414 Nicollet Mall
Minneapolis, Minnesota 55401

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August 1, 2017

—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-17-___

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 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

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	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-17-___

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 4,922 Dekatherms, with an increase in demand related costs of approximately $1,534,000 for the 2017-2018 year. 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 2017-2018 Heating Season Supply Plan effective November 1, 2017, 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, 2017.

At the Commission's January 26, 2017 Agenda Meeting regarding last year's Contract Demand Entitlement Petition (Docket No. G002/M-16-649), we committed to file additional information in the next filing on whether there is a standard from a state or federal agency on the appropriate reserve margin (as there is for electric) and why we believe our reserve range--and not something less or more--is correct and a fair expenditure for our customers to pay. We address this in Section V, Part F and Attachment 1below.

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 - 8th 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 1, 2017. The Company requests Commission approval to implement the rate impact of this filing in our purchased gas adjustment (PGA) effective with November 1, 2017 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, 2017, 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 Tariff 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	Carl Cronin
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 Carl Cronin 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, 2017, and respectfully request Commission approval of the revised entitlements effective on November 1, 2017. 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 2016-2017 heating season, as described in Attachment 1. Our forecasted firm customer count in Minnesota State increased by 3,373 customers, from 454,396 forecast for the 2016-2017 heating season to 457,769 forecast for the 2017-2018 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 4,922 Dekatherms (Dth), from 725,225 to 730,147.

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,[1] and outlines the changes in the Company's Energy Firm DD Requirements, daily pipeline entitlement, pipeline billing units and storage entitlements from the 2016-2017 entitlement levels.

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 decreased slightly for the Minnesota State jurisdiction from 87.98 percent to 87.57 percent.

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

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 $159,658.

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 2017-2018 heating season.

F. Reserve Margin Standards

We are unaware of any state or federal specification of standards for a reserve margin for retail gas distribution utilities. However, the Commission has generally found between 5 and 7 percent to be reasonable.

NSP's reserve margin serves two functions: (1) as a reserve should actual customer use on a Design Day exceed the forecast; and (2) as a protection against unexpected failures or outages of our upstream interstate pipelines, as occurred in 2014 during the TransCanada outage. The proposed 2017-2018 heating season DD reserve margin for Minnesota State is 46,151 Dth/day or 6.3 percent. The reserve proposed in this case is a slight increase from the 5.6 percent proposed in our last Contract Demand Entitlements filing in November 2016. The total reserve margin related cost represents approximately 1.5% of total gas supply costs and is an economical tool to address uncertainty.[2] The increase in reserve margin results from the addition of entitlements to bolster specific regional sections of our system. We believe this reserve margin is appropriate, given the need to balance the uncertainty of: (a) projecting 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. A complete discussion of our reserve margin is in **Attachment 1**.

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[2] Assuming a weighted average demand cost per Dth for reserve margin entitlements.

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	Demand Profile, Storage Entitlements
1, page 2	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 Trade Secret **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 $1,534,074.35 or about three percent of the total Minnesota State demand costs, effective November 1, 2017. 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 2017-2018 Heating Season Supply Plan effective November 1, 2017, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2017 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 1, 2017

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	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-17-___

PETITION

SUMMARY OF FILING

Please take notice that on August 1, 2017, 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 2017-2018 Heating Season Supply Plan effective November 1, 2017. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2017, 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 for 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.

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

Our forecasted firm customer count in Minnesota State increased by 3,373 customers, from 454,396 forecast for the 2016-2017 heating season to 457,769 forecast for the 2017-2018 heating season. This projection contributes to an increase in DD requirements in Minnesota State of 4,922 Dekatherms (Dth), from 725,225 to 730,147, using the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**.

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 60 data points, from January 2011-December 2016, as shown on **Attachment 1, Schedule 1, Pages 2-5**. Nearly 70% of all regression statistics were very strong with R-squared values at or above 90 percent.[2] The regions with R-squared values below 90 percent were generally those with much lower customer counts. In all, R-squared values were, on average, 90 percent. 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.

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. 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 705,678 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 24,469 Dth is added to the DD estimate for the Residential, Small and Large Commercial classes to determine the total Minnesota State DD Projection of 730,147 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 will 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.

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

2. Change in Resources to Meet Design Day

Attachment 2, Schedule 1, Page 1 of 2 details the demand entitlement changes to meet the increased DD in Minnesota State for the 2017-2018 heating season compared to the 2016-2017 heating season as filed in Docket No. G002/M-16-649. **Attachment 1, Schedule 2** details the demand cost component changes for the 2017-2018 heating season. The projected DD for the Company increased by 9,560 Dth/day (4,923 Dth/day for Minnesota) for the 2017-2018 heating season. The demand entitlement changes discussed below represent a combination of renewals of existing contract entitlements and new, incremental contracts to serve the growth in projected DD. **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 $1,751,826 ($1,534,074 for Minnesota), including contract demand and supplier entitlement changes. This increase is due to three main factors: a slight increase in the long term discounted rate of contracts on Northern Natural; added entitlements due to on-system growth and; an active rate case proceeding at the Federal Energy Regulatory Commission on an upstream pipeline.

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

Since the 2016-2017 heating season, we made three additions to our firm capacity entitlement levels on Northern. We added 918 Dth/day of incremental capacity at St. Cloud, Minnesota, 3,333 Dth/day in the Lake Elmo, Minnesota area, and 8,486 Dth/day in the Twin Cities to be effective November 1, 2017. The additions are all necessary to meet DD requirements in these areas.

In addition, as discussed last year, the Company previously exercised its unilateral right on 8 long-term transportation contracts for a ten-year extension. This extension renewed long term capacity at a slight ($0.01/Dth/day) rate increase from the currently effective discount beginning November 1, 2017. While the extension includes a slight increase in rates, it is still a roughly 50% discount from Northern's applicable maximum tariff rate. These transportation agreements continue to be necessary to serve firm customers in central and northern Minnesota. The discount extension provision saves our customers $12.1 million/year compared with the max tariff rate.

Finally, NSP renewed a portion of our Northern storage capacity, which expired on May 31, 2017, for a five-year term. Northern's Firm Deferred Delivery (FDD) storage service allows for an immediate load-following gas supply, providing greater reliability of service when responding to weather changes and system changes. Further, the service provides the opportunity to off-set some of those storage costs by avoiding imbalance costs, overrun penalties, and the need to buy higher-priced gas in the intra-day spot market.

b. Change in Viking Gas Transmission (Viking) entitlement (effective November 1, 2017)

NSP renewed one Viking firm capacity entitlement this year. The previous capacity of 15,600 Dth/day expires October 31, 2017 and has 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 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. In January 2017, Viking posted its remaining available capacity for the 2017-2018 heating season. NSP evaluated the available capacity, price, and term which would have been required to acquire the capacity. Alternatives were also explored, and a delivered supply contract for a similar quantity provided substantially similar service at a significantly reduced cost to customers. As such, NSP has acquired the additional seasonal delivered supply of 20,000 Dth/day for the 2017-2018 heating season, to meet the portion of DD more recently served with the seasonal Viking entitlement. Acquiring seasonal delivered capacity rather than long-term Viking capacity resulted in costs savings of roughly $1.2 million on an annual basis.

c. Change in Great Lakes Gas Transmission (Great Lakes) entitlement (effective October 1, 2017)

NSP renewed three Great Lakes firm capacity entitlements this year. The previous capacity of 9,248 Dth/day expires March 31, 2018 and has been renewed on a winter-only basis for a two-year term. We also renewed summer capacity of 895 Dth/day for the same term. In addition, we extended the term of capacity of 3,509 Dth/day in the winter (4,475 Dth/day summer), which expires on March 31, 2019 for a term of one-year at the current discounted rate. By extending all the agreements at once, we were able to preserve the discount from the maximum tariff rate. This capacity supports the winter withdrawal and summer injection of the ANR Storage quantities described below.

