in reducing GHG emissions, including policies and practices related to infrastructure, cost recovery, fuel resources, and more. Conceptually, the Future of Gas proceeding would be an appropriate venue to discuss the pros and cons of gas integrated resource plans

Provided that actions taken in 21-135 do not limit the type of fuel resource that can be deployed under the utility practices, the Department sees little risk in limiting innovation plans under NGIA or the Future of Gas docket through actions taken in 21-135. In fact, actions taken in 21-135 could further development of ideas explored in the Future of Gas docket focused on reducing GHG emissions.

B. Office of the Attorney General

The OAG stated that, in any order implementing prospective changes, the Commission should 1) be clear that it is not relieving the Gas Utilities of the obligation to exercise their experience and judgment to act prudently during future pricing events, 2) make changes to ensure that curtailment is a viable tool to mitigate future pricing events, and (3) encourage the Gas Utilities to continue to take steps to optimize their hedging strategies.

1. The Gas Utilities Have the Responsibility to Exercise Their Experience and Judgment to Act Prudently in Response to Pricing Events

Gas Utilities need to evaluate situations based on the information that they have available to them, and exercise their judgment and experience to make prudent decisions. This is the standard that the Gas Utilities should always be held to; it is the standard that informed the disallowance recommendations by the OAG, the Department, and CUB; and it is the standard that formed the basis for the Commission's disallowances in these matters. While it is important for the utilities to seek stakeholder and Commission feedback on their forward-looking plans to address price spikes, the Commission should take care not to relieve them of their ongoing obligations to make prudent decisions in the best interests of ratepayers.

CenterPoint indicated that it is requesting Commission directives to implement its proposals because some of them could jeopardize system reliability and, as part of its plan, CenterPoint included a formulaic price-based trigger for implementation. While this type of trigger might make sense as a general guiding principle, it is too simplistic to be a hard and fast rule. The Gas Utilities always need to balance safety, reliability, and affordability. The specific details of any future pricing event are impossible to predict, and the number of factors that influence safety, reliability, and affordability are too numerous to be reduced to an objective and mechanical plan. This is why utility employees, and not the Commission, are responsible for the operational decisions.

2. The Gas Utilities Should Use Curtailment as a Tool To Protect Ratepayers in Future Pricing Events

Curtailment of interruptible customers has the potential to be an effective mechanism for protecting ratepayers from future price spikes. In order to ensure that this tool is available when needed, the Commission should clarify that the utilities' tariffs do allow for economic curtailments while not unnecessarily constraining them and take steps to ensure that interruptible customers actually curtail when called upon to do so.

The Gas Utilities' interruptible tariffs already provide for economic curtailment. That said, if the Gas Utilities believe that their customers will benefit from minor revisions that more explicitly contemplate economic curtailments, it would be reasonable to do so in order to eliminate any remaining dispute on this point. The Gas Utilities all requested to include a strict price-based trigger in their proposed revisions. However, such a trigger would not only be unnecessary, but could harm ratepayers. By tying economic curtailment to a formulaic trigger, the Gas Utilities would be arbitrarily limiting their ability to make use of this tool. There are no such restrictive parameters for curtailing customers to address capacity constraints or reliability issues; rather, the utilities exercise their judgment to decide when to curtail. It would be unreasonable to restrict the Gas Utilities' ability to curtail in order to advance affordability concerns in a way that the tariffs do not for other types of curtailments. Thus, the Commission should reject the Gas Utilities' proposed price-based trigger.

In order for curtailments to effectively address price spikes, interruptible customers must actually curtail when called on to do so. Unfortunately, this has been an ongoing problem. During a period of extreme cold weather in 2019, CenterPoint, Xcel, and MERC curtailed interruptible customers, and all three had very poor compliance rates. All three utilities argued against increased penalties proposed by the OAG, instead arguing that the existing penalties were sufficient. During the February Event, CenterPoint and Xcel actually saw worse non-compliance rates than in 2019.

When faced with ongoing non-compliance problems, Xcel, in its ongoing rate case,[16] proposed to reset its non-compliance penalties every year, thereby reducing the disincentive for interruptible customers who fail to curtail. In the Xcel rate case, OAG presented analysis showing that a group of 52 customers failed to comply with any curtailment calls in 2019 or 2021, saved $6.7 million by paying interruptible rates and incurred only $1.4 million in penalties. In other words, this group of customers saved an average of over $100,000 by benefitting from interruptible rates, never curtailing, and instead simply paying the penalties.

