414 Nicollet Mall
Minneapolis, Minnesota 55401

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August 2, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-19-498

Dear Mr. Wolf:

Enclosed is the Petition for approval of changes in Contract Demand Entitlements of Northern States Power Company, doing business as Xcel Energy, pursuant to Minn. Rule 7825.2910, Subp. 2.

Portions of our filing contain trade secret information as defined under Minn. Stat. § 13.37. As such, this data is protected from public disclosure and has been marked accordingly. Xcel Energy makes extensive efforts to maintain the secrecy of this information. This information is not available outside the Company except to other parties involved in contracts and to regulatory agencies under the confidentiality provisions of state or federal law, as evidenced by the non-disclosure provisions in the contracts. Xcel Energy also provides this information to state regulatory agencies in the Annual Automatic Adjustment of Charges Reports and in the monthly purchased gas adjustment (PGA) filings in the confidential trade secret versions of these reports.

The supply information has economic value to Xcel Energy, its customers, suppliers, and competitors in at least three ways. If suppliers know the terms of Xcel Energy's supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. Suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Competitors of Xcel Energy such as other LDCs also purchase their services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may offer slightly better prices to suppliers, denying Xcel Energy's access to this gas or other services.

Any of these results would harm Xcel Energy and its natural gas customers. Because Xcel Energy competes for supplies, transportation, storage, and other services in the wholesale market, disclosure would directly harm Xcel Energy by making its delivered supply cost less competitive. To the extent that Xcel Energy supply costs rise, Xcel Energy's regulated sales customers would have to pay higher natural gas rates. This result would not serve the public interest.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service lists.

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

Sincerely,

/s/

LISA PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF CHANGES IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-19-___

PETITION

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition for approval of a Change in Contract Demand Entitlements, pursuant to Minn. Stat. § 216B.16, Subd. 7 and Minn. Rule 7825.2910, Subp. 2. This petition seeks approval from the Commission to allow the Company to implement, through the PGA, changes in our interstate pipeline transportation, storage entitlements, and other demand-related contracts for the upcoming year. We have projected an increase in Minnesota design day requirements of 7,955 Dekatherms, with an increase in demand related costs of approximately $13,686,106 (or 27%) for the 2019-2020 year. Approximately 90% of this increase is due to one interstate pipeline transportation provider significantly raising its tariff rates.[1] Annually updating our natural gas transportation, storage entitlements, and supply contracts is important to ensure the Company has access to sufficient capacity to cover the anticipated peak demand of our natural gas customers.

The Company respectfully requests approval to implement our 2019-2020 Heating Season Supply Plan effective November 1, 2019, for customers served with natural gas in the State of Minnesota. Pursuant to Minn. Rule 7825.2920 and prior Commission practice, we will provisionally implement the PGA rate changes associated with this filing on November 1, 2019.

[1] This expected rate increase is described in more detail on Attachment 1, page 8 (Section A.4.e). The Company filed a protest with the Federal Energy Regulatory Commission (FERC) and will be an active participant in the FERC proceeding. The Company will update this filing if there is any rate change resulting from the FERC proceeding.

In the October 1, 2018 Comments of the Department of Commerce, Division of Energy Resources, in last year's Contract Demand Entitlement filing, Docket No. G002/M-18-528, the Department requested Xcel Energy to provide not only the costs to Xcel Energy of the "Northern Lights 2019" project, but also a detailed description of the incremental annual and/or winter peak-day capacity that Xcel Energy has contracted with NNG. This can be found in Attachment 1, Page 5 and Attachment 1, Schedule 2, Page 2 of 2.

The following attachments are included with this Petition:

- Attachment 1: Filing Requirements Pursuant to Minn. Rule 7825.2910, Subp. 2.
- Attachment 2: Information Provided in Response to the Department Letter Dated October 1, 1993 and Storage Entitlements required by Order dated October 16, 2015 in Docket No. G002/M-14-654.
- Attachment 3: Information Provided in Response to Report Requirements in Docket No. G002/M-08-46 and Order dated April 22, 2016 in Docket No. G002/M-16-88 Regarding Use of Financial Instruments to Limit Price Volatility.

I. SUMMARY OF FILING

A one-paragraph summary of the filing accompanies this Petition pursuant to Minnesota Rule 7829.1300, Subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, Subd. 3, Xcel Energy has electronically filed this document. In compliance with Minn. Rule 7825.2910, Subp. 3, Xcel Energy has served a summary of this Petition on the interveners in the two most recent (2009 and 2006) general rate case filings for the Company's natural gas utility operation. The Summary has also been served on all parties on Xcel Energy's miscellaneous gas service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. Rule 7829.1300, Subp. 3, Xcel Energy provides the following required information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Mara K. Ascheman
Senior Attorney
Xcel Energy
414 Nicollet Mall, 401 - 8^{th} Floor
Minneapolis, MN 55401
(612) 215-4605

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on August 2, 2019. The Company requests Commission approval to implement the rate impact of this filing in our purchased gas adjustment (PGA) effective with November 1, 2019 usage. Pursuant to Minn. Stat. § 216B.16, Subd. 7, Minn. Rule 7825.2920, and our Purchased Gas Adjustment tariff (Minnesota Gas Rate Book Sheet Nos. 5-40, revision 2; 5-41, revision 7; 5-42, revision 3), Xcel Energy will provisionally place the PGA changes into effect on November 1, 2019, subject to later Commission approval.

D. Statute Controlling Schedule for Processing the Filing

The applicable statute is Minn. Stat. § 216B.16, Subd. 7. This statute does not state a specific timeframe for Commission action. The applicable rules are Minn. Rules 7825.2910, Subp. 2, 7825.2920, 7829.1300, and 7929.1400. Under Minn. Rule 7829.0100, Subp. 11, the Commission treats all filings that do not fall into a specific category as Miscellaneous Filings. Minn. Rule 7829.1400, Subpts. 1 and 4, permit comments in response to a miscellaneous filing within 30 days of filing, with reply comments 10 days thereafter.

E. Utility Employee Responsible for Filing

Lisa Peterson
Manager, Regulatory Analysis
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
(612) 330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minnesota Rule 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

Mara K. Ascheman	Lynnette Sweet
Senior Attorney	Regulatory Administrator
Xcel Energy	Xcel Energy
414 Nicollet Mall, 401 - 8th Floor	414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401	Minneapolis, MN 55401
mara.k.ascheman@xcelenergy.com	regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Lynnette Sweet at the Regulatory Records email address above.

V. DESCRIPTION AND PURPOSE OF FILING

This filing seeks Commission approval to allow the Company to implement, through the PGA, changes in our interstate pipeline transportation, storage entitlements, and other demand-related contracts for the upcoming year. Updating our natural gas transportation, storage entitlements, and supply contracts on an annual basis is important to ensuring the Company has access to sufficient capacity to cover the anticipated peak demand of our natural gas customers. To determine the amount required, we consider our forecast of customer needs under Design Day (DD) conditions. By comparing that anticipated need to our current supply arrangements, we can determine what incremental additions are needed to ensure we can meet our customer needs under the most extreme conditions at reasonable cost.

Pursuant to Minn. Rule 7825.2920 and prior Commission practice, we will provisionally implement the PGA rate changes associated with this filing on November 1, 2019, and respectfully request Commission approval of the revised entitlements effective on November 1, 2019. We list the changes reflected in this filing below.

A. Change in Design Day

Our filing reflects a change in our DD forecast from the 2018-2019 heating season, as described in Attachment 1, Page 3. Our forecasted firm customer count in Minnesota State increased by 4,307 customers, from 461,078 forecast for the 2018-2019 heating season to 465,382 forecast for the 2019-2020 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 7,955 Dekatherms (Dth), from 735,741 to 743,696.

B. Change in Resources to meet Design Day

Reflected in this filing are changes in our resources used to meet our DD customer requirements, including entitlements on our pipeline and storage supplier systems: Northern Natural Gas Company, Viking Gas Transmission Company, Great Lakes Gas Transmission Company, ANR Pipeline Company, WBI Energy Transmission, and ANR Storage Company. Depending on the service, these changes take effect at various times during the heating season.

Attachment 1 and Attachment 2 provide background information regarding each of these proposed changes. Specifically, Attachment 1 contains the following documentation required by Minn. Rule 7825.2910, Subp. 2:

- a description of the factors contributing to the need for changing demand;
- the Company's DD demand by customer class and the change in DD demand, if any, necessitating the demand revision;
- a summary of the levels of winter versus summer usage for all customer classes; and
- a description of DD gas supply from all sources under the new level, allocation, or form of demand.

The information provided in Attachment 2 is in response to the October 1, 1993 letter from the Department and the October 16, 2015 Order of the Commission,[2] and outlines the changes in the Company's Energy Firm DD Requirements, daily pipeline entitlement, pipeline billing units and storage entitlements from the 2018-2019 entitlement levels.

[2] Docket No. G002/M-14-654.

C. Change in Jurisdictional Allocations

The changes in the DD forecast slightly alter the allocation of entitlements between the Minnesota and North Dakota retail natural gas jurisdictions. This filing updates this allocation to reflect the latest DD forecast. The DD allocation factor increased slightly for the Minnesota State jurisdiction from 87.51 percent to 87.57 percent.

D. Change in Supply Reservation Fees

This filing also reflects updated costs for firm gas supply reservation fees. The total change in supplier reservation charges is an increase of $111,882.

E. Heating Season Plan for Use of Financial Instruments

Attachment 3 provides information in response to the reporting requirements established in Docket No. G002/M-12-519 (Order dated September 23, 2013) regarding our use of financial instruments to limit commodity price volatility, and Docket No. G002/M-16-88 (Order dated April 22, 2016) regarding benefits to customers. The attachment discusses the anticipated benefits of the contracts to ratepayers and shows a summary of hedge transactions for the 2019-2020 heating season.

F. Reserve Margin Information

We propose a capacity reserve margin of 6.4 percent for the 2019-2020 heating season, as discussed in Attachment 1, section C and Attachment 2, Schedule 1, Page 3 of 3.

G. Information Provided in Attachments

Xcel Energy has endeavored to provide all requested information, and has taken steps to ensure the filing's accuracy so that this Petition contains the necessary information for approval of the changes in Contract Demand Entitlements. The location of specific types of information is detailed in the List of Attachments below.

Attachment 1: Filing Requirements Pursuant to Minn. Rule 7825.2910, Subp. 2

Schedule	Title
1	Derivation of Minnesota Jurisdiction Allocation Factor
2	Demand Cost of Gas Impact
3, page 1	Summary of Design Day Demand by Customer Class
3, page 2	Derivation of Actual Peak Day Use Per Customer
4	Historical Sales – Seasonal Usage
5	Firm Supply Entitlements

Attachment 2: Information Provided in Response to the Department Letter dated October 1, 1993 and Commission Order dated October 16, 2015.

Schedule	Title
1, page 1-2	Demand Profile, Storage Entitlements
1, page 3	Changes to Contract Entitlements
2, page 1-3	Rate Impact
2, page 4	Derivation of Current PGA Costs

Attachment 3: Information Provided in Response to Report Requirements in Docket No. G002/M-08-46 Regarding Use of Financial Instruments to Limit Price Volatility, and Docket No. G002/M-16-88 (Order dated April 22, 2016) regarding benefits to customers.

Schedule	Title
1	Summary of Hedge Transactions

VI. EFFECT OF CHANGE UPON XCEL ENERGY REVENUE

As calculated in Attachment 1, Schedule 2, Page 1 of 2, the effect of the proposed changes in demand cost upon Xcel Energy's Minnesota State annual revenue is an increase of $13,686,106 or about 27 percent of the total Minnesota State demand costs, effective November 1, 2019. The cost change will automatically be reflected in rates through the operation of the Company's PGA clause. The demand rate calculation is shown in Attachment 2, Schedule 2, Page 4 of 4.

CONCLUSION

Xcel Energy respectfully requests Commission approval of our 2019-2020 Heating Season Supply Plan effective November 1, 2019, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2019 usage. Approval will enable us to provide continued reliable and competitive service for our natural gas customers in Minnesota. The Company will provisionally reflect the change in entitlement costs associated with the revised contract demand entitlements in the Company's November PGA, subject to later Commission approval.

