414 Nicollet Mall
Minneapolis, MN 55401

September 15, 2022

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: COMMENTS-GAS PRACTICES
FEBRUARY 2021 NATURAL GAS PRICE INVESTIGATION
DOCKET NOS. G999/CI-21-135 AND G002/CI-21-610

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission (Commission) the attached comments regarding our gas practices in response to the Commission's August 23, 2022 Notice of Comment Period Docket Nos. G999/CI-21-135, G008/M-21-138, G004/M-21-235, G002/CI-21-610 and G011/CI-21-611.

We appreciate the opportunity to provide this information to the Commission. We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list.

Please contact me at lisa.r.peterson@xcelenergy.com or (612) 330-7681 or Jennifer Roesler at jennifer.roesler@xcelenergy.com or (612) 330-1925 if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
DIRECTOR, REGULATORY PRICING AND ANALYSIS

c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF A COMMISSION INVESTIGATION INTO THE IMPACT OF SEVERE WEATHER IN FEBRUARY 2021 ON IMPACTED MINNESOTA NATURAL GAS UTILITIES AND CUSTOMERS

DOCKET NO. G999/CI-21-135

IN THE MATTER OF A PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY TO RECOVER FEBRUARY 2021 NATURAL GAS COSTS

DOCKET NO. G002/CI-21-610

COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission (Commission) these Comments in response to the Commission's August 23, 2022, Notice of Comment Period, which required the Company and other gas utilities to review their natural gas supply practices and report on improvements or modifications they intended to pursue, including the timeframe for implementing these practices and proposed tariffs, if necessary. The August 23 Notice also requested gas utilities comment on integrated resource planning, the Performance-Based Gas Purchasing Plan Statute (Minn. Stat. § 216B.167) and any recommended statute or rule changes.

As we explained during the Commission's Agenda Meeting on the underlying prudence investigation, the extraordinary natural gas price spike during Presidents Day weekend 2021 was and continues to be deeply concerning. Since that time we have thought about actions the Company can take to mitigate the impact of a similar event, should it happen in the future, without unduly raising the costs to supply our customers with natural gas year over year. In this filing, we will explain a number of changes we have made to our gas supply and purchasing practices since Winter Storm Uri. The Company believes that its actions leading up to and during Winter Storm Uri were prudent, but we understand our role as a provider of natural gas in this state is to learn from Winter Storm Uri and the ongoing natural gas price volatility, making changes we deem appropriate. As the discussed below, many of the changes were made prior to the Commission's decision in the underlying prudence investigation that either do not require Commission approval or will receive Commission approval in a different docket, including:

- Procuring new transportation service agreements that allow us to strengthen the geographic diversity of supply;[1]
- Reviewing our baseload gas purchase strategy;
- Adding the Company's internal temperature forecast to the TESLA load forecasting model;
- Advocating for changes to the North American Electric Standards Board standard contract for gas purchasing;
- Regularly evaluating whether new or additional storage contracts can be added to our portfolio;
- Continuing a communications plan to specifically ask customers to conserve natural gas when prices are above a certain cost threshold;[2] and
- Entering into a peaking supply deal during the 2021-2022 heating season, where the Company had the right to call on daily supply priced at the First of Month index.[3]

Based on the Commission's August 23 Notice, we are suggesting three new changes in this filing. Each is in a slightly different procedural posture. In this filing, we:

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[1] These transportation contracts will be evaluated in the context of the Company's 2022-2023 Contract Demand Entitlements filing, Docket No. G002/M-22-429.

[2] The Commission's August 30, 2021 Order in Docket Nos. G999/CI-21-135 and G002/CI-21-610 required the Company (and other natural gas utilities) to create a Communications plan and contemplated that the plan would be approved by the Commission's Executive Secretary. As explained in more detail below, the Company's Communication Plan has not been approved by the Commission, but the Company has nevertheless been prepared to implement the Communications Plan should the threshold identified in the plan have been met.

[3] This peaking supply deal will be evaluated in the context of the Company's 2021-2022 Contract Demand Entitlements filing, Docket No. G002/M-21-589, which is still pending before the Commission.

- Identify a regulatory timing issue relating to when (and how) the Commission currently evaluates financial hedges and request feedback from parties and the Commission on whether there is a reasonable way to address these timing challenges;
- Describe our plan to start utilizing our Wescott peak-shaving facility for economic dispatch starting in the 2023-2024 heating season; and
- Request Commission approval of changes to our interruptible gas tariffs so that our interruptible customers have transparency that they will be curtailed for economic purposes when a certain trigger is met.

We look forward to engaging with stakeholders on targeted improvements or modifications that can help to protect customers from extraordinary natural gas price spikes in the future, while ensuring the Company's overall costs for natural gas supply continue to remain reasonable.

In addition to this Company-specific filing, the Company has signed on to a joint letter from the impacted gas utilities. In that letter, the joint gas utilities inform parties of a natural gas price threshold they will all use to trigger certain actions such as economic curtailment of interruptible customers. The Company plans to use the same trigger to implement its communications plan and, when we are prepared to do so, economic dispatch of the Wescott plant. Additional details of these proposals will be explained below. The joint filing also addresses questions about the Performance-Based Gas Purchasing Plan Statute and the possibility for statute and rule changes.

Again, we thank the Commission for commencing this process and look forward to receiving the parties' feedback.

I. IMPROVEMENTS OR MODIFICATIONS TO PRACTICES

A. Gas Contracting

In the Commission's August 23 Notice, the Commission specifically directed the Company to consider changes to its gas contracting practices. The Company interprets this request to mean evaluating the natural gas transportation services it secures to deliver natural gas to our distribution system and whether those contracts provide sufficient geographic diversity of supply. As explained below, we already source gas supply from multiple locations providing diversity of supply and the related reliability. In this section we explain new transportation agreements we acquired which further improve reliability and geographic diversity of our natural gas supply. These transportation agreements will be evaluated in the context of the Company's annual Contract Demand Entitlements filings, and therefore do not require explicit Commission approval in this docket.

