414 Nicollet Mall
Minneapolis, Minnesota 55401

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

August 1, 2014

—Via Electronic Filing—

Burl W. Haar
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-14-___

Dear Dr. Haar:

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, Subd. 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) 330-7529 or paul.lehman@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

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

DOCKET NO. G002/M-14-____

PETITION

INTRODUCTION

Pursuant to Minn. Stat. § 216B.16, Subd. 7 and Minn. Rule 7825.2910, Subp. 2, 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. Xcel Energy requests approval to implement our 2014-2015 Heating Season Supply Plan effective November 1, 2014, for customers served with natural gas in the State of Minnesota.

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, Minnesota 55401
(612) 330-5500

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

Alison C. Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall — 5th Floor
Minneapolis, Minnesota 55401
(612) 215-4662

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on August 1, 2014. The Company requests Commission approval to implement the rate impact of this filing in our purchased gas adjustment (PGA) effective with November 1, 2014 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, 2014, 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, permits comments in response to a miscellaneous filing within 30 days of filing, with reply comments 10 days thereafter.

E. Utility Employee Responsible for Filing

Paul J Lehman
Manager, Regulatory Compliance and Filings
Xcel Energy
414 Nicollet Mall — 7th Floor
Minneapolis, Minnesota 55401
(612) 330-7529

IV. 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, 2014, and respectfully request Commission approval of the revised entitlements effective on November 1, 2014. 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 2013-2014 heating season, as described in **Attachment 1**.

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 outlines the changes in the Company's Energy Firm DD Requirements, daily pipeline entitlement, and pipeline billing units from the 2013-2014 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.

D. Change in Supply Reservation Fees

This filing also reflects updated costs for firm gas supply reservation fees.

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. The attachment shows a summary of hedge transactions for the 2014-2015 heating season.

F. Classification and Billing of Demand Costs

In the Company's 2007 Contract Demand Entitlement filing[1] and with updates in subsequent Contract Demand Entitlement filings, we included a proposal to assign some demand costs – storage capacity demand charges and pipeline balancing charges – to interruptible customers. These requested changes have been settled as described below.

In the 2012 natural gas Automatic Annual Adjustment filing,[2] the Commission ordered:

> Prospectively, all regulated natural gas utilities shall recover balancing service costs, and shall credit the utility's penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that can reasonably be implemented.

We began treating pipeline balancing charges as commodity costs instead of demand costs in our November 2013 PGA.

[1] Docket No. G002/M-07-1395.

[2] Docket No. G002/AA-12-756, Order dated November 14, 2013.

In our grouped 2007-2013 Contract Demand Entitlement filings,[3] the Commission ordered:

> Required Xcel to allocate some storage-capacity demand charges to interruptible sales customers by including the costs in the commodity cost of gas withdrawn from storage and delivered to firm- and interruptible-sales customers, effective July 1, 2014.

We began treating storage-capacity demand charges as commodity costs instead of demand costs in our July 2014 PGA.

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

Schedule	Title
1, page 1	Demand Profile
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

Schedule	Title
1	Summary of Hedge Transactions

[3] Docket Nos. G002/M-07-1395, G002/M-08-1315, G002/M-09-1287, G002/M-10-1163, G002/M-11-1076, G002/M-12-862, and G002/M-13-663, Order dated June 9, 2014.

V. 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 $1,490,881.76 or about three percent of the total Minnesota State demand costs, effective November 1, 2014. 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.**

VI. 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:

Alison C. Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall — 5th Floor
Minneapolis, Minnesota 55401

SaGonna Thompson
Records Analyst
Xcel Energy
414 Nicollet Mall — 7th Floor
Minneapolis, Minnesota 55401

CONCLUSION

Xcel Energy respectfully requests Commission approval of our 2014-2015 Heating Season Supply Plan effective November 1, 2014, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2014 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, 2014

Northern States Power Company

/s/

BY: ________________________

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
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Betsy Wergin	Commissioner

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

DOCKET NO. G002/M-14-____

SUMMARY

SUMMARY OF FILING

Please take notice that on August 1, 2014, 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 2014-2015 Heating Season Supply Plan effective November 1, 2014. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2014, 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

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

estimated. Prior to the 2004-2005 Docket, we used a single methodology, based on a linear regression calculation.

We project our forecasted firm customer count in Minnesota State to increase by 4,836 customers, from 441,573 to 446,409, between the 2013-2014 and the 2014-2015 heating season forecasts. This projection contributes to an increase in DD requirements in Minnesota State of 9,010 Dekatherms (Dth), from 706,935 to 715,945, using the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**. The remainder of the increase is attributable to new gas distribution services for two Minnesota communities in the process of converting from propane to firm natural gas service.[2] More detail on this conversion appears in Section 2b below.

We also used the Avg. Monthly DD to develop the allocations by state and by service region as shown on **Attachment 1, Schedule 1, Page 1 of 4**. The Avg. Monthly DD calculation is based on linear regression using 60 data points, from January 2009-December 2013, as shown on **Attachment 1, Schedule 1, Pages 2-4**. Nearly 75% of all regression statistics were very strong with R-squared values at or above 95 percent.[3] The regions with R-squared values below 95 percent were generally those with much lower customer counts. In all, R-squared values were, on average, 93 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 690,637 Dth (not including the new communities). The Small and Large Demand Billed contracted customer Billing Demand of 21,803 Dth is added to the DD estimate for the Residential, Small and Large Commercial classes and the DD

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[2] In Docket No. G002/M-14-583, we have requested New Area Surcharge riders for Barnesville, Holdingford, and Pillager. The additional firm requirements are for Barnesville and Holdingford. Pillager can be served with existing entitlements and new entitlements we already planned to secure.

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

estimate for the new communities noted above to determine the total Minnesota State DD Projection of 715,945 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.

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 2014-2015 heating season compared to the 2013-2014 heating season as filed in Docket No. G002/M-13-0663. **Attachment 1, Schedule 2** details the demand cost component changes for the 2014-2015 heating season. **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 a decrease of demand related total costs of approximately $3.6 million. This decrease is largely attributable to upstream/system supply cost decreases, most of which are storage capacity demand charges now allocated as commodity costs.[4]

a. Change in Northern Natural Gas (Northern) entitlement (effective November 1, 2014)

Four modifications were made to firm capacity entitlement levels on Northern in the past year. First, we added 3,981 Dth/day of incremental capacity at Brainerd, MN to be effective November 1, 2014. Additional capacity was needed in Brainerd, MN to ensure adequate capacity to meet the demands of our firm customers and maintain a five percent reserve margin in the event of DD conditions. In addition, beginning November 1, 2014, capacity at Brainerd was set to ratchet up to 4,894 Dth/day from 4,839 Dth/day, an increase of 55 Dth/day. Combined, these additions at Brainerd increase total entitlement by 4,036 Dth/day to a total of 8,875 Dth/day beginning November 1, 2014. This level of entitlement at Brainerd will remain in effect until

[4] In compliance with the Order dated June 9, 2014 in Docket Nos. G002/M-07-1395, G002/M-08-1315, G002/M-09-1287, G002/M-10-1163, G002/M-11-1076, G002/M-12-862, and G002/M-13-663, about $5 million of storage capacity demand charges are now allocated as commodity costs.

October 31, 2021. We have seen steady load growth in the Brainerd area for some time. The area is growing faster than projections, and we have increased firm capacity to keep up with that growth, including supporting the conversion of propane services in the area.

Second, in June 2013 we added 1,100 Dth/day of incremental firm capacity at Red Wing, MN. Like Brainerd, additional capacity was needed at Red Wing to ensure adequate capacity in the event of DD conditions. We forecasted demand at Red Wing five years out in order to provide sufficient incremental capacity in the Red Wing area and maintain an appropriate reserve margin of 5% over the entire five year term.

Third, we added 1,050 Dth/day of incremental capacity at Kandiyohi, MN. During the extended cold of last heating season, demand at Kandiyohi was consistently above our firm upstream capacity entitlement. An analysis showed we needed an additional 1,050 Dth/day of winter capacity to meet the updated DD requirements, maintain a 5% reserve margin, and serve expected propane conversions in the area. The additional capacity will be effective November 1, 2014.