Dated: August 2, 2019

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF CHANGE IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-19-___

PETITION

SUMMARY OF FILING

Please take notice that on August 2, 2019, Northern States Power Company, doing business as Xcel Energy, filed a Request for Change in Contract Demand Entitlements pursuant to Minnesota Rule 7825.2910, Subp. 2. Xcel Energy requests Commission approval to implement its 2019-2020 Heating Season Supply Plan effective November 1, 2019. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2019, subject to later Commission approval.

ATTACHMENT 1

Northern States Power Company

Filing Upon Change in Demand
Filing Requirements Pursuant to Minnesota Rule 7825.2910, Subp. 2

Northern States Power Company

Filing Requirements Pursuant to Minnesota Rule 7825.2910, Subp. 2
Filing Upon Change in Demand

A. Description of the factors contributing to the need for change in demand:

As discussed in our Petition, the factors contributing to the need for a change in demand include:

- Increase in Design Day (DD) requirements,
- Changes in Resources required to meet the DD and provide an adequate reserve margin,
- Updates to Jurisdictional Allocations, and
- Changes in Supply Reservation Fees.

We discuss each of these factors below.

1. Change in Design Day

Our objective in calculating DD customer demand is to forecast anticipated demand at design temperatures, so that adequate firm supply resources may be planned for and made available if DD weather conditions occur. We recognize that customer response to temperature is dynamic, particularly if we experience severely cold seasonal temperatures. Therefore, we continue to: (1) calculate DD using both Actual Peak Use per Customer Design Day (UPC DD) and Average Monthly Design Day (Avg. Monthly DD) methods; and (2) consider the results when predicting future DD needs.

In the Company's 2004-2005 Contract Demand Entitlements filing, the Company described its addition of a second methodology for calculating our DD, the UPC DD.[1] The addition of UPC DD ensures that the DD is adequately and accurately estimated. Prior to the 2004-2005 Docket, we used a single methodology, based on a linear regression calculation of average monthly weather and usage data.

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[1] Docket No. G002/M-04-1735.

During the recent polar vortex event in January – February 2019, NSP had sufficient gas supply transportation capacity as a result of the design day methodologies employed. NSP experienced a peak throughput of 772,354 Dth, and a firm sales throughput of 738,482 Dth on January 30, 2019, the coldest day of the event (-22 degrees F). This was 4 degrees warmer than our design day temperature and less than our projected design day requirement of 840,709 Dth. Using the recorded throughput on a per degree day basis of 8,880 Dth/HDD, this would project a design day throughput of 808,000 Dth at the design temperature. With these results, we continue to believe that the current methodologies of projecting design day continue to adequately project natural gas requirement during a cold weather or design day event.

Our forecasted firm customer count in Minnesota State increased by 4,307 customers, from 461,078 forecast for the 2018-2019 heating season to 465,382 forecast for the 2019-2020 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 7,955 Dekatherms (Dth), from 735,741 to 743,696, using the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**.

a. Average Monthly Design Day

We use the Avg. Monthly DD to develop the allocations by state and by service region as shown on **Attachment 1, Schedule 1, Page 1 of 5**. The Avg. Monthly DD calculation is based on linear regression using 62 data points, from January 2014-February 2019, as shown on **Attachment 1, Schedule 1, Pages 2-5**. Nearly 81% of all regression statistics were very strong with R-squared values at or above 80 percent.[2] The regions with R-squared values below 80 percent were generally those with much lower customer counts. Traditionally, these regressions use 60 data points in complete years. However, in order to incorporate the extreme cold events of January 2019, we have included the additional months through February 2019.

In performing the regression analysis above, three areas (Grand Forks MN Small Commercial (GFMSC), Fargo MN Residential (FGMR), and WBI Residential (WBIR) resulted in negative intercept coefficients. Strictly speaking, this would indicate negative gas use at 0 HDD, which is not realistically possible. To correct for this, we adjusted the heating degree day values to 0 for each summer month for the affected areas. This supports our base use of gas during the summer months, which is not temperature dependent, and is more reflective of reality. We then performed the

[2] The closer its R squared value is to 100 percent or "1", the greater the ability of that model to predict a trend.

regression analysis on the three areas, which resulted in positive intercept coefficients, though not statistically significant from zero.

Additionally we tested each regional demand area and commercial class regression for the presence of autocorrelation, as the Department requested in Docket No. G002/M-17-586. For each regression analysis in the Avg. Monthly DD model we calculated the Durbin-Watson statistic, a common measure for the presence of autocorrelation. Consistent with other statistics and expectations, the most independent errors existed for residential customer regions, while those most prone to autocorrelation were small commercial classes. There were no Durbin-Watson results substantially over 2, and ten regressions with values below 1, indicating positive autocorrelation. In other words, the previous error predicted the following error term.

To address the autocorrelation bias present in these regression models, the company employed a two-stage regression model, whereby the original data values were transformed and lagged by 1 time-span with the estimate of the autocorrelation effect. The regression analysis is then performed on the transformed data. In using a standard Ordinary Least Squares model, the error terms are not used in determining the coefficients of the variables. As such, the coefficients of the two-stage regression results are very similar to the original, however in all cases the autocorrelation was corrected with new Durbin-Watson statistics over 1. The values of the regression results are displayed in **Attachment 1, Schedule 1, Pages 2-5.**

Given the robust regression statistics, we believe the Avg. Monthly DD method accurately captures the DD relationship between the states and service regions and produces the appropriate allocations by state and service region according to current customer use trends.

b. Actual Peak Use Per Firm Customer

The actual use per firm customer data contains the daily total usage for firm customers that do not have individual actual peak day information. As detailed in **Attachment 1, Schedule 3, Page 2 of 2,** the actual peak day use per firm customer remains the same at 1.57393 Dth as experienced January 29, 2004. The extreme cold weather event experienced this past winter has not changed the actual peak day use. For non-demand-billed customers, the projected DD is calculated as the sum of the Avg. Monthly DD totals for all service regions to yield the Projected DD for these Minnesota State customers of 717,640 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 26,056 Dth is added to the DD estimate for the Residential, Small and Large Commercial classes to determine the total Minnesota

State DD Projection of 743,696 Dth as shown on **Attachment 1, Schedule 3, Page 1 of 2**.

We continue to maintain and compare both methodologies. We believe that the models are adequately estimating natural gas needs during cold weather and the current use per customer estimate should be maintained. However, we continue to evaluate the models each year to determine if they are adequately projecting natural gas supply needs and adjust the use per customer estimate if necessary.

2. *Change in Resources to Meet Design Day*

Attachment 2, Schedule 1, Pages 1-2 detail the demand entitlement changes to meet the increased DD in Minnesota State for the 2019-2020 heating season compared to the 2018-2019 heating season as filed in Docket No. G002/M-18-528. **Attachment 1, Schedule 2** details the demand cost component changes for the 2019-2020 heating season. The projected DD for the Company increased by 8,539 Dth/day (7,955 Dth/day for Minnesota) for the 2019-2020 heating season. The demand entitlement changes discussed below represent a combination of renewals of existing contract entitlements, new and incremental contracts to serve the slight growth in projected DD, and changes to reservation rates on interstate pipelines. **Attachment 1, Schedule 2, Page 2 of 2** also shows the year-to-year demand cost changes allocated by jurisdiction or upstream/system supply. The schedule shows an increase of demand related total costs of approximately $15,628,761 ($13,686,106 for Minnesota), including contract demand and supplier entitlement changes. This increase is due primarily to the dramatic proposed increase in Northern Natural Gas's tariff rates projected to be in effect January 1, 2020, which represents 90% of the total demand related increase.

a. Change in Northern Natural Gas (Northern) entitlement (effective November 1, 2017)

As discussed in the 2018-2019 Contract Demand Entitlement filing, NSP has contracted for incremental capacity on Northern's system as part of its Northern Lights 2019 project and existing contract rights, to be effective November 1, 2019 to meet growing demand. This expansion, for an additional 10,482 Dth/day on a year-round basis, is part of NSP's existing discount agreement with Northern, and provides NSP with capacity to meet design day requirements. Specifically, the incremental capacity provides for growth in the St. Cloud, MN area, as well as the Twin Cities. The incremental capacity is priced at the existing substantial discount, and is in effect for the remainder of the contract term.

b. Change in Viking Gas Transmission (Viking) entitlement (effective November 1, 2018)

NSP renewed three Viking firm capacity entitlements this year. The previous capacities of, 10,000 Dth/day, 72,213 Dth/day, and 15,000 Dth/day expires October 31, 2019 and have been renewed at the same terms for a five-year term. This capacity continues to be necessary to meet our DD requirements.

For the past several years, NSP has purchased some short-term capacity on Viking to address a small portion of our overall DD projections. However, recent market conditions on Viking, driven largely by a favorable spot market price differential between Emerson and Chicago City Gates, have resulted in higher than normal demand on Viking. For the 2019-2020 season, NSP will look instead to acquire 10,794 Dth/day of delivered supply from a producer/marketer on Viking capacity for December through February, to meet seasonal peaking needs. The demand costs for this deal are currently estimated at the Viking maximum tariff rate, and included in the supply reservation fees section.

c. Change in Great Lakes Gas Transmission (Great Lakes) entitlement (effective April 1, 2020)

NSP consolidated three Great Lakes firm transportation agreements into the renewal of two contracts effective April 1, 2020 at the same terms as the original agreements. These agreements provide access to gas stored in ANR Storage (ANRS) facilities in Michigan, and provide regional diversity in our winter gas supplies. This provides additional reliability in meeting our design day supply needs.

d. Change in ANR Pipeline entitlement (effective April 1, 2018)

Small additions were made to entitlement holdings on ANR Pipeline pursuant to ANR Pipeline's tariff. These are annual adjustments to match the changes in ANR's in-kind fuel percentages made each spring, and approved by the Federal Energy Regulatory Commission. These volume changes maintain our delivery quantities in response to changes in fuel requirements and do not materially impact demand costs.

Additionally, we renewed one firm transportation agreement, which provides 66,500 Dth/day of transportation capacity upstream of our Viking entitlements, for five years at the maximum tariff rate. This is a slight rate increase from our previous contract rate. However, this region is fully contracted and we were unable to continue the previous rate. This contract provides access to Chicago market gas supplies; providing regional diversity of supply and gas supplies for our backhaul services on Viking. This contract remains necessary to meet the supply requirements on a design day.

e. Change in ANR Storage Co (ANRS) entitlement (effective April 1, 2020)

NSP has extended our service agreement with ANRS for an additional year, effective April 1, 2020. This agreement allows for the storage of gas supplies in Michigan, and provides cost effective method to meet our obligation to supply gas at the Carlton interconnect with Northern. In addition, the capacity provides regional supply diversity, and increased reliability of gas supplies during extreme cold events.