By way of background, Minnesota has no natural gas reserves or production facilities of its own, and therefore the Company must arrange for transportation of natural gas across interstate natural gas pipelines. The natural gas may come from one of several producing areas, which for Minnesota customers is primarily the southwestern and western United States, the Chicago Hub, and western Canada. The Company builds its transportation and supply portfolio with a focus to deliver safe, reliable, gas service at a reasonable cost for its customers. The Company's plan provides significant operational and cost benefits to its customers through access to a geographically diverse supply mix and storage services. Historically, this portfolio has delivered benefits to our customers by providing reliable gas supplies, moderating costs, and allowing customers to experience decreases in gas prices. As the Company contracts for natural gas transportation services (contract demand entitlements) for the upcoming heating seasons, we are mindful of the geographic diversity of our natural gas supply. We believe geographic diversity of supply can help protect our customers from production and transportation disruptions and limit the effect of extraordinary natural gas spikes.

For service beginning with the upcoming 2022-2023 heating season, we acquired an incremental 22,000 Dth/day of backhaul firm transportation entitlement on Viking, effective November 1, 2022, to match newly acquired capacity on ANR Pipeline as part of its Wisconsin Access Project.[4] This capacity provides the Company with additional access to gas supplies from the Chicago gas markets, via ANR Pipeline and the Marshfield/Viking interconnect for delivery to customers along the Viking system in Minnesota and North Dakota. NSP historically has used delivered supply from a producer or marketer, typically sourced from the Emerson Hub to fill a portion of

[4] The Federal Energy Regulatory Commission recently approved ANR Pipeline's proposed Wisconsin Access Project at Docket No. CP21-78-000.

our design day needs as Viking has been sold out on a forward haul basis, and ANR deliveries to Marshfield have been fully subscribed. This additional capacity increases our geographic diversity of supplies by providing additional firm transportation access to supplies from the Chicago market.

The Company 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 construction of additional facilities on Viking and, therefore, the service will not be available until December 1, 2023. This capacity will transport gas supplies on a firm basis from the Emerson Hub at the U.S./Canadian border to various locations in Minnesota and North Dakota as customer demand dictates. The additional firm pipeline capacity will improve our ability to reliably access gas quantities from the Emerson Hub.

B. Purchasing

The Commission's August 23 Notice also asked the Company to evaluate purchasing practices. This filing discusses two different aspects of natural gas purchasing. First, the Company's portfolio practices--its baseload management practices as well as how storage inventory, withdrawal capabilities and weather forecasts play a role in purchasing decisions. The Company also discusses industry practices, namely the use of the NAESB standard contract, and whether changes should be made to that process.

1. The Company's Purchasing Practices

With regard to the Company's purchasing practices, this filing focuses on the Company's baseload management practices, as this comprises a significant portion of our winter supply and costs, and its forecasting practices. As explained in more detail below, last heating season (i.e, the 2021-2022 heating season), the Company purchased an average of approximately 12% more baseload supply from December 2021 through February 2022 as a result of storage inventory levels and winter conditions. While baseload purchases continue to be based on numerous factors, the Company currently plans to evaluate each month the appropriateness of purchasing incremental baseload amounts for that month. On forecasting, at the time of Winter

Storm Uri, the Company used a blend of two third-party weather forecasts as inputs to the gas model. The Company now incorporates our own internal weather forecast.

By way of background, purchasing baseload gas requires the purchaser to acquire gas in non-varying quantities for each day of the month. In deciding whether to increase baseload quantities, the Company must consider, among other things, (1) the Company's minimum load forecast for the month, (2) market conditions and expectations, (3) load expectations for the entire month, and (4) the Company's storage inventory, storage ratchets and required inventory levels at the end of the month. 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. These options raise serious issues. 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. Pipeline penalties are typically set at multiples of the daily spot price making it more expensive to incur the penalty than to pursue other options. If a utility such as Xcel Energy purchases too much gas for its low demand days, it has limited options available to it, each of which creates the potential of significant cost to customers.

The Company purchases most of our winter baseload quantity over the summer months to spread out the price risk of these large quantities. Additionally, producers seek to sell a significant portion of their winter quantity early to lock in supply and prices. This creates a market risk that if less baseload is purchased in the summer, producers may not retain adequate supply for us to fill our needs in the winter. During the winter 2021-2022 heating season the Company purchased an average of approximately 12% more baseload supply during from December 2021 to February 2022 primarily due to extended cold weather during the 2021-2022 winter which made it easier to manage higher baseload supply. At this time, the Company anticipates buying approximately the same level of baseload over the upcoming winter, however we will make any appropriate adjustments to those anticipated baseload quantities on a monthly basis. These monthly evaluations will be dependent on a number of factors, including storage inventory levels, market conditions and projected weather.

As explained during the underlying prudence investigation, the Company uses the TESLA model to forecast its natural gas loads. The TESLA model is a linear regression-based load forecasting model developed by TESLA Inc. and is used worldwide by entities in the energy and other industries. The TESLA model produces LDC load forecasts for five geographic areas—including two in the Company's natural gas service area (St. Paul Metro and Fargo) and one very near our gas service area (La Crosse, Wisconsin). At the time of Winter Storm Uri, the TESLA model used a blend of temperature forecasts from two third-party vendors—MDA/Maxar and Global Weather Corporation. At the end of last heating season (in March of 2022), the Company began to utilize the Company's internal temperature forecasts into the TESLA model. The inclusion of the Company's internal forecast provides localized expertise and perspectives of the weather forecast, and more closely aligns our weather and load forecasts.