Lastly, 431 Dth/day of incremental capacity was added for the St. Cloud and Becker, MN areas. According to design day calculations, we are projected to need additional capacity of 380 Dth/day on Northern's Paynesville lateral and 51 Dth/day on Northern's Watkins lateral beginning November 1, 2014. Both laterals are west of the Minneapolis-St. Paul metropolitan area. Without increasing capacity on these laterals, we will outgrow the daily firm entitlement on Northern needed to meet our firm customer's requirements at design day temperatures.

b. Change in Viking Gas Transmission (Viking) entitlement (effective November 1, 2014)

NSP renewed several Viking firm capacity entitlements in the past year. First, the seasonal capacity of 10,542 Dth/day purchased last winter expired February 28, 2014. In its place, we plan to purchase slightly more (10,646 Dth/day) short-term capacity for this winter to meet DD projections. This capacity is available to serve Grand Forks/East Grand Forks area, the Fargo/Moorhead area, and the Minneapolis/St. Paul metro area (through Northern) throughout the winter. We keep these costs low by only purchasing this capacity for a few months in the winter, since it is not needed on a year-round basis.

Second, we renewed Viking contract AF0103 for five years until October 31, 2019. This contract previously had year-round capacity of 10,000 Dth/day with 5,000 Dth/day of additional capacity in summer months April through October. After reviewing renewal options, we determined the Viking system is long on capacity during summer months and the additional 5,000 Dth/day is not needed. The contract was renewed for only the year-round capacity of 10,000 Dth/day which saves ratepayers $120,000 annually. The capacity under this contract will continue to serve the Grand Forks/East Grand Forks area, the Fargo/Moorhead area, and the St. Cloud, Brainerd, Minneapolis/St. Paul areas (through Northern).

Lastly, we made two contract changes to provide additional supply diversity and system reliability on Viking. Currently, Viking flows south from Emerson, MN, the interconnect between TransCanada and Viking, to Marshfield, WI, the interconnect between Viking and ANR Pipeline. Viking initiated a construction project to facilitate the increased flow of natural gas on Viking north from Marshfield. A bi-directional Viking system benefits us and other shippers in two ways. First, bi-directionality allows greater gas supply flexibility by providing greater access to the liquid natural gas supply hub near Chicago, IL through Viking's Marshfield interconnection. Second, bi-directionality improves reliability in the event a single point of receipt is lost from service. Such an event occurred in January 2014 when a rupture occurred on TransCanada cutting off all natural gas supplies at Emerson for a couple of days. Additional supply sources at Marshfield will reduce our dependence on gas supplies at Emerson. Viking indicates that the new facilities will be ready for service by November 1, 2014.

To support the construction of these facilities, we agreed to two contract changes. First, we extended Viking contract AF0156, by an additional 26 months from the original expiration date in 2017. This contract has primary delivery points at Green Lake, Chisago (Minneapolis/St. Paul through Northern), Pierz (St. Cloud and Brainerd), and Fargo/Moorhead. Second, we agreed to enter into a new contract for an incremental 15,000 Dth/day of year-round capacity with a Marshfield receipt point This new contract is required to serve new DD needs identified this year. The largest customer demand growth is expected in the Holdingford and Barnesville, MN areas that are converting from propane to natural gas service (see footnote 2 above).

However, as with the other Viking contracts mentioned here, the capacity will be available to serve areas throughout Minnesota and North Dakota (Minneapolis/St. Paul, St. Cloud, Brainerd, Fargo/Moorhead, and Grand Forks/East Grand Forks).

c. Change in Great Lakes Gas Transmission (Great Lakes) entitlement (effective November 1, 2014)

NSP renewed one Great Lakes firm capacity entitlement this year. The seasonal capacity of 6,706 Dth/day purchased last winter expired March 31, 2014. In its place, we purchased 9,248 Dth/day of capacity for this winter. This capacity was renewed for a five-month term beginning November 1, 2014 to support the winter withdrawal of the ANR Storage quantities described below.

d. Change in ANR Pipeline entitlement (effective April 1, 2014)

Several small additions were made to entitlement holdings on ANR Pipeline pursuant to ANR Pipeline's tariff. These are annual adjustments to match the changes in ANR's in-kind fuel percentages made each spring 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.

e. Change in ANR Storage entitlement (effective April 1, 2014)

We renewed our contract with ANR Storage for one-year until March 31, 2015 and slightly increased storage capacity under the contract from 994,305 Dth to 1,165,185 Dth. Natural gas withdrawn from the ANR Storage facility is transported on Great Lakes to the Carlton, MN 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 given this past winter's challenging supply availability and unusual natural gas price volatility. Furthermore, daily withdrawal capability decreases 6,049 Dth/day to 9,248 Dth/day to allow for an extended withdrawal season.

3. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor decreased slightly for the Minnesota State jurisdiction from 88.95 percent to 88.42 percent. While most of the firm capacity entitlement changes occurred at Minnesota delivery points, overall the North Dakota DD projection grew more than the Minnesota DD projection causing the North Dakota DD allocation factor to increase slightly. 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 4**. 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 existing supplier reservation charges is a decrease of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. **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**.

We propose to slightly increase our capacity reserve margin from 6.0 percent in November 2013 to 6.3 percent in November 2014, as described in **Attachment 2, Schedule 1, Page 2 of 2**. We believe this reserve margin is appropriate, given the need to balance the uncertainty of: (a) experiencing DD conditions; (b) actual consumer demand during DD conditions; and (c) the need to protect against the potential loss of a source of firm natural gas supply.

We add firm resources to meet projected firm customer demand and plans to maintain a reserve margin as close as practicable to either the capability of the largest pump at Wescott used to vaporize LNG or to the capability of either of the St. Paul metro propane-air peak shaving plants. Capacity decisions are based on projected demand, and the most economic method of adding capacity often involves adding increments that do not precisely match expected changes in demand. The reserve margin ensures reliability for our firm natural gas customers in Minnesota. The proposed 2014-2015 heating season DD reserve margin for Minnesota State is 45,409 Dth/day or 6.3 percent.

C. 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**.

D. 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.**

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2014-2015 Heating Season

Service Region (1)	Projected Jan 2015 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	313,267	71	10,864	0.0287222	91	1.2979426	1.009	496,492	507,356	
BRAINERD	15,753	3	360	0.0178996	91	1.2572660	1.009	18,984	19,344	
MAINLINE	15,204	11	2,478	0.0305909	88	1.3768399	1.009	23,468	25,947	
MAINLINE-WELCOME	2,257	0	0	0.0159436	88	0.9274533	1.009	2,588	2,588	
WILLMAR	10,219	2	254	0.0176371	88	0.9182249	1.009	12,413	12,667	
PAYNESVILLE	41,496	22	3,329	0.0339742	94	1.1624541	1.009	69,306	72,635	
VGT-CHISAGO	3,195	0	0	0.0129214	91	1.3260017	1.009	3,770	3,770	
WATKINS	7,217	1	306	0.0152262	94	1.1962850	1.009	8,681	8,987	
TOMAH	15,657	9	1,280	0.0302557	88	0.5606349	1.009	22,941	24,222	
RED WING	7,569	5	1,163	0.0294223	88	1.2725557	1.009	11,413	12,575	
GRAND FORKS MN	2,943	1	63	0.0270622	98	0.3599729	1.009	4,477	4,541	
FARGO MN	11,504	3	1,706	0.0266812	98	0.3125694	1.009	16,103	17,809	
NEW COMMUNITIES									3,504	
MN State	**446,281**	**128**	**21,803**					**690,638**	**715,945**	**88.42%**
GRAND FORKS ND	15,497	0	0	0.0153539	98	1.7291628	1.009	28,250	28,250	
FARGO ND	35,489	0	0	0.0151189	98	1.8481980	1.009	63,903	63,903	
WBI ND	1,081	0	0	0.0123918	98	0.9618616	1.009	1,572	1,572	
ND State	52,067	0	0					93,726	93,726	11.58%
TOTAL	**498,348**	**128**	**21,803**					**784,364**	**809,671**	**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 2009 to December 2013.
(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
2014-2015 Heating Season