To solve this problem, the OAG recommended that any customer who fails two consecutive curtailment calls should be put on "probation," where it will pay firm rates unless and until it can demonstrate that it has resolved whatever problem causes the failure to curtail. The Commission should institute such a probationary period for all of the utilities in order to ensure that curtailment calls will actually be effective.

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[16] Docket No. G-002/GR-21-178.

3. The Gas Utilities Should Continue Taking Steps to Optimize Their Hedging Strategies

Hedging plans can also help the Gas Utilities mitigate the effects of future natural gas price spikes. Xcel believes it would be beneficial to create an expedited regulatory process to explore policy issues around financial hedging. The OAG supports Xcel's desire to continue examining whether and how hedging can be used to protect ratepayers from exposure to future price spikes and looks forward to reviewing any future proposals the utilities put forward.

C. Citizens Utility Board of Minnesota

1. The Commission should prioritize solutions that do not require new, long-term investments

CUB noted that natural gas consumption has seen steady growth, supporting the continued build-out of a utility system that is heavily dependent on large capital investments. However, indications suggest that distribution gas system growth may soon slow. The U.S. Energy Information Administration projects that residential gas demand will shrink between 2022 and 2050, and that domestic, non-industrial demand overall will grow very slowly.[17] Natural gas costs are higher today than at any point since the fracking boom, further encouraging conservation efforts and hastening the emerging cost parity of electrification alternatives for homes and businesses. Conservation and electrification incentives in the Inflation Reduction Act may further speed demand reductions. Additionally, the gas system could be subject to future greenhouse gas regulations, and it may be necessary to reduce natural gas usage to achieve climate goals, including Minnesota's statutory greenhouse gas reduction goal.[18]

This uncertainty may result in investments made to meet today's peak demands may not be needed in the future. Infrastructure investments are often decades-long propositions. If demand no longer grows at the same rate, or if it shrinks, rates will need to increase to pay for those investments, further incentivizing conservation and electrification, and so on. If such a scenario were to arise, it would have potentially catastrophic effects on those customers least able to make the investments needed to leave the gas system.

Therefore, CUB recommended that, if possible, the Gas Utilities avoid new, large-scale investments until those investments can be informed by transparent, long-term planning.

2. The two-pronged trigger should be rejected

CUB has high-level concerns about the trigger the Gas Utilities have proposed and disagreed that using this threshold is an appropriate means of determining when utilities should take action to mitigate ratepayer harm associated with price spike events. Relying on a trigger, such as that proposed by the Gas Utilities, removes rather than enhances the utilities' ability and obligation to apply their technical expertise and industry experience to changing market and weather conditions to balance safety, reliability, and affordability under variable conditions.

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[17] https://www.eia.gov/outlooks/aeo/production/sub-topic-03.php.

[18] Minn. Stat. § 216H.02.

Future price spike events may, and likely will, look different than those in the February Event. Gas Utilities should not be bound by metrics that cannot possibly account for all variables, nor should they be permitted to justify potentially imprudent decisions by basing them on a that threshold without considering the totality of the circumstances.

In contrast to the Gas Utilities' proposal, CUB recommended that the Commission adopt a filing and review requirement if prices exceed a certain threshold where the utility would make a filing to the Commission identifying its costs, what actions the utility took in response to the costs, and justifications for why its actions were prudent. Parties reviewing this filing could, if warranted, then recommend that the Commission order a prudence review of those costs, or the Commission could order such review on its own initiative. If the Commission calls for such a review, the cost of gas above the threshold should not be collected from customers until the utility has demonstrated prudent action. Triggering this threshold does not predetermine what actions the utility should have taken – that is context specific. The filing requirement does not imply the utility should have, or should not have, called upon any specific resource. The purpose of this filing is to create an automatic process for review when prices reach a certain threshold. For discussion purposes, CUB proposed adoption of the $20/Dth threshold that was considered to be "extraordinary" during the February Event.