In March 2017, Great Lakes filed a rate case (Docket No. RP17-598) with the Federal Energy Regulatory Commission (FERC) proposing an increase in rates to become effective October 1, 2017, subject to refund. NSP is an active participant in this case to ensure a just and reasonable outcome for our customers. The proposed rates are included in this filing. The outcome of the rate case proceeding will be incorporated once the final FERC decision is known.

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

We renewed our gas storage contract with ANR Storage for two-years until March 31, 2020 at the existing rates and contract entitlements. Natural gas withdrawn from the ANR Storage facility is transported on Great Lakes to the Carlton, Minnesota interconnect with Northern for downstream deliveries generally to the greater Minneapolis/St. Paul metro area. The extension of this contract provides for greater supply flexibility and natural gas supply price protection in winter months. Flexibility and price protection are particularly important as a balance against the challenging supply availability and unusual natural gas price volatility at the Emerson supply point near the Minnesota/Canadian border.

e. Change in ANR Pipeline entitlement (effective April 1, 2017)

Small reductions 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 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.

3. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor decreased slightly for the Minnesota State jurisdiction from 87.98 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.

4. Change in Supplier Reservation Fees

The total change in supplier reservation charges is an increase of $159,658. **Attachment 1, Schedule 2** lists the changes in Supply Entitlements.

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

NSP's reserve margin serves two functions: (1) as a reserve should actual customer use on a Design Day exceed the forecast; and (2) as a protection against unexpected failures or outages of our upstream interstate pipelines, as occurred in 2014 during the TransCanada outage. During that event, NSP was able to maintain gas distribution service to all customers despite the upstream outage in part because of our reserve margin.

To our knowledge, reserve levels are not set or specified by any state or federal agency for utility gas service. However, the Commission has generally found between 5 and 7 percent to be reasonable. We plan for no system outages related to upstream resources when considering our gas reserve margin. Any outage could result in the loss of heat for our customers during some of the coldest parts of the year and would necessitate extraordinary and time-consuming measures to resume service. We deem such an event unacceptable and design our system and entitlements accordingly.

This use of reserve margin differs from the electric industry. For the electric transmission system managed by the Midwest Independent System Operator (MISO), for example, the reserve margin is two to three times higher than our gas reserve margin and based on an assumed loss of load one day in every ten years.

We add firm resources to meet projected firm customer demand on Design Day, including a reserve margin as close as practicable to the capacity of one of our two propane peak-shaving plants in the St. Paul area (approximately 45,000 Dth/day). Therefore, the reserve margin would provide sufficient back-up on a Design Day if a plant should fail. This structure gives us the ability to respond to unexpected events with either our own peak-shaving assets or the upstream pipeline transportation provided by others. This improves reliability by giving us diversity of supply and assets. We believe such an arrangement is critical to supplying our customers' needs reliably and economically.

The revised reserve margin increases slightly from 5.6 percent in November 2016 to 6.3 percent in November 2017, as described in **Attachment 2, Schedule 1, Page 2 of 2**. The reserve margin related cost represents approximately 1.5% of total gas supply costs and is an economical tool to address uncertainty.[3] The increase in reserve margin results from the addition of entitlements to bolster specific regional sections of our system. We believe this reserve margin is appropriate, given the need to balance the uncertainty of: (a) projecting 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. The proposed 2017-2018 heating season DD reserve margin for Minnesota State is 46,151 Dth/day or 6.3 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**.

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.**

[3] Assuming a weighted average demand cost per Dth for reserve margin entitlements.

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2017-2018 Heating Season

Service Region (1)	Projected Jan 2017 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	321,406	75	12,381	0.0323276	91	1.1886587	1.009	504,520	516,901	
BRAINERD	17,469	3	361	0.0216362	91	1.1096428	1.009	21,523	21,884	
MAINLINE	15,342	12	2,659	0.0347435	88	1.2751866	1.009	23,504	26,163	
MAINLINE-WELCOME	2,412	0	0	0.0165776	88	0.8634343	1.009	2,694	2,694	
WILLMAR	9,741	2	363	0.0226737	88	0.8689892	1.009	12,195	12,558	
PAYNESVILLE	41,800	24	4,098	0.0406783	94	1.0645893	1.009	71,114	75,212	
VGT-CHISAGO	2,143	0	0	0.0132839	91	1.0874763	1.009	2,312	2,312	
WATKINS	7,867	1	409	0.0174936	94	1.0486959	1.009	9,598	10,007	
TOMAH	15,715	9	1,444	0.0346161	88	0.5158502	1.009	23,357	24,801	
RED WING	7,693	5	1,208	0.0328045	88	1.1860992	1.009	11,593	12,801	
GRAND FORKS MN	3,052	1	63	0.0333585	98	0.2653216	1.009	4,745	4,808	
FARGO MN	12,989	6	1,481	0.0306823	98	0.2220981	1.009	18,524	20,005	
MN State	**457,631**	**138**	**24,469**					**705,678**	**730,147**	**87.57%**
GRAND FORKS ND	16,055	0	0	0.0164733	98	1.7522312	1.009	29,701	29,701	
FARGO ND	39,320	0	0	0.0163405	98	1.8791585	1.009	72,357	72,357	
WBI ND	1,224	0	0	0.0115971	98	1.9143092	1.009	1,625	1,625	
ND State	56,599	0	0					103,683	103,683	12.43%
TOTAL	**514,230**	**138**	**24,469**					**809,361**	**833,829**	**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 2012 to December 2016.
(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