3. Change in Interstate Pipeline Tariff Rates

a. Tax Cut and Jobs Act

Following passage of the Tax Cut and Jobs Act (TCJA) in December 2017, FERC issued an order requiring each interstate pipeline to file a new 501-G form, which estimated the impact of the tax cut on rates. Each interstate pipeline NSP utilizes (with the exception of WBI, which has filed a full Section 4) filed its required form. Great Lakes took advantage of an option in FERC's order and concurrently filed a Limited Section 4 rate case to adjust rates for the impact of the tax cut, discussed below. No other interstate pipeline offered a rate decrease for NSP. Viking was required by its previous rate case settlement to file for new rates to be effective January 1, 2020. Additionally, FERC initiated a Section 5 (complaint) rate proceeding against Northern, discussed more below. FERC has not yet taken action, either to close the docket or initiate a proceeding, on either ANR Pipeline or ANR Storage. NSP has been an active participant in each case.

b. Change in GLGT Tariff Rates (effective February 1, 2019)

As discussed above, as part of its required 501-G form, Great Lakes concurrently filed a Limited Section 4 rate case to reduce rates by 2% effective February 1, 2019. The limited nature of the section 4 only allowed reductions related to the TCJA. FERC approved Great Lakes' rate change, which became effective February 1, 2019, which we have passed on to customers through the PGA and reflected as a change in **Attachment 1, Schedule 2 Pages 1 and 2.**

c. Change in WBI Tariff Rates (effective May 1, 2019)

On November 1, 2018 WBI filed a Section 4 rate case in accordance with its previous settlement. The filed case proposed a rate increase of 26% to rates for NSP. On November 31, 2018 FERC suspended the rates for the maximum five-months, to be effective May 1, 2019 subject to refund. NSP and other shippers subsequently participated in settlement discussions, including two settlement conferences, with WBI. On May 20, 2019 all parties agreed to a settlement in principle, providing for the reduction from the filed rates of 15%, subject to the approval of FERC. WBI subsequently moved to place the settlement rates into effect subject to the approval of the settlement by FERC. The Settlement rates were implemented May 1, 2019, and included as a change in **Attachment 1, Schedule 2 Pages 1 and 2.** The unopposed Settlement was filed with FERC on June 28.

d. Change in Viking Tariff Rates (effective January 1, 2020)

On June 28, 2019 Viking filed with the FERC a general Section 4 rate case (RP19-1340) to change rates effective August 1, 2019 in accordance with its previous rate case settlement. Viking proposed an average seven percent rate increase to the rates for NSP. On July 10, NSP filed a protest requesting the proposed rates be suspended for the maximum five-months, implemented thereafter subject to refund, and set for hearing. We anticipate new rates to be effective January 1, 2020 subject to refund pending the resolution of the case. NSP will be an active participant in the case as Viking's largest customer. The impact of the proposed rate increase is included in **Attachment 1, Schedule 2 Pages 1 and 2.** NSP will update the CD Filing with any rate change as a result of the rate case proceeding.

e. Change in Northern Tariff Rates (effective January 1, 2020)

As mentioned above, in response to Northern's filed Form 501-G, the comments from shippers in the docket, and its own analysis, FERC initiated a Section 5 (complaint) rate proceeding against Northern on January 16, 2019 (RP19-59), stating that Northern may be over-recovering its cost of service. The order required Northern to file a Cost and Revenue Study by April 1, 2019.

On July 1, Northern filed a Section 4 rate case (RP19-1353) proposing a 91% rate increase to the Market Area, including NSP's service territory, effective August 1, 2019. We anticipate that FERC will suspend the rates for the maximum five-month term to be effective January 1, 2020 subject to refund. NSP filed a protest of

Northern's proposed rates on July 15, and will be an active participant in the case to ensure just and reasonable rates moving forward. While NSP has significant discounts on much of its service from Northern, the proposed rate increase is a significant impact on our demand costs, and is the majority of the increase shown on Attachment **1, Schedule 2 Pages 1 and 2.** NSP will update the CD Filing with any rate change as a result of the rate case proceeding.

4. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor increased slightly for the Minnesota State jurisdiction from 87.51 percent to 87.57 percent. As in previous years, we calculate the allocation factor by dividing the DD forecasted demand for Minnesota by the DD demand for the Company. The Minnesota State, North Dakota State, and Company totals are provided on **Attachment 1, Schedule 1, Page 1 of 5**. We used the traditional method of Avg. Monthly DD to update the allocation factors, since this approach accurately estimates the relationship of DD between the states and regional jurisdictions and accurately incorporates the monthly non-electronic pipeline measurements.

5. Change in Supplier Reservation Fees

The total change in supplier reservation charges is an increase of $111,882. **Attachment 1, Schedule 2, Page 1** lists the changes in Supply Entitlements. This includes the projected costs of delivered supply to meet design day requirements in lieu of purchasing Viking seasonal capacity as discussed above.

B. The Utility's Design Day demand by customer class and the change in DD demand, if any, necessitating the demand revision:

We provide the DD demand and change in DD demand by class as **Attachment 1, Schedule 3**.

C. Reserve Margin

We propose to slightly increase our capacity reserve margin from 6.0 percent in November 2018 to 6.4 percent in November 2019, as noted in **Attachment 2, Schedule 1, Page 2 of 2**. We believe this reserve margin is appropriate, given the need to balance the uncertainty of: (a) experiencing DD conditions; (b) actual consumer demand during DD conditions; and (c) the need to protect against the potential loss of a source of firm natural gas supply.

We add firm resources to meet projected firm customer demand and plan to maintain a reserve margin as close as practicable to either the capability of the largest pump at Wescott used to vaporize LNG or to the capability of either of the St. Paul metro propane-air peak shaving plants. Capacity decisions are based on projected demand, and the most economic method of adding capacity often involves adding increments that do not precisely match expected changes in demand. The reserve margin ensures reliability for our firm natural gas customers in Minnesota. The proposed 2019-2020 heating season DD reserve margin for Minnesota State is 47,643 Dth/day or 6.4 percent.

D. Summary of the levels of winter versus summer usage for all customer classes:

We provide the summary of winter and summer sales by class on **Attachment 1, Schedule 4, Page 1 of 1**.

E. Description of Design Day gas supply from all sources under the new level allocation or form of demand:

We provide our firm supply entitlements on **Attachment 1, Schedule 5, Page 1 of 1.**

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

Avg Monthly DD Method

2019-2020 Heating Season

Service Region (1)	Projected Jan 2020 Firm Res & Comm Customers (2)	Contracted Demand by Small & Large Demand Billed Comm'l Customers (3a)	(3b)	Load Variation (Dth/Degree) (4)	Degree per Design Day (5)	Monthly Base Use (Dth) (6)	Unacc. Factor (7)	Res & Comm Design Day (Dth) (8)	Total Design Day (Dth) (9)	Jurisdictional Allocation Factors (10)
METRO	328,997	67	11,499	0.0338408	91	1.0753066	0.0123	507,245	518,744	
BRAINERD	18,728	3	361	0.0241607	91	0.8264515	0.0123	23,560	23,921	
MAINLINE	15,639	13	3,275	0.0364465	88	1.1231084	0.0123	23,961	27,236	
MAINLINE-WELCOME	2,551	0	0	0.0180999	88	0.7824322	0.0123	2,889	2,889	
WILLMAR	10,996	3	527	0.0255449	88	0.9465323	0.0123	14,165	14,692	
PAYNESVILLE	36,242	23	4,173	0.0456789	94	0.9967440	0.0123	71,946	76,119	
VGT-CHISAGO	2,241	0	0	0.0140115	91	0.7728068	0.0123	2,440	2,440	
WATKINS	8,342	1	409	0.0188576	94	0.9557147	0.0123	10,365	10,774	
TOMAH	16,157	10	1,686	0.0353054	88	0.4987981	0.0123	24,098	25,784	
RED WING	8,078	6	1,277	0.0352651	88	1.1703044	0.0123	12,564	13,841	
GRAND FORKS MN	3,162	2	156	0.0389955	98	0.1414159	0.0123	4,834	4,990	
FARGO MN	14,113	7	2,693	0.0333239	98	0.3234892	0.0123	19,572	22,265	
MN State	**465,247**	**135**	**26,056**					**717,640**	**743,696**	**87.57%**
GRAND FORKS ND	16,763	0	0	0.0168617	98	1.7088940	0.0123	30,429	30,429	
FARGO ND	39,665	0	0	0.0170163	98	1.7840127	0.0123	72,743	72,743	
WBI ND	1,343	0	0	0.0164493	98	1.7158716	0.0123	2,381	2,381	
ND State	57,771	0	0					105,553	105,553	12.43%
TOTAL	**523,018**	**135**	**26,056**					**823,193**	**849,248**	**100.00%**

(1) Regional areas of the company.
(2) Estimated firm customers.
(3a) Firm Large and Small Commercial Demand Billed customers.
(3b) Firm contracted Design Day entitlement for Large and Small Commercial Demand Billed customers.
(4) Temperature dependent usage as determined by linear regression based on using 60 months January 2014 to February 2019.
(5) Degree Days for a Design Day in that region.
(6) Monthly base usage determined by linear regression based on using the same 60 months as in (4).
(7) Factor to correct for unaccounted gas usage.
(8) Estimated Design Day Demand for Firm Residential & Commercial Customers.
(9) Estimated Total Design Day for Firm Residential, Commercial, and Demand Billed Customers.
(10) Jurisdictional allocation factors based on percent of Total Company Design Day Demand.

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2019-2020 Heating Season

Division/Region (1)	Projected Firm Jan 2019 Cust (2)	Load Variation (Dth/Deg) (3) X Variable 1	DD/ Design Day (4)	Monthly Base Use (Dth) (5) Intercept	R-Square	T-Stat	P-Value	Lost & Unacc. Factor (6)	Design Day (Dth) 2020 Unacc. Volume	Design Day (Dth) 2020 Load Variation	Design Day (Dth) 2020 Day Base	Design Day (Dth) 2020 Total	2019 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO																
Total Residential	306,303	0.0107028	91	1.1031101	0.9850	63.3251	0.0000	0.0123	3,795	298,325	11,115	**313,234**	303,539	9,695	15,505	**328,739**
Total Small Commercial	15,309	0.0308814	91	0.5583191	0.8787	21.0419	0.0000	0.0123	531	43,022	281	**43,834**	49,929	(6,094)	2,170	**46,004**
Total Large Commercial	7,385	0.1760303	91	26.4790076	0.9781	52.1713	0.0000	0.0123	1,530	118,291	6,432	**126,253**	113,349	12,904	6,249	**132,502**
Industrial	67	Contract Demand	-	-				-	-	-	-	**11,499**	12,381	(882)	-	**11,499**
	329,064	0.0338408		1.075306587					5,855	459,638	17,828	**494,820**	479,198	15,622	23,924	**518,744**
														3.3%		
BRAINERD																
Total Residential	17,272	0.0101898	91	0.8170983	0.9796	54.1540	0.0000	0.0123	202	16,016	464	**16,682**	15,483	1,200	826	**17,508**
Total Small Commercial	1,204	0.0204896	91	0.8824523	0.8499	18.6087	0.0000	0.0123	28	2,246	35	**2,309**	2,576	(268)	114	**2,423**
Total Large Commercial	252	0.1299905	91	52.8871580	0.9560	36.4255	0.0000	0.0123	42	2,978	438	**3,458**	2,967	490	171	**3,629**
Industrial	3	Contract Demand	-	-				-	-	-	-	**361**	361	(0)	-	**361**
	18,731	0.0241607		0.826451452					272	21,240	937	**22,810**	21,388	1,422	1,111	**23,921**
														6.6%		
MAINLINE																
Total Residential	14,097	0.0102830	88	1.1515435	0.9773	51.2020	0.0000	0.0123	163	12,756	534	**13,453**	13,068	385	666	**14,119**
Total Small Commercial	1,147	0.0263703	88	0.7874151	0.8105	16.1856	0.0000	0.0123	33	2,661	30	**2,724**	3,084	(360)	135	**2,858**
Total Large Commercial	395	0.1713801	88	47.3203396	0.9254	27.5226	0.0000	0.0123	81	5,958	615	**6,654**	5,766	888	329	**6,983**
Industrial	13	Contract Demand	-	-				-	-	-	-	**3,275**	2,659	616	-	**3,275**
	15,652	0.0364465		1.123108413					277	21,376	1,179	**26,106**	24,578	1,528	1,130	**27,236**
														6.2%		
MAINLINE-WELCOME																
Total Residential	2,398	0.0100968	88	0.6479960	0.9761	49.8942	0.0000	0.0123	27	2,130	51	**2,208**	2,093	115	109	**2,317**
Total Small Commercial	133	0.0162866	88	2.2153248	0.5647	8.9520	0.0000	0.0123	2	191	10	**203**	201	3	10	**213**
Total Large Commercial	20	0.1473830	88	126.9132074	0.2973	5.1776	0.0000	0.0123	4	255	82	**341**	314	27	17	**358**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,551	0.0180999		0.782432236					33	2,576	143	**2,752**	2,607	145	136	**2,889**
														5.6%		
WILLMAR																
Total Residential	10,165	0.0101076	88	0.9051442	0.8979	23.1842	0.0000	0.0123	115	9,042	303	**9,459**	8,376	1,083	468	**9,927**
Total Small Commercial	671	0.0266888	88	1.5302717	0.8696	20.1933	0.0000	0.0123	20	1,576	34	**1,630**	1,652	(23)	81	**1,710**
Total Large Commercial	160	0.1601433	88	23.2632720	0.9047	24.0864	0.0000	0.0123	29	2,257	123	**2,409**	1,898	511	119	**2,528**
Industrial	3	Contract Demand	-	-				-	-	-	-	**527**	363	164	-	**527**
	10,999	0.0255449		0.946532308					164	12,875	459	**14,024**	12,289	1,735	668	**14,692**
														14.1%		
PAYNESVILLE																
Total Residential	32,227	0.0103799	94	0.9966904	0.8223	16.8296	0.0000	0.0123	399	31,444	1,057	**32,899**	35,811	(2,912)	1,628	**34,528**
Total Small Commercial	2,857	0.0573631	94	0.9934512	0.3249	5.5101	0.0000	0.0123	190	15,406	93	**15,690**	12,025	3,665	777	**16,466**
Total Large Commercial	1,158	0.1705856	94	30.2900257	0.6846	11.5491	0.0000	0.0123	242	18,568	1,154	**19,964**	21,196	(1,232)	988	**20,952**
Industrial	23	Contract Demand	-	-				-	-	-	-	**4,173**	4,098	75	-	**4,173**
	36,265	0.0456789		0.996743965					831	65,419	2,304	**72,726**	73,130	(404)	3,393	**76,119**
														-0.6%		
VGT-CHISAGO																
Total Residential	2,133	0.0100379	91	0.7584719	0.9645	40.7041	0.0000	0.0123	25	1,949	53	**2,027**	1,888	138	100	**2,127**
Total Small Commercial	100	0.0210113	91	1.0437947	0.9518	34.7031	0.0000	0.0123	2	191	3	**196**	227	(30)	10	**206**
Total Large Commercial	8	0.1424190	91	1.8150719	0.9025	23.7833	0.0000	0.0123	1	100	0	**102**	88	14	5	**107**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,241	0.0140115		0.772806808					28	2,240	57	**2,325**	2,203	122	115	**2,440**
														5.5%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2019-2020 Heating Season