2. *Industry Practices—the NAESB Standard Contract*

Like the vast majority of other load-serving entities, the Company purchases gas supply using the standard North American Energy Standards Board (NAESB) contract (which was accepted by FERC and codified in FERC Regulations). The current standard contract contains a very flexible force majeure provision that excuses seller performance during freezing weather conditions. Many sellers used this provision to claim force majeure and not deliver gas to purchasers during the February Event. The Company had a number of force majeure claims during Winter Storm Uri and investigated them to ensure their validity. As we have reported previously in our quarterly filings, we are trying to make policy change on the standard NAESB contract itself. On July 11, 2022, our Senior Director of Federal Regulatory Affairs presented to the NARUC Committee on Gas on the force majeure provisions in the NAESB contract and our experience during Winter Storm Uri, and then 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.

On July 25, 2022, FERC and the North American Electric Reliability Corporation (NERC) sent a letter to NAESB encouraging them to convene a gas-electric forum to address reliability challenges. The convening of this forum is consistent with one of the key recommendations in the report FERC and NERC prepared and published in November 2021 related to Winter Storm Uri. NAESB commenced this work on August 30, 2022. This forum is expected to convene virtual meetings between now and mid-November. Unlike normal NAESB activities, the forum is not expected to result in new standards but rather a report with policy recommendations that will be given to various policy makers, in three broad categories: information sharing; improved gas reliability; and fuel access

The expanded list of issues for this working group is as follows:

1. Whether and how natural gas information could be aggregated on a regional basis for sharing with Bulk Electric System operators in preparation for and during events in which demand is expected to rise sharply for both electricity and natural gas, including whether creation of a voluntary natural gas coordinator would be feasible;
2. Whether Congress should consider placing additional or exclusive authority for natural gas pipeline reliability within a single federal agency, as it appears that no single agency has responsibility to ensure the systemic reliability of the interstate natural gas pipeline system;
3. Additional state actions (including possibly establishing an organization to set standards, as NERC does for Bulk Electric System entities) to enhance the reliability of intrastate natural gas pipelines and other intrastate natural gas facilities;
4. Programs to encourage and provide compensation opportunities for natural gas infrastructure facility winterization;
5. Which entity has authority, and under what circumstances, to take emergency actions to give critical electric generating units pipeline transportation priority second only to residential heating load, during cold weather events in which natural gas supply and transportation is limited but demand is high;

6. Which entity has authority to require certain natural gas-fired generating units to obtain either firm supply and/or transportation or duel fuel capability, under what circumstances such requirements would be cost-effective, and how such requirements could be structured, including associated compensation mechanisms, whether additional infrastructure buildout would be needed, and the consumer cost impacts of such a buildout;
7. Expanding/revising natural gas demand response/interruptible customer programs to better coordinate the increasing frequency of coinciding electric and natural gas peak load demands and better inform natural gas consumers about real-time pricing;
8. Methods to streamline the process for, and eliminate barriers to, identifying, protecting, and prioritizing critical natural gas infrastructure load;
9. Whether resource accreditation requirements for certain natural gas-fired generating units should factor in the firmness of a generating unit's gas commodity and transportation arrangements and the potential for correlated outages for units served by the same pipeline(s);
10. Whether there are barriers to the use of dual-fuel capability that could be addressed by changes in state or federal rules or regulations. Dual-fuel capability can help mitigate the risk of loss of natural gas fuel supply, and issues to consider include facilitating testing to run on the alternate fuel, ensuring an adequate supply of the alternate fuel and obtaining the necessary air permits and air permit waivers. The forum could also consider the use of other resources which could mitigate the risk of loss of natural gas fuel supply;
11. Electric and natural gas industry interdependencies (communications, contracts, constraints, scheduling);
12. Increasing the amount or use of market-area and behind-the-city-gate natural gas storage; and
13. Whether or how to increase the number of "peak-shaver" natural gas-fired generating units that have on-site liquid natural gas storage. (Winter 2022-2023)

The Company will continue its advocacy to make policy changes to the NAESB standard purchase contract and participate in the NAESB forum described above.

C. Hedging

The Commission's August 23 Notice also asked the Company to evaluate its hedging practices. Financial instruments can provide price protection against monthly price volatility and can protect customers from some natural gas price increases, but oftentimes have costs associated with procuring them whether or not they give a benefit for our customers. Depending on what ultimately happens in the natural gas market, the hedge may or may not be triggered, and when adding in the cost to procure the financial instrument the hedge may or may not ultimately save customers money. As explained below, the Company annually reviews its hedging program, but the current regulatory review process contemplates infrequent or after-the-fact reviews. As we describe below, the Company 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.

By way of background the Company annually updates its Gas Price Volatility Mitigation Plan. The overall goal of the Company's plan is to reduce the exposure to and magnitude of monthly gas price spikes at a reasonable cost to our customers. The Company's financial hedging program is currently designed to insure against sharp upward price movements in the monthly market for baseload gas through the use of financial products. Because the Company's financial hedging program is focused on monthly prices increasing over future month's forecasted prices, the Company would not expect the financial aspect of its hedge program to insure against daily price spikes. The Company continually surveys the financial hedging market and has identified no counterparties that are willing to offer daily financial products at any significant quantity.

The Company's financial hedging strategy calls for hedging transactions to be contracted between the months of April through October for the upcoming winter. This timeframe allows the Company to analyze market data regarding production trends, demand trends and storage inventory levels in making its hedging decisions. The seasonal nature of the strategy is intended to provide a desired level of price risk protection while maintaining a balance between market premiums and overall plan costs.