2017-2018 Heating Season

Division/Region (1)	Projected Firm Jan 2018 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) 2018 Unacc. Volume	Design Day (Dth) 2018 Load Variation	Design Day (Dth) 2018 Day Base	Design Day (Dth) 2018 Total	2017 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO																
Total Residential	299,354	0.0104591	91	1.1361863	0.9862	64.4664	0.0000	0.0123	3,631	284,920	11,188	**299,740**	295,547	4,193	27,885	**327,625**
Total Small Commercial	15,339	0.0358219	91	2.2993965	0.9314	28.0659	0.0000	0.0123	627	50,002	1,160	**51,790**	53,402	(1,612)	4,818	**56,608**
Total Large Commercial	6,712	0.1687602	91	25.5288493	0.9823	56.8001	0.0000	0.0123	1,333	103,079	5,637	**110,048**	109,001	1,047	10,238	**120,286**
Industrial	75	Contract Demand	-	-				-	-	-	-	**12,381**	11,266	1,115	-	**12,381**
	321,481	0.0323276		1.188658675					5,592	438,001	17,985	**473,959**	469,217	4,743	42,941	**516,901**
														1.0%		
BRAINERD																
Total Residential	16,126	0.0095271	91	0.8800282	0.9866	65.3803	0.0000	0.0123	177	13,981	467	**14,625**	13,787	838	1,361	**15,985**
Total Small Commercial	1,146	0.0231857	91	4.3211496	0.9081	23.9396	0.0000	0.0123	32	2,417	163	**2,612**	2,514	97	243	**2,855**
Total Large Commercial	198	0.1172550	91	48.4166133	0.9524	34.0561	0.0000	0.0123	30	2,110	315	**2,454**	2,046	409	228	**2,683**
Industrial	3	Contract Demand	-	-				-	-	-	-	**361**	360	1	-	**361**
	17,472	0.0216362		1.109642838					239	18,508	945	**20,052**	18,707	1,346	1,832	**21,884**
														7.2%		
MAINLINE																
Total Residential	13,874	0.0099842	88	1.1365387	0.9833	58.4668	0.0000	0.0123	156	12,190	519	**12,864**	12,900	(36)	1,197	**14,061**
Total Small Commercial	1,106	0.0289835	88	3.0851799	0.8766	20.2981	0.0000	0.0123	36	2,820	112	**2,968**	3,016	(48)	276	**3,244**
Total Large Commercial	363	0.1614093	88	37.7193584	0.8826	20.8767	0.0000	0.0123	69	5,152	450	**5,671**	5,873	(202)	528	**6,199**
Industrial	12	Contract Demand	-	-				-	-	-	-	**2,659**	3,092	(433)	-	**2,659**
	15,354	0.0347435		1.275186644					261	20,162	1,081	**24,162**	24,882	(719)	2,000	**26,163**
														-2.9%		
MAINLINE-WELCOME																
Total Residential	2,267	0.0096673	88	0.7116689	0.9763	48.9318	0.0000	0.0123	24	1,929	53	**2,006**	1,952	54	187	**2,193**
Total Small Commercial	129	0.0157354	88	2.5930268	0.5330	8.1367	0.0000	0.0123	2	179	11	**192**	183	9	18	**210**
Total Large Commercial	16	0.1439802	88	118.8223038	0.4559	6.9708	0.0000	0.0123	3	201	62	**267**	261	6	25	**292**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,412	0.0165776		0.863434283					30	2,309	126	**2,465**	2,396	69	229	**2,694**
														2.9%		
WILLMAR																
Total Residential	8,990	0.0095894	88	0.7888140	0.9822	56.5254	0.0000	0.0123	96	7,586	233	**7,915**	8,506	(591)	736	**8,651**
Total Small Commercial	636	0.0294235	88	1.9503214	0.9201	25.8380	0.0000	0.0123	21	1,647	41	**1,708**	1,856	(148)	159	**1,867**
Total Large Commercial	116	0.1412952	88	19.6445230	0.8791	20.5406	0.0000	0.0123	19	1,441	75	**1,534**	1,356	178	143	**1,677**
Industrial	2	Contract Demand	-	-				-	-	-	-	**363**	363	0	-	**363**
	9,743	0.0226737		0.868989201					135	10,673	349	**11,520**	12,080	(560)	1,038	**12,558**
														-4.6%		
PAYNESVILLE																
Total Residential	37,094	0.0094404	94	0.9136990	0.9889	71.8390	0.0000	0.0123	417	32,917	1,115	**34,449**	34,731	(281)	3,205	**37,654**
Total Small Commercial	3,476	0.0346349	94	2.6975432	0.9477	32.4319	0.0000	0.0123	143	11,315	308	**11,766**	12,315	(549)	1,095	**12,861**
Total Large Commercial	1,231	0.1515610	94	26.7899124	0.9830	57.8701	0.0000	0.0123	228	17,533	1,084	**18,845**	18,555	290	1,753	**20,599**
Industrial	24	Contract Demand	-	-				-	-	-	-	**4,098**	3,060	1,038	-	**4,098**
	41,824	0.0406783		1.06458929					788	61,765	2,508	**69,159**	68,661	498	6,053	**75,212**
														0.7%		
VGT-CHISAGO																
Total Residential	2,041	0.0092351	91	0.9866490	0.9784	51.2825	0.0000	0.0123	22	1,715	66	**1,803**	1,734	69	168	**1,971**
Total Small Commercial	95	0.0253411	91	3.2718375	0.7534	13.3111	0.0000	0.0123	3	220	10	**233**	248	(15)	22	**254**
Total Large Commercial	7	0.1223322	91	(1.6432247)	0.8200	16.2539	0.0000	0.0123	1	79	(0)	**79**	59	20	7	**87**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	2,143	0.0132839		1.087476311					26	2,014	76	**2,116**	2,041	75	197	**2,312**
														3.7%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2017-2018 Heating Season

WATKINS																
Total Residential	7,588	0.0092720	94	0.9892062	0.9740	46.5974	0.0000	0.0123	84	6,614	247	**6,945**	6,690	255	646	**7,591**
Total Small Commercial	220	0.0379042	94	2.6544027	0.8541	18.4238	0.0000	0.0123	10	785	19	**814**	834	(20)	76	**889**
Total Large Commercial	59	0.1471947	94	101.7686534	0.5135	7.8245	0.0000	0.0123	12	813	197	**1,023**	853	169	95	**1,118**
Industrial	1	Contract Demand	-	-				-	-	-	-	**409**	306	103	-	**409**
	7,868	0.0174936		1.048695926					106	8,212	463	**9,190**	8,683	507	817	**10,007**
														5.8%		
TOMAH																
Total Residential	14,102	0.0097799	88	0.4199511	0.9800	53.2936	0.0000	0.0123	151	12,136	195	**12,482**	12,223	259	1,161	**13,644**
Total Small Commercial	1,238	0.0253784	88	1.4501115	0.9525	34.1079	0.0000	0.0123	35	2,766	59	**2,860**	2,785	75	266	**3,126**
Total Large Commercial	375	0.1736076	88	18.4900864	0.9678	41.7591	0.0000	0.0123	73	5,726	228	**6,027**	6,076	(49)	561	**6,587**
Industrial	9	Contract Demand	-	-				-	-	-	-	**1,444**	1,556	(112)	-	**1,444**
	15,724	0.0346161		0.515850153					259	20,628	482	**22,813**	22,640	173	1,988	**24,801**
														0.8%		
RED WING																
Total Residential	6,975	0.0096313	88	0.9200756	0.9851	61.9378	0.0000	0.0123	75	5,911	211	**6,198**	6,093	105	577	**6,774**
Total Small Commercial	549	0.0290761	88	4.5965925	0.9450	31.5691	0.0000	0.0123	18	1,405	83	**1,507**	1,562	(56)	140	**1,647**
Total Large Commercial	169	0.1851825	88	19.7247852	0.9634	39.0758	0.0000	0.0123	35	2,757	110	**2,902**	3,109	(207)	270	**3,172**
Industrial	5	Contract Demand	-	-				-	-	-	-	**1,208**	673	535	-	**1,208**
	7,698	0.0328045		1.186099189					128	10,074	404	**11,814**	11,438	377	987	**12,801**
														3.3%		
GRAND FORKS MN																
Total Residential	2,724	0.0093597	98	0.1975690	0.9670	41.2201	0.0000	0.0123	31	2,499	18	**2,548**	2,433	114	237	**2,785**
Total Small Commercial	261	0.0367848	98	0.7266252	0.8811	20.7287	0.0000	0.0123	12	940	6	**958**	994	(36)	89	**1,047**
Total Large Commercial	67	0.1211557	98	15.5694506	0.9531	34.3363	0.0000	0.0123	10	791	34	**835**	682	153	78	**913**
Industrial	1	Contract Demand	-	-				-	-	-	-	**63**	63	0	-	**63**
	3,053	0.0333585		0.26532158					53	4,230	58	**4,405**	4,173	232	404	**4,808**
														5.5%		
FARGO MN																
Total Residential	11,696	0.0082714	98	0.0536018	0.9743	46.8777	0.0000	0.0123	117	9,480	21	**9,617**	9,019	599	895	**10,512**
Total Small Commercial	1,021	0.0287545	98	1.9250521	0.9247	26.6835	0.0000	0.0123	36	2,878	65	**2,978**	2,859	119	277	**3,256**
Total Large Commercial	272	0.1539384	98	20.9674513	0.9645	39.6984	0.0000	0.0123	53	4,110	188	**4,351**	3,954	397	405	**4,756**
Industrial	6	Contract Demand	-	-				-	-	-	-	**1,481**	1,940	(458)	-	**1,481**
	12,995	0.0306823		0.222098067					205	16,468	273	**18,428**	17,772	657	1,577	**20,005**
														3.7%		

MN COMPANY						
Total Residential	**422,831**	**411,193**	**405,615**	**5,577**	**38,254**	**449,447**
Total Small Commercial	**25,216**	**80,385**	**82,568**	**-2,183**	**7,478**	**87,863**
Total Large Commercial	**9,584**	**154,037**	**151,825**	**2,212**	**14,330**	**168,368**
Contract Demand	**138**	**24,469**	**22,679**	**1,790**	**0**	**24,469**
	457,769	**670,084**	**662,687**	**7,396**	**60,063**	**730,147**
				1.1%		