WATKINS																
Total Residential	8,050	0.0098395	94	0.9576443	0.9576	37.1407	0.0000	0.0123	94	7,445	254	**7,793**	7,287	506	386	**8,179**
Total Small Commercial	222	0.0320588	94	0.6650074	0.6746	11.2892	0.0000	0.0123	8	668	5	**681**	783	(101)	34	**715**
Total Large Commercial	71	0.1916161	94	46.7508339	0.9438	32.0143	0.0000	0.0123	17	1,276	109	**1,402**	1,204	198	69	**1,471**
Industrial	1	Contract Demand	-	-				-	-	-	-	**409**	409	(0)	-	**409**
	8,343	0.0188576		0.955714661					120	9,389	367	**10,285**	9,682	603	489	**10,774**
														6.2%		
TOMAH																
Total Residential	14,490	0.0101033	88	0.3683388	0.9778	51.8616	0.0000	0.0123	160	12,883	176	**13,219**	12,759	460	654	**13,873**
Total Small Commercial	1,276	0.0261148	88	1.8144991	0.9550	35.9960	0.0000	0.0123	37	2,933	76	**3,046**	2,963	83	151	**3,197**
Total Large Commercial	391	0.1847407	88	20.3026325	0.9663	41.8022	0.0000	0.0123	81	6,355	261	**6,697**	5,990	707	331	**7,028**
Industrial	10	Contract Demand	-	-				-	-	-	-	**1,686**	1,444	242	-	**1,686**
	16,167	0.0353054		0.498798149					278	22,171	513	**24,648**	23,156	1,492	1,137	**25,784**
														6.4%		
RED WING																
Total Residential	7,293	0.0102082	88	0.9221528	0.9206	26.6206	0.0000	0.0123	83	6,552	221	**6,856**	6,591	265	339	**7,195**
Total Small Commercial	592	0.0293619	88	4.2520705	0.7679	14.2422	0.0000	0.0123	20	1,530	83	**1,633**	1,621	11	81	**1,714**
Total Large Commercial	193	0.1932484	88	24.7353051	0.8446	18.2331	0.0000	0.0123	42	3,283	157	**3,483**	3,063	420	172	**3,655**
Industrial	6	Contract Demand	-	-				-	-	-	-	**1,277**	1,208	69	-	**1,277**
	8,084	0.0352651		1.170304419					145	11,365	461	**13,248**	12,483	765	593	**13,841**
														6.1%		
GRAND FORKS MN																
Total Residential	2,816	0.0096728	98	0.1125491	0.9776	51.6100	0.0000	0.0123	33	2,670	10	**2,713**	2,624	88	134	**2,847**
Total Small Commercial	257	0.0258860	98	0.0937766	0.7760	14.4516	0.0000	0.0123	8	651	1	**660**	888	(228)	33	**693**
Total Large Commercial	89	0.1333730	98	17.0737557	0.9721	46.0816	0.0000	0.0123	15	1,168	50	**1,233**	1,028	206	61	**1,294**
Industrial	2	Contract Demand	-	-				-	-	-	-	**156**	63	93	-	**156**
	3,164	0.0389955		0.141415909					56	4,489	61	**4,762**	4,603	159	228	**4,990**
														3.5%		
FARGO MN																
Total Residential	12,698	0.0082400	98	0.3119423	0.9731	47.0285	0.0000	0.0123	127	10,254	130	**10,512**	10,195	317	520	**11,032**
Total Small Commercial	1,076	0.0249048	98	0.2251964	0.8620	19.5447	0.0000	0.0123	32	2,625	8	**2,665**	2,972	(307)	132	**2,797**
Total Large Commercial	339	0.1542430	98	25.3004296	0.9722	46.2374	0.0000	0.0123	66	5,124	282	**5,472**	4,868	604	271	**5,743**
Industrial	7	Contract Demand	-	-				-	-	-	-	**2,693**	1,481	1,212	-	**2,693**
	14,120	0.0333239		0.323489171					226	18,003	420	**21,342**	19,517	1,825	923	**22,265**
														9.4%		
MN STATE																
Total Residential	**429,943**											**431,055**	**419,716**	**11,340**	**21,336**	**452,392**
Total Small Commercial	**24,844**											**75,271**	**78,920**	**-3,649**	**3,726**	**78,997**
Total Large Commercial	**10,460**											**177,467**	**161,730**	**15,737**	**8,784**	**186,251**
Contract Demand	**135**											**26,056**	**24,469**	**1,587**	**0**	**26,056**
	465,382											**709,849**	**684,834**	**25,015**	**33,847**	**743,696**
														3.7%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2019-2020 Heating Season

Division/Region (1)	Projected Firm Jan 2019 Cust (2)	Load Variation (Dth/Deg) (3) X Variable 1	DD/ Design Day (4)	Monthly Base Use (Dth) (5) Intercept	R-Square			Lost & Unacc. Factor (6)	Design Day (Dth) 2020 Unacc. Volume	Load Variation	Day Base	Total	2019 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND																
Total Residential	14,605	0.0093014	98	0.3238288	0.9797	54.2823	0.0000	0.0123	165	13,313	156	**13,634**	13,057	577	675	**14,309**
Total Small Commercial	2,158	0.0680364	98	11.0842751	0.9682	43.1063	0.0000	0.0123	186	14,387	787	**15,360**	14,794	566	760	**16,120**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	16,763	0.0168617		1.708894026					351	27,700	942	**28,994**	27,851	1,142	1,435	**30,429**
														4.1%		
FARGO ND																
Total Residential	33,415	0.0089048	98	0.2902766	0.9813	56.5758	0.0000	0.0123	362	29,161	319	**29,841**	29,444	397	1,477	**31,318**
Total Small Commercial	6,250	0.0603864	98	9.7706283	0.9728	46.7033	0.0000	0.0123	478	36,985	2,009	**39,471**	38,528	943	1,954	**41,425**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	39,665	0.0170163		1.784012719					840	66,145	2,328	**69,313**	67,972	1,341	3,431	**72,743**
														2.0%		
WBI ND																
Total Residential	1,161	0.0099262	98	0.3681947	0.9533	35.3097	0.0000	0.0123	14	1,130	14	**1,158**	1,086	72	57	**1,215**
Total Small Commercial	182	0.0581581	98	10.3328752	0.3610	5.9547	0.0000	0.0123	13	1,035	62	**1,110**	546	564	55	**1,165**
Total Large Commercial	-	-	98	-	0.0000	0.0000	0.0000	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	1,343	0.0164493		1.715871645					27	2,165	76	**2,268**	1,632	636	112	**2,381**
														39.0%		
ND STATE																
Total Residential	**49,182**											**44,633**	**43,587**	**1,046**	**2,209**	**46,842**
Total Small Commercial	**8,589**											**55,941**	**53,868**	**2,073**	**2,769**	**58,710**
Total Large Commercial	**0**											**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**											**-**	**-**	**-**	**-**	**-**
	57,771											**100,574**	**97,455**	**3,119**	**4,978**	**105,553**
														3.2%		
Grand Total																
Total Residential	**479,125**											**475,689**	**463,302**	**12,386**	**23,546**	**499,234**
Total Small Commercial	**33,433**											**131,212**	**132,788**	**(1,576)**	**6,495**	**137,707**
Total Large Commercial	**10,460**											**177,467**	**161,730**	**15,737**	**8,784**	**186,251**
Contract Demand	**135**											**26,056**	**24,469**	**1,587**	**-**	**26,056**
	523,153											**810,423**	**782,289**	**28,134**	**38,825**	**849,248**
														3.6%		

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

Avg Monthly DD Method

2019-2020 Heating Season

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2020 FORECAST	2019 FORECAST	Difference	%Diff
METRO	328,997	323,155	5,842	1.8%
BRAINERD	18,728	18,185	543	3.0%
MAINLINE	15,639	15,378	260	1.7%
MAINLINE-WELCOME	2,551	2,486	64	2.6%
WILLMAR	10,996	9,939	1,058	10.6%
PAYNESVILLE	36,242	40,872	(4,630)	-11.3%
VGT-CHISAGO	2,241	2,200	40	1.8%
WATKINS	8,342	8,137	205	2.5%
TOMAH	16,157	15,954	203	1.3%
RED WING	8,078	7,865	214	2.7%
GRAND FORKS MN	3,162	3,119	44	1.4%
FARGO MN	14,113	13,649	464	3.4%
MN STATE	465,247	460,940	4,307	0.9%
GRAND FORKS ND	16,763	16,365	398	2.4%
FARGO ND	39,665	40,002	(337)	-0.8%
WBI ND	1,343	1,294	49	3.8%
ND STATE	57,771	57,661	110	0.2%
TOTAL NSP MN	523,018	518,601	4,417	**0.9%**

2019 Customer Counts

	MN	ND	
Res	429,943	49,182	**479,125**
Sm Com	24,844	8,589	**33,433**
Lg Com	10,460	0	**10,460**
Ind	135	0	**135**
	465,382	57,771	**523,153**

2019 Design Day Use By Customer Class

	MN	ND	
Res	452,392	46,842	**499,234**
Sm Com	78,997	58,710	**137,707**
Lg Com	186,251	0	**186,251**
Ind	26,056	0	**26,056**
	743,696	105,553	**849,248**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2020 FORECAST	2019 FORECAST	Difference	%Diff
METRO	518,744	515,184	3,560	0.7%
BRAINERD	23,921	23,008	913	4.0%
MAINLINE	27,236	26,267	968	3.7%
MAINLINE-WELCOME	2,889	2,808	80	2.9%
WILLMAR	14,692	13,208	1,484	11.2%
PAYNESVILLE	76,119	78,452	(2,333)	-3.0%
VGT-CHISAGO	2,440	2,373	67	2.8%
WATKINS	10,774	10,397	377	3.6%
TOMAH	25,784	24,829	955	3.8%
RED WING	13,841	13,352	488	3.7%
GRAND FORKS MN	4,990	4,953	37	0.7%
FARGO MN	22,265	20,908	1,358	6.5%
MN STATE	743,696	735,741	7,955	1.1%
GRAND FORKS ND	30,429	29,999	430	1.4%
FARGO ND	72,743	73,211	(468)	-0.6%
WBI ND	2,381	1,758	623	35.4%
ND STATE	105,553	104,968	585	0.6%
TOTAL NSP MN	849,248	840,709	8,539	1.0%