The Commission and stakeholders review the Company's financial hedges in the context of two different types of regulatory proceedings: (1) variance requests to answer the question whether the Company can recover the costs of hedging through its Purchase Gas Adjustment (PGA) and if so, the parameters (this type of proceeding takes place approximately every three to four years) and (2) the Company's Annual Automatic Adjustment (AAA) of charges, wherein the Company provides the Gas Price Volatility Mitigation Plan it used to plan its hedges for the prior year and then details on the costs of its hedges. While this regulatory review structure has worked reasonably well in the past when gas prices were more stable, it may be worth revisiting now that gas prices are more volatile. The rule variance proceeding takes place too infrequently to react to the changing market for natural gas (for reference, the Company's last hedging rule variance filing was filed in November 2019 and grants the Company a variance to the PGA rules through June 30, 2024). The AAA review is very thorough, but takes place after the fact and therefore makes it a poor mechanism to provide timely feedback on the Company's hedging programs (for example, the Company is still waiting on a Commission decision on its 2018-2019; 2019-2020 and 2020-2021 Gas AAA filings),

The Company's currently approved hedging plan targets the Company hedging no more than 50 percent of our annual expected winter requirements (through either physical storage or financial hedging), and no more than 25 percent of our annual expected winter requirements can be hedged with monthly financial instruments. The Commission effectively also approved an annual budget limited the amount that the Company can pass through the PGA. *See* Docket No. G002/M-19-703. The 50% level has been determined to be a prudent target level when balancing costs and benefits of financial hedging programs. Although these monthly hedges were generally not triggered during the February Event, as we have seen gas prices rise this past year, we expect they could provide protection for customers in the coming heating seasons.

However, 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 our 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 percent of our 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 percent of our annual winter quantity requirements. In preparation for this heating season, the Company 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 from recovery years down the road in an AAA—perhaps under the theory that the Company did not adhere to the Commission approved budget; (3) or seek an amendment to the hedging variance, which may not be completed quickly enough in order for the Company to incorporate the feedback into its hedging transactions (as explained above, we generally enter into hedging transactions from April to October). Given the other changes in practice described here as well as the cost pressures on our customers, the Company has 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 currently overpriced for the benefits received.

Based on this recent example, the Company 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. As described above, financial hedging, in particular, is a strategy that in some years will save customers money and in other years will be a cost for a hedge that goes unutilized. The Company invites feedback from stakeholders on whether such an expedited process is feasible, or if not, their view of how the Company should address policy choices such as this in the future.

D. Storage

In the Commission's August 23 Notice, it asked the gas utilities to evaluate their storage practices. As demonstrated during Winter Storm Uri, natural gas in storage is an important reliability tool but is also can be an effective physical hedge against extraordinary natural gas price spikes and can therefore help protect customers from future pricing events. For the past several years, the Commission has asked the Company to evaluate storage alternatives. The Company credits the Commission for requiring the Company to regularly evaluate underground storage alternatives because it adds transparency to the analysis the Company regularly conducts. The Company is interested in procuring additional storage, but the demand for storage outpaces its availability, and the storage that is currently available is father away from our service territory meaning that there are additional transportation costs, and constraints to get the natural gas from storage to our distribution system. We will continue to keep stakeholders apprised of our efforts in obtaining additional cost-effective storage in our annual Contract Demand Entitlements filing.

In 2015, in the context of the Commission's consideration of a variance to the Purchased Gas Adjustment rules to recover taxes associated with storing natural gas in Kansas, the Commission ordered the Company to explain when its storage contracts were expiring and whether there were more cost-effective storage alternatives. *See* Docket No. G002/M-15-149. That analysis has been a regular part of the Company's subsequent Kansas Tax rule variances, and later, the Company's annual Contract Demand Entitlements filings. While that compliance obligation stemmed from the Commission wanting to understand whether there were more cost-effective alternatives than storing natural gas in Kansas, we are appreciative of the Commission's compliance requirement because it provides regular transparency into the storage availability and the costs related thereto.

To ensure the most cost-effective storage service for our customers, we consider the following factors when evaluating service options: reservation costs (capacity & deliverability); transportation to our service area; flexibility of services, and whether storage and transportation capacity is available for purchase. The Company currently holds storage service on three interstate providers: Northern Natural Gas (12.58 Bcf annually), ANR Pipeline (0.95 Bcf annually), and ANR Storage Company (1.16 Bcf annually). NNG storage service provides "on-demand" capabilities via its Firm Deferred Delivery (FDD) storage service in our areas. FDD service allows for immediate withdrawal from and injections to storage in response to our customer's needs providing greater reliability of service. Furthermore, during higher or lower loads than expected, this service provides significant cost savings to customers by avoiding imbalance costs, overrun penalties, and the need to buy higher-priced gas in the intra-day spot market.

NSP is exploring options to expand storage capacity. Additional storage would reduce gas purchases priced at the daily gas price, provide reliability of supplies, and, depending on the location, provide increased regional diversity. In general, interstate storage and transportation capacity continue to be fully subscribed (sold-out) near our service areas. While more distant storage providers may offer available storage capacity, the transportation capacity needed on upstream pipelines to move the gas from those storage fields to our service areas is typically fully subscribed. For example, ANR Pipeline's storage facilities and ANR Storage, connected through Viking or Northern Border Pipeline, would require expansion of their mainline facilities to provide more service to NNG interconnects and on to our service areas. The Company will continue to update the Commission on progress in this area in the context of our annual Contract Demand Entitlements filing.

E. Peak-Shaving

As the Department of Commerce has noted: "peak shaving has historically been designed, and used in this market, as a reliability tool for the distribution system that supplements the system in the event of near design-day conditions or in response to other unexpected reliability issues."[5] In the underlying prudence investigation, certain parties made the argument that just because an asset was historically designed and used for a specific purpose, it need not continue to be used in that manner. The Company agrees that *so long as* the asset's original purpose is still met (in this case, reliability to our customers during the coldest days our system is expected to experience), the asset can be used in additional ways. To that end, the Company is evaluating the potential to economically dispatch its Wescott peaking plant starting in the 2023-2024 heating season, when certain conditions are met.