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

Avg Monthly DD Method

2017-2018 Heating Season

Division/Region (1)	Projected Firm Jan 2018 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) 2018 Unacc. Volume	Load Variation	Day Base	Total	2017 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND																
Total Residential	13,913	0.0090692	98	0.3707366	0.9831	58.1654	0.0000	0.0123	154	12,365	170	**12,689**	12,489	200	1,180	**13,869**
Total Small Commercial	2,142	0.0645630	98	10.7250457	0.9562	35.5649	0.0000	0.0123	175	13,553	756	**14,484**	14,007	477	1,348	**15,832**
Total Large Commercial	-	-	98	-	0.0000	65535.0000	#NUM!	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	16,055	0.0164733		1.752231177					329	25,919	925	**27,173**	26,496	677	2,528	**29,701**
														2.6%		
FARGO ND																
Total Residential	33,212	0.0086147	98	0.3924082	0.9806	54.2043	0.0000	0.0123	349	28,039	429	**28,817**	27,425	1,392	2,681	**31,498**
Total Small Commercial	6,108	0.0583518	98	9.9638277	0.9645	39.7125	0.0000	0.0123	453	34,926	2,002	**37,381**	34,917	2,464	3,478	**40,859**
Total Large Commercial	-	-	98	-	0.0000	65535.0000	#NUM!	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	39,320	0.0163405		1.879158499					802	62,965	2,431	**66,198**	62,342	3,856	6,159	**72,357**
														6.2%		
WBI ND																
Total Residential	1,059	0.0097066	98	0.1384226	0.9565	35.7274	0.0000	0.0123	12	1,007	5	**1,025**	967	57	95	**1,120**
Total Small Commercial	165	0.0237104	98	13.2927820	0.2795	4.7434	0.0000	0.0123	6	384	72	**462**	422	40	43	**505**
Total Large Commercial	-	-	98	-	0.0000	65535.0000	#NUM!	0.0123	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-				-	-	-	-	**-**	-	0	-	**-**
	1,224	0.0115971		1.914309191					18	1,392	77	**1,487**	1,390	97	138	**1,625**
														7.0%		
ND COMPANY																
Total Residential	**48,184**											**42,530**	**40,881**	**1,649**	**3,957**	**46,487**
Total Small Commercial	**8,415**											**52,327**	**49,347**	**2,981**	**4,868**	**57,196**
Total Large Commercial	**0**											**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**											**-**	**-**	**-**	**-**	**-**
	56,599											**94,858**	**90,228**	**4,630**	**8,825**	**103,683**
														5.1%		
Grand Total																
Total Residential	**471,015**											**453,723**	**446,497**	**7,226**	**42,211**	**495,934**
Total Small Commercial	**33,631**											**132,712**	**131,915**	**798**	**12,346**	**145,059**
Total Large Commercial	**9,584**											**154,037**	**151,825**	**2,212**	**14,330**	**168,368**
Contract Demand	**138**											**24,469**	**22,679**	**1,790**	**-**	**24,469**
	514,368											**764,942**	**752,915**	**12,026**	**68,888**	**833,829**
														1.6%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
Avg Monthly DD Method
2017-2018 Heating Season

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2018 FORECAST	2017 FORECAST	Difference	%Diff
METRO	321,406	318,688	2,717	0.9%
BRAINERD	17,469	16,653	817	4.9%
MAINLINE	15,342	15,431	(88)	-0.6%
MAINLINE-WELCOME	2,412	2,364	48	2.0%
WILLMAR	9,741	10,491	(750)	-7.1%
PAYNESVILLE	41,800	42,446	(646)	-1.5%
VGT-CHISAGO	2,143	2,091	53	2.5%
WATKINS	7,867	7,649	218	2.8%
TOMAH	15,715	15,497	218	1.4%
RED WING	7,693	7,682	11	0.1%
GRAND FORKS MN	3,052	2,968	84	2.8%
FARGO MN	12,989	12,297	692	5.6%
MN STATE	457,631	454,258	3,373	0.7%
GRAND FORKS ND	16,055	16,080	(25)	-0.2%
FARGO ND	39,320	37,778	1,542	4.1%
WBI ND	1,224	1,177	47	4.0%
ND STATE	56,599	55,035	1,564	2.8%
TOTAL NSP MN	514,230	509,293	4,937	**1.0%**

2018 Customer Counts

	MN	ND	
Res	422,831	48,184	**471,015**
Sm Com	25,216	8,415	**33,631**
Lg Com	9,584	0	**9,584**
Ind	138	0	**138**
	457,769	56,599	**514,368**

2018 Design Day Use By Customer Class

	MN	ND	
Res	449,447	46,487	**495,934**
Sm Com	87,863	57,196	**145,059**
Lg Com	168,368	0	**168,368**
Ind	24,469	0	**24,469**
	730,147	103,683	**833,829**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2018 FORECAST	2017 FORECAST	Difference	%Diff
METRO	516,901	513,964	2,936	0.6%
BRAINERD	21,884	20,499	1,385	6.8%
MAINLINE	26,163	27,011	(848)	-3.1%
MAINLINE-WELCOME	2,694	2,630	64	2.4%
WILLMAR	12,558	13,225	(667)	-5.0%
PAYNESVILLE	75,212	75,071	141	0.2%
VGT-CHISAGO	2,312	2,240	72	3.2%
WATKINS	10,007	9,501	506	5.3%
TOMAH	24,801	24,700	101	0.4%
RED WING	12,801	12,489	312	2.5%
GRAND FORKS MN	4,808	4,575	234	5.1%
FARGO MN	20,005	19,319	686	3.6%
MN STATE	730,147	725,225	4,922	0.7%
GRAND FORKS ND	29,701	29,085	616	2.1%
FARGO ND	72,357	68,434	3,923	5.7%
WBI ND	1,625	1,526	99	6.5%
ND STATE	103,683	99,044	4,638	4.7%
TOTAL NSP MN	833,829	824,269	9,560	1.2%

MN / ND Allocation Factors

2018 DD	2017 DD	
0.8757	0.8798	**MN State Allocation**
0.1243	0.1202	**ND State Allocation**

NNG SYSTEM	2018 FORECAST	2017 FORECAST	Difference	%Diff
METRO	516,901	513,964	2,936	0.6%
BRAINERD	21,884	20,499	1,385	6.8%
MAINLINE	26,163	27,011	(848)	-3.1%
MAINLINE-WELCOME	2,694	2,630	64	2.4%
WILLMAR	12,558	13,225	(667)	-5.0%
PAYNESVILLE	75,212	75,071	141	0.2%
WATKINS	10,007	9,501	506	5.3%
TOMAH	24,801	24,700	101	0.4%
RED WING	12,801	12,489	312	2.5%
NNG SUBTOTAL	703,021	699,091	3,930	0.6%

VGT SYSTEM				
VGT-CHISAGO	2,312	2,240	72	3.2%
GRAND FORKS MN	4,808	4,575	234	5.1%
FARGO MN	20,005	19,319	686	3.6%
GRAND FORKS ND	29,701	29,085	616	2.1%
FARGO ND	72,357	68,434	3,923	5.7%
WBI ND	1,625	1,526	99	6.5%
VGT SUBTOTAL	130,808	125,178	5,630	4.5%
VGT & NNG TOTAL	833,829	824,269	9,560	1.2%