3. Interruptible Tariffs

CUB wanted to make clear tariff modifications are not necessary to ensure the Gas Utilities utilize curtailment to help mitigate ratepayer harm associated with any extreme price spike events that occur in the 2022-2023 heating season. The disallowances previously ordered in these dockets are indicative of the Commission's determination that the utilities are accountable for acting prudently to help protect ratepayers from financial harm in future price spike events, including calling for price-based curtailments. Doing so reasonably balances the utility's responsibility for providing safe, reliable, and affordable gas service. In determining that CenterPoint and Great Plains both acted imprudently by not calling for economic curtailments during the February Event, the Commission rejected these utilities' arguments that they are unable to exercise economic curtailments just because existing tariff language does not expressly "provide for" this action. CUB recognized that additional edits to interruptible tariffs may be helpful to provide clarity on when and how economic curtailments are exercised; however, in the near-term, tariff revisions should not be treated as a prerequisite to the utilities exercising economic curtailments.

CUB is concerned that the proposed tariff revisions do not sufficiently distinguish between economic and reliability-based curtailments, thus failing to enhance ratepayer protections in future price spike events. The proposed $50/Dth threshold would have been triggered only twice over the previous decade. One such occasion is the February Event and the other occasion was the extreme cold event that occurred around the 2017/2018 New Year holiday. In both cases, spiking gas prices coincided with, and were partially caused by, disruptions in gas supply, which also threatened reliability.

CUB stated that the Gas Utilities have not sufficiently explained the significance or usefulness of the proposed economic threshold. In response to an information request asking the utilities explain how they developed the threshold, they responded that the threshold meets the

Commission's directive while ensuring these resources are available to "ensure continuous and reliable service to customers."[19]

Tariff adjustments should clarify, not obscure, the distinction between when and why curtailments are called for reliability reasons versus economic reasons. As shown in Table 1, CUB recommended that the Commission order the utilities to propose two distinct tariffs to reflect the value of each type of interruption.

Table 1: CUB's Proposed Framework for Interruptible Tariffs

	Economic Tariff	Reliability Tariff
Frequency of Calls	Triggered more frequently (often prior to reliability trigger)	Triggered less frequently (often following economic trigger)
Discount Level	Provides higher rate discount than reliability tariff	Provides lower rate discount than provided by current tariff
Information on Threshold	Soft/non-binding threshold (for instance, may adjust based on time occurring during heating season, etc.) triggers filing requirement; threshold should be lower than currently proposed and informed by analysis of historical and forecasted spot prices; threshold should not preclude curtailment at lower threshold given totality of circumstances	Soft/non-binding threshold (for instance, may adjust based on time occurring during heating season, availability of other resources, etc.); threshold triggers filing requirement but does not preclude curtailment at lower threshold given totality of circumstances
Filing Requirements	Reaching threshold triggers utility notice filing requirement, which may prompt parties to request a prudence review. If Commission orders prudence review, cost of gas above threshold will not be collected from any customers until the utility has demonstrated prudent action	Reaching threshold triggers utility notice filing requirement, which may prompt parties to request a prudence review. If Commission orders prudence review, cost of gas above threshold will not be collected from any customers until the utility has demonstrated prudent action
Additional Information	Consumer protection provision that economic triggers are not called more than a certain number of times per heating season.	Consumer protection provision that economic triggers are not called more than a certain number of times per heating season.

4. Peaking Plants

CUB stated that disallowances previously ordered in these dockets are indicative of the Commission's determination that the Gas Utilities are not practically or legally prohibited from dispatching peaking resources to mitigate harm associated with extreme pricing events. CUB does not believe that the Commission ordering the Gas Utilities to use peaking resources in this

[19] Joint Utilities' Response to CUB Information Request 01, see Attachment A.

way is a prerequisite to them dispatching peaking resources to address price spikes that may occur, so long as the utility prudently determines that such an action balances the utility's responsibility for providing safe, reliable, and affordable gas service. CUB is again concerned about the utilities' proposal to draw a bright line for the economic dispatching of peaking plants, as it does not take into account the external environment or the utility's specific situation. Peaking plants and interruptible tariffs are different resources, and should thus be treated differently. Interruption is a demand-side resource that impacts a customer's use of gas. Peaking resources are supply-side resources that do not impact demand; however, it is vital that peaking resources remain available throughout the duration of the heating season to ensure reliability.

CUB recommended that Xcel and CenterPoint be ordered to refile in the present dockets more dynamic proposals that recognize that calling on peaking resources depends on the economic and situational context of the utility and the market.