By way of background, the peaking plants have *historically* had two primary purposes: (1) peak shaving to supplement pipeline capacity as the system approaches design day conditions and (2) supplementing supply when intra-day gas demand is higher than anticipated and no other gas supply is immediately available. The Company plans for Design Day to meet customer requirements under the coldest expected conditions. With regard to the second primary purpose, a "gas day" runs for a 24-hour period starting at 9:00 a.m. This means the final part of the gas day overnight and very early in the morning when it can be hard to find a willing gas supplier and there are no opportunities to schedule transportation for such gas. So, in circumstances where it appears that gas demand is going to outpace the amount of gas we purchased and

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[5] Comments of the Minnesota Commerce Department, Division of Energy Resources, May 10, 2021, Docket No. G999/CI-21-135.

have available for the day (for example, because it is colder than forecast), we will inject gas from the peaking plants into the gas system.

Starting at the beginning of the 2023-2024 heating season, the Company expects to use LNG stored in its Wescott facility in situations where the price of gas reaches extraordinary levels, like they did over Presidents Day weekend, while maintaining sufficient inventory to meet Design Day and operational requirements. The Company proposes to operate Wescott, up to its maximum deliverable capacity (i.e., 156,000 Dth/day), within the sole discretion of the Company when the following triggers, proposed by the Gas Utilities in their September 15, 2022 filing, have been met:

The prior gas day (or multiple days in the case of weekends and holidays) settled Gas Daily daily index price at the Ventura or Demarc pricing hubs:

1. is greater than or equal to $50.00 per Dth; <u>and</u>
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.

Use of the facility for economic dispatch in the event the triggers have been met will depend on the level of LNG inventory at the time of the event. Plant operations are always subject to operational and safety considerations which may preempt its production of gas supply. The Company will, first and foremost, maintain inventory levels that support the system during a design day event or other operational needs. Liquefying natural gas (i.e., cooling the gas to a temperature at which it turns from a gas to a liquid and can be stored) is not a quick process. Some work was done on the plant's liquefaction equipment during the summer of 2022 limiting the time the Company had available to liquefy LNG for the upcoming heating season. Based on this, the Company does not expect to have sufficient additional inventory to economically dispatch Wescott during the 2022-2023 heating season. Over time, however, the Company plans to build and maintain inventory for price mitigation operations. Timing of any potential price mitigation event will be a key factor in the decision to dispatch the plant for price mitigation purposes. As alluded to above, Wescott has limited ability to liquify, or make, LNG. As a result, inventory in the tank will be reserved to ensure sufficient quantities for a design day, reliability events like an interstate pipeline failure (as in 2014 with TransCanada), system operational requirements, and the probability of other needs later in the winter. As we move through the winter season, the probabilities of such events change and may free more inventory for price mitigation. As mentioned above, the Company expects to start this economic dispatch proposal in the 2023-2024 heating season, depending on the LNG inventory at Wescott.

The Company focuses its economic dispatch proposal on its Wescott plant because of the differences between the Wescott LNG plant on one hand and the Sibley and Maplewood Propane Air plants on the other:

- The technical maximum single day withdrawal capacity of Wescott is 156,000 Dth, primarily limited by the downstream distribution system which serves the St. Paul metro area. The Company needs to maintain a heel within the tanks (i.e., cannot drain the tank completely during a heating season). Nevertheless, the storage volumes make Wescott capable of dispatching its maximum output numerous days *per heating season*. That said, the Company does not readily have the ability to liquefy and store additional natural gas during the heating season.

- By contrast, Sibley can store approximately 114,000 Dth equivalent of propane and Maplewood can store approximately 124,000 Dth equivalent of propane (i.e., a combined 2.6 million gallons of propane). Sibley has a technical maximum single day withdrawal capacity of 46,000 Dth and Maplewood has a technical maximum single day withdrawal capacity of 44,000 Dth. Like Wescott, these limitations are primarily limited by the downstream distribution system. Propane is delivered in its liquid state via truck to Sibley and Maplewood. Trucking propane to refill Sibley and Maplewood can occur over the heating season. The storage vessels at Sibley and Maplewood make those plants capable of dispatching their maximum output approximately 2 days *before needing to be refilled*. Trucking up to 2.6 million gallons of propane to Sibley and Maplewood customarily takes several weeks and is subject to the market price of propane.

Because of the smaller capacity of the tanks and the time and price uncertainty of replacement fuel at Sibley and Maplewood, the Company is focusing its economic dispatch proposal on the Wescott plant.

As the Commission and stakeholders may well be aware, interruptible customers do not pay for the Company's peaking plants. Peaking plants are a capacity resource. As the Company 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, the Company believes it is important to use the same trigger for economic dispatch of the plants and economic curtailment of interruptible customers as further discussed below. If the triggers differ, we would need to reallocate costs to ensure different classes of customers are fairly paying for the infrastructure they use.

As the Company continues to develop its plan to economically dispatch the Wescott plant, it may require additional regulatory approvals (for example, to address the cost allocation issue above). The Company will endeavor to make such filings timely so that they are not a barrier to the planned implementation timeline.

F. Interruptible Customers

In this filing, we are requesting Commission approval of change to our interruptible tariffs to make clear that the Company plans to economically curtail its customers when the following trigger, proposed by the Joint Gas Utilities in their September 15, 2022 filing, has been met:

The prior gas day (or multiple days in the case of weekends and holidays) settled Gas Daily daily index price at the Ventura or Demarc pricing hubs:

1. is greater than or equal to $50.00 per Dth; <u>and</u>
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.

These proposed changes to our tariff, in clean and redline, are attached to this filing as Attachment A. We believe these changes are in the public interest so that our customers, the Commission and stakeholders have transparency into the circumstances under which we propose to economically curtail our interruptible customers.