MN / ND Allocation Factors

2020 DD	2019 DD	
0.8757	0.8751	**MN State Allocation**
0.1243	0.1249	**ND State Allocation**

NNG SYSTEM	2020 FORECAST	2019 FORECAST	Difference	%Diff
METRO	518,744	515,184	3,560	0.7%
BRAINERD	23,921	23,008	913	4.0%
MAINLINE	27,236	26,267	968	3.7%
MAINLINE-WELCOME	2,889	2,808	80	2.9%
WILLMAR	14,692	13,208	1,484	11.2%
PAYNESVILLE	76,119	78,452	(2,333)	-3.0%
WATKINS	10,774	10,397	377	3.6%
TOMAH	25,784	24,829	955	3.8%
RED WING	13,841	13,352	488	3.7%
NNG SUBTOTAL	714,000	707,507	6,493	0.9%

VGT SYSTEM				
VGT-CHISAGO	2,440	2,373	67	2.8%
GRAND FORKS MN	4,990	4,953	37	0.7%
FARGO MN	22,265	20,908	1,358	6.5%
GRAND FORKS ND	30,429	29,999	430	1.4%
FARGO ND	72,743	73,211	(468)	-0.6%
WBI ND	2,381	1,758	623	35.4%
VGT SUBTOTAL	135,248	133,201	2,047	1.5%
VGT & NNG TOTAL	849,248	840,709	8,540	1.0%

Northern States Power Company — Docket No. G002/M-19-___
DEMAND COST OF GAS IMPACT - NOVEMBER 2019 — Attachment 1
Schedule 2

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
ANR FSS (Jan - Dec)[1]	(19)	$ 1.7820	12	$ (406.30)
ANR FTS-1 (Apr - Oct)[2]	4	$ 5.7290	7	$ 160.41
ANR FTS-1 (Jan-Dec)[2]	(66,500)	$ 5.3660	12	$ (4,282,068.00)
ANR FTS-1 (Jan-Dec)[2]	66,500	$ 5.7290	12	$ 4,571,742.00
GLT FT (Nov - Mar)[3]	(9,248)	$ 8.3530	5	$ (386,242.72)
GLT FT (Nov - Mar)[3]	9,248	$ 8.1860	5	$ 378,520.64
GLT FT (Nov - Mar)[3]	(3,509)	$ 8.3530	5	$ (146,553.39)
GLT FT (Nov - Mar)[3]	3,509	$ 8.1860	5	$ 143,623.37
GLT FT (Apr - Oct)[3]	(4,475)	$ 8.3530	7	$ (261,657.73)
GLT FT (Apr - Oct)[3]	5,370	$ 8.1860	7	$ 307,711.74
GLT FT (Apr - Oct)[3]	(895)	$ 8.3530	7	$ (52,331.55)
WBI FT-1 (Jan-Dec)[4]	(8,000)	$ 9.2100	12	$ (884,160.00)
WBI FT-1 (Jan-Dec)[4]	8,000	$ 9.8417	12	$ 944,798.40
WBI FT-1 (Jan-Dec)[4]	(461)	$ 9.2100	12	$ (50,949.72)
WBI FT-1 (Jan-Dec)[4]	461	$ 9.8417	12	$ 54,444.01
VGT FT-A (Jan - Dec)[5]	(20,200)	$ 4.3706	10	$ (882,861.20)
VGT FT-A (Jan - Dec)[5]	20,200	$ 4.6653	10	$ 942,390.60
VGT FT-A (Jan - Dec)[5]	(29,002)	$ 4.3706	10	$ (1,267,561.41)
VGT FT-A (Jan - Dec)[5]	29,002	$ 4.6653	10	$ 1,353,030.31
VGT FT-A (Nov-Mar)[5]	(4,239)	$ 4.3706	3	$ (55,580.92)
VGT FT-A (Nov-Mar)[5]	4,239	$ 4.6653	3	$ 59,328.62
VGT FT-A (Jan - Dec)[5]	(10,000)	$ 4.3706	10	$ (437,060.00)
VGT FT-A (Jan - Dec)[5]	10,000	$ 4.6653	10	$ 466,530.00
VGT FT-A (Jan - Dec)[5]	(15,600)	$ 5.3593	10	$ (836,050.80)
VGT FT-A (Jan - Dec)[5]	15,600	$ 5.6540	10	$ 882,024.00
VGT FT-A (Jan - Dec)[5]	(1,903)	$ 4.3706	10	$ (83,172.52)
VGT FT-A (Jan - Dec)[5]	1,903	$ 4.6653	10	$ 88,780.66
VGT FT-A (Jan - Dec)[5]	(72,213)	$ 5.3593	10	$ (3,870,111.31)
VGT FT-A (Jan - Dec)[5]	72,213	$ 5.6540	10	$ 4,082,923.02
VGT FT-A (Jan - Dec)[5]	(15,000)	$ 5.3593	10	$ (803,895.00)
VGT FT-A (Jan - Dec)[5]	15,000	$ 5.6540	10	$ 848,100.00
NNG TFX (Nov-Mar)[7]	3,382	$ 9.3568	5	$ 158,223.49
NNG TFX (Apr-Oct)[7]	3,382	$ 4.0000	7	$ 94,696.00
NNG TFX (Jan-Dec)[7]	3,767	$ 4.5600	12	$ 206,130.24
NNG TFX (Nov-Mar)[7]	3,333	$ 6.1032	5	$ 101,709.83
NNG TFX (Apr-Oct)[7]	3,333	$ 4.5000	7	$ 104,989.50
NNG TF12-Base (Nov-Mar)[6]	(104,117)	$ 10.2300	3	$ (3,195,350.73)
NNG TF12-Base (Nov-Mar)[6]	104,117	$ 10.3207	3	$ 3,223,680.97
NNG TF12-Base (Apr-Oct)[6]	(104,117)	$ 5.6830	7	$ (4,141,878.38)
NNG TF12-Base (Apr-Oct)[6]	104,117	$ 10.3207	7	$ 7,521,922.25
NNG TF5 (Nov-Mar)[6]	(62,415)	$ 15.1530	3	$ (2,837,323.49)
NNG TF5 (Nov-Mar)[6]	62,415	$ 24.2448	3	$ 4,539,717.58
NNG TFX (Nov-Mar)[7]	(28,500)	$ 15.1530	3	$ (1,295,581.50)
NNG TFX (Nov-Mar)[7]	28,500	$ 28.8810	3	$ 2,469,325.50
NNG TFX (Nov-Mar)[7]	(57,491)	$ 15.1530	3	$ (2,613,483.37)
NNG TFX (Nov-Mar)[7]	20,861	$ 28.8810	3	$ 1,807,459.62
NNG TFX (Nov-Mar)[7]	36,630	$ 22.1055	3	$ 2,429,173.40
NNG TFX (Jul-Aug)[7]	(16,436)	$ 5.6830	2	$ (186,811.58)
NNG TFX (Jul-Aug)[7]	15,436	$ 10.8300	2	$ 334,343.76
NNG TFX (Jul-Aug)[7]	1,000	$ 10.0000	2	$ 20,000.00
NNG TFX (Apr-Jun/Sept-Oct)[7]	(35,739)	$ 5.6830	5	$ (1,015,523.69)
NNG TFX (Apr-Jun/Sept-Oct)[7]	15,436	$ 10.8300	5	$ 835,859.40
NNG TFX (Apr-Jun/Sept-Oct)[7]	20,303	$ 10.0000	5	$ 1,015,150.00
NNG TFX (Nov-Mar)[7]	(8,875)	$ 15.1530	3	$ (403,448.63)
NNG TFX (Nov-Mar)[7]	8,875	$ 28.8810	3	$ 768,956.63
NNG TFX (Apr-Oct)[7]	(8,875)	$ 5.6830	7	$ (353,056.38)
NNG TFX (Apr-Oct)[7]	8,875	$ 10.8300	7	$ 672,813.75
NNG FDD (Jan-Dec)[8]	(140,230)	$ 1.7140	10	$ (2,403,542.20)
NNG FDD (Jan-Dec)[8]	140,230	$ 3.7443	10	$ 5,250,631.89
NNG FDD (Jan-Dec)[8]	(78,050)	$ 1.7140	10	$ (1,337,777.00)
NNG FDD (Jan-Dec)[8]	78,050	$ 3.7443	10	$ 2,922,426.15
Total				$ 15,516,878.25

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Total	5,394	$111,882.39
Total MN & ND Demand Cost Adjustment		**$15,628,760.64**
Minnesota Allocation Factor (MN/ND Allocated Demand)		87.57%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 13,686,105.69**

[1] ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v.1.1.0, Effective August 1, 2016
[2] ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 2.0.0, Effective April 1, 2017
[3] GLT Third Revised Volume No. 1, Part 4 Statement of Rates, v.1.0.0, Effective June 1, 2018
[4] WBI Third Revised Volume No. 1, Fifteenth Revised Sheet No. 12, Effective May 1, 2019
[5] VGT Volume No. 1, Part 5.0 Statement of Rates, (RP19-1340) Effective January 1, 2020
[6] NNG Sixth Revised Volume No. 1, Fifteenth Revised Sheet No. 50 (RP19-1353), Effective January 1, 2020
[7] NNG Sixth Revised Volume No. 1, Eighteenth Revised Sheet No. 51 (RP19-1353), Effective January 1, 2020
[8] NNG Sixth Revised Volume No. 1, Second Revised Sheet No. 55 (RP19-1353), Effective January 1, 2020