5. Storage

CUB again mentioned that the disallowances previously ordered in these dockets are indicative of the Commission's determination that the utilities are not practically or legally prohibited from withdrawing gas from storage to mitigate harm associated with extreme pricing events, so long as doing so prudently balances the utility's obligation to provide safe, reliable, and affordable service. CUB does not believe that a trigger, such as that proposed by the Gas Utilities, is alone an appropriate mechanism to determine whether and when to withdraw gas from storage. Rather, the Gas Utilities should consider the totality of the circumstances when determining whether, when, and how much gas to withdraw from storage.

6. Risk-Sharing Mechanism

CUB recommended that the utilities be ordered to work with stakeholders to propose, in their September 2023 AAA filings, a risk-sharing mechanism that would incentivize utilities to minimize exposure to future gas price spikes. CUB disagreed that the AAA or PGA rules provide sufficient protection to customers and that no changes are needed. PGA and AAA processes may reduce regulatory lag for utilities and conserve utility and public resources. However, these same mechanisms also reduce the utility's incentive to control costs and enable utilities to pass all risk to ratepayers.

CUB filing mentioned some possible risk-sharing options; however, parties have not had an opportunity to respond.

7. Integrated Resource Plans

CUB disagreed with several aspects of the Gas Utilities' comments on gas IRPs. First, although some elements of an IRP are captured in other dockets, these dockets do not capture the full IRP process, nor the full value that an IRP can provide. The fact that elements of gas utility planning are included in so many different dockets underscores the need to ensure that planning is thorough and is consistent across proceedings. Second, an IRP is concerned with the long-term decision making of the utility, not its day-to-day operations. An IRP focuses on assessing costs and risks of various portfolios of resources under numerous environments. It is less focused on specific contracts and more on the costs and risks of various supply basins, transportation pipelines, and physical and financial hedging strategies. In contrast, the utilities' planning currently occurs throughout various dockets (including the Contract Demand Entitlements Filings) which focus only on short-term needs, or internally at each company. Third, though Xcel asserted that few jurisdictions require gas IRPs, such a requirement is not unprecedented. Long-standing gas IRP requirements that exist in at least three U.S. states could serve as a model for how such a requirement could be adopted in Minnesota.

CUB recommended that the Commission (1) require the Gas Utilities to file integrated resource plans and (2) open a new docket, separate from the Future of Gas docket, seeking input on the procedure and content of in those plans.

8. Hedging

CUB noted that, in its comments, Xcel stated that if it increases its hedging budget, that could cause hedging costs to increase for ratepayers and suggested that these public policy considerations warrant a separate, expedited regulatory process to obtain feedback from stakeholders and the Commission. While CUB appreciates and shares Xcel's concerns about the policy matters and financial implications of revising its hedging strategy, CUB is hesitant to support an additional regulatory proceeding to address these issues. CUB believes there are more concrete steps the Commission and Gas Utilities could and should take to implement risk-sharing mechanisms that incent utilities to ensure their gas purchasing decisions are as cost-effective as possible. CUB would prefer to see those strategies implemented before the Commission engages in a complex regulatory review of financial hedging strategies. However, if the Commission opens a separate proceeding to address hedging, CUB recommends that the Commission authorize the Department to engage an outside expert for this purpose.

D. Center for Energy and the Environment

CEE noted that the Gas Utilities all recommended that the Commission consider discussing IRP for natural gas utilities through Docket No. G-999/CI-21-565 and that some utilities highlighted limitations in the role that integrated resource planning could play in mitigating future natural gas price spikes, but all utilities indicated that resource planning might provide value to long-term planning of the natural gas system.

CEE believes that an IRP process for natural gas utilities will be a necessary and valuable tool for ensuring that Minnesota's natural gas system and utilities evolve to meet Minnesota's future energy needs safely, affordably, and reliably, while supporting Minnesota's greenhouse gas reduction goals. With the passage of the NGIA, gas utilities will begin investing in a range of new and innovative energy resources. Over time, some or all of those innovative resources will likely transition from relatively small pilot investments to become larger, standard parts of the utilities' energy resource supply. As this transition occurs, it will be increasingly important for utilities and regulators to conduct long-term planning to ensure that customer needs are safely, sufficiently, and cost-effectively met, while reducing greenhouse gas emissions in keeping with the State's goals.