By way of background, Xcel Energy offers natural gas service on an interruptible basis to Commercial and Industrial sales and Transportation customers. We have approximately 300 non-firm natural gas sales customers and 15 non-firm transportation customers in Minnesota. Customers on interruptible rate services agree to curtail their gas usage within one hour of notification and, in return, they pay a reduced rate per therm on their gas distribution rates year-round. In order to qualify for this program, customers must provide and maintain suitable and adequate alternate fuel-capable standby facilities and have access to sufficient standby alternate fuel for curtailment periods. When gas interruptions are called, we count on customers to curtail system gas use and switch to their alternate fuel source. If unauthorized use of gas occurs during a control period, we are required by tariff to impose penalties, which are then credited to firm customers.

In the last several years, we made a number of adjustments to our interruptible tariff language and the penalty structure for curtailment non-compliance, but full compliance from our interruptible customers when we call on them continues to be a challenge. The Company experienced significant customer non-compliance over multiple curtailments called during the 2013-14 heating season. Consequently, we proposed tariff language changes to strengthen the tariff language disallowing unauthorized gas usage during curtailments, as well as increase the penalty charge for unauthorized use of gas from $10 per Dth to $50 per Dth. Those tariff changes were effective May 24, 2015.[6] As a result of the Commission proceeding for the 2019 severe weather event,[7] and because of the continued issues of non-compliance, we modified our interruptible tariff language regarding customer contacts, attestation of functioning back-up equipment, and customer responsibility to comply with curtailment requests. Penalties for repeated curtailment non-compliance were set at $100 per Dth. These tariff changes were effective May 1, 2020. We are required to provide an analysis in our September 1 AAA filing of the circumstances under which a customer fails to curtail in two separate events or with a single noncompliant event that is significant.

[6] Docket No. G002/M-14-540.
[7] Docket No. E,G999/CI-19-160.

Interruptible Service is provided pursuant to two different tariffed offerings: our Interruptible Service (Rate Codes: Small 105 & 111, Medium 106, Large 120) and our Interruptible Transportation Service (Rate Codes: Small 123, Medium 107, Large 124). Both of these tariffs clearly provide, under the Character of Service header, that "[d]elivery of gas hereunder shall be subject to curtailment whenever requested by the Company." Based on this tariff language, the Company feels that it has the authority to curtail for a variety of reasons—most commonly reliability, but also for economic purposes if it chooses to do so. Nevertheless, we believe it is reasonable to add a trigger for economic curtailment to the tariff so that our customers on this program are well informed of this proposal and have transparency into the trigger as they consider service under this tariff.

The requested tariff change can be effective as soon the Commission approves it, but the Company would ask the Commission to consider this tariff change to be effective at the end of the 2022-2023 heating season (i.e., April 1, 2023). Changing the Company's interruptible tariff in the middle of a heating season is likely to cause confusion and frustration for our interruptible customers.

G. Customer Communications

Pursuant to Commission's August 30, 2021 Order in Docket No. G-999/CI-21-135, the Company developed and filed with the Commission a Communication Plan to call on customers to conserve when a certain threshold is met. Since its November 1, 2021 Communications Plan filing, the Company has been prepared to implement its communications plan should it have been or should it be necessary. In this filing, the Company is informing stakeholders that it is still committed to implement its communication plan, with the trigger proposed in the September 15, 2022 Joint Gas Utilities filing.

Throughout the winter, the Company frequently provides messaging to customers about conservation. This includes using social media to encourage customers to follow easy tips to save energy during the cold season, as well as sharing safety and winter weather readiness messages through both social media and media. Historically, when we issued broader pleas for conservation (for example, during the 2019 Polar Vortex), they were based on ensuring system reliability, and reserved for situations where we need curtailment by our customers in order to preserve the operation of the system and meet the needs of all our customers.

In the Commission's August 30, 2021 Order in Docket No. G999/CI-21-135, the Commission directed "[b]y November 1, 2021, the Gas Utilities shall file for approval communications plans for future price spikes. The plan should include multiple means of customer outreach, including phone calls, text messages, emails, and social media. The Commission delegates authority to the Executive Secretary to review and approve communications plans."

Consistent with the Commission's Order Point, on November 1, 2021, the Gas Utilities jointly filed a communications plan which contemplated sending customers a plea to conserve when certain conditions were met. The threshold proposed in the Gas Utilities' November 1, 2021 filing would have been triggered during the TransCanada pipeline explosion event in 2014, the price increase around New Year's 2018, and the February Event in 2021.

On November 1, 2021, the Company also made its own filing detailing how we intended to communicate with our customers should the conditions articulated above be met. The Commission's Order point required the Communication Plan to include "multiple means of customer outreach including phone calls, text messages, e-mails and social media." As demonstrated by the chart below, our Communication Plan included each component, but in some instances limited the scope of some means of communication. For example, if Xcel Energy were to call each of its approximately 480,000 natural gas customers in a short amount of time, we'd expect a certain percentage of them to call back with clarifying questions. Our call centers are not staffed to handle that volume of incoming returned calls, nor do we think it's particularly wise to send more calls to the call center during periods that will more likely than not occur during extreme weather when customers with emergencies may be trying to reach us. Therefore, we proposed to call only our Commercial and Industrial customers. This is a smaller number of customers that generally have higher usage (sometimes materially higher usage) than our residential customer class. We will reach out to all customers regardless of class via e-mail and text to the extent we have their contact information and have permission to contact them.

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.

The Company has developed templates for these communications so that we will be ready to act promptly should such a notice be required, but each communication will need to be tailored somewhat to the unique facts of the situation giving rise to the plea for conservation.