Division/Region (1)	Projected Firm Jan 2015 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) 2015 Unacc. Volume	Load Variation	Day Base	Total	2014 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO														
Total Residential	291,635	0.0103975	91	1.1932072	0.9868	0.0090	2,586	275,936	11,447	**289,970**	287,515	2,454	45,521	**335,491**
Total Small Commercial	16,237	0.0352415	91	3.2822310	0.9751	0.0090	484	52,071	1,753	**54,309**	54,475	(166)	8,526	**62,835**
Total Large Commercial	5,395	0.1620705	91	25.4712214	0.9841	0.0090	757	79,570	4,520	**84,847**	85,689	(842)	13,320	**98,167**
Industrial	71	Contract Demand	-	-		-	-	-	-	**10,864**	10,400	464	-	**10,864**
	313,338	0.0287222		1.297942582			3,828	407,578	17,720	**439,989**	438,079	1,910	67,367	**507,356**
												0.4%		
BRAINERD														
Total Residential	14,499	0.0091311	91	0.9626714	0.9869	0.0090	113	12,048	459	**12,620**	12,429	190	1,981	**14,601**
Total Small Commercial	1,128	0.0212660	91	5.0380414	0.9636	0.0090	21	2,184	187	**2,392**	2,473	(81)	375	**2,767**
Total Large Commercial	126	0.1061675	91	41.4376843	0.9613	0.0090	12	1,213	171	**1,396**	1,375	22	219	**1,616**
Industrial	3	Contract Demand	-	-		-	-	-	-	**360**	0	360	-	**360**
	15,756	0.0178996		1.257266001			146	15,444	817	**16,768**	16,277	491	2,576	**19,344**
												3.0%		
MAINLINE														
Total Residential	13,718	0.0097957	88	1.2032387	0.9824	0.0090	111	11,825	543	**12,479**	12,288	191	1,959	**14,438**
Total Small Commercial	1,189	0.0279367	88	3.4573334	0.9077	0.0090	28	2,922	135	**3,085**	3,176	(91)	484	**3,569**
Total Large Commercial	298	0.1651818	88	35.8207819	0.9485	0.0090	42	4,327	351	**4,720**	4,837	(117)	741	**5,461**
Industrial	11	Contract Demand	-	-		-	-	-	-	**2,478**	2,478	0	-	**2,478**
	15,215	0.0305909		1.376839904			181	19,074	1,029	**22,762**	22,779	(17)	3,184	**25,947**
												-0.1%		
MAINLINE-WELCOME														
Total Residential	2,126	0.0094371	88	0.8272221	0.9763	0.0090	16	1,766	58	**1,840**	1,823	17	289	**2,129**
Total Small Commercial	117	0.0166464	88	1.8864444	0.6779	0.0090	2	171	7	**180**	186	(7)	28	**208**
Total Large Commercial	14	0.1395665	88	100.3048168	0.4693	0.0090	2	170	46	**217**	246	(29)	34	**252**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,257	0.0159436		0.927453271			20	2,106	111	**2,237**	2,256	(19)	351	**2,588**
												-0.8%		
WILLMAR														
Total Residential	9,452	0.0093144	88	0.8057061	0.9878	0.0090	72	7,747	251	**8,070**	7,967	103	1,267	**9,337**
Total Small Commercial	697	0.0307441	88	2.4073772	0.9726	0.0090	17	1,886	55	**1,958**	2,022	(64)	307	**2,266**
Total Large Commercial	71	0.1034811	88	21.7159497	0.8795	0.0090	6	644	51	**701**	797	(96)	110	**811**
Industrial	2	Contract Demand	-	-		-	-	-	-	**254**	213	42	-	**254**
	10,221	0.0176371		0.918224853			96	10,277	356	**10,983**	10,999	(16)	1,684	**12,667**
												-0.1%		
PAYNESVILLE														
Total Residential	36,846	0.0093190	94	0.9168612	0.9889	0.0090	300	32,277	1,111	**33,689**	32,833	855	5,289	**38,977**
Total Small Commercial	3,709	0.0339165	94	3.6438549	0.9797	0.0090	110	11,823	445	**12,378**	12,321	57	1,943	**14,321**
Total Large Commercial	941	0.1461055	94	25.3450445	0.9865	0.0090	123	12,927	785	**13,835**	13,982	(147)	2,172	**16,007**
Industrial	22	Contract Demand	-	-		-	-	-	-	**3,329**	3,339	(10)	-	**3,329**
	41,518	0.0339742		1.162454112			534	57,027	2,341	**63,231**	62,475	756	9,404	**72,635**
												1.2%		
VGT-CHISAGO														
Total Residential	3,012	0.0088833	91	1.1940189	0.9824	0.0090	23	2,435	118	**2,576**	2,505	70	404	**2,980**
Total Small Commercial	175	0.0371025	91	3.6255155	0.9409	0.0090	6	591	21	**617**	623	(6)	97	**714**
Total Large Commercial	8	0.0906823	91	(2.3817448)	0.8910	0.0090	1	66	(1)	**65**	64	1	10	**76**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	3,195	0.0129214		1.32600168			29	3,091	139	**3,259**	3,193	66	512	**3,770**
												2.1%		
WATKINS														
Total Residential	6,939	0.0088798	94	1.0999220	0.9866	0.0090	54	5,792	251	**6,098**	5,984	114	957	**7,055**
Total Small Commercial	238	0.0355941	94	3.3989075	0.9399	0.0090	7	797	27	**831**	834	(4)	130	**961**
Total Large Commercial	40	0.0990427	94	153.1203159	0.2661	0.0090	5	370	200	**575**	656	(81)	90	**665**
Industrial	1	Contract Demand	-	-		-	-	-	-	**306**	252	54	-	**306**
	7,218	0.0152262		1.196285039			67	6,959	478	**7,809**	7,726	83	1,178	**8,987**
												1.1%		
TOMAH														
Total Residential	14,037	0.0096569	88	0.4652479	0.9844	0.0090	109	11,929	215	**12,253**	12,269	(16)	1,924	**14,177**
Total Small Commercial	1,314	0.0244448	88	1.4683083	0.9676	0.0090	26	2,826	63	**2,916**	3,028	(113)	458	**3,373**
Total Large Commercial	306	0.1650619	88	17.0111702	0.9718	0.0090	42	4,447	171	**4,660**	4,756	(96)	732	**5,391**
Industrial	9	Contract Demand	-	-		-	-	-	-	**1,280**	2,795	(1,515)	-	**1,280**
	15,666	0.0302557		0.56063487			177	19,202	450	**21,109**	22,848	(1,739)	3,113	**24,222**
												-7.6%		
RED WING														
Total Residential	6,843	0.0095127	88	0.9632300	0.9829	0.0090	54	5,728	217	**5,999**	5,933	66	942	**6,940**
Total Small Commercial	584	0.0272161	88	4.9385322	0.8841	0.0090	13	1,399	95	**1,508**	1,510	(2)	237	**1,744**
Total Large Commercial	142	0.1800002	88	19.9700557	0.9512	0.0090	21	2,244	93	**2,358**	2,432	(74)	370	**2,728**
Industrial	5	Contract Demand	-	-		-	-	-	-	**1,163**	807	356	-	**1,163**
	7,574	0.0294223		1.272555675			88	9,372	405	**11,027**	10,681	345	1,549	**12,575**
												3.2%		
GRAND FORKS MN														
Total Residential	2,637	0.0089881	98	0.2025857	0.9711	0.0090	21	2,323	18	**2,362**	2,311	51	371	**2,733**
Total Small Commercial	260	0.0375284	98	1.8083164	0.9625	0.0090	9	955	15	**979**	967	12	154	**1,132**
Total Large Commercial	46	0.1127531	98	10.0453181	0.9711	0.0090	5	510	15	**530**	528	1	83	**613**
Industrial	1	Contract Demand	-	-		-	-	-	-	**63**	63	-	-	**63**
	2,944	0.0270622		0.359972861			35	3,787	48	**3,933**	3,870	64	608	**4,541**
												1.6%		
FARGO MN														
Total Residential	10,369	0.0079782	98	0.0973211	0.9732	0.0090	73	8,107	33	**8,214**	8,082	131	1,289	**9,503**
Total Small Commercial	937	0.0286706	98	2.5300418	0.9512	0.0090	24	2,634	78	**2,736**	2,758	(22)	430	**3,166**
Total Large Commercial	197	0.1459244	98	18.5495281	0.9669	0.0090	26	2,821	120	**2,968**	2,970	(2)	466	**3,434**
Industrial	3	Contract Demand	-	-		-	-	-	-	**1,706**	916	790	-	**1,706**
	11,507	0.0266812		0.312569373			124	13,562	232	**15,624**	14,726	897	2,185	**17,809**
												6.1%		
NEW COMMUNITIES														**3,504**
MN COMPANY														
Total Residential	**412,114**									**396,167**	**391,941**	**4,227**	**62,193**	**458,360**
Total Small Commercial	**26,584**									**83,888**	**84,374**	**-487**	**13,169**	**97,057**
Total Large Commercial	**7,583**									**116,872**	**118,332**	**-1,460**	**18,347**	**135,220**
Contract Demand	**128**									**21,803**	**21,262**	**540**	**0**	**21,803**
New Communities														**3,504**
	446,409									**618,731**	**615,910**	**2,821**	**93,709**	**715,945**
												0.5%		