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-19-___
Attachment 1
Schedule 2
Page 2 of 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2018 SUPPLEMENTAL FILED COSTS				**$33,161,575.83**	**$23,939,582.41**	**$57,101,158.24**				
2018 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2018 ACTUAL COSTS				**$ 33,161,575.83**	**$ 23,939,582.41**	**$ 57,101,158.24**				
CHANGES FOR 2019 FILING										
Contract Demand Entitlement Changes										
ANR FSS (Jan - Dec)	(19)	$ 1.7820	12		$ (406.30)	$ (406.30)			$ (406.30)	1
ANR FTS-1 (Apr - Oct)	4	$ 5.7290	7		$ 160.41	$ 160.41			$ 160.41	1
ANR FTS-1 (Jan-Dec)	(66,500)	$ 5.3660	12	$ (4,282,068.00)		$ (4,282,068.00)			$ (4,282,068.00)	
ANR FTS-1 (Jan-Dec)	66,500	$ 5.7290	12	$ 4,571,742.00		$ 4,571,742.00			$ 4,571,742.00	
GLT FT (Nov - Mar)	(9,248)	$ 8.3530	5		$ (386,242.72)	$ (386,242.72)			$ (386,242.72)	2
GLT FT (Nov - Mar)	9,248	$ 8.1860	5		$ 378,520.64	$ 378,520.64			$ 378,520.64	2
GLT FT (Nov - Mar)	(3,509)	$ 8.3530	5		$ (146,553.39)	$ (146,553.39)			$ (146,553.39)	2
GLT FT (Nov - Mar)	3,509	$ 8.1860	5		$ 143,623.37	$ 143,623.37			$ 143,623.37	2
GLT FT (Apr - Oct)	(4,475)	$ 8.3530	7	$ (261,657.73)		$ (261,657.73)			$ (261,657.73)	2
GLT FT (Apr - Oct)	5,370	$ 8.1860	7	$ 307,711.74		$ 307,711.74			$ 307,711.74	2
GLT FT (Apr - Oct)	(895)	$ 8.3530	7	$ (52,331.55)		$ (52,331.55)			$ (52,331.55)	2
WBI FT-1 (Jan-Dec)	(8,000)	$ 9.2100	12	$ (884,160.00)		$ (884,160.00)		$ (884,160.00)		3
WBI FT-1 (Jan-Dec)	8,000	$ 9.8417	12	$ 944,798.40		$ 944,798.40		$ 944,798.40		3
WBI FT-1 (Jan-Dec)	(461)	$ 9.2100	12	$ (50,949.72)		$ (50,949.72)		$ (50,949.72)		3
WBI FT-1 (Jan-Dec)	461	$ 9.8417	12	$ 54,444.01		$ 54,444.01		$ 54,444.01		3
VGT FT-A (Jan - Dec)	(20,200)	$ 4.3706	10	$ (882,861.20)		$ (882,861.20)		$ (882,861.20)		4
VGT FT-A (Jan - Dec)	20,200	$ 4.6653	10	$ 942,390.60		$ 942,390.60		$ 942,390.60		4
VGT FT-A (Jan - Dec)	(29,002)	$ 4.3706	10	$ (1,267,561.41)		$ (1,267,561.41)	$ (1,267,561.41)			4
VGT FT-A (Jan - Dec)	29,002	$ 4.6653	10	$ 1,353,030.31		$ 1,353,030.31	$ 1,353,030.31			4
VGT FT-A (Nov-Mar)	(4,239)	$ 4.3706	3		$ (55,580.92)	$ (55,580.92)	$ (55,580.92)			4
VGT FT-A (Nov-Mar)	4,239	$ 4.6653	3		$ 59,328.62	$ 59,328.62	$ 59,328.62			4
VGT FT-A (Jan - Dec)	(10,000)	$ 4.3706	10	$ (437,060.00)		$ (437,060.00)	$ (437,060.00)			4
VGT FT-A (Jan - Dec)	10,000	$ 4.6653	10	$ 466,530.00		$ 466,530.00	$ 466,530.00			4
VGT FT-A (Jan - Dec)	(15,600)	$ 5.3593	10	$ (836,050.80)		$ (836,050.80)	$ (836,050.80)			4
VGT FT-A (Jan - Dec)	15,600	$ 5.6540	10	$ 882,024.00		$ 882,024.00	$ 882,024.00			4
VGT FT-A (Jan - Dec)	(1,903)	$ 4.3706	10	$ (83,172.52)		$ (83,172.52)	$ (83,172.52)			4
VGT FT-A (Jan - Dec)	1,903	$ 4.6653	10	$ 88,780.66		$ 88,780.66	$ 88,780.66			4
VGT FT-A (Jan - Dec)	(72,213)	$ 5.3593	10	$ (3,870,111.31)		$ (3,870,111.31)		$ (3,870,111.31)		4
VGT FT-A (Jan - Dec)	72,213	$ 5.6540	10	$ 4,082,923.02		$ 4,082,923.02		$ 4,082,923.02		4
VGT FT-A (Jan - Dec)	(15,000)	$ 5.3593	10	$ (803,895.00)		$ (803,895.00)	$ (803,895.00)			4
VGT FT-A (Jan - Dec)	15,000	$ 5.6540	10	$ 848,100.00		$ 848,100.00	$ 848,100.00			4
NNG TFX (Nov-Mar)	3,382	$ 9.3568	5		$ 158,223.49	$ 158,223.49	$ 158,223.49			5
NNG TFX (Apr-Oct)	3,382	$ 4.0000	7	$ 94,696.00		$ 94,696.00	$ 94,696.00			5
NNG TFX (Jan-Dec)	3,767	$ 4.5600	12	$ 206,130.24		$ 206,130.24	$ 206,130.24			5
NNG TFX (Nov-Mar)	3,333	$ 6.1032	5		$ 101,709.83	$ 101,709.83				5
NNG TFX (Apr-Oct)	3,333	$ 4.5000	7	$ 104,989.50		$ 104,989.50				5
NNG TF12-Base (Nov-Mar)	(104,117)	$10.2300	3	$ (3,195,350.73)		$ (3,195,350.73)	$ (3,195,350.73)			6
NNG TF12-Base (Nov-Mar)	104,117	$10.3207	3	$ 3,223,680.97		$ 3,223,680.97	$ 3,223,680.97			6, 11
NNG TF12-Base (Apr-Oct)	(104,117)	$ 5.6830	7	$ (4,141,878.38)		$ (4,141,878.38)	$ (4,141,878.38)			6
NNG TF12-Base (Apr-Oct)	104,117	$10.3207	7	$ 7,521,922.25		$ 7,521,922.25	$ 7,521,922.25			6, 11
NNG TF5 (Nov-Mar)	(62,415)	$15.1530	3		$ (2,837,323.49)	$ (2,837,323.49)	$ (2,837,323.49)			6
NNG TF5 (Nov-Mar)	62,415	$24.2448	3		$ 4,539,717.58	$ 4,539,717.58	$ 4,539,717.58			6, 11
NNG TFX (Nov-Mar)	(28,500)	$15.1530	3		$ (1,295,581.50)	$ (1,295,581.50)	$ (1,295,581.50)			6
NNG TFX (Nov-Mar)	28,500	$28.8810	3		$ 2,469,325.50	$ 2,469,325.50	$ 2,469,325.50			6
NNG TFX (Nov-Mar)	(57,491)	$15.1530	3		$ (2,613,483.37)	$ (2,613,483.37)	$ (2,613,483.37)			6
NNG TFX (Nov-Mar)	20,861	$28.8810	3		$ 1,807,459.62	$ 1,807,459.62	$ 1,807,459.62			6
NNG TFX (Nov-Mar)	36,630	$22.1055	3		$ 2,429,173.40	$ 2,429,173.40	$ 2,429,173.40			6, 11
NNG TFX (Jul-Aug)	(16,436)	$ 5.6830	2	$ (186,811.58)		$ (186,811.58)	$ (186,811.58)			6
NNG TFX (Jul-Aug)	15,436	$10.8300	2	$ 334,343.76		$ 334,343.76	$ 334,343.76			6
NNG TFX (Jul-Aug)	1,000	$10.0000	2	$ 20,000.00		$ 20,000.00	$ 20,000.00			6, 11
NNG TFX (Apr-Jun/Sept-Oct)	(35,739)	$ 5.6830	5	$ (1,015,523.69)		$ (1,015,523.69)	$ (1,015,523.69)			6
NNG TFX (Apr-Jun/Sept-Oct)	15,436	$10.8300	5	$ 835,859.40		$ 835,859.40	$ 835,859.40			6
NNG TFX (Apr-Jun/Sept-Oct)	20,303	$10.0000	5	$ 1,015,150.00		$ 1,015,150.00	$ 1,015,150.00			6, 11
NNG TFX (Nov-Mar)	(8,875)	$15.1530	3		$ (403,448.63)	$ (403,448.63)	$ (403,448.63)			6
NNG TFX (Nov-Mar)	8,875	$28.8810	3		$ 768,956.63	$ 768,956.63	$ 768,956.63			6
NNG TFX (Apr-Oct)	(8,875)	$ 5.6830	7	$ (353,056.38)		$ (353,056.38)	$ (353,056.38)			6
NNG TFX (Apr-Oct)	8,875	$10.8300	7	$ 672,813.75		$ 672,813.75	$ 672,813.75			6
NNG FDD (Jan-Dec)	(140,230)	$ 1.7140	10		$ (2,403,542.20)	$ (2,403,542.20)			$ (2,403,542.20)	6
NNG FDD (Jan-Dec)	140,230	$ 3.7443	10		$ 5,250,631.89	$ 5,250,631.89			$ 5,250,631.89	6
NNG FDD (Jan-Dec)	(78,050)	$ 1.7140	10		$ (1,337,777.00)	$ (1,337,777.00)			$ (1,337,777.00)	6
NNG FDD (Jan-Dec)	78,050	$ 3.7443	10		$ 2,922,426.15	$ 2,922,426.15			$ 2,922,426.15	6
Total				$ 5,967,560.63	$ 9,549,317.62	$ 15,516,878.25	$ 10,269,467.79	$ 336,473.80	$ 4,704,237.33	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										7
										7
										8
										9
									PROTECTED DATA ENDS]	
Total				$ -	$ 111,882.39	$ 111,882.39	$ (15,000.00)	$ 142,082.39	$ -	
TOTAL OF 2019 CHANGES				**$ 5,967,560.63**	**$ 9,661,200.01**	**$ 15,628,760.64**	**$ 10,254,467.79**	**$ 478,556.19**	**$ 4,704,237.33**	
2019 COSTS				**$ 39,129,136.46**	**$ 33,600,782.42**	**$ 72,729,918.88**				
2019 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							96%	4%		10

Footnote
1. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
2. Rate change pursuant to Limited Section 4, Result of Tax Cuts and Jobs Act (RP19-409)
3. Rate change pursuant to rate case settlement (RP19-165)
4. Rate change due to ongoing Rate Case (RP19-1340), Rates to be effective January 1, 2020
5. Acquisition of new capacity in Northern Lights 2019 to meet Design Day requirements
6. Rate change due to ongoing Rate Case (RP19-1353), Rates to be effective January 1, 2020
7. Expired peaking supply contract with demand charges in effect November 1, 2018 through March 31, 2019.
8. Acquired peaking supply contract with demand charges in effect November 1, 2019 through March 31, 2020
9. Delivered supply in lieu of seasonal Viking capacity purchase.
10. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purposes of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.
11. Rate increase triggers discount provision in two contracts for original capacity, limiting increase

DESIGN DAY CALCULATION

State of Minnesota	Jan-2020 Budget Customer	2020 MMBtu Design Day[1]	2019 MMBtu Design Day[1]	MMBtu Change
Residential	429,943	452,392	452,071	321
Commercial	35,304	265,247	259,201	6,046
Demand Billed	135	26,056	24,469	1,587
State of Minnesota Total	**465,382**	**743,696**	**735,741**	**7,955**
State of North Dakota Total	57,771	105,553	104,968	585
Total Xcel Energy - Gas Utility Operations	523,153	849,248	840,708	8,540

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER
UPC DD Method

Minnesota Company	Jan-2020 Budget Customer	Jan-2019 Budget Customer	Change
Residential	479,125	474,906	4,219
Commercial	43,893	43,695	198
TOTAL	523,018	518,601	4,417
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	823,192	816,240	
Demand Billed Customers	135	138	
Contracted Billing Demand of Demand Billed Customers	26,056	24,469	
Projected Design Day (Dth)	849,248	840,708	8,540

[2] Determined from Peak Day usage at an average temperature of -15 degrees Fahrenheit on Thursday, Jan. 29, 2004

MINNESOTA COMPANY ENTITLEMENT ESTIMATE PER CUSTOMER

	Jan-2020 Budget	Jan-2019 Budget
Reserve Margin	54,417	50,462
Total Available Capacity	903,665	891,171
Entitlement per Customer	1.7273	1.7180

Northern States Power Company
DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER
Design Day: Heating Season 2019-2020

	Description	Values	Units	Equation
(1)	Date of Peak Day	January 29, 2004		
(2)	Day of the Week	Thursday		
(3)	Total Throughput including Peakshaving	648,400	Dth	
(4)	Actual Large and Small Comm'l Demand Billed Usage	(13,863)	Dth	
(5)	Total Throughput including Peakshaving less Demand Billed	634,537	Dth	(5) = (3) - (4)
(6)	Interruptible Customers Status	All Curtailed		
(7)	Average Actual Gas Day Temperature	-15	Deg F	
(8)	Heating Degree Days (HDD) 65 degree base	80	HDDs	(8) = 65 - (7)
		[PROTECTED DATA BEGINS		
(9)	Limited Firm/Standby Dth Demand on system		Dth	
(10)	Total Firm Throughput less Ltd F/Stdby & Demand Billed Customers		Dth	(10) = (5) + (9)
(11)	2004 Non-HDD Sensitive Base Dth[1]		Dth	
(12)	Total HDD sensitive Firm throughput		Dth	(12) = (10) + (11)
(13)	Actual Peak Day Dth/HDD		Dth/HDD	(13) = (12) / (8)
		PROTECTED DATA ENDS]		
(14)	Base + (Actual Dth/HDD * 91 HDDs)	695,134	Dth	(14) = -(11) + [(13) x 91 HDDs]
(15)	Base + (Actual Dth/HDD * 91 HDDs) + Actual Demand Billed Usage	708,997		(15) = (14) + -(4)
(16)	Average Monthly Projected 2004 Design Day[1]	677,930	Dth	
(17)	Actual Peak Day UPC vs. Avg Monthly Design Day	(31,067)	Dth	(17) = (16) - (15)
(18)	Average Monthly 2004 Design Day Reserve Margin[1]	44,733	Dth	
(19)	Actual 2004 Reserve Margin based on Peak Actuals	13,666	Dth	(19) = (18) + (17)
(20)	January 2004 Projected Firm Residential & Comm'l Customers[1]	441,656	Customers	
(21)	Peak Day Actual Use Per Residential & Comm'l Firm Customer	1.57393	Dth/customer	(21) = (14) / (20)