PUBLIC DOCUMENT
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
NNG TFX (Nov - Mar)[1]	8,486	$ 15.1530	5	$ 642,941.79
NNG TFX (Apr - Oct)[1]	8,486	$ 5.6830	7	$ 337,581.57
NNG TFX (Nov - Mar)[1]	3,333	$ 6.1032	5	$ 101,709.83
NNG TFX (Apr - Oct)[1]	3,333	$ 4.5000	7	$ 104,989.50
NNG TFX (Nov - Mar)[1]	918	$ 9.3568	5	$ 42,947.71
NNG TFX (Nov - Mar)[1]	918	$ 4.0000	7	$ 25,704.00
NNG TF5 (Nov - Mar)[2]	(13,233)	$ 3.6480	5	$ (241,369.92)
NNG TF5 (Nov - Mar)[2]	13,233	$ 3.9520	5	$ 261,484.08
NNG TF12 (Jan - Dec)[2]	(31,801)	$ 3.6480	12	$ (1,392,120.58)
NNG TF12 (Jan - Dec)[2]	31,801	$ 3.9520	12	$ 1,508,130.62
NNG TF5 (Nov - Mar)[2]	(15,338)	$ 4.2560	5	$ (326,392.64)
NNG TF5 (Nov - Mar)[2]	15,338	$ 4.5600	5	$ 349,706.40
NNG TF12 (Jan - Dec)[2]	(32,608)	$ 4.2560	12	$ (1,665,355.78)
NNG TF12 (Jan - Dec)[2]	32,608	$ 4.5600	12	$ 1,784,309.76
NNG TF5 (Nov - Mar)[2]	(1,028)	$ 3.8000	5	$ (19,532.00)
NNG TF5 (Nov - Mar)[2]	1,028	$ 4.1040	5	$ 21,094.56
NNG TF12 (Jan - Dec)[2]	(30,118)	$ 3.8000	12	$ (1,373,380.80)
NNG TF12 (Jan - Dec)[2]	30,118	$ 4.1040	12	$ 1,483,251.26
NNG TFX (Nov - Mar)[1]	(48,576)	$ 3.6480	5	$ (886,026.24)
NNG TFX (Nov - Mar)[1]	48,576	$ 3.9520	5	$ 959,861.76
NNG TFX (Jan - Dec)[1]	(10,000)	$ 3.0400	12	$ (364,800.00)
NNG TFX (Jan - Dec)[1]	10,000	$ 3.3440	12	$ 401,280.00
NNG TFX (Jan - Dec)[1]	(1,680)	$ 3.9520	12	$ (79,672.32)
NNG TFX (Jan - Dec)[1]	1,680	$ 4.2560	12	$ 85,800.96
NNG TFX (Nov - Mar)[1]	(2,270)	$ 4.2560	5	$ (48,305.60)
NNG TFX (Nov - Mar)[1]	2,270	$ 4.5600	5	$ 51,756.00
NNG TFX (Nov - Mar)[1]	(8,546)	$ 3.8000	5	$ (162,374.00)
NNG TFX (Nov - Mar)[1]	8,546	$ 4.1040	5	$ 175,363.92
NNG TFX (Apr - Jun, Sep - Oct)[1]	(7,701)	$ 3.8000	5	$ (146,319.00)
NNG TFX (Apr - Jun, Sep - Oct)[1]	7,701	$ 4.1040	5	$ 158,024.52
NNG TFX (July - Aug)[1]	(3,376)	$ 3.8000	2	$ (25,657.60)
NNG TFX (July - Aug)[1]	3,376	$ 4.1040	2	$ 27,710.21
NNG TFX (Nov - Mar)[1]	(13,333)	$ 5.3736	5	$ (358,231.04)
NNG TFX (Nov - Mar)[1]	13,333	$ 6.1032	5	$ 406,869.83
NNG TFX (Nov - Mar)[1]	(9,373)	$ 8.6272	5	$ (404,313.73)
NNG TFX (Nov - Mar)[1]	9,373	$ 9.3568	5	$ 438,506.43
VGT FT-A (Nov - Apr)[3]	(16,371)	$ 4.7507	6	$ (466,642.26)
ANR FSS (Jan - Dec)[4]	(65)	$ 1.7820	12	$ (1,389.96)
GLT FT (Nov - Mar)[5]	(9,248)	$ 11.4420	5	$ (529,078.08)
GLT FT (Nov - Mar)[5]	9,248	$ 14.9660	5	$ 692,027.84
GLT FT (Apr - Oct)[5]	(895)	$ 11.4420	7	$ (71,684.13)
GLT FT (Apr - Oct)[5]	895	$ 14.9660	7	$ 93,761.99
Total				$ 1,592,168.87

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

PROTECTED DATA ENDS]

Total	5,000	$159,657.50

Total MN & ND Demand Cost Adjustment	**$1,751,826.37**
Minnesota Allocation Factor (MN/ND Allocated Demand)	87.57%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand	**$ 1,534,074.35**

[1]NNG Sixth Revised Volume No. 1, Twelfth Revised Sheet No. 51, Effective April 1, 2017
[2]NNG Sixth Revised Volume No. 1, Eleventh Revised Sheet No. 50, Effective April 1, 2017
[3]VGT Volume No. 1, Part 5.0 Statement of Rates, Effective April 1, 2017
[4]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 2.0.0, Effective April 1, 2017
[5]GLT Third Revised Volume No. 1, Part 4.2 - Statement of Rates, v.4.0.0, Effective October 1 2017 Subject to Refund (RP17-598)