Northern States Power Company
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
2014-2015 Heating Season

Division/Region (1)	Projected Firm Jan 2015 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) 2015 Unacc. Volume	Design Day (Dth) 2015 Load Variation	Design Day (Dth) 2015 Day Base	Design Day (Dth) 2015 Total	2014 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND														
Total Residential	13,423	0.0086295	98	0.4315125	0.9855	0.0090	104	11,352	191	**11,646**	10,956	691	1,828	**13,475**
Total Small Commercial	2,074	0.0588853	98	10.1296723	0.9646	0.0090	114	11,966	691	**12,771**	12,091	680	2,005	**14,776**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	15,497	0.0153539		1.729162758			218	23,318	881	**24,417**	23,047	1,370	3,833	**28,250**
												5.9%		
FARGO ND														
Total Residential	30,140	0.0083356	98	0.4109462	0.9842	0.0090	225	24,621	407	**25,254**	23,718	1,536	3,965	**29,219**
Total Small Commercial	5,349	0.0533406	98	9.9467517	0.9709	0.0090	267	27,961	1,750	**29,979**	28,115	1,864	4,706	**34,685**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	35,489	0.0151189		1.848198031			493	52,582	2,158	**55,233**	51,832	3,401	8,671	**63,903**
												6.6%		
WBI ND														
Total Residential	928	0.0088960	98	0.3485312	0.9525	0.0090	7	809	11	**827**	778	49	130	**957**
Total Small Commercial	152	0.0336792	98	4.6966561	0.8289	0.0090	5	503	24	**532**	519	12	83	**615**
Total Large Commercial	-	-	98	-	0.0000	0.0090	0	0	0	**0**	0	0	0	**0**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	1,081	0.0123918		0.961861611			12	1,313	34	**1,359**	1,298	62	213	**1,572**
												4.7%		
ND COMPANY														
Total Residential	**44,492**									**37,728**	**35,451**	**2,277**	**5,923**	**43,651**
Total Small Commercial	**7,575**									**43,281**	**40,725**	**2,556**	**6,795**	**50,076**
Total Large Commercial	**0**									**-**	**-**	**-**	**-**	**-**
Contract Demand	**0**									**-**	**-**	**-**	**-**	**-**
	52,067									**81,009**	**76,176**	**4,833**	**12,717**	**93,726**
												6.3%		
Grand Total														
Total Residential	**456,606**									**433,895**	**427,392**	**6,503**	**68,116**	**502,011**
Total Small Commercial	**34,159**									**127,169**	**125,099**	**2,069**	**19,964**	**147,133**
Total Large Commercial	**7,583**									**116,872**	**118,332**	**(1,460)**	**18,347**	**135,220**
Contract Demand	**128**									**21,803**	**21,262**	**540**	**-**	**21,803**
New Communities														**3,504**
	498,476									**699,740**	**692,086**	**7,653**	**106,427**	**809,671**
												1.1%		

Northern States Power Company

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2014-2015 Heating Season

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2015 FORECAST	2014 FORECAST	Difference	%Diff
METRO	313,267	309,872	3,396	1.1%
BRAINERD	15,753	15,581	172	1.1%
MAINLINE	15,204	15,040	164	1.1%
MAINLINE-WELCOME	2,257	2,232	25	1.1%
WILLMAR	10,219	10,107	112	1.1%
PAYNESVILLE	41,496	41,051	445	1.1%
VGT-CHISAGO	3,195	3,159	35	1.1%
WATKINS	7,217	7,138	80	1.1%
TOMAH	15,657	15,489	169	1.1%
RED WING	7,569	7,487	82	1.1%
GRAND FORKS MN	2,943	2,911	32	1.1%
FARGO MN	11,504	11,379	124	1.1%
MN STATE	446,281	441,446	4,835	1.1%
GRAND FORKS ND	15,497	14,882	615	4.1%
FARGO ND	35,489	34,086	1,403	4.1%
WBI ND	1,081	1,038	43	4.1%
ND STATE	52,067	50,006	2,061	4.1%
TOTAL NSP MN	498,348	491,452	6,896	**1.4%**

2015 Customer Counts

	MN	ND	
Res	412,114	44,492	**456,606**
Sm Com	26,584	7,575	**34,159**
Lg Com	7,583	0	**7,583**
Ind	128	0	**128**
	446,409	52,067	**498,476**

2015 Design Day Use By Customer Class

	MN	ND	
Res	458,360	43,651	**502,011**
Sm Com	97,057	50,076	**147,133**
Lg Com	135,220	0	**135,220**
Ind	21,803	0	**21,803**
New Comm	3,504	0	**3,504**
	715,945	93,726	**809,671**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2015 FORECAST	2014 FORECAST	Difference	%Diff
METRO	507,356	503,546	3,810	0.8%
BRAINERD	19,344	18,769	575	3.1%
MAINLINE	25,947	25,887	60	0.2%
MAINLINE-WELCOME	2,588	2,601	(13)	-0.5%
WILLMAR	12,667	12,650	17	0.1%
PAYNESVILLE	72,635	71,527	1,107	1.5%
VGT-CHISAGO	3,770	3,682	88	2.4%
WATKINS	8,987	8,870	117	1.3%
TOMAH	24,222	25,918	(1,696)	-6.5%
RED WING	12,575	12,193	383	3.1%
GRAND FORKS MN	4,541	4,453	88	2.0%
FARGO MN	17,809	16,840	968	5.7%
NEW COMMUNITIES	3,504	-	3,504	
MN STATE	715,945	706,935	9,010	1.3%
GRAND FORKS ND	28,250	26,575	1,676	6.3%
FARGO ND	63,903	59,766	4,137	6.9%
WBI ND	1,572	1,496	76	5.1%
ND STATE	93,726	87,837	5,889	6.7%
TOTAL NSP MN	809,671	794,772	14,899	1.9%

MN / ND Allocation Factors

2015 DD	2014 DD	
0.8842	0.8895	**MN State Allocation**
0.1158	0.1105	**ND State Allocation**

NNG SYSTEM	2015 FORECAST	2014 FORECAST	Difference	%Diff
METRO	507,356	503,546	3,810	0.8%
BRAINERD	19,344	18,769	575	3.1%
MAINLINE	25,947	25,887	60	0.2%
MAINLINE-WELCOME	2,588	2,601	(13)	-0.5%
WILLMAR	12,667	12,650	17	0.1%
PAYNESVILLE	72,635	71,527	1,107	1.5%
WATKINS	8,987	8,870	117	1.3%
TOMAH	24,222	25,918	(1,696)	-6.5%
RED WING	12,575	12,193	383	3.1%
NNG SUBTOTAL	686,321	681,960	4,361	0.6%