[1]As described in Company's 2003 - 2004 Contract Demand Filing

Northern States Power Company
MINNESOTA STATE HISTORICAL SALES - SEASONAL USAGE
(Dth)

Customer Class

	Jul-2018	Aug-2018	Sep-2018	Oct-2018	Nov-2018	Dec-2018	Jan-2019	Feb-2019	Mar-2019	Apr-2019	May-2019	Jun-2019	Total	Winter	Summer
Residential	662,434	671,444	618,611	1,811,800	3,466,003	5,339,399	6,939,032	7,148,798	7,059,418	4,021,734	2,357,150	1,150,596	41,246,420	29,952,651	11,293,769
Interdepartmental	185	190	196	280	627	1,230	1,367	1,432	1,416	873	630	352	8,778	6,072	2,706
Small Commercial Firm	93,519	81,734	75,625	225,372	443,470	801,333	1,039,540	1,111,300	1,121,987	668,134	342,971	163,496	6,168,480	4,517,631	1,650,850
Large Commercial Firm	350,233	362,035	365,947	766,067	1,449,152	2,303,012	2,777,593	2,862,167	3,015,796	1,796,427	1,102,901	580,502	17,731,831	12,407,719	5,324,112
Commercial Firm	443,937	443,958	441,768	991,719	1,893,249	3,105,574	3,818,500	3,974,899	4,139,199	2,465,434	1,446,501	744,350	23,909,089	16,931,421	6,977,668
Small Commercial Demand Billed	5,316	6,489	3,755	7,284	6,109	11,178	10,901	12,061	13,639	9,519	7,238	5,631	99,121	53,889	45,232
Large Commercial Demand Billed	144,126	132,809	150,368	178,581	265,926	353,569	362,072	370,456	380,255	276,751	231,535	160,504	3,006,953	1,732,279	1,274,674
Large Demand Billed - Generation	1,302	1,207	1,242	1,617	1,268	1,818	1,366	1,129	1,549	1,606	1,611	1,272	16,987	7,131	9,857
Commercial Demand Billed	150,744	140,505	155,365	187,482	273,303	366,566	374,340	383,646	395,444	287,876	240,384	167,408	3,123,061	1,793,298	1,329,763
Total Commercial Firm	594,681	584,463	597,133	1,179,201	2,166,552	3,472,140	4,192,840	4,358,545	4,534,643	2,753,310	1,686,885	911,758	27,032,151	18,724,720	8,307,431
Total Firm	1,257,115	1,255,908	1,215,743	2,991,001	5,632,555	8,811,539	11,131,872	11,507,344	11,594,061	6,775,044	4,044,035	2,062,354	68,278,570	48,677,371	19,601,200
Small Interruptible	62,079	66,882	59,581	122,556	211,297	312,338	341,517	326,436	379,303	247,484	167,333	87,534	2,384,340	1,570,891	813,449
Medium Interruptible	260,717	294,522	332,943	353,832	577,951	687,232	682,200	723,515	760,317	598,283	451,743	346,671	6,069,927	3,431,216	2,638,712
Large Interruptible	164,779	170,923	211,532	133,867	196,843	284,448	265,062	321,957	344,169	261,829	213,096	117,229	2,685,736	1,412,480	1,273,256
Med. & Lg. Interruptible - Generation	11,550	5,736	15,045	8,214	8,996	5,135	6,091	16,855	29,785	14,095	15,934	9,492	146,927	66,861	80,066
Total Interruptible	499,125	538,063	619,101	618,469	995,088	1,289,153	1,294,870	1,388,764	1,513,573	1,121,691	848,107	560,927	11,286,930	6,481,447	4,805,483
Total Firm and Interruptible	1,756,240	1,793,971	1,834,844	3,609,470	6,627,643	10,100,692	12,426,742	12,896,107	13,107,634	7,896,736	4,892,142	2,623,280	79,565,500	55,158,818	24,406,682
Firm Transportation	42,340	47,880	47,778	43,334	48,533	54,504	52,689	62,463	51,434	48,665	47,412	51,274	598,306	269,623	328,683
Interruptible Transportation	309,092	320,911	318,725	316,200	372,940	405,350	406,246	411,143	412,324	413,650	368,679	323,806	4,379,066	2,008,003	2,371,063
Negotiated Transporation	430,444	500,065	479,423	468,829	535,631	727,099	751,968	729,524	592,933	705,792	645,076	531,021	7,097,805	3,337,155	3,760,650
Interdepartmental Transport - Generation	4,158,656	3,552,706	2,368,122	939,315	773,017	1,163,487	1,588,235	3,149,296	3,196,325	3,917,336	2,507,885	3,175,396	30,489,776	9,870,360	20,619,416
Total Transportation	4,940,532	4,421,562	3,214,048	1,767,678	1,730,121	2,350,440	2,799,138	4,352,426	4,253,016	5,085,443	3,569,052	4,081,497	42,564,953	15,485,141	27,079,812
Total Customer Sales	6,696,771	6,215,533	5,048,892	5,377,148	8,357,764	12,451,132	15,225,880	17,248,533	17,360,650	12,982,179	8,461,194	6,704,777	122,130,453	70,643,959	51,486,494
Monthly Heating Degree Days	0	7	117	595	1,092	1,202	1,569	1,448	1,129	557	295	10	8,020	6,440	1,581

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2019-2020 Heating Season

Firm Supplies (1)	**Current Quantity Effective Nov-19 Dth/Day**	**Proposed Quantity Effective Nov-20 Dth/Day**	**Proposed Quantity Change Nov-20 Dth/Day**
A. Upstream Supply			
	[PROTECTED DATA BEGINS		
ANR Firm 3rd Party (2)			
ANRP Storage (2)			
ANR Storage Company (3)			
GLGT Firm 3rd Party (3)			
B. Minnesota Company Delivered Supply			
WBI Firm 3rd Party			
VGT Firm 3rd Party			
NNG Firm 3rd Party			
NNG FDD Storage			**PROTECTED DATA ENDS]**
LP Peak Shaving	90,000	90,000	-
LNG Peak Shaving	156,000	156,000	-
TOTAL	891,084	903,665	12,581
C. Minnesota State Delivered Supply			
State of MN Allocators	87.51%	87.57%	
TOTAL	779,788	791,339	11,552

(1) Contracts are available for inspection upon request
(2) ANR feeds VGT.
(3) GLGT feeds NNG or VGT

ATTACHMENT 2

Northern States Power Company

Proposal for Entitlement Changes

Information provided in response to the
Department letter dated October 1, 1993 and the
Commission Order dated October 16, 2015 in Docket No. G002/M-14-654

PROPOSAL FOR ENTITLEMENT CHANGE
Department Format dated October 1, 1993

1 Provide a peak-day/design-day study by class for the twelve months ending one year from the proposed implementation date of the change(s):

See Attachment 1, Schedule 3.

2 Provide Heating Degree Day (HDD) data for the most recent twelve month period ending March 31 or September 30. This should include HDD, use per firm customer, and the peak season and off-peak HDD used for calculating the Company's design days:

See Attachment 1, Schedule 1, and Attachment 1, Schedule 4.

3 Historical and Projected Design-Day and Peak Demand Requirements:

Minnesota State

Heating Season[1]	Number of Firm Customers[2]	Design Day Requirement (Dth)	Total Entitlement plus Storage plus Peak Shaving[3] (Dth)	Peak Day Sendout (Dth)	Heating Degree Days	Actual Peak Day
(1)	(2)	(3)	(4)	(5)	(6)	
Proposed: 2019/2020	465,382	743,696	791,339	Unknown	Unknown	Unknown
2018/2019	461,078	735,741	779,864	735,822	75	1/29/2019
2017/2018	457,769	730,147	776,298	745,131	69	12/26/2017
2016/2017	454,396	725,225	765,534	733,711	66	1/5/2017
2015/2016	450,630	717,478	762,152	719,329	74	1/17/2016
2014/2015	446,409	715,945	761,354	687,501	64	1/12/2015
2013/2014	441,573	706,935	749,325	689,990	82	1/6/2014
2012/2013	439,210	702,159	745,247	689,747	71	1/21/2013
2011/2012	439,055	702,294	745,094	659,263	65	1/19/2012
2010/2011	436,594	699,611	743,781	675,667	69	1/20/2011
2009/2010	433,698	694,487	748,267	590,931	67	12/10/2009
2008/2009	428,852	685,005	732,291	601,425	78	1/15/2009
2007/2008	431,503	683,717	721,506	585,874	72	1/29/2008
2006/2007	424,415	677,733	696,257	568,963	67	2/2/2007
2005/2006	421,570	670,846	691,689	537,660	63	12/5/2005
2004/2005	410,986	649,655	675,120	537,374	60	1/5/2005

1 Per Annual Financial Reports.

2 Provide data and calculations for projected number of firm customers by class and in total corresponding to the design day requirement.

See Attachment 1, Schedule 1.

3 Total entitlement for Minnesota is calculated from the Proposed November 1 Entitlement.

See Attachment 1, Schedule 5.

4 Demand Profile:

See Attachment 2, Schedule 1.

5 Rate Impact:

See Attachment 2, Schedule 2.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Docket No. G002/M-19-___
Attachment 2
Schedule 1

Northern States Power Company
COMPANY DEMAND PROFILE
2019-2020 Heating Season

Contract No.	Type of Capacity or Entitlement	Current Amount Dth or MMBtu	Proposed Change Dth or MMBtu	Proposed Amount Dth or MMBtu	Contract Length and Expiration Date	Change Description	% of Peak Day Entitlement	
	Capacity Entitlements							
112183	NNG TF12 BASE (Max)	104,117	0	104,117	10 yrs - 10/31/27		11.52%	
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27		0.00%	
112182	NNG TF12 BASE (Disc)	18,674	667	19,341	10 yrs - 10/31/27		2.14%	
112182	NNG TF12 VARIABLE (Disc.)	75,853	(667)	75,186	10 yrs - 10/31/27		8.32%	
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27		6.91%	
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27		3.28%	
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 10/31/22		3.15%	
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27		6.44%	
112185	NNG TFX (Disc. 12-month)	29,554	7,100	36,654	10 yrs - 10/31/27	Growth Election	4.06%	
112185	NNG TFX 5 (Disc)	6,493	0	6,493	10 yrs - 10/31/27		Summer Only	
112185	NNG TFX 2 (Disc)	2,168	0	2,168	10 yrs - 10/31/27		Summer Only	
112186	NNG TFX (Max)	57,491	0	57,491	10 yrs - 10/31/27		6.36%	
112186	NNG TFX 2 (Max)	16,436	0	16,436	10 yrs - 10/31/27		Summer Only	
112186	NNG TFX 5 (Max)	35,739	0	35,739	10 yrs - 10/31/27		Summer Only	
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27		2.77%	
122067	NNG TFX (Disc. Nov-Mar)	10,291	3,382	13,673	10 yrs - 10/31/27	Growth Election	1.51%	
122067	NNG TFX 7 (Disc)	10,291	3,382	13,673	10 yrs - 10/31/27	Growth Election	Summer Only	
122068	NNG TFX (Nov-Mar)	8,875	0	8,875	10 yrs - 10/31/27		0.98%	
122068	NNG TFX 7 (Max)	8,875	0	8,875	10 yrs - 10/31/27		Summer Only	
		[PROTECTED DATA BEGINS						
	VGT to NNG Chisago (1)							
	VGT Pierz to NNG (2)							
	Capacity Release							**PROTECTED DATA ENDS]**
AF0044	VGT FT-A 12 Mos.	29,002	0	29,002	5 yrs - 10/31/23		3.21%	
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/23		0.47%	
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/24	Contract Extension	1.11%	
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	5 yrs - 10/31/22		1.73%	
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/21		0.21%	
AF0217	VGT FT-A 12 Mos.	72,213	0	72,213	5 yrs - 10/31/24	Contract Extension	7.99%	
AF0218	VGT FT-A 12 Mos.	15,000	0	15,000	5 yrs - 10/31/24	Contract Extension	1.66%	
AF0329	VGT FT-A 12 Mos.	20,200	0	20,200	5 yrs - 10/31/23		2.24%	
	WBI FT-1097	8,000	0	8,000	6.5 yrs - 10/31/25		0.89%	
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%	
	City Gate Deliveries	24,000	0	24,000	10 yrs - 10/31/22		2.66%	
	City Gate Deliveries	5,400	(5,400)	0	1 yrs - 2/28/19	Contract expiration	0.00%	
	City Gate Deliveries		10,794	10,794	3 mos - 2/29/20	Planned Seasonal Acquisition	1.19%	
	LP Peak Shaving	90,000	0	90,000			9.96%	
	LNG Peak Shaving	156,000	0	156,000			17.26%	
	Total Design Day Capacity	**891,171**		**903,665**			**100%**	
	Heating Season Total	891,171		903,665				
	Non-Heating Season Total	480,579		491,061				