To date, the Company's communication plan has not been commented on by any stakeholder or approved by the Commission's Executive Secretary. While it was contemplated, we do not believe specific Commission action is needed with regard to the plan: the Company has been prepared since its November 1, 2021 filing to implement this communications plan should gas prices exceed the trigger. As mentioned above the Company will utilize its proposed communication plan when the following trigger, proposed by the Joint Gas Utilities in their September 15, 2022 filing, has been met:

The prior gas day (or multiple days in the case of weekends and holidays) settled Gas Daily daily index price at the Ventura or Demarc pricing hubs:

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.

As a reminder, utilizing this Communication Plan would be expected to have limited impact on the amount of natural gas the Company purchases the first several times the Company makes such a plea since we do not know how customers will react to a plea to conserve for economic reasons. Over time, after the Company has issued multiple pleas and gains this understanding, it may allow us to change the amount of natural gas the Company purchases. Therefore, this proposal should be viewed as one that has the potential to protect customers from price spikes but only once we have additional understanding of our customer's reaction to calls to conserve.

H. Other Relevant Practices

Since Winter Storm Uri, the Company has looked for different types of natural gas supply deals to determine whether purchases structured different can help to protect customers from extraordinary natural gas price spikes. As described below, the Company found a peaking supply deal and purchased it for last heating season. The Company has not yet found a similar peaking supply deal for the upcoming 2022-2023 heating season but continues to look for a deal that will provide protection for our costs and prices that seem to be commensurate with the level of protection.

During the 2021-2022 heating season, the Company entered into a peaking supply deal designed to limit a part of our exposure to a dramatic increase in daily spot prices like those experienced during Winter Storm Uri. Typical peaking deals allow the Company to call on supply at the daily market price, thus exposing those quantities to daily price fluctuations. The deal that the Company entered into allowed the Company up to 10,000 Dth/day at the first-of-month index price. It was entered into to limit exposure to significant upward changes in daily spot prices on up to 10,000 Dth/day of peaking supplies. This deal protected a small quantity of gas from Winter Storm Uri type price increases. The Company has been unable to identify suppliers willing to do such deals at larger quantities. Suppliers report that they do not have the financial strength to offer such daily price protection at larger quantities. However, we will continue to search for more such deals in the future. This physical supply structure required an incremental demand cost of approximately $1.3 million. The Commission has yet to consider the Company's Contract Demand Entitlements filing for the 2021 heating season, but in the Department's 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."[8]

II. OTHER TOPICS REQUESTED

A. Integrated Resource Planning

As the Commission and stakeholders are aware, together we all are currently or about to address important natural gas policy questions in numerous regulatory dockets:

- the issues being investigated in this Notice of Comment period, stemming from the February 2021 natural gas price spike;
- the Future of Gas docket, G999/CI-21-565, which will evaluate changes to natural gas utility regulatory and policy structures needed to meet or exceed Minnesota's greenhouse gas (GHG) emission reduction goals, commencing with technical conferences in September 2022;
- the Natural Gas Innovation Act, and the expectations for innovation plans filed by some natural gas utilities in 2023;
- the Energy Conservation and Optimization (ECO) Act, and the expectation that the first conservation plans under ECO will be filed in mid-2023; and
- potentially, questions relating to Gas Utility Infrastructure Costs in the event the legislature does not reauthorize Minn. Stat. § 216B.1635 before it expires on June 30, 2023.

[8] Comments of the Minnesota Commerce Department, Division of Energy Resources, February 14, 2022, Docket No. G002/M-21-589.

In addition, the Company announced a Net-Zero Vision for Natural Gas on November 1, 2021. Through this vision, we are committed to delivering reliable, affordable natural gas service with 25 percent fewer GHGs by 2030 (from 2020 levels) and net-zero emissions by 2050. This starts by accelerating our plans to reduce methane emissions and our goal to purchase natural gas only from suppliers with certified low-methane emissions once those supplies become available and improving our gas delivery system to achieve net-zero methane emissions by 2030. Therefore, eventually, this vision will bring additional public policy questions to the Commission.

Reflecting on all of this important work, the Company believes that integrated natural gas resource planning should be discussed, but that the Commission and stakeholders should take the time in the above referenced policy dockets to get the details right. (It's worth noting that integrated resource planning is an identified topic of discussion in the Future of Gas docket). As we wait for that work to make progress, the Company wants to highlight all of the valuable resource planning-type information the Company gives to parties in the context of the Contract Demand Entitlements filing. Admittedly, the Contract Demand Entitlements filing is a filing focused on the short term (i.e., the next heating season), but gives parties important and valuable information on the Company's gas transportation and storage contracting efforts as we are waiting for the details of integrated resource planning to be fleshed out. With regard to the Contract Demand Entitlements filing: today, that filing gives details on:

- our firm customers at a high level and by customer class (Attachment 1, Schedule 1, Pages 1-4)
- their monthly historical usage by month for the previous year (Attachment 1, Schedule 4, Page 1),
- the calculation of our expectations for the design day demand in the coming heating season at a high level and by customer class (Attachment 1, Schedule 1, Page 1-4)
- how that compares to the year previous (Attachment 1, Schedule 1, Page 5), and
- the transportation entitlements and peak shaving resources that we have obtained to serve their firm needs at a high level and detailed level (Attachment 1, Schedule 5, Page 1 and Attachment 2, Schedule 1, Pages 2-3.

The information about transportation entitlements allows the stakeholders to understand:

- the geographic diversity of our natural gas supply (Attachment 1, Schedule 5, Page 1),
- the lengths of our transportation contracts and their expiration dates (Attachment 2, Schedule 1, Pages 1-2), and
- whether the Company has entered into new peaking supply deals like the one described in Section I.H above (Attachment 1, Schedule 2, Page 1).

In addition, the petition gives details on our storage portfolio, when our storage contracts expire and the cost of storage alternatives (Petition Section V.I). The filing also describes the Company's financial hedges entered into for the upcoming heating season (Attachment 3, Schedule 1, Page 2).