VGT SYSTEM				
VGT-CHISAGO	3,770	3,682	88	2.4%
GRAND FORKS MN	4,541	4,453	88	2.0%
FARGO MN	17,809	16,840	968	5.7%
GRAND FORKS ND	28,250	26,575	1,676	6.3%
FARGO ND	63,903	59,766	4,137	6.9%
WBI ND	1,572	1,496	76	5.1%
NEW COMMUNITIES	3,504	-	3,504	
VGT SUBTOTAL	123,350	112,812	10,538	9.3%
VGT & NNG TOTAL	809,671	794,772	14,899	1.9%

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company | Docket No. G002/M-14-____
DEMAND COST OF GAS IMPACT - NOVEMBER 2014 | Attachment 1
Schedule 2

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
NNG TFX (Nov - Mar)[1]	1,100	$ 15.1530	5	$ 83,341.50
NNG TFX (Apr - Oct)[1]	1,100	$ 5.6830	7	$ 43,759.10
NNG TFX (Nov - Mar)[1]	1,050	$ 15.1530	5	$ 79,553.25
NNG TFX (Apr - Oct)[1]	1,050	$ 5.6830	7	$ 41,770.05
NNG TFX (Nov - Mar)[1]	431	$ 8.6272	5	$ 18,591.62
NNG TFX (Apr - Oct)[1]	431	$ 4.0000	7	$ 12,068.00
NNG TFX (Nov - Mar)[1]	4,036	$ 15.1530	5	$ 305,787.54
NNG TFX (Apr - Oct)[1]	4,036	$ 5.6830	7	$ 160,556.12
VGT FT-A (Jan - Dec)[2]	15,000	$ 4.4954	12	$ 809,172.00
VGT FT-A (Dec - Feb)[2]	(10,542)	$ 3.7671	3	$ (119,138.30)
VGT FT-A (Dec - Feb)[2]	10,646	$ 3.6918	3	$ 117,908.71
VGT FT-A (Apr - Oct)[2]	(5,000)	$ 3.4671	7	$ (121,348.50)
GLGT FT (Nov - Mar)[3]	(6,706)	$ 9.4560	5	$ (317,059.68)
GLGT FT (Nov - Mar)[4]	9,248	$ 14.6460	5	$ 677,231.04
ANR FTS (Jan - Dec)[5]	80	$ 4.1600	7	$ 2,329.60
ANR FSS (Jan - Dec)[6]	84	$ 2.0400	12	$ 2,056.32
ANR FSS (Jan - Dec)[6]	434	$ 0.4000	12	$ 2,083.20
ANRS FS (Jan - Dec)[7]	(6,049)	$ 1.0924	12	$ (79,295.13)
ANRS FS (Jan - Dec)[7]	170,880	$ 0.0133	12	$ 27,169.92
Total				$ 1,746,536.34

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Total	(20,000)	($60,400.00)

Total MN & ND Demand Cost Adjustment	**$1,686,136.34**
Minnesota Allocation Factor (MN/ND Allocated Demand)	88.42%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand	**$ 1,490,881.76**

[1]NNG Sixth Revised Volume No. 1, Seventh Revised Sheet No. 51, Effective April 1, 2014
[2]VGT Volume No. 1, Part 5.0 Statement of Rates, Effective April 1, 2014
[3]GLT Third Revised Volume No. 1, Part 4.1 Statement of Rates, Effective August 1, 2011
[4]GLT Seasonal Peak Rates, Effective April 1, 2014
[5]ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v. 0.0.0, Effective September 30, 2010
[6]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 0.0.0, Effective September 30, 2010
[7]ANRS First Revised Volume No. 1, Part 4.2 - Statement of Rates, v. 3.0.0, Effective October 1, 2013

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year

Docket No. G002/M-14-____
Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2013 SUPPLEMENTAL FILED COSTS				**$28,800,397.12**	**$27,121,493.62**	**$55,921,890.74**				
2013 CHANGES FILED COMPARED TO ACTUAL COSTS										
NNG TFX (Mar - 3-Day)	14,137	$15.1530	0.10		$ 21,139.93	$ 21,139.93	$ 21,139.93			1
NNG TFX (Mar - 3-Day)	12,787	$15.1530	0.10		$ 19,121.19	$ 19,121.19	$ 19,121.19			1
Total					$ 40,261.12	$ 40,261.12	$ 40,261.12			
2013 ACTUAL COSTS				**$ 28,800,397.12**	**$ 27,161,754.74**	**$ 55,962,151.86**				
CHANGES FOR 2014 FILING										
Contract Demand Entitlement Changes										
NNG TFX (Mar - 3-Day)	(14,137)	$15.1530	0.10		$ (21,139.93)	$ (21,139.93)	$ (21,139.93)			1
NNG TFX (Mar - 3-Day)	(12,787)	$15.1530	0.10		$ (19,121.19)	$ (19,121.19)	$ (19,121.19)			1
NNG TFX (Nov - Mar)	1,100	$15.1530	5		$ 83,341.50	$ 83,341.50	$ 83,341.50			2
NNG TFX (Apr - Oct)	1,100	$ 5.6830	7	$ 43,759.10		$ 43,759.10	$ 43,759.10			2
NNG TFX (Nov - Mar)	1,050	$15.1530	5		$ 79,553.25	$ 79,553.25	$ 79,553.25			3
NNG TFX (Apr - Oct)	1,050	$ 5.6830	7	$ 41,770.05		$ 41,770.05	$ 41,770.05			3
NNG TFX (Nov - Mar)	431	$ 8.6272	5		$ 18,591.62	$ 18,591.62	$ 18,591.62			4
NNG TFX (Apr - Oct)	431	$ 4.0000	7	$ 12,068.00		$ 12,068.00	$ 12,068.00			4
NNG TFX (Nov - Mar)	4,036	$15.1530	5		$ 305,787.54	$ 305,787.54	$ 305,787.54			5
NNG TFX (Apr - Oct)	4,036	$ 5.6830	7	$ 160,556.12		$ 160,556.12	$ 160,556.12			5
VGT FT-A (Jan - Dec)	15,000	$ 4.4954	12	$ 809,172.00		$ 809,172.00	$ 189,022.58	$ 620,149.42		6
VGT FT-A (Dec - Feb)	(10,542)	$ 3.7671	3		$ (119,138.30)	$ (119,138.30)		$ (119,138.30)		7
VGT FT-A (Dec - Feb)	10,646	$ 3.6918	3		$ 117,908.71	$ 117,908.71		$ 117,908.71		8
VGT FT-A (Apr - Oct)	(5,000)	$ 3.4671	7	$ (121,348.50)		$ (121,348.50)	$ (107,296.34)	$ (14,052.16)		9
GLGT FT (Nov - Mar)	(6,706)	$ 9.4560	5		$ (317,059.68)	$ (317,059.68)			$ (317,059.68)	10
GLGT FT (Nov - Mar)	9,248	$14.6460	5		$ 677,231.04	$ 677,231.04			$ 677,231.04	11
ANR FTS (Jan - Dec)	80	$ 4.1600	7		$ 2,329.60	$ 2,329.60			$ 2,329.60	12
ANR FSS (Jan - Dec)	84	$ 2.0400	12		$ 2,056.32	$ 2,056.32			$ 2,056.32	12
ANR FSS (Jan - Dec)	434	$ 0.4000	12		$ 2,083.20	$ 2,083.20			$ 2,083.20	12
ANRS FS (Jan - Dec)	(6,049)	$ 1.0924	12		$ (79,295.13)	$ (79,295.13)			$ (79,295.13)	13
ANRS FS (Jan - Dec)	170,880	$ 0.0133	12		$ 27,169.92	$ 27,169.92			$ 27,169.92	13
ANR Capacity Release					$ 85,500.00	$ 85,500.00			$ 85,500.00	14
VGT Rate Changes				$ (130,646.03)	$ (1,468.81)	$ (132,114.84)	$ (116,815.94)	$ (15,298.90)		15
WBI Rate Changes				$ (153,608.14)		$ (153,608.14)		$ (153,608.14)		15
ANRP Storage Capacity Demand Charge Reallocation	79,102	$ 0.4000	12		$ (379,688.00)	$ (379,688.00)			$ (379,688.00)	16
ANRS Storage Capacity Demand Charge Reallocation	1,165,185	$ 0.0133	12		$ (185,264.42)	$ (185,264.42)			$ (185,264.42)	16
NNG Storage Capacity Demand Charge Reallocation	2,516,995	$ 0.3567	5		$ (4,489,060.58)	$ (4,489,060.58)			$ (4,489,060.58)	16
Total				$ 661,722.60	$ (4,209,683.35)	$ (3,547,960.75)	$ 670,076.34	$ 435,960.63	$ (4,653,997.73)	
Supplier Entitlement Changes										
[TRADE SECRET BEGINS										
									TRADE SECRET ENDS]	
Total				$ -	$ (60,400.00)	$ (60,400.00)	$ (60,400.00)	$ -	$ -	
TOTAL OF 2014 CHANGES				**$ 661,722.60**	**$ (4,270,083.35)**	**$ (3,608,360.75)**	**$ 609,676.34**	**$ 435,960.63**	**$ (4,653,997.73)**	
2014 COSTS				**$ 29,462,119.72**	**$ 22,891,671.39**	**$ 52,353,791.11**				
2014 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							58%	42%		18