CEE believes that IRPs may also play a role in protecting ratepayers from future price spikes in the geological natural gas market and, potentially, other resource markets like renewable natural gas or hydrogen. As natural gas utilities diversify the energy resources that supply current natural gas end uses, there may be opportunities to offset certain resources in the event of a price spike by switching to another, similar resource. Additionally, reducing Minnesota's purchases of geological natural gas may have market price effects and result in a reduction in wholesale natural gas prices.

CEE agreed that it would be appropriate to discuss, consider, and, potentially, build the IRP requirements and framework in Docket No. G-999/CI-21-565. Given the broad implications, importance, and complexity of this issue, CEE believes that IRP design will require significant record development and focused attention. Therefore, in whatever docket or context the Commission decides to consider IRP, it may be helpful for the Commission to set a defined scope, process, and timeline upfront. Specifically, CEE recommended establishment of a process that culminates in a clear decision point, at which time the Commission determines whether IRP is valuable and necessary for Minnesota's natural gas utilities.

V. Staff Comments

Staff considers the Gas Utilities' filings to mostly informational regarding steps they have taken to better insulate ratepayers from another "pricing event". Since it seems like many of the changes have already been implemented and were not accompanied by approval requests, Staff interpreted them as the utilities using their operational expertise to help minimize possible ratepayer impacts in the case of future pricing events. The utilities have also discussed prospective action that can further protect ratepayers in the future. CenterPoint requested a Commission directive to implement its proposed short-term modifications regarding price-based withdrawals from Waterville storage, price-based dispatch of LNG peak shaving, and price-based curtailment of system sales interruptible customers, all of which would be based on the two-prong price trigger proposed in the Gas Utilities' joint filing. However, other than approval of the two-pronged trigger and the revised curtailable tariffs, the other Gas Utilities made very few "asks".

Conversely, the Department, the OAG and CUB have made many recommendations. However, most of them will require more record development, ongoing progress reporting and/or completion deadlines. As a result, some recommendations are not included in the decision alternatives. Since progress in this area is likely to be a multi-year effort, rather than making piece-meal decisions at this time, if the Commission would prefer a more robust, "cleaner" set of recommendations, it may want to consider asking the utilities to make annual compliances that detail their recent efforts and address the various parties' recommendations. Filings could be made on or before July 1 of each year.

As stated by Xcel, on November 1, 2021, the gas utilities filed a communications plan that has yet to be commented on or approved. Even though Xcel did not think any Commission action is necessary, the Commission may want to ask the utilities and stakeholders if it should proactively approve these plans or if comments should be filed within 90 days of this agenda meeting.

Staff notes the CEE has recommended that development of an IRP process should be initiated. Since Gas Utilities have suggested that the IRP decision could not only be addressed in Docket No. G-999/CI-21-565 but it is already part of the record being developed that docket, Staff has not included a decision alternative related to the IRP.

VI. Decision Alternatives

Interruptible Customers

1. Approve the following economic trigger for interruptible customers' curtailment: (Gas Utilities)

   The prior gas day (or multiple days in the case of weekends and holidays) settled Gas Daily daily index price at [any of the identified pricing hub(s) where the utility would purchase daily supplies]:

   1. is greater than or equal to $50.00 per Dth; **and**
   2. is greater than or equal to five times the weighted average cost of gas forecast for the month at issue in the utility's filed PGA for that month.

2. Do not approve the economic trigger for interruptible customers' curtailment. (CUB, DOC, OAG)

3. Approve CenterPoint's revised interruptible customers' tariff. (CPE)

4. Do not approve CenterPoint's revised interruptible customers' tariff. (CUB).

5. Approve Xcel's revised interruptible customers' tariff to be effective April 1, 2023. (Xcel).

6. Do not approve Xcel's revised interruptible customers' tariff. (CUB)

7. Approve Great Plains' revised interruptible customers' tariff. (GP)

8. Do not approve Great Plains' revised interruptible customers' tariff. (CUB).

9. Approve MERC's revised interruptible customers' tariff. (MERC)

10. Do not approve MERC's revised interruptible customers' tariff. (CUB)

11. Order Gas Utilities to explore the development of new interruptible service offerings that are designed to allow for a reasonable degree of economic curtailments in future heating seasons. (DOC)