As demonstrated, this is a tremendous amount of information about our near-term expectations about our firm customers' natural gas needs and our plans to meet those needs, but its significance might not be fully appreciated by stakeholders because of the question the Commission customarily seeks to answer in a Contract Demand Entitlements docket (i.e., whether the Commission should accept the proposed level of demand entitlements and allow the Company to recover the costs through the PGA). In future Contract Demand Entitlements filings, the Company will provide this context for all of the valuable information that is given in the docket.

Admittedly, the Contract Demand Entitlement filing does not contain all of the information commonly contained in a resource plan, like conservation programs, demand side resources and a longer-term look at the Company's expected demand and supply. These components, however, will be informed by the policy dockets and discussions the Commission is about to undertake in this docket. For these reasons, the Company recommends that a broader discussion about integrated resource planning be move to one of the other policy dockets for further development.

B. Statutory or Rule Changes

As discussed in the joint gas utilities filing, the Company has not identified or proposed any statutory or rule changes. Should the Company identify any statute or rule changes in the future, however, we will bring them to the Commission's attention.

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

As discussed in the joint gas utilities filing, CenterPoint Energy is the only Company to have a Performance-Based Gas Purchasing Plan under Minn. Stat. § 216B.167. Throughout the years, the Company 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 the Company's experience and our evaluation of performance-based mechanisms in other states, it takes years and considerable stakeholder engagement to get mechanisms correct since the mechanism needs 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, the Company is willing to participate in such discussions. Due to the time, stakeholder engagement involved and other interrelated policy issues that the Commission is currently considering, however, such a mechanism would likely take a long time to develop well.

CONCLUSION

We appreciate the opportunity to provide this information to the Commission.

Dated: September 15, 2022

Northern States Power Company

Redline

AVAILABILITY

This rate is available to any interruptible commercial or industrial customer. Customer's rate will be based on peak day demand: Small – less than 2,000 Therms; Medium – more than 2,000 and less than 50,000 Therms; Large – more than 50,000 Therms. Customer agrees:

1. To curtail use within one hour after Company notification,
2. To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3. To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder.

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion. If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply. However, any use under this rate is still curtailable at Company option.

Curtailment notifications will be made to customer provided notification devices (*e.g.* phone, email, text
message, fax, pager) a minimum of one hour prior to the curtailment start. Notifications identifying the end of
the curtailment period will be made to interruptible gas customers in the same manner. The Company will ~~N~~
complete customer curtailment notification testing by December 1 annually. ~~N~~

CHARACTER OF SERVICE

Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, explicitly including N
times when the prior gas day (or multiple days in the case of weekends and holidays) settled Gas Daily index N
price at the Ventura or Demarc pricing hubs: N

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

~~.~~ Service shall be provided through a Company owned and maintained meter with telemetering or other automated meter reading capabilities installed. Customer shall provide, install, and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment.

If the Customer fails to provide phone and/or electrical service that meets Company requirements, then the Company may take one of the following actions and charge the Customer for the costs:

1. Equip customer with cellular meter reading technology, if service is available, for an initial cost of $1,800 and a monthly cost of $10.00 for cellular service and maintenance.
2. Equip customer with a recording instrument for an initial cost of $2,100 and a monthly cost of $52.44 for reading the recording instrument manually each month by the Company via laptop computer.
3. A Small Interruptible customer that meets size requirements may be moved to service on Commercial Firm Service (does not require telemetering).

(Continued on Sheet No. 5-11)

Clean

AVAILABILITY
This rate is available to any interruptible commercial or industrial customer. Customer's rate will be based on peak day demand: Small – less than 2,000 Therms; Medium – more than 2,000 and less than 50,000 Therms; Large – more than 50,000 Therms. Customer agrees:

1. To curtail use within one hour after Company notification,
2. To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3. To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder.

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion. If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply. However, any use under this rate is still curtailable at Company option.

Curtailment notifications will be made to customer provided notification devices (*e.g.* phone, email, text message, fax, pager) a minimum of one hour prior to the curtailment start. Notifications identifying the end of the curtailment period will be made to interruptible gas customers in the same manner. The Company will complete customer curtailment notification testing by December 1 annually.

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, explicitly including N
times when the prior gas day (or multiple days in the case of weekends and holidays) settled Gas Daily index N
price at the Ventura or Demarc pricing hubs: N
1. is greater than or equal to $50.00 per Dth; <u>and</u> N
2. is greater than or equal to five times the weighted average cost of gas forecast for the month at issue in the N
utility's filed PGA for that month. N

Service shall be provided through a Company owned and maintained meter with telemetering or other automated meter reading capabilities installed. Customer shall provide, install, and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment.

If the Customer fails to provide phone and/or electrical service that meets Company requirements, then the Company may take one of the following actions and charge the Customer for the costs:
1. Equip customer with cellular meter reading technology, if service is available, for an initial cost of $1,800 and a monthly cost of $10.00 for cellular service and maintenance.
2. Equip customer with a recording instrument for an initial cost of $2,100 and a monthly cost of $52.44 for reading the recording instrument manually each month by the Company via laptop computer.
3. A Small Interruptible customer that meets size requirements may be moved to service on Commercial Firm Service (does not require telemetering).

(Continued on Sheet No. 5-11)

CERTIFICATE OF SERVICE

I, Crystal Syvertsen, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket Nos. G999/CI-21-135
G002/CI-21-610

Dated this 15th day of September 2022

/s/
____
Crystal Syvertsen
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Brenda A.	Bjorklund	brenda.bjorklund@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-610_Official Service List
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Barbara	Case	barbara.case@state.mn.us	Office of Administrative Hearings	600 N. Robert St. St. Paul, Mn. 55101	Electronic Service	No	OFF_SL_21-610_Official Service List
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-610_Official Service List
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