PUBLIC DOCUMENT
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-17-____
Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2016 SUPPLEMENTAL FILED COSTS				**$31,480,058.49**	**$23,662,641.61**	**$55,142,700.10**				
2016 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total					$ -	$ -				
2016 ACTUAL COSTS				**$ 31,480,058.49**	**$ 23,662,641.61**	**$ 55,142,700.10**				
CHANGES FOR 2017 FILING										
Contract Demand Entitlement Changes										
NNG TFX (Nov - Mar)	8,486	$ 15.1530	5		$ 642,941.79	$ 642,941.79	$ 642,941.79			1
NNG TFX (Apr - Oct)	8,486	$ 5.6830	7	$ 337,581.57		$ 337,581.57	$ 337,581.57			1
NNG TFX (Nov - Mar)	3,333	$ 6.1032	5		$ 101,709.83	$ 101,709.83	$ 101,709.83			1
NNG TFX (Apr - Oct)	3,333	$ 4.5000	7	$ 104,989.50		$ 104,989.50	$ 104,989.50			1
NNG TFX (Nov - Mar)	918	$ 9.3568	5		$ 42,947.71	$ 42,947.71	$ 42,947.71			1
NNG TFX (Nov - Mar)	918	$ 4.0000	7	$ 25,704.00		$ 25,704.00	$ 25,704.00			1
NNG TF5 (Nov - Mar)	(13,233)	$ 3.6480	5		$ (241,369.92)	$ (241,369.92)	$ (241,369.92)			2
NNG TF5 (Nov - Mar)	13,233	$ 3.9520	5		$ 261,484.08	$ 261,484.08	$ 261,484.08			2
NNG TF12 (Jan - Dec)	(31,801)	$ 3.6480	12	$ (1,392,120.58)		$ (1,392,120.58)	$ (1,392,120.58)			2
NNG TF12 (Jan - Dec)	31,801	$ 3.9520	12	$ 1,508,130.62		$ 1,508,130.62	$ 1,508,130.62			2
NNG TF5 (Nov - Mar)	(15,338)	$ 4.2560	5		$ (326,392.64)	$ (326,392.64)	$ (326,392.64)			2
NNG TF5 (Nov - Mar)	15,338	$ 4.5600	5		$ 349,706.40	$ 349,706.40	$ 349,706.40			2
NNG TF12 (Jan - Dec)	(32,608)	$ 4.2560	12	$ (1,665,355.78)		$ (1,665,355.78)	$ (1,665,355.78)			2
NNG TF12 (Jan - Dec)	32,608	$ 4.5600	12	$ 1,784,309.76		$ 1,784,309.76	$ 1,784,309.76			2
NNG TF5 (Nov - Mar)	(1,028)	$ 3.8000	5		$ (19,532.00)	$ (19,532.00)	$ (19,532.00)			2
NNG TF5 (Nov - Mar)	1,028	$ 4.1040	5		$ 21,094.56	$ 21,094.56	$ 21,094.56			2
NNG TF12 (Jan - Dec)	(30,118)	$ 3.8000	12	$ (1,373,380.80)		$ (1,373,380.80)	$ (1,373,380.80)			2
NNG TF12 (Jan - Dec)	30,118	$ 4.1040	12	$ 1,483,251.26		$ 1,483,251.26	$ 1,483,251.26			2
NNG TFX (Nov - Mar)	(48,576)	$ 3.6480	5		$ (886,026.24)	$ (886,026.24)	$ (886,026.24)			2
NNG TFX (Nov - Mar)	48,576	$ 3.9520	5		$ 959,861.76	$ 959,861.76	$ 959,861.76			2
NNG TFX (Jan - Dec)	(10,000)	$ 3.0400	12	$ (364,800.00)		$ (364,800.00)	$ (364,800.00)			2
NNG TFX (Jan - Dec)	10,000	$ 3.3440	12	$ 401,280.00		$ 401,280.00	$ 401,280.00			2
NNG TFX (Jan - Dec)	(1,680)	$ 3.9520	12	$ (79,672.32)		$ (79,672.32)	$ (79,672.32)			2
NNG TFX (Jan - Dec)	1,680	$ 4.2560	12	$ 85,800.96		$ 85,800.96	$ 85,800.96			2
NNG TFX (Nov - Mar)	(2,270)	$ 4.2560	5		$ (48,305.60)	$ (48,305.60)	$ (48,305.60)			2
NNG TFX (Nov - Mar)	2,270	$ 4.5600	5		$ 51,756.00	$ 51,756.00	$ 51,756.00			2
NNG TFX (Nov - Mar)	(8,546)	$ 3.8000	5		$ (162,374.00)	$ (162,374.00)	$ (162,374.00)			2
NNG TFX (Nov - Mar)	8,546	$ 4.1040	5		$ 175,363.92	$ 175,363.92	$ 175,363.92			2
NNG TFX (Apr - Jun, Sep - Oct)	(7,701)	$ 3.8000	5	$ (146,319.00)		$ (146,319.00)	$ (146,319.00)			2
NNG TFX (Apr - Jun, Sep - Oct)	7,701	$ 4.1040	5	$ 158,024.52		$ 158,024.52	$ 158,024.52			2
NNG TFX (July - Aug)	(3,376)	$ 3.8000	2	$ (25,657.60)		$ (25,657.60)	$ (25,657.60)			2
NNG TFX (July - Aug)	3,376	$ 4.1040	2	$ 27,710.21		$ 27,710.21	$ 27,710.21			2
NNG TFX (Nov - Mar)	(13,333)	$ 5.3736	5		$ (358,231.04)	$ (358,231.04)	$ (358,231.04)			2
NNG TFX (Nov - Mar)	13,333	$ 6.1032	5		$ 406,869.83	$ 406,869.83	$ 406,869.83			2
NNG TFX (Nov - Mar)	(9,373)	$ 8.6272	5		$ (404,313.73)	$ (404,313.73)	$ (404,313.73)			2
NNG TFX (Nov - Mar)	9,373	$ 9.3568	5		$ 438,506.43	$ 438,506.43				2
VGT FT-A (Nov - Apr)	(16,371)	$ 4.7507	6		$ (466,642.26)	$ (466,642.26)	$ (466,642.26)			3
ANR FSS (Jan - Dec)	(65)	$ 1.7820	12		$ (1,389.96)	$ (1,389.96)				4
GLT FT (Nov - Mar)	(9,248)	$ 11.4420	5		$ (529,078.08)	$ (529,078.08)		$ (529,078.08)		5
GLT FT (Nov - Mar)	9,248	$ 14.9660	5		$ 692,027.84	$ 692,027.84			$ 692,027.84	5
GLT FT (Apr - Oct)	(895)	$ 11.4420	7	$ (71,684.13)		$ (71,684.13)			$ (71,684.13)	5
GLT FT (Apr - Oct)	895	$ 14.9660	7	$ 93,761.99		$ 93,761.99			$ 93,761.99	5
Total				$ 891,554.19	$ 700,614.68	$ 1,592,168.87	$ 970,024.78	$ (529,078.08)	$ 714,105.70	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										6
										6
										6
										6
										6
										6
									PROTECTED DATA ENDS]	
Total				$ -	$ 159,657.50	$ 159,657.50	$ (112,142.50)	$ 271,800.00	$ -	
TOTAL OF 2017 CHANGES				**$ 891,554.19**	**$ 860,272.18**	**$ 1,751,826.37**	**$ 857,882.28**	**$ (257,278.08)**	**$ 714,105.70**	
2017 COSTS				**$ 32,371,612.68**	**$ 24,522,913.79**	**$ 56,894,526.47**				
2017 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							77%	-23%		7

Footnote
1. Incremental capacity added around Twin Cities, MN starting November 1, 2017.
2. NNG discount package renewal with $0.01/Dth/day increase
3. Expired winter firm transport capacity, November 1, 2016 through April 30, 2017.
4. Volume additions on ANR transport and storage agreements. Upstream capacity serves demand in both MN and ND.
5. Rate increase subject to refund as filed in GLT FERC rate case (RP17-598)
6. Expired peaking supply contract with demand charges in effect November 1, 2015 through March 31, 2016.
7. 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.

Northern States Power Company Docket No. G002/M-17-___
SUMMARY OF DESIGN DAY DEMAND BY CUSTOMER CLASS Attachment 1
Design Day: Heating Season 2017-2018 Schedule 3

DESIGN DAY CALCULATION

State of Minnesota	Jan-2018 Budget Customer	2018 MMBtu Design Day[1]	2017 MMBtu Design Day[1]	MMBtu Change
Residential	422,831	449,447	445,249	4,198
Commercial	34,800	256,231	257,297	(1,065)
Demand Billed	138	24,469	22,679	1,790
State of Minnesota Total	**457,769**	**730,147**	**725,225**	**4,922**
State of North Dakota Total	56,599	103,683	99,044	4,638
Total Xcel Energy - Gas Utility Operations	514,368	833,829	824,269	9,560

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER
UPC DD Method

Minnesota Company	Jan-2018 Budget Customer	Jan-2017 Budget Customer	Change
Residential	471,015	466,313	4,702
Commercial	43,215	42,980	235
TOTAL	514,230	509,293	4,937
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	809,360	801,591	
Demand Billed Customers	138	138	
Contracted Billing Demand of Demand Billed Customers	24,469	22,679	
Projected Design Day (Dth)	833,829	824,269	9,560

[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-2018 Budget	Jan-2017 Budget
Reserve Margin	52,660	45,854
Total Available Capacity	886,489	870,123
Entitlement per Customer	1.7235	1.7080

PUBLIC DOCUMENT
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

Northern States Power Company
DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER
Design Day: Heating Season 2017-2018

	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-2016	Aug-2016	Sep-2016	Oct-2016	Nov-2016	Dec-2016	Jan-2017	Feb-2017	Mar-2017	Apr-2017	May-2017	Jun-2017	Total	Winter	Summer
Residential	635,391	663,649	651,295	1,022,205	1,892,682	4,084,196	7,460,167	5,222,291	5,130,344	2,970,863	1,932,950	1,046,928	32,712,961	23,789,681	8,923,280
Interdepartmental	19	(409)	1	51	503	889	1,495	1,392	1,163	1,088	729	535	7,456	5,442	2,014
Small Commercial Firm	84,066	80,254	80,051	119,272	233,897	580,107	1,166,462	837,512	807,700	458,545	282,308	139,079	4,869,253	3,625,677	1,243,576
Large Commercial Firm	324,025	334,646	337,325	494,397	859,057	1,668,093	2,896,803	2,158,137	2,144,330	1,329,991	913,534	505,539	13,965,877	9,726,420	4,239,457
Commercial Firm	408,111	414,490	417,377	613,721	1,093,457	2,249,089	4,064,760	2,997,040	2,953,193	1,789,623	1,196,571	645,154	18,842,586	13,357,540	5,485,047
Small Commercial Demand Billed	5,568	5,917	4,670	4,962	8,803	10,058	13,588	13,510	12,145	9,643	7,770	6,616	103,250	58,104	45,145
Large Commercial Demand Billed	141,920	130,389	140,388	152,904	201,664	211,979	362,731	371,636	283,216	235,979	185,141	181,897	2,599,843	1,431,225	1,168,618
Large Demand Billed - Generation	1,503	1,729	1,294	1,518	854	1,615	1,118	1,765	1,093	1,404	1,403	1,374	16,671	6,445	10,225
Commercial Demand Billed	148,991	138,035	146,352	159,384	211,321	223,652	377,437	386,911	296,454	247,026	194,314	189,887	2,719,763	1,495,775	1,223,988
Total Commercial Firm	557,102	552,525	563,729	773,104	1,304,778	2,472,741	4,442,196	3,383,951	3,249,647	2,036,649	1,390,885	835,041	21,562,349	14,853,314	6,709,035
Total Firm	1,192,493	1,216,174	1,215,024	1,795,309	3,197,460	6,556,938	11,902,364	8,606,242	8,379,992	5,007,512	3,323,834	1,881,968	54,275,311	38,642,995	15,632,315
Small Interruptible	60,220	62,162	63,285	77,787	156,070	252,165	382,033	305,144	313,741	209,133	152,397	109,468	2,143,605	1,409,153	734,452
Medium Interruptible	315,499	345,146	255,291	356,395	590,331	560,626	785,794	(478,792)	618,342	585,943	450,499	374,318	4,759,391	2,076,300	2,683,091
Large Interruptible	142,114	137,341	163,410	151,627	96,716	135,686	238,519	1,341,184	195,649	241,427	141,007	143,866	3,128,547	2,007,754	1,120,793
Med. & Lg. Interruptible - Generation	23,969	14,967	7,264	3,330	6,420	3,506	1,040	1,079	10,412	12,049	12,536	16,077	112,649	22,458	90,192
Total Interruptible	541,802	559,616	489,250	589,140	849,537	951,983	1,407,385	1,168,615	1,138,144	1,048,552	756,440	643,729	10,144,193	5,515,665	4,628,528
Total Firm and Interruptible	1,734,295	1,775,789	1,704,274	2,384,449	4,046,998	7,508,921	13,309,749	9,774,857	9,518,136	6,056,064	4,080,274	2,525,697	64,419,504	44,158,660	20,260,843
Firm Transportation	30,213	27,961	36,158	36,410	38,213	40,117	55,571	56,663	56,262	57,550	43,489	51,481	530,088	246,826	283,262
Interruptible Transportation	297,029	302,523	309,753	312,546	335,585	351,088	404,350	425,296	362,719	393,969	323,766	313,417	4,132,041	1,879,038	2,253,003
Negotiated Transporation	366,441	418,348	456,821	373,635	423,089	601,105	687,561	679,715	582,428	624,629	516,027	569,952	6,299,751	2,973,898	3,325,853
Interdepartmental Transport - Generation	2,371,352	2,705,989	793,051	936,076	1,073,930	649,210	1,321,982	579,552	1,593,051	1,075,726	1,385,744	1,329,730	15,815,394	5,217,725	10,597,669
Total Transportation	3,065,035	3,454,821	1,595,783	1,658,667	1,870,817	1,641,520	2,469,464	1,741,226	2,594,460	2,151,874	2,269,026	2,264,580	26,777,274	10,317,487	16,459,787
Total Customer Sales	4,799,330	5,230,610	3,300,058	4,043,116	5,917,814	9,150,441	15,779,213	11,516,083	12,112,596	8,207,938	6,349,301	4,790,277	91,196,777	54,476,147	36,720,630
Monthly Heating Degree Days	1	2	55	375	631	1,372	1,359	944	968	439	210	6	6,362	5,274	1,088

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2017-2018 Heating Season

Firm Supplies (1)	**Current Quantity Effective Nov-16 Dth/Day**	**Proposed Quantity Effective Nov-17 Dth/Day**	**Proposed Quantity Change Nov-17 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	870,123	886,489	16,366
C. Minnesota State Delivered Supply			
State of MN Allocators	87.98%	87.57%	
TOTAL	765,534	776,298	10,764

(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] (1)	Number of Firm Customers[2] (2)	Design Day Requirement (Dth) (3)	Total Entitlement plus Storage plus Peak Shaving[3] (Dth) (4)	Peak Day Sendout (Dth) (5)	Heating Degree Days (6)	Actual Peak Day
Proposed: 2017/2018	457,769	730,147	776,298	Unknown	Unknown	Unknown
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	765,534	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
2003/2004	401,633	603,468	643,315	561,250	80	1/29/2004

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.

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NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

Docket No. G002/M-17-___
Attachment 2
Schedule 1
Page 1 of 2

Northern States Power Company
COMPANY DEMAND PROFILE
2017-2018 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		11.74%	
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27		0.00%	
112182	NNG TF12 BASE (Disc)	26,626	(5,549)	21,077	10 yrs - 10/31/27		2.38%	
112182	NNG TF12 VARIABLE (Disc.)	67,901	5,549	73,450	10 yrs - 10/31/27		8.29%	
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27		7.04%	
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27		3.34%	
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 10/31/22		3.21%	
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27		6.56%	
112185	NNG TFX (Disc. 12-month)	26,221	3,333	29,554	10 yrs - 10/31/27	Growth Election	3.33%	
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)	49,005	8,486	57,491	10 yrs - 10/31/27	Growth Election	6.49%	
112186	NNG TFX 2 (Max)	7,950	8,486	16,436	10 yrs - 10/31/27	Growth Election	Summer Only	
112186	NNG TFX 5 (Max)	27,253	8,486	35,739	10 yrs - 10/31/27	Growth Election	Summer Only	
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27		2.82%	
122067	NNG TFX (Disc. Nov-Mar)	9,373	918	10,291	10 yrs - 10/31/27	Growth election	1.16%	
122067	NNG TFX 7 (Disc)	9,373	918	10,291	10 yrs - 10/31/27	Growth election	Summer Only	
122068	NNG TFX (Nov-Mar)	8,875	0	8,875	10 yrs - 10/31/27		1.00%	
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 - 10/31/18		3.27%	
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/18		0.48%	
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/19		1.13%	
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	5 yrs - 10/31/22	Contract extension	1.76%	
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	8 yrs - 10/31/19		8.15%	
AF0218	VGT FT-A 12 Mos.	15,000	0	15,000	5 yrs - 10/31/19		1.69%	
AF0307	VGT FT-A (Nov-Apr)	16,371	(16,371)	0	6 mos - 4/30/2017	Contract expired	0.00%	
	WBI FT-1097	8,000	0	8,000	26.5 yrs - 10/31/19		0.90%	
	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	Contract Extension	2.71%	
	City Gate Deliveries	0	20,000	20,000	1 yrs - 3/31/18	Contract Acquisition	2.26%	
	LP Peak Shaving	90,000	0	90,000			10.15%	
	LNG Peak Shaving	156,000	0	156,000			17.60%	
	Total Design Day Capacity	**870,123**		**886,489**			**100%**	
	Heating Season Total	870,123		886,489				
	Non-Heating Season Total	439,156		460,379				
	Miscellaneous Entitlements with Reservation Fees							
	Additional Pipeline Entitlements							
	ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/18			
	ANR FTS-106211 (Summer) (1)	4,935	0	4,935	3 yrs - 03/31/18			
	ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/18			
	ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	9 yrs - 10/31/2019			
	GLT FT171836 (2)	3,509	0	3,509	5 yrs - 03/31/20	Contract extension		
	GLT FT171836 (2)	4,475	0	4,475	5 yrs - 03/31/20	Contract extension		
	GLT Backhaul FT18130 (2)	895	0	895	3 yrs. - 10/31/19	Contract extension		
	GLT Backhaul FT18129 (2)	9,248	0	9,248	3 yrs. - 03/31/20	Contract extension		
	NNG SMS (3)	30,650		30,650	15 yrs - 10/31/17			
	VGT OBA (3)	7,400		7,400	14 yrs - 10/31/16			
	Supply Entitlements (4)							
	[PROTECTED DATA BEGINS							
						PROTECTED DATA ENDS]		
	Storage Entitlements - Deliverability							
	ANR Pipeline Storage	15,300	(65)	15,235	3 yrs - 3/31/18	Fuel adjustment		
	ANR Storage	9,248	0	9,248	3 yrs - 3/31/20	Contract extension		
	FDD Service (5)	140,230		140,230	5 yrs - 5/31/22	Partial contract extension		
	FDD Service	78,050		78,050	15 yrs - 5/31/27			
	Storage Entitlements - Capacity							
	ANR Pipeline Storage	951,000	(4,030)	946,970	3 yrs - 3/31/18	Fuel adjustment		
	ANR Storage	1,165,000	0	1,165,000	3 yrs - 3/31/20	Contract extension		
	FDD Service (5)	8,084,975	0	8,084,975	5 yrs - 5/31/22	Partial contract extension		
	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 1,400,000 Dth in May 2018, 6,529,975 Dth in May 2019, & 155,000 Dth in May 2022

Northern States Power Company

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2017

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	870,123	16,366	886,489
Non-Heating Season	439,156	21,223	460,379
Heating Season Forecasted Design Day	824,269	9,560	833,829
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	45,854	6,806	52,660
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	5.6%	0.8%	6.3%
Total MN State Available Capacity:			
State of MN Allocation Factor	87.98%	-0.41%	87.57%
State of MN Heating Season Capacity	765,534	10,764	776,298
State of MN Design Day Demand	725,225	4,922	730,147
State of MN Heating Season Capacity Reserve/(Shortage)	40,309	5,842	46,151
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	5.6%	0.8%	6.3%

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

MINNESOTA STATE RATE IMPACT

Date to implement proposed changes: November 1, 2017
$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-16-649)	Last Month PGA: July 2017	Estimated Nov. 2017 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	$2.8801	$2.7645	$3.0125	-45.27%	4.60%	8.97%	$0.2480
Demand Cost of Gas (1)	$0.9008	$0.8350	$0.8387	$0.8733	-3.05%	4.59%	4.13%	$0.0346
Distribution Margin	$1.8591	$1.8591	$1.8591	$1.8591	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$5.5742	$5.4623	$5.7449	-30.48%	3.06%	5.17%	$0.2826
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$484.70	$474.97	$499.54	-30.48%	3.06%	5.17%	$24.57
Average Annual Total Demand Cost of Gas	$78.33	$72.61	$72.93	$75.94				**$3.01**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.8801	$2.7645	$3.0125	-45.10%	4.60%	8.97%	$0.2480
Demand Cost of Gas (1)	$0.8984	$0.8306	$0.8342	$0.8794	-2.11%	5.88%	5.42%	$0.0452
Distribution Margin	$1.2331	$1.2331	$1.2331	$1.2331	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.9438	$4.8318	$5.1250	-32.73%	3.67%	6.07%	$0.2932
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,404.16	$1,372.35	$1,455.63	-32.73%	3.67%	6.07%	$83.28
Average Annual Total Demand Cost of Gas	$255.17	$235.91	$236.93	$249.77				**$12.84**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.8801	$2.7645	$3.0125	-45.10%	4.60%	8.97%	$0.2480
Demand Cost of Gas (1)	$0.8917	$0.8306	$0.8342	$0.8621	-3.32%	3.79%	3.34%	$0.0279
Distribution Margin	$1.2315	$1.2315	$1.2315	$1.2315	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.9422	$4.8302	$5.1061	-32.91%	3.32%	5.71%	$0.2759
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$7,228.67	$7,064.86	$7,468.40	-32.91%	3.32%	5.71%	$403.54
Average Annual Total Demand Cost of Gas	$1,304.24	$1,214.87	$1,220.13	$1,260.94				**$40.81**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-16-649)	Last Month PGA: July 2017	Estimated Nov. 2017 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	$2.8801	$2.7645	$3.0125	-45.15%	4.60%	8.97%	$0.2480
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9635	$0.9635	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$3.8436	$3.7280	$3.9760	-38.41%	3.44%	6.65%	$0.2480
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$30,503.52	$29,586.10	$31,554.26	-38.41%	3.44%	6.65%	$1,968.15
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	$2.8801	$2.7645	$3.0125	-44.92%	4.60%	8.97%	$0.2480
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4751	$0.4751	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$3.3552	$3.2396	$3.4876	-41.33%	3.95%	7.66%	$0.2480
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$217,113.68	$209,633.29	$225,681.18	-41.33%	3.95%	7.66%	$16,047.89
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	$2.8801	$2.7645	$3.0125	-45.23%	4.60%	8.97%	$0.2480
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4346	$0.4346	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$3.3147	$3.1991	$3.4471	-41.92%	3.99%	7.75%	$0.2480
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$2,472,705.09	$2,386,469.89	$2,571,472.76	-41.92%	3.99%	7.75%	$185,002.87
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	$0.2480	8.97%	$0.0346	4.13%	$3.01	$24.57	5.17%
Small Commercial	$0.2480	8.97%	$0.0452	5.42%	$12.84	$83.28	6.07%
Large Commercial	$0.2480	8.97%	$0.0279	3.34%	$40.81	$403.54	5.71%
Small Interruptible	$0.2480	8.97%	$0.0000	NA	$0.00	$1,968.15	6.65%
Medium Interruptible	$0.2480	8.97%	$0.0000	NA	$0.00	$16,047.89	7.66%
Large Interruptible	$0.2480	8.97%	$0.0000	NA	$0.00	$185,002.87	7.75%

DERIVATION OF CURRENT PGA COSTS

Nov. 2017 - Projected Costs (Actual prices will be determined Nov.1, 2017)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$32,371,613	$24,522,914	
2.	x Minnesota Design Day Ratio (2017 Demand Entitlement Filing)	87.57%	87.57%	
3.	Annual System Demand Allocation to MN	$28,347,821	$21,474,716	
4.	MN State Design Day (2017 Demand Entitlement Filing)	730,147	730,147	
5.	- Small & Large Demand Billed Dth (2017 Demand Entitlement Filing)	24,469	24,469	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	705,678	705,678	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$27,397,821	$20,755,049	
8.	Demand Billed Cost Allocation (3 - 7)	$950,000	$719,667	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	552,768,428	413,787,731	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.04956	$0.05016	$0.09972
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)			$0.09972
14.	Total Demand Rate -Commercial (10 + 12)			$0.09972
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$950,000	$719,667	$1,669,667
16.	/ Annual Contract Billing Demand (2017 Demand Entitlement Filing)			2,936,267
17.	Monthly Commercial Demand Billed Demand Rate			$0.56864

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$25,093,283
19.	x MN Portion of Monthly Retail Sales	85.48%
20.	MN Portion of Monthly Commodity Costs	$21,449,738
21.	MN Budgeted Calendar Month Retail Therm Sales	71,203,385
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.30125

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.40097**
24.	Small & Large Commercial (14 +22)	**$0.40097**
25.	Small & Large Demand Billed - Demand (17)	**$0.56864**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.30125**

*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 (OR PRIVILEGED) DATA HAS BEEN EXCISED

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

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

CERTIFICATE OF SERVICE

I, Carl Cronin, 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, and
Xcel Energy Misc. Gas Service List

Dated this 1st day of August 2017

/s/
____
Carl Cronin
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
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	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
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	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
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_6-1429_1
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	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 551012130	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	Yes	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
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	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
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
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	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
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	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
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1153_Official
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	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 551012130	Electronic Service	Yes	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	Yes	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
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
Matthew P	Loftus	matthew.p.loftus@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	No	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

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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	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	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

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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
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	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
Corey	Conover	corey.conover@minneapolismn.gov	Minneapolis City Attorney	350 S. Fifth Street City Hall, Room 210 Minneapolis, MN 554022453	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
Carl	Cronin	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
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	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 551012130	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
Sandra	Hofstetter	sHofstetter@mnchamber.com	MN Chamber of Commerce	7261 County Road H Fremont, WI 54940-9317	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
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	sjphillips@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

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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 55101	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
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
Zeviel	Simpser	zsimpser@briggs.com	Briggs and Morgan PA	2200 IDS Center80 South Eighth Street Minneapolis, MN 554022157	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	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas

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Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	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