Communications Plans

12. Approve the Gas Utilities' November 1, 2021 communications plans. (Staff)

OR

13. Instruct the Executive Secretary to issue a notice requesting comments on the Gas Utilities' November 1, 2021 communications plans. Comments should be on or before March 8, 2023. (Staff)

Annual Filings

14. Order the Gas Utilities to, by July 1 of each year, make annual compliance filings that detail their recent efforts and address parties' recommendations made in this proceeding. (Staff)

[If the Commission prefers, some or all subsequent decision alternatives can be incorporated into the July 1, 2023 filing}

Gas Contracting

15. Order the Gas Utilities to participate in NAESB's Gas/Electric Harmonization Forum and other relevant efforts to track and pursue beneficial reforms, such as improving the force majeure language in the NAESB standard contract. (DOC)

16. Order the Gas Utilities to continue to explore the availability and cost of contracting, hedging, and supply options that would provide better protection against price spikes. (DOC)

17. Order the Gas Utilities to continue exploring the availability and cost of contracting, hedging, and supply options that would provide better protection against price spikes. (DOC, OAG)

Gas Purchasing

18. Approve CenterPoint's, MERC's, and Great Plains' plans to incorporate a greater degree of baseload purchases. (CPE, MERC, GP, DOC)

19. Order Xcel to propose a plan to incorporate a greater degree of baseload purchases. (DOC)

Supply Diversity

20. Order Gas Utilities to discuss, in future Contract Demand Entitlement filings, how changes to their pipeline capacity affect their supply diversity and, if pipeline capacity comes at a cost premium but increases supply diversity, to provide a meaningful cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option. (DOC)

Supply Reserve Margin

21. Order Gas Utilities to commit to improving their supply reserve margin practices to minimize these quantities to the greatest extent possible and be prepared to explain the level of their supply reserve margins in the future. (DOC)

Hedging

22. Order the Gas Utilities to, in their relevant annual, forward-looking gas planning or hedging filings, include their expected supply mix across different load and weather conditions throughout each month of the upcoming winter season, the forecasted minimum, average, and maximum day load requirements and the expected mix of baseload, storage, and spot supply on those days. (DOC)

Storage

23. Approve Great Plains' changes to its storage withdrawals throughout the winter that maintain greater withdrawal capability for the later part of the season. (GP, DOC)

24. Order CenterPoint, MERC, and Xcel to propose potential modifications to storage inventory management that could preserve withdrawal capabilities for later in the winter. (DOC)

25. Approve CenterPoint's plan for 55,000 Dth/day of storage withdrawals from Waterville if the two-prong price trigger occurs, depending on storage inventory levels and withdrawal constraints. (CPE)

26. Approve CenterPoint's proposal to incorporate an additional 10% of storage withdrawals from Waterville into its daily purchasing plans when it believes that additional withdrawal will be available but notes that the use of the economic trigger is limited in nature. (CPE, DOC)

27. Allow CenterPoint to explore the acquisition of additional deliverability for Waterville and potential expansion. (DOC)

Peak Shaving

28. Approve CenterPoint's plan for economic dispatch of up to 25% of its total daily LNG capacity beginning after January 20 each year if the two-prong price trigger occurs. (CPE)

29. Order CenterPoint to use the circumstances of the event, the prevailing winter, and the status of its fuel inventory to inform its peak-shaving dispatch decisions. (DOC)

30. Order Xcel to use the circumstances of the event, the prevailing winter, and the status of its fuel inventory to inform its peak-shaving dispatch decisions. (DOC)

31. Order Xcel and CenterPoint to file more dynamic proposals that recognize that calling on peaking resources depends on the economic and situational context of the utility and the market. (CUB)

Customer Communications

32. Approve Xcel's approach of engaging in economic conservation requests in anticipation of extreme spot price spikes and studying customer responses. (DOC)

33. Order MERC, CenterPoint and Great Plains to design plans that study customer responses to conservation calls. (DOC)

Gas IRPs

34. Do not pursue the concept of Gas IRPs. (Gas Utilities, DOC)

35. Order the Gas Utilites to file integrated resource plans and open a new docket seeking input on the procedure and content of in those plans . (CUB)

Risk-Sharing Mechanism

36. Order the Gas Utilites to work with stakeholders to propose, in their September 2023 AAA filings, a risk-sharing mechanism that would incentivize utilities to minimize exposure to future gas price spikes. (CUB)