Footnote

1. These two contracts were put in place because of gas supply emergencies or to avoid paying higher gas prices at Emerson. Both contracts delivered to MN customers. The contracts were initiated after the March PGA had been filed and were not included in any PGA thereafter so they are not included in the totals above. Because these contracts were used in emergency situations, it is not anticipated they will be in effect again. They will be accounted for in NSP's annual true-up filing.
2. Incremental capacity added at Red Wing, MN starting November 1, 2014.
3. Incremental capacity added at Kandiyohi, MN starting November 1, 2014.
4. Incremental capacity added at St. Cloud, MN starting November 1, 2014.
5. Incremental capacity added at Brainerd, MN starting November 1, 2014.
6. Incremental capacity serving Fargo, ND area and new communities in Barnesville and Holdingford, MN starting November 1, 2014. Costs are allocated based on expected capacity to be used in each state.
7. Expired firm transport capacity serving Fargo ND, December 1, 2013 through February 28, 2014.
8. Renewed firm transport capacity serving Fargo, ND, December 1, 2014 through February 28, 2015.
9. Expired summer capacity on Viking, not renewed.
10. Expired winter backhaul capacity on Great Lakes, not renewed.
11. Incremental backhaul transport capacity on Great Lakes for November 1, 2014 through March 28, 2015. Will be used for ANRS storage withdrawals.
12. Volume additions on ANR transport and storage agreements. Upstream capacity serves demand in either MN or ND.
13. Volume changes on ANR Storage contract. Withdrawal capacity aligns with backhaul capacity on Great Lakes.
14. ANR capacity release in effect November 1, 2013 through March 31, 2014.
15. Miscellaneous demand rate changes on VGT and WBI contracts. These rate changes did not impact transport capacity volumes.
16. Storage capacity demand charges have been reallocated to commodity charges effective July 1, 2014 per MN PUC order.
17. Expired peaking supply contract with demand charges in effect November 1, 2013 through March 31, 2014.
18. 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.

SUMMARY OF DESIGN DAY DEMAND BY CUSTOMER CLASS

Design Day: Heating Season 2014-2015

DESIGN DAY CALCULATION

State of Minnesota	Jan-2015 Budget Customer	2015 MMBtu Design Day[1]	2014 MMBtu Design Day[1]	MMBtu Change
Residential	412,114	458,360	451,937	6,423
Commercial	34,167	232,277	233,736	(1,459)
Demand Billed	128	21,803	21,262	540
New Communities		3,504		
State of Minnesota Total	**446,409**	**715,945**	**706,935**	**9,010**
State of North Dakota Total	52,067	93,726	87,837	5,889
Total Xcel Energy - Gas Utility Operations	498,476	809,671	794,772	14,899

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

Minnesota Company	Jan-2015 Budget Customer	Jan-2014 Budget Customer	Change
Residential	456,606	450,209	6,397
Commercial	41,742	41,243	499
TOTAL	498,348	491,452	6,896
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	784,364	773,510	
Demand Billed Customers	128	127	
Contracted Billing Demand of Demand Billed Customers	21,803	21,262	
Demand of New Communities	3,504		
Projected Design Day (Dth)	809,671	794,772	14,899

[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-2015 Budget	Jan-2014 Budget
Reserve Margin	51,394	47,639
Total Available Capacity	861,065	842,411
Entitlement per Customer	1.7274	1.7137

Northern States Power Company

DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER

Design Day: Heating Season 2014-2015

	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)
		[TRADE SECRET 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)
		TRADE SECRET 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)
`

Docket No. G002/M-14-____
Attachment 1
Schedule 4

Customer Class

	Jul-2013	Aug-2013	Sep-2013	Oct-2013	Nov-2013	Dec-2013	Jan-2014	Feb-2014	Mar-2014	Apr-2014	May-2014	Jun-2014	Total	Winter	Summer
Residential	753,876	674,711	642,089	1,185,560	2,678,151	5,672,843	8,688,643	6,947,427	6,890,348	4,141,400	2,333,419	1,019,315	41,627,781	30,877,412	10,750,369
Interdepartmental	36	20	19	53	461	1,254	2,233	2,106	2,261	1,329	842	375	10,988	8,314	2,674
Small Commercial Firm	171,801	159,856	160,554	227,854	551,989	1,192,115	1,912,322	1,624,517	1,629,232	953,613	522,335	250,154	9,356,341	6,910,174	2,446,167
Large Commercial Firm	286,994	241,345	243,408	389,319	867,459	1,712,529	2,564,959	2,162,094	2,200,741	1,376,508	808,717	396,146	13,250,217	9,507,781	3,742,436
Commercial Firm	458,831	401,221	403,980	617,225	1,419,909	2,905,898	4,479,514	3,788,716	3,832,233	2,331,449	1,331,894	646,675	22,617,546	16,426,270	6,191,277
Small Commercial Demand Billed	5,504	6,372	4,283	7,286	8,496	13,753	17,870	14,341	18,393	12,268	9,908	6,822	125,296	72,854	52,442
Large Commercial Demand Billed	131,230	135,848	133,605	143,307	202,246	274,484	384,035	348,260	365,045	267,285	217,931	171,482	2,774,759	1,574,070	1,200,688
Large Demand Billed - Generation	1,480	1,359	981	2,092	864	1,208	1,271	1,129	1,644	1,346	1,640	1,612	16,626	6,116	10,510
Commercial Demand Billed	138,213	143,579	138,868	152,685	211,607	289,445	403,176	363,731	385,082	280,899	229,479	179,916	2,916,680	1,653,040	1,263,640
Total Commercial Firm	597,044	544,801	542,848	769,910	1,631,515	3,195,343	4,882,690	4,152,446	4,217,316	2,612,348	1,561,373	826,591	25,534,226	18,079,310	7,454,916
Total Firm	1,350,920	1,219,511	1,184,937	1,955,470	4,309,666	8,868,185	13,571,333	11,099,874	11,107,664	6,753,748	3,894,792	1,845,906	67,162,008	48,956,722	18,205,286
Small Interruptible	80,763	61,490	71,929	99,927	222,143	376,327	470,684	324,926	485,195	305,904	238,236	110,499	2,848,023	1,879,275	968,748
Medium Interruptible	282,051	293,491	274,333	364,454	645,181	698,562	821,324	682,406	710,988	696,905	591,608	375,680	6,436,985	3,558,462	2,878,523
Large Interruptible	120,780	154,247	161,908	120,599	124,574	170,863	280,980	216,224	215,453	183,881	134,609	123,558	2,007,677	1,008,095	999,582
Med. & Lg. Interruptible - Generation	21,817	3,242	1,373	1,654	7,425	4,851	13,504	3,597	13,410	7,971	12,815	10,282	101,942	42,788	59,154
Total Interruptible	505,410	512,471	509,543	586,634	999,323	1,250,604	1,586,492	1,227,154	1,425,047	1,194,660	977,269	620,020	11,394,627	6,488,620	4,906,008
Total Firm and Interruptible	1,856,330	1,731,983	1,694,481	2,542,104	5,308,989	10,118,789	15,157,825	12,327,027	12,532,711	7,948,408	4,872,061	2,465,926	78,556,635	55,445,342	23,111,293
Firm Transportation	25,933	23,715	21,413	25,167	27,784	32,020	36,451	32,688	29,989	22,879	21,084	18,017	317,140	158,932	158,208
Interruptible Transportation	330,532	343,644	315,513	385,899	420,154	443,205	439,835	389,736	331,271	336,847	333,885	289,682	4,360,203	2,024,201	2,336,002
Negotiated Transporation	487,838	496,453	440,540	482,835	527,740	429,290	505,572	362,300	447,665	501,320	518,979	441,017	5,641,549	2,272,567	3,368,982
Interdepartmental Transport - Generation	1,385,826	1,358,441	628,629	801,337	1,474,559	1,218,015	656,619	355,859	316,575	491,863	768,654	699,715	10,156,093	4,021,627	6,134,466
Total Transportation	2,230,129	2,222,253	1,406,095	1,695,238	2,450,237	2,122,530	1,638,477	1,140,583	1,125,500	1,352,909	1,642,602	1,448,431	20,474,985	8,477,327	11,997,658
Total Customer Sales	4,086,460	3,954,235	3,100,576	4,237,343	7,759,226	12,241,319	16,796,302	13,467,611	13,658,210	9,301,318	6,514,662	3,914,357	99,031,620	63,922,669	35,108,951
Monthly Heating Degree Days	11	0	66	499	951	1,621	1,752	1,564	1,205	665	243	19	8,596	7,094	1,502

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2014-2015 Heating Season

Firm Supplies (1)	**Current Quantity Effective Nov-13 Dth/Day**	**Proposed Quantity Effective Nov-14 Dth/Day**	**Proposed Quantity Change Nov-14 Dth/Day**
A. Upstream Supply			
	[TRADE SECRET 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			**TRADE SECRET ENDS]**
LP Peak Shaving	90,000	90,000	-
LNG Peak Shaving	156,000	156,000	-
TOTAL	842,411	861,065	18,654
C. Minnesota State Delivered Supply			
State of MN Allocators	88.95%	88.42%	
TOTAL	749,325	761,354	12,029

(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

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: 2014/2015	446,409	715,945	761,354	Unknown	Unknown	Unknown
2013/2014	441,573	706,935	749,325	689,990	82	1/6/2014
2012/2013	439,210	702,159	745,247	689,747	71	1/21/2013
2011/2012	439,055	702,294	745,094	659,263	65	1/19/2012
2010/2011	436,594	699,611	743,781	675,667	69	1/20/2011
2009/2010	433,698	694,487	748,267	590,931	67	12/10/2009
2008/2009	428,852	685,005	732,291	601,425	78	1/15/2009
2007/2008	431,503	683,717	721,506	585,874	72	1/29/2008
2006/2007	424,415	677,733	696,257	568,963	67	2/2/2007
2005/2006	421,570	670,846	691,689	537,660	63	12/5/2005
2004/2005	410,986	649,655	675,120	537,374	60	1/5/2005
2003/2004	401,633	603,468	643,315	561,250	80	1/29/2004
2002/2003	395,807	607,856	642,275	534,385	65	1/20/2003

1 Per Annual Financial Reports.

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

See Attachment 1, Schedule 1.

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

See Attachment 1, Schedule 5.

4 Demand Profile:

See Attachment 2, Schedule 1.

5 Rate Impact:

See Attachment 2, Schedule 2.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Docket No. G002/M-14-____
Attachment 2
Schedule 1

Northern States Power Company
COMPANY DEMAND PROFILE
2014-2015 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 - 10/31/17		12.09%	
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/17		0.00%	
112182	NNG TF12 BASE (Disc)	9,202	0	9,202	10 yrs - 10/31/17		1.07%	
112182	NNG TF12 VARIABLE (Disc.)	85,325	0	85,325	10 yrs - 10/31/17		9.91%	
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/17		7.25%	
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/17		3.44%	
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	8 yrs - 10/31/17		3.31%	
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/17		6.76%	
112185	NNG TFX (Disc. 12-month)	21,680	0	21,680	10 yrs - 10/31/17		2.52%	
112185	NNG TFX 5 (Disc)	6,493	0	6,493	10 yrs - 10/31/17		Summer Only	
112185	NNG TFX 2 (Disc)	2,168	0	2,168	10 yrs - 10/31/17		Summer Only	
112186	NNG TFX (Max)	46,855	2,150	49,005	10 yrs - 10/31/17		5.69%	
112186	NNG TFX 2 (Max)	5,800	2,150	7,950	10 yrs - 10/31/17		Summer Only	
112186	NNG TFX 5 (Max)	25,103	2,150	27,253	10 yrs - 10/31/17		Summer Only	
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/17		2.90%	
122067	NNG TFX (Disc. Nov-Mar)	6,298	431	6,729	10 yrs - 10/31/17	Growth election	0.78%	
122067	NNG TFX 7 (Disc)	6,298	431	6,729	10 yrs - 10/31/17	Growth election	Summer Only	
122068	NNG TFX (Nov-Mar)	4,839	4,036	8,875	10 yrs - 10/31/24	Incremental capacity	1.03%	
122068	NNG TFX 7 (Max)	4,839	4,036	8,875	10 yrs - 10/31/24	Incremental capacity	Summer Only	
		[TRADE SECRET BEGINS						
	VGT to NNG Chisago (1)							
	VGT Pierz to NNG (2)							
	Capacity Release							**TRADE SECRET ENDS]**
AF0044	VGT FT-A 12 Mos.	29,002	0	29,002	5 yrs - 10/31/18		3.37%	
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/18		0.49%	
AF0103	VGT FT-A (Apr-Oct)	5,000	(5,000)	0	15 yrs - 10/31/14	Contract expired	Summer Only	
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/19	Contract renewal	1.16%	
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	8.5 yrs - 10/31/17		1.81%	
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/16		0.22%	
AF0156	VGT FT-A 12 Mos.	72,213	0	72,213	8 yrs - 10/31/17		8.39%	
TBD	VGT FT-A 12 Mos.	0	15,000	15,000	5 yrs - 10/31/19	Capacity acquisition	1.74%	
TBD	VGT FT-A (Dec-Feb)	10,542	104	10,646	3 mos - 2/28/2015	Capacity acquisition	1.24%	
	WBI FT-1097	8,000	0	8,000	26.5 yrs - 10/31/19		0.93%	
	WBI FT-157	461	0	461	20 yrs - 07/01/33	Contract renewal	0.05%	
	City Gate Deliveries	24,000	0	24,000	10 yrs - 10/31/17		2.79%	
	LP Peak Shaving	90,000	0	90,000			10.45%	
	LNG Peak Shaving	156,000	0	156,000			18.12%	
	Total Design Day Capacity	**842,411**		**861,065**			**100%**	
	Heating Season Total	842,411		861,065				
	Non-Heating Season Total	413,204		416,971				
	Miscellaneous Entitlements with Reservation Fees							
	Additional Pipeline Entitlements							
	ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	7 yrs - 03/31/15			
	ANR FTS-106211 (Summer) (1)	4,855	80	4,935	7 yrs - 03/31/15	Capacity decrease w/ fuel filing		
	ANR FTS-106211 (Winter) (1)	15,171	0	15,171	7 yrs - 03/31/15			
	ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	9 yrs - 10/31/2019			
	GLT FT14739 (2)	3,509	0	3,509	4 yrs - 03/31/14			
	GLT FT14739 (2)	4,475	0	4,475	4 yrs - 03/31/14			
	GLT Backhaul (2)	6,706	(6,706)	0	5 mos. - 03/31/14	Contract expired		
	GLT Backhaul (2)	0	9,248	9,248	5 mos. - 03/31/15			
	NNG SMS (3)	30,650		30,650	15 yrs - 10/31/17			
	VGT OBA (3)	7,400		7,400	14 yrs - 10/31/09			
	Supply Entitlements (4)							
	[TRADE SECRET BEGINS							
						TRADE SECRET ENDS]		
	Storage Entitlements							
	ANR Pipeline Storage (.946 MMcf)	15,226	84	15,310	7 yrs - 3/31/15	Capacity increase w/ fuel filing		
	ANR Storage (.994 MMcf)	15,297	(6,049)	9,248	1 yrs - 3/31/15	Contract extension		
	FDD Service (8.085 MMcf)	140,230		140,230	4 yrs - 5/31/18	Contract extension		
	FDD Service (4.5 MMcf)	78,050		78,050	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.

Northern States Power Company

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2014

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	842,411	18,654	861,065
Non-Heating Season	413,204	3,767	416,971
Heating Season Forecasted Design Day	794,772	14,899	809,671
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	47,639	3,755	51,394
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	6.0%	0.4%	6.3%
Total MN State Available Capacity:			
State of MN Allocation Factor	88.95%	-0.53%	88.42%
State of MN Heating Season Capacity	749,325	12,029	761,354
State of MN Design Day Demand	706,935	9,010	715,945
State of MN Heating Season Capacity Reserve/(Shortage)	42,390	3,019	45,409
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	6.0%	0.3%	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.

Northern States Power Company
MINNESOTA STATE RATE IMPACT

Date to implement proposed changes: `
$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-13-663)	Last Month PGA: July 2014	Estimated Nov. 2014 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	$3.7332	$4.7116	$4.4493	-19.17%	19.18%	-5.57%	($0.2623)
Demand Cost of Gas (1)	$0.9008	$0.9347	$0.8287	$0.8349	-7.32%	-10.68%	0.75%	$0.0062
Distribution Margin	$1.8591	$1.8591	$1.8591	$1.8591	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$6.5270	$7.3994	$7.1433	-13.56%	9.44%	-3.46%	($0.2561)
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$567.55	$643.41	$621.14	-13.56%	9.44%	-3.46%	($22.27)
Average Annual Total Demand Cost of Gas	$78.33	$81.28	$72.06	$72.60				**$0.54**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$3.7332	$4.7116	$4.4493	-18.91%	19.18%	-5.57%	($0.2623)
Demand Cost of Gas (1)	$0.8984	$0.9323	$0.8322	$0.8381	-6.71%	-10.10%	0.71%	$0.0059
Distribution Margin	$1.2331	$1.2331	$1.2331	$1.2331	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$5.8986	$6.7769	$6.5205	-14.41%	10.54%	-3.78%	($0.2564)
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,675.35	$1,924.81	$1,851.99	-14.41%	10.54%	-3.78%	($72.82)
Average Annual Total Demand Cost of Gas	$255.17	$264.80	$236.37	$238.04				**$1.68**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$3.7332	$4.7116	$4.4493	-18.91%	19.18%	-5.57%	($0.2623)
Demand Cost of Gas (1)	$0.8917	$0.9116	$0.8119	$0.8229	-7.72%	-9.73%	1.35%	$0.0110
Distribution Margin	$1.2315	$1.2315	$1.2315	$1.2315	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$5.8763	$6.7550	$6.5037	-14.54%	10.68%	-3.72%	($0.2513)
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$8,594.92	$9,880.14	$9,512.58	-14.54%	10.68%	-3.72%	($367.56)
Average Annual Total Demand Cost of Gas	$1,304.24	$1,333.34	$1,187.52	$1,203.61				**$16.09**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-13-663)	Last Month PGA: July 2014	Estimated Nov. 2014 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	$3.7332	$4.7116	$4.4493	-18.99%	19.18%	-5.57%	($0.2623)
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	$4.6967	$5.6751	$5.4128	-16.16%	15.25%	-4.62%	($0.2623)
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$37,273.81	$45,038.49	$42,956.85	-16.16%	15.25%	-4.62%	($2,081.64)
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	$3.7332	$4.7116	$4.4493	-18.65%	19.18%	-5.57%	($0.2623)
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	$4.2083	$5.1867	$4.9244	-17.16%	17.02%	-5.06%	($0.2623)
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$272,317.12	$335,628.62	$318,655.39	-17.16%	17.02%	-5.06%	($16,973.23)
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	$3.7332	$4.7116	$4.4493	-19.11%	19.18%	-5.57%	($0.2623)
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	$4.1678	$5.1462	$4.8839	-17.71%	17.18%	-5.10%	($0.2623)
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$3,109,100.05	$3,838,966.21	$3,643,295.84	-17.71%	17.18%	-5.10%	($195,670.37)
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	($0.2623)	-5.57%	$0.0062	0.75%	$0.54	($22.27)	-3.46%
Small Commercial	($0.2623)	-5.57%	$0.0059	0.71%	$1.68	($72.82)	-3.78%
Large Commercial	($0.2623)	-5.57%	$0.0110	1.35%	$16.09	($367.56)	-3.72%
Small Interruptible	($0.2623)	-5.57%	$0.0000	NA	$0.00	($2,081.64)	-4.62%
Medium Interruptible	($0.2623)	-5.57%	$0.0000	NA	$0.00	($16,973.23)	-5.06%
Large Interruptible	($0.2623)	-5.57%	$0.0000	NA	$0.00	($195,670.37)	-5.10%

DERIVATION OF CURRENT PGA COSTS

Nov. 2014 - Projected Costs (Actual prices will be determined Nov.1, 2014)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$29,462,120	$22,891,671	
2.	x Minnesota Design Day Ratio (2014 Demand Entitlement Filing)	88.42%	88.42%	
3.	Annual System Demand Allocation to MN	$26,050,406	$20,240,816	
4.	MN State Design Day (2014 Demand Entitlement Filing)	715,945	715,945	
5.	- Small & Large Demand Billed Dth (2014 Demand Entitlement Filing)	21,803	21,803	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	694,142	694,142	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$25,257,084	$19,624,415	
8.	Demand Billed Cost Allocation (3 - 7)	$793,322	$616,401	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	538,954,024	403,492,517	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.04686	$0.04864	$0.09550
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)			$0.09550
14.	Total Demand Rate -Commercial (10 + 12)			$0.09550
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$793,322	$616,401	$1,409,723
16.	/ Annual Contract Billing Demand (2014 Demand Entitlement Filing)			2,616,352
17.	Monthly Commercial Demand Billed Demand Rate			$0.53881

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$37,960,771
19.	x MN Portion of Monthly Retail Sales	86.83%
20.	MN Portion of Monthly Commodity Costs	$32,961,337
21.	MN Budgeted Calendar Month Retail Therm Sales	74,081,430
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.44493

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.54043**
24.	Small & Large Commercial (14 +22)	**$0.54043**
25.	Small & Large Demand Billed - Demand (17)	**$0.53881**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.44493**

*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.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

SUMMARY OF COMPANY HEDGE TRANSACTIONS
2014-2015 Heating Season

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

CERTIFICATE OF SERVICE

I, Theresa Sarafolean, 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 2014

/s/
____
Theresa Sarafolean

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
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
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
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 90 S 7th St Minneapolis, MN 55402-4129	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
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
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_6-1429_1
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_6-1429_1
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East 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
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_6-1429_1
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_6-1429_1
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	90 South 7th Street Suite #4800 Minneapolis, MN 554024129	Electronic Service	No	OFF_SL_6-1429_1
Paula	Johnson	paulajohnson@alliantenergy.com	Alliant Energy-Interstate Power and Light Company	P.O. Box 351 200 First Street, SE Cedar Rapids, IA 524060351	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
John	Lindell	agorud.ecf@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
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	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Paper Service	No	OFF_SL_6-1429_1
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
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_9-1153_Official
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
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
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 90 S 7th St Minneapolis, MN 55402-4129	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
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
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 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 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_9-1153_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Paper Service	No	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_9-1153_Official
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_9-1153_Official
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	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
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	90 South 7th Street Suite #4800 Minneapolis, MN 554024129	Electronic Service	No	OFF_SL_9-1153_Official
John	Lindell	agorud.ecf@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
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Paper 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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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
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