Miscellaneous Entitlements with Reservation Fees

Additional Pipeline Entitlements					
ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/21	
ANR FTS-106211 (Summer) (1)	5,448	4	5,452	3 yrs - 03/31/21	Fuel Adjustment
ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/21	
ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	5 yrs - 10/31/2023	Contract Extension
GLT FT1718539 (2)	3,509	0	3,509	2 yrs - 03/31/21	Contract Extension
GLT FT1718539 (2)	4,475	895	5,370	2 yrs - 03/31/21	Contract Extension
GLT Backhaul FT18130 (2)	895	(895)	0	3 yrs. - 10/31/19	Contract Expired & Combined
GLT Backhaul FT18129 (2)	9,248	0	9,248	4 yrs. - 03/31/21	Contract Extension
NNG SMS (3)	30,650		30,650	5 yrs - 10/31/22	
VGT OBA (3)	7,400		7,400	month-to-month	

Supply Entitlements (4)

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Storage Entitlements - Deliverability					
ANR Pipeline Storage	15,295	(19)	15,276	3 yrs - 3/31/21	Fuel adjustment
ANR Storage	9,248	0	9,248	4 yrs - 3/31/21	Contract Extension
FDD Service (5)	140,230	0	140,230	5 yrs - 5/31/23	
FDD Service	78,050	0	78,050	15 yrs - 5/31/27	
Storage Entitlements - Capacity					
ANR Pipeline Storage	948,290	(1,178)	947,112	3 yrs - 3/31/21	Fuel adjustment
ANR Storage	1,165,000	0	1,165,000	4 yrs - 3/31/21	
FDD Service (5)	8,084,975	0	8,084,975	5 yrs - 5/31/23	
FDD Service	4,500,000	0	4,500,000	15 yrs - 5/31/27	

(1) Not included in total peak deliverability -- feeds VGT (capacity not additive)
(2) Not included in total peak deliverability -- feeds NNG (capacity not additive).
(3) Not included in total peak deliverability -- entitlement delivered by or associated with TF or FT-A service.
(4) Supply contracts containing reservation fees.
(5) Capacity expires 155,000 Dth in May 2022, 1,400,000 Dth in May 2023 & 6,529,975 Dth in May 2023

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2019

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	891,171	12,494	903,665
Non-Heating Season	480,579	10,482	491,061
Heating Season Forecasted Design Day	840,709	8,540	849,248
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	50,462	3,954	54,417
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	6.0%	0.4%	6.4%
Total MN State Available Capacity:			
State of MN Allocation Factor	87.51%	0.06%	87.57%
State of MN Heating Season Capacity	779,864	11,476	791,339
State of MN Design Day Demand	735,741	7,955	743,696
State of MN Heating Season Capacity Reserve/(Shortage)	44,123	3,521	47,643
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	6.0%	0.4%	6.4%

(1) Entitlement changes for November are included in Available Capacity.
Please reference Attachment 1 Schedule 5 for the detail on supply entitlement changes.

Northern States Power Company
MINNESOTA STATE RATE IMPACT

Date to implement proposed changes: November 1, 2019
$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-18-528)	Last Month PGA: July 2019	Estimated Nov. 2019 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$5.5042	$2.7649	$2.0539	$2.3388	-57.51%	-15.41%	13.87%	$0.2849
Demand Cost of Gas (1)	$0.9008	$0.8296	$0.8393	$1.0118	12.32%	21.96%	20.55%	$0.1725
Distribution Margin	$1.8591	$1.8591	$1.7600	$1.7600	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$5.4536	$4.6532	$5.1106	-38.16%	-6.29%	9.83%	$0.4574
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$474.21	$404.61	$444.38	-38.16%	-6.29%	9.83%	$39.77
Average Annual Total Demand Cost of Gas	$78.33	$72.14	$72.98	$87.98				**$15.00**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.7649	$2.0539	$2.3388	-57.38%	-15.41%	13.87%	$0.2849
Demand Cost of Gas (1)	$0.8984	$0.8395	$0.8492	$1.0344	15.14%	23.22%	21.81%	$0.1852
Distribution Margin	$1.2331	$1.2331	$1.1673	$1.1673	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.8375	$4.0704	$4.5405	-40.40%	-6.14%	11.55%	$0.4701
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,373.97	$1,156.10	$1,289.62	-40.40%	-6.14%	11.55%	$133.52
Average Annual Total Demand Cost of Gas	$255.17	$238.44	$241.19	$293.80				**$52.60**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.7649	$2.0539	$2.3388	-57.38%	-15.41%	13.87%	$0.2849
Demand Cost of Gas (1)	$0.8917	$0.8168	$0.8263	$0.9928	11.34%	21.55%	20.15%	$0.1665
Distribution Margin	$1.2315	$1.2315	$1.1658	$1.1658	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.8132	$4.0460	$4.4974	-40.90%	-6.56%	11.16%	$0.4514
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$7,039.99	$5,917.87	$6,578.10	-40.90%	-6.56%	11.16%	$660.24
Average Annual Total Demand Cost of Gas	$1,304.24	$1,194.68	$1,208.58	$1,452.11				**$243.53**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-18-528)	Last Month PGA: July 2019	Estimated Nov. 2019 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible								
Commodity Cost of Gas (WACOG)	$5.4926	$2.7649	$2.0539	$2.3388	-57.42%	-15.41%	13.87%	$0.2849
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9121	$0.9121	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$3.7284	$2.9660	$3.2509	-49.65%	-12.81%	9.61%	$0.2849
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$29,589.28	$23,538.80	$25,799.79	-49.65%	-12.81%	9.61%	$2,261.00
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible								
Commodity Cost of Gas (WACOG)	$5.4696	$2.7649	$2.0539	$2.3388	-57.24%	-15.41%	13.87%	$0.2849
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4498	$0.4498	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$3.2400	$2.5037	$2.7886	-53.09%	-13.93%	11.38%	$0.2849
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$209,659.18	$162,011.19	$180,446.85	-53.09%	-13.93%	11.38%	$18,435.66
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible								
Commodity Cost of Gas (WACOG)	$5.5006	$2.7649	$2.0539	$2.3388	-57.48%	-15.41%	13.87%	$0.2849
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4114	$0.4114	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$3.1995	$2.4653	$2.7502	-53.66%	-14.04%	11.56%	$0.2849
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$2,386,768.28	$1,839,085.18	$2,051,614.69	-53.66%	-14.04%	11.56%	$212,529.51
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$0.2849	13.87%	$0.1725	20.55%	$15.00	$39.77	9.83%
Small Commercial	$0.2849	13.87%	$0.1852	21.81%	$52.60	$133.52	11.55%
Large Commercial	$0.2849	13.87%	$0.1665	20.15%	$243.53	$660.24	11.16%
Small Interruptible	$0.2849	13.87%	$0.0000	NA	$0.00	$2,261.00	9.61%
Medium Interruptible	$0.2849	13.87%	$0.0000	NA	$0.00	$18,435.66	11.38%
Large Interruptible	$0.2849	13.87%	$0.0000	NA	$0.00	$212,529.51	11.56%

Demand Cost (Res, Sm & Lg Commercial Firm)		Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$39,129,136	$33,600,782	
2.	x Minnesota Design Day Ratio (2019 Demand Entitlement Filing)	87.57%	87.57%	
3.	Annual System Demand Allocation to MN	$34,265,385	$29,424,205	
4.	MN State Design Day (2019 Demand Entitlement Filing)	743,696	743,696	
5.	- Small & Large Demand Billed Dth (2019 Demand Entitlement Filing)	26,056	26,056	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	717,640	717,640	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$33,064,869	$28,393,304	
8.	Demand Billed Cost Allocation (3 - 7)	$1,200,516	$1,030,901	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	609,479,653	463,406,847	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.05425	$0.06127	$0.11552
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.11552
14.	Total Demand Rate -Commercial (10 + 12)			$0.11552
Demand Cost (Demand Billed)				
15.	Cost Allocated to Demand Billed (8)	$1,200,516	$1,030,901	$2,231,417
16.	/ Annual Contract Billing Demand (2019 Demand Entitlement Filing)			3,126,720
17.	Monthly Commercial Demand Billed Demand Rate			$0.71366

Commodity Costs		Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$21,750,718
19.	x MN Portion of Monthly Retail Sales	85.93%
20.	MN Portion of Monthly Commodity Costs	$18,690,392
21.	MN Budgeted Calendar Month Retail Therm Sales	79,913,924
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.23388

Total Gas Cost per Therm		
23.	Residential (13 + 22)	**$0.34940**
24.	Small & Large Commercial (14 +22)	**$0.34940**
25.	Small & Large Demand Billed - Demand (17)	**$0.71366**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.23388**

*Commodity costs are projected and for illustrative purposed only.

ATTACHMENT 3

Northern States Power Company

Information provided in response to reporting requirements in Docket No. G002/M-08-46 (Order dated May 27, 2008) Regarding use of financial instruments to limit price volatility and Docket No. G002/M-16-88 (Order dated April 22, 2016) Regarding benefits of the contracts.

Order Point 2 of the Commission's April 22, 2016 Order in Docket No. G002/M-16-88 requires the following:

> *Include, in its requests for approval of changes in demand entitlements submitted on approximately August 1 of each year, a list of all financial instrument arrangements entered into for the upcoming heating season, including the cost premium associated with each contract, the size of each contract, contract date, contract price, and an explanation of the anticipated benefits of these contract to Xcel's ratepayers.*

The overall anticipated benefit of the Company's Price Volatility Mitigation Plan, is to reduce our customers' exposure to, and the magnitude of gas price spike events at a reasonable cost. The goal of the plan is not to attempt to outguess the market or to speculate on the future direction of energy prices. In the development and implementation to the Plan, the Company realizes that the final result of our efforts may be higher prices than purchasing all gas supply on the monthly spot market. However, the Company maintains that price volatility mitigation is important in order to protect the Company and our customers from the risk of very high gas prices due to unforeseeable market conditions and/or events.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

SUMMARY OF COMPANY HEDGE TRANSACTIONS
2019-2020 Heating Season

Transaction Date	Hedge Instrument	Counterparty	Premium ($/Dth)	Call Strike Price	Put Strike Price	Daily Vol (Dth)	Basis Point	Monthly Volumes (Dth) November	December	January	February	March	Total Volume (Dth)	Total Dollars

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Certificate of Service

I, Jim Erickson, 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. G002/GR-06-1429
G002/GR-09-1153
Xcel Energy Misc. Gas Service List

Dated this 2nd day of August 2019

/s/
____
Jim Erickson
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_6-1429_1
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_6-1429_1
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_6-1429_1
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_6-1429_1
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_6-1429_1
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_6-1429_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_6-1429_1
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_6-1429_1
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_6-1429_1
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.	202 South Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_6-1429_1
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_6-1429_1
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_6-1429_1
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 202 South Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_6-1429_1
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_6-1429_1
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_6-1429_1
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_6-1429_1
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_9-1153_Official
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_9-1153_Official
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_9-1153_Official
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_9-1153_Official
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_9-1153_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_9-1153_Official
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_9-1153_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_9-1153_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_9-1153_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1153_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas

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Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 551017741	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas

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David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas