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414 Nicollet Mall
Minneapolis, Minnesota 55401

November 2, 2009

—ELECTRONIC FILING—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

Re: PETITION FOR APPROVAL OF CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-09-_______

Dear Dr. Haar:

Enclosed is the public Petition for Approval of Changes in Contract Demand Entitlements of Northern States Power Company, a Minnesota corporation ("Xcel Energy or the "Company"), for approval of a change in Contract Demand Entitlements pursuant to Minn. Rule 7825.2910, Subd. 2. Copies of the non-public version are being provided separately.

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 it's 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.

Copies of this filing have been served on the Office of the Attorney General – Residential Utilities Division and a summary of the filing has been served on the parties on the attached service lists. Please call me at (612) 330-6089 if you have any questions regarding this filing.

Sincerely,

/s/

SCOTT SCHEFFER
REGULATORY CASE SPECIALIST

Enclosures

c: Service Lists

PUBLIC DOCUMENT
TRADE SECRET DATA REMOVED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR APPROVAL OF CHANGES IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-09-____

PETITION

INTRODUCTION

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), submits to the Minnesota Public Utilities Commission ("Commission") this Petition for approval of a Change in Contract Demand Entitlements, pursuant to Minn. Stat. § 216B.16, Subd. 7 and Minn. R. 7825.2910, Subp. 2. Xcel Energy requests approval to implement our 2009-2010 Heating Season Supply Plan effective November 1, 2009, 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. R. 7825.2910, Subp. 3, Xcel Energy has also served a summary of this Petition on the interveners in the two most recent (2006 and 2004) general rate case filings for the Company's natural gas utility operation. Also, the summary has been served on all parties on Xcel Energy's miscellaneous gas service list.

III. GENERAL FILING INFORMATION

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

A. Name, Address, and Telephone Number of Utility

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

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

Matthew P. Loftus
Senior Attorney
Xcel Energy Services Inc.
414 Nicollet Mall — 5th Floor
Minneapolis, Minnesota 55401
(612) 215-4501

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on November 2, 2009. The Company requests Commission approval to implement the rate impact of this filing in our Purchased Gas Adjustment ("PGA") effective with November 1, 2009 usage. Pursuant to Minn. Stat. § 216B.16, Subd. 7, Minn. R. 7825.2920, Subp. 2, and our Purchased Gas Adjustment tariff (Minnesota Gas Rate Book sheet number 5-40, revision 2; sheet number 5-41, revision 3; and sheet number 5-42, revision 2) Xcel Energy has provisionally placed the PGA changes into effect on November 1, 2009, 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. R. 7825.2910, Subp. 2, 7829.1300, 7929.1400 and 7825.2910. Under Minn. R. 7829.0100, Subp. 11, the Commission treats all filings that do not fall into a specific category as Miscellaneous Tariff Filings. Minn. R. 7829.1400, Subp. 1, 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

Allen D. Krug
Managing Director, Government and Regulatory Affairs
Xcel Energy Services Inc.
414 Nicollet Mall — 7th Floor
Minneapolis, Minnesota 55401
(612) 330-6270

IV. DESCRIPTION AND PURPOSE OF FILING

With this filing, we seek Commission approval 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 growing customer needs under the most extreme conditions at reasonable cost.

Pursuant to Minn. R. 7825.2910, Subp. 2, and prior Commission practice, we will provisionally implement the PGA rate changes associated with this filing on November 1, 2009, and respectfully request Commission approval of the revised entitlements effective on November 1, 2009. 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 2008-2009 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 ("Northern"), Viking Gas Transmission Company ("Viking"), Great Lakes Transmission Company ("Great Lakes"), ANR Pipeline Company ("ANR"), and Williston Basin Interstate Pipeline Company ("WBI").

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. R. 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 Minnesota Office of Energy Security ("OES"), and outlines the changes in the Company's Energy Firm DD Requirements, daily pipeline entitlement, and pipeline billing units from the 2008-2009 entitlement levels pending Commission approval in Docket No. G002/M-08-1315.

C. Change in Jurisdictional Allocations

The changes in the DD forecast alter the allocation of entitlements between the Minnesota and North Dakota retail natural gas jurisdictions. This filing reflects this reallocation.

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 the Commission's May 27, 2008 Order in Docket No. G002/M-08-46 regarding our use of financial instruments to limit commodity price volatility. Attachment 3 shows a summary of hedge transactions for the 2009-2010 heating season and how each instrument relates to the $32 million cap on such costs.

F. Classification and Billing of Demand Costs

In the Company's 2007 Contract Demand Entitlement filing, we included a proposal to assign some demand costs to interruptible customers.[1] In the October 7, 2008 OES Comments in Docket No. G002/M-07-1395, the OES recommended approval of our proposal. However, the Commission has not yet acted on our 2007 filing. Therefore, we again made the proposal through Attachment 4 in our 2008 filing, which provided updates showing its effect on prices by customer class.[2] Our 2008 filing is also awaiting Commission action. The Company continues to support its proposal, and looks forward to the Commission's decision on this issue.

G. Information Provided in Attachments

We outline below the location of the various Schedules and other information supporting our filing.

Attachment 1 – Filing Requirements Pursuant to Minn. R. 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 October 1, 1993 OES Letter.

Schedule	Title
1, page 1	Demand Profile
1, page 2	Changes to Contract Entitlements
2, page 1	Rate Impact
2, page 2	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.

[1] Docket No. G002/M-07-1395.
[2] Docket No. G002/M-08-1315.

Schedule	Title
1	Summary of Hedge Transactions

Attachment 4 – Economic analysis of 2009 Fargo lateral construction project.

V. EFFECT OF CHANGE UPON XCEL ENERGY REVENUE

As calculated in Trade Secret **Attachment 1**, **Schedule 2,** the effect of the proposed changes in demand cost upon Xcel Energy's Minnesota state annual revenue is an increase of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** effective November 1, 2009. 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 2 of 2.**

VI. MISCELLANEOUS INFORMATION

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

Matthew P. Loftus
Senior Attorney
Xcel Energy Services Inc.
414 Nicollet Mall — 5^{th} Floor
Minneapolis, Minnesota 55401

SaGonna Thompson
Records Specialist
Xcel Energy
414 Nicollet Mall — 7^{th} Floor
Minneapolis, Minnesota 55401

CONCLUSION

Xcel Energy respectfully requests the Commission approve our 2009-2010 Heating Season Supply Plan effective November 1, 2009, and our implementation of the retail rate impact of this filing in our PGA effective with November 1, 2009 usage. Commission 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: November 2, 2009

Northern States Power Company,

a Minnesota corporation

/s/

BY: ______________________

AMY LIBERKOWSKI
MANAGER, PRICING AND PLANNING

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR APPROVAL OF CHANGE IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-09-____

SUMMARY

SUMMARY OF FILING

Please take notice that on November 2, 2009, Northern States Power Company, a Minnesota corporation, filed a Request for Change in Contract Demand Entitlements pursuant to Minnesota R. 7825.2910, Subp. 2. Xcel Energy requests Commission approval to implement its 2009-2010 Heating Season Supply Plan effective November 1, 2009. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2009, subject to later Commission approval.

ATTACHMENT 1

Northern States Power Company,
A Minnesota corporation

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

Northern States Power Company,
A Minnesota corporation

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 DD requirements,
- Resources required to meet the DD and provide an adequate reserve margin,
- Changes in 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 accurately, so that adequate firm supply resources can be planned for and available, if DD weather occurs. 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, which used a linear regression calculation.

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

We project our forecasted firm customer count in Minnesota state to increase by 4,846 customers (from 428,852 to 433,698) between the 2008-2009 and the 2009-2010 heating season forecasts. This projection equates to an increase in DD requirements in Minnesota state of 9,482 Dekatherms ("Dth") (from 685,005 to 694,487) using the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**. This increase in required firm Dth stems solely from the increased number of customers.

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 the linear regression, which uses March 2005 – December 2008 data as shown on **Attachment 1, Schedule 1, Pages 2 - 4**. We were only able to use 46 months of data instead of the usual 60 months of data because of the change in customer groups that was described in last year's filing. However, in all but a few regions, the regression statistics were very strong with R-squared values in excess of 95%. The regions with R-squared values below 95 percent were those with lower customer counts. In all, R-squared values were 85 percent or higher. This method captures the relationship of DD between the states and service regions and incorporates non-electronic pipeline measurements that are estimated in the Actual Peak UPC DD.

The actual use per firm customer data contains the daily total usage for all the firm customers that do not have individual actual peak day information. As described in **Attachment 1, Schedule 3, Page 2 of 2,** the peak day actual use per firm customer remains the same at 1.57393 Dth. For non-demand-billed customers, the projected DD is calculated as number of customers multiplied by peak day actual use per customer to yield the Projected DD for these Minnesota state customers of 674,048 Dth. The Small and Large Demand Billed contracted customer Billing Demand of 20,439 Dth and is added to the DD estimate for the Residential, Small Commercial, and Large Commercial classes to determine the total Minnesota state DD Projection of 694,487 Dth as shown on **Attachment 1, Schedule 3, Page 1 of 2**.

We continue to maintain and compare both methodologies. We compared the actual peak days experienced by the Company under non-DD conditions with both the UPC DD and the Avg. Monthly DD to ensure adequate firm resources are available to meet the varied demand requirements of our customers. If cold temperatures occur, then the actual use per customer of 1.57393 Dth, as shown on **Attachment 1, Schedule 3**, **Page 2 of 2**, would be adjusted accordingly. Likewise, if cold temperatures are not experienced, the actual use per customer of 1.57393 Dth would be maintained (assuming no operating experience contrary to the conditions observed on January 29, 2004). In that case, the UPC DD would be adjusted for updated Residential, Small Commercial, and Large Commercial customer counts and any changes to the contracted Billing Demand for the Small and Large Demand Billed customers.

2. Change in Resources to Meet Design Day

Attachment 2, Schedule 1, Page 1 of 2 details the demand entitlement changes to meet DD for the Xcel Energy Minnesota company 2009-2010 Heating Season Gas Resource Plan compared to the 2008-09 plan filed in Docket No. G002/M-08-1315. **Attachment 1, Schedule 2** details the demand cost component changes for the 2009-2010 heating season.

a. Change in Northern Natural Gas ("Northern") entitlements (effective November 1, 2009)

At the end of the 2008/09 winter, 10,084 Dth/day of maximum rate winter capacity expired on contract number 111739. Due to the higher expense of the maximum rate winter capacity, in comparison to the options described below, we elected not to renew this maximum rate capacity.

To replace this expiring capacity and to meet the increased peak day demand requirements for our customers served on Northern, we elected two different growth options in our long-term contract with Northern. First we elected 10,000 Dth/day of discounted annual capacity from Chisago, the interconnect between Viking and Northern, to Xcel Energy's Hugo Town Border Station ("TBS"). Second, we elected an additional 10,000 Dth/day, as part of our biennial growth election, of discounted annual capacity from Ventura, the interconnect between Northern Border Pipeline and Northern, to Xcel Energy's Lake Elmo TBSs. The expiring maximum rate winter capacity was more expensive than the annual discounted capacity options for the same volume of firm entitlement as indicated on **Attachment 1, Schedule 2, Page 1**.

b. Change in Viking Gas Transmission ("Viking") entitlements (effective November 1, 2009)

We made several modifications to our entitlement levels on Viking. First, contract number AF0035 capacity totaling 12,000 Dth/day expired on October 31, 2009. We acquired this backhaul capacity from Chisago to the Fargo lateral in 1999 as a result of a construction project to loop approximately 9 miles on the Fargo lateral.[2] This firm entitlement will be replaced with the additional entitlement we are required to purchase to fund the 2009 Fargo lateral construction project, as more fully-described below.

Second, last winter we acquired an additional 820 Dth/day of short term capacity on Viking, which expired in March 2009. We acquired this capacity last winter because of the delay of the in-service date of the 2009 Fargo lateral construction project described in detail below. We will replace this expiring firm entitlement with the additional entitlement we will acquire as part of the 2009 Fargo lateral construction project.

Lastly, with respect to the 2009 Fargo lateral construction project, we entered into a cost-based Precedent Agreement with Viking dated May 15, 2008 ("Cost-Based Precedent Agreement") to add firm transportation with deliveries to Fargo, ND; Moorhead, MN; and Dilworth, MN ("Fargo Area"). During the 2007-2008 heating season, average daily temperatures were below minus ten degrees Fahrenheit for a total of seven days, with the coldest average daily temperature of minus 19 degrees Fahrenheit occurring on February 20, 2008. During that time, Viking experienced pressure drops during certain peak hours on the 18-mile, 8-inch Fargo lateral which serves the Fargo Area communities. During the winter of 2008-2009, average daily temperatures were below minus ten degrees Fahrenheit for a total of seven days with the coldest average daily temperature of minus 22.58 degrees Fahrenheit occurring on January 15, 2009. Had temperatures reached DD temperatures of minus 33 degrees Fahrenheit, the Fargo lateral would not have been adequately sized to meet the peak hourly load requirements of the firm customers in the Fargo Area. When evaluating the Viking system in total on a DD, we had adequate firm capacity. However, when looking at the Fargo lateral specifically, on both a daily and hourly basis, there was a capacity shortfall.

Based on the above, the Company was concerned about the ability of the existing Fargo lateral to supply enough gas to meet the Company's firm requirements in the

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[2] *See* the Commission's ORDER IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY – GAS UTILITY FOR APPROVAL OF AFFILIATED INTEREST AGREEMENT BETWEEN NSP AND VIKING GAS TRANSMISSION COMPANY dated August 24, 1999 in Docket No. G-002/AI-99-830 (the "August 24, 1999 Order").

Fargo Area. To ensure adequate supply for our customers, we considered options of how to increase the available capacity. We determined the best option to be a Cost-Based Precedent Agreement, which provided for an increase in the total size of the lateral from 53,332 Dth/day or 2,222 Dth/hour to 91,000 Dth/day or 3,792 Dth/hour. The project went into service on October 14, 2009. The cost of the project is estimated at $14,692,000.[3]

According to Viking's tariff, Sheet 62, Section 16.3, we had three options to reimburse Viking for the cost of the project. We could pay Viking: (1) a Contribution In Aid Of Construction ("CIAC"); (2) a separately stated reservation charge; or (3) purchase incremental entitlement. We rejected the first two options because we needed the additional entitlement to meet the DD requirements of the firm customers in the Fargo Area.

Therefore, we elected to purchase the additional entitlement to pay for the cost of the 2009 Fargo lateral construction project. We negotiated a formula in the Cost-Based Precedent Agreement to calculate the incremental capacity for every dollar spent on the project. Accordingly, we will purchase a certain volume of firm entitlement to pay for the cost of the project. We provide the formula in **Attachment 4, page 1 of 3.** Based on the estimated cost of the 2009 Fargo lateral construction project, we are required to purchase 89,263 Dth, which has an annual cost of $4.9 million per year for 8 years, of firm annual entitlement according to the terms of the Cost-Based Precedent Agreement. Of the 89,263 Dth, 57,178 Dth will deliver to the Fargo area.

October 14, 2009 was the in-service date of the project. On that day, we began paying maximum tariff rates on 89,263 Dth of incremental entitlement. According to the terms of the Cost-Based Precedent Agreement, on February 11, 2010 (120 days after the in-service date), Viking will provide Xcel Energy with the actual cost of the project, and will perform a true-up to reflect the actual project costs – changing the demand level to reflect the actual cost of the project.[4] Under the true-up, if the total project cost exceeds $14,692,000, Xcel Energy will be required to purchase more firm entitlement; however, if the total project cost is less than $14,692,000, Xcel Energy will purchase less firm entitlement. We will submit an update to this filing and adjust

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[3] As described below, actual project costs will not be finalized until February 11, 2010.

[4] This provision of the Cost-Based Precedent Agreement is similar to the "reimbursement agreement" associated with the prior Fargo lateral contract, in that both ensure that the actual costs of construction are paid by the Company. *See* Section 3 and 4 to Attachment A-1 of the Commission's August 24, 1999 Order. .

the PGA with a March 1, 2010 effective date, once the actual level of entitlement is known.

The additional entitlement that Xcel Energy will purchase to fund the 2009 Fargo lateral construction project costs will be used to help facilitate another one-time option that the Company has in its long-term agreement with Northern. In particular, we have an option to realign 36,316 Dth/day of maximum rate south end receipt capacity to Chisago and receive a discount rate ("Northern Chisago realignment discount option").

After the one-time realignment to Chisago is effectuated, we have the ability to elect up to five percent growth per year of incremental entitlement with Chisago receipts at the discount rate at St. Cloud area and Hugo area TBSs ("St. Cloud and Hugo growth option"). We anticipate a need for additional firm capacity for the St. Cloud area. Since the costs to add additional entitlement is very expensive, the St. Cloud and Hugo growth option is a reasonable alternative.

To effectuate both the one-time Northern Chisago realignment discount option and the St. Cloud and Hugo growth option, we need the ability to deliver gas to Chisago. We cannot do this directly, due to the unavailability of liquid trading points in this area. We will acquire the gas in Chicago, IL, at the liquid Joliet Hub, transport it on ANR to Marshfield, and backhaul it on Viking to Chisago. Chisago is not a liquid trading point, therefore, purchasing gas at this point is not a viable option. The only way to deliver gas to Chisago on a reliable basis is to hold upstream transportation and deliver the gas to that point. Since Viking is sold out on a forward haul basis, the most economical way to deliver gas to Chisago is to backhaul the gas from Marshfield, which is the interconnect between Viking and ANR Pipeline. Marshfield is also not a liquid trading point and purchasing gas at this point is also not a viable option. The only way to deliver gas to Marshfield on a reliable basis is to acquire the gas in Chicago, IL, at the liquid Joliet Hub and transport the gas acquired there on ANR to Marshfield.

We considered the costs of the delivery options described above, as well as the resulting Northern Chisago realignment discount option, versus the costs associated with continuing to pay Northern maximum rates for transportation with south end receipts plus the cost of an expansion at both St. Cloud and Hugo. We provide the results of our economic analysis as **Attachment 4, page 2 of 3**. The analysis shows that by choosing the delivery options, as well as the resulting Northern Chisago realignment discount option, Xcel Energy customers will save approximately $323,000 beginning November 1, 2010. Moreover, the savings will increase to $1.1 million per year beginning November 1, 2012.[5]

Based on the above analysis, and in order to move forward with the delivery options and the resulting Northern Chisago realignment discount option, we executed a Precedent Agreement with ANR on June 30, 2008 for incremental firm entitlement from the Joliet Hub to Marshfield. The in-service date for this capacity is November 1, 2010. Moreover, on March 18, 2009, we provided notice to Northern, that effective November 1, 2010, the Company had elected to use our one-time North Chisago realignment discount option.

Thus, not only does the additional entitlement, purchased by Xcel Energy in connection with the 2009 Fargo Lateral Fargo lateral construction project, provide additional capacity needed for the Fargo Area, but it also allows the Company to provide overall savings to our customers by effectuating both the Northern Chisago realignment discount option and the St. Cloud and Hugo growth option.

3. Change in Jurisdictional Allocations

a. Change in Minnesota Jurisdiction Allocation Factor

The DD allocation factor increased slightly for the Minnesota state jurisdiction from 89.34% to 89.56%. As in previous years, we calculate the allocation factor by dividing the DD forecasted demand for Minnesota state 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

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[5] In the analysis contained in **Attachment 4, page 2 of 3**, Xcel Energy originally assumed that it would have to purchase incremental backhaul on Viking to facilitate the delivery of gas to Chisago beginning on 11/1/2010. Instead the incremental entitlement of 32,085 Dth, which will not deliver capacity to the Fargo area, will be used to deliver gas to Chisago to effectuate the one-time Chisago realignment. Therefore, Xcel Energy will not have to purchase as much Viking backhaul volumes as originally contained in the economic analysis. Instead of needing to purchase 35,094 Dth of backhaul on Viking, Xcel Energy will only need to acquire 3,009 Dth (35,094 Dth – 32,085 Dth) beginning November 1, 2010. **Attachment 4, page 3 of 3**, contains the revised economics of not having to acquire 32,085 Dth of Viking backhaul to Chisago, since these volumes were acquired to support the 2009 Fargo lateral construction project. The analysis shows that Xcel Energy customer savings will increase from approximately $323,000 to $616,000 beginning November 1, 2010, ratcheting up from $1.1 million to $1.4 million per year beginning November 1, 2012.

the relationship of DD between the states and regional jurisdictions and incorporates accurately the monthly non-electronic pipeline measurements.

b. Change in Minnesota Grand Forks Area Jurisdictional Allocation Factor

The DD allocation factor for East Grand Forks, MN increased from 14.37% to 14.67%. This increase is the result of an increase in DD demand for East Grand Forks, MN relative to the change in DD demand for Grand Forks, ND. We calculated the allocation factor by dividing the DD demand for the city of East Grand Forks, MN by the DD demand total for the Grand Forks area (Grand Forks and East Grand Forks). We used this allocation factor to allocate the costs of the incremental capacity contracted on Viking several years ago, related to the Grand Forks area transmission-looping project.[6] We provide Minnesota state, North Dakota state, and Company totals on **Attachment 1, Schedule 1, Page 1 of 4**. We used the traditional method of Avg. Monthly DD to update the Minnesota Grand Forks Area Jurisdictional Allocation Factor.

c. Inclusion of Fargo Lateral Costs in the Derivation of the General System Allocator

Since the resulting Viking contract AF0035 expired on October 31, 2009 and was not renewed, the Minnesota Fargo DD allocation factor is no longer needed. This allocation factor was previously used to allocate the costs of the incremental capacity on Viking related to a looping project completed in this area several years ago.[7] Given the previously discussed system benefits that will accrue to customers in both Minnesota and North Dakota as a result of the incremental entitlement procured on the expanded Fargo lateral, it is appropriate to apply the general system allocator to these costs.

We have updated the PGA to reflect this change. Please note that on Schedule A, Page 3 of 5 of the PGA, we have removed the lines "Fargo Base Total Demand," "Minnesota Allocator," and "Annual Fargo Demand Allocation to MN." We have

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[6] *See* the Commission's ORDER IN THE MATTER OF A REQUEST FOR APPROVAL BY NORTHERN STATES POWER – GAS UTILITY OF AFFILIATED INTEREST AGREEMENT BETWEEN NSP-GAS AND VIKING GAS TRANSMISSION COMPANY dated October 11, 1996 in Docket No. G-002/AI-96-817.
[7] *See* supra fn. 1.

also updated the calculations to reflect the removal. **Attachment 2, Schedule 2, Page 2 of 2** displays the new format.

4. *Change in Supplier Reservation Fees*

The total change in existing supplier reservation charges for Minnesota state is **[TRADE SECRET BEGINS TRADE SECRET ENDS] Attachment 1, Schedule 2** lists the changes in Supply Entitlements. Our producer demand expense is attributable to the acquisition of two Emerson peaking supply contracts and two Viking city gate peaking contracts that were executed in lieu of acquiring additional annual or heating season interstate pipeline firm transportation service.

B. The Utility's DD 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 increase our capacity reserve margin from 6.9% in November 2008 (as amended in January 2009) to 7.7% in November 2009, 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) the likelihood of experiencing DD conditions (the most recent extreme cold period occurred in late January to early February 1996); (b) actual consumer demand during DD conditions (given the recent decline in use per customer described in Docket Nos. G002/GR-04-1511 and G002/GR-06-1429); and (c) the need to protect against the potential loss of a source of firm 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 2009-2010 heating season DD reserve margin for Minnesota state is 53,779 Dth/day or 7.7%.

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 DD 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, a Minnesota corporation

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2009-2010 Heating Season

Service Region (1)	Projected Jan 2010 Firm Res & Comm'l 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'l Design Day (Dth) (8)	Total Design Day (Dth) (9)	Jurisdictional Allocation Factors (10)
METRO	306,882	75	11,864	0.0142736	91	2.0573905	1.009	490,375	502,239	
BRAINERD	14,260	3	348	0.0106834	91	1.8771074	1.009	17,239	17,588	
MAINLINE	14,609	10	2,435	0.0142648	88	2.3272791	1.009	22,760	25,195	
MAINLINE-WELCOME	2,212	0	0	0.0105812	88	1.4156932	1.009	2,528	2,528	
WILLMAR	9,636	1	90	0.0113405	88	1.2868023	1.009	11,719	11,809	
PAYNESVILLE	39,948	19	2,212	0.0141531	94	2.0110457	1.009	65,249	67,461	
VGT-CHISAGO	2,933	0	0	0.0099902	91	1.3704168	1.009	3,271	3,271	
WATKINS	6,918	1	252	0.0101583	94	1.7279610	1.009	8,183	8,434	
TOMAH	15,276	10	1,419	0.0142472	88	1.1366068	1.009	23,073	24,491	
RED WING	7,482	5	848	0.0130973	88	1.9168008	1.009	10,639	11,486	
GRAND FORKS MN	2,842	1	63	0.0127429	98	0.9733191	1.009	4,256	4,320	14.67%
FARGO MN	10,575	2	909	0.0118284	98	1.0384681	1.009	14,756	15,665	
MN State	**433,571**	**127**	**20,439**					**674,048**	**694,487**	**89.56%**
GRAND FORKS ND	14,255	0	0	0.0147438	98	1.9120848	1.009	25,126	25,126	85.33%
FARGO ND	30,946	0	0	0.0146493	98	2.2037919	1.009	54,558	54,558	
WBI ND	942	0	0	0.0119188	98	0.4505725	1.009	1,303	1,303	
ND State	46,143	0	0					80,987	80,987	10.44%
TOTAL	**479,714**	**127**	**20,439**					**755,035**	**775,474**	**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 46 months Mar. 2005 to Dec. 2008
(5) Degree Days for a Design Day in that region.
(6) Monthly base usage determined by linear regression based on using the same 46 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, a Minnesota corporation
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
2009-2010 Heating Season

Division/Region (1)	Projected Firm Jan 2010 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) 2010 Unacc. Volume	Load Variation	Day Base	Total	2009 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
METRO														
Total Residential	285,672	0.0105115	91	1.4222955	0.9864	0.0090	2,580	273,258	13,365	**289,203**	288,721	482	45,862	**335,066**
Total Commercial	21,210	0.0649947	91	10.6186136	0.9782	0.0090	1,196	125,447	7,409	**134,051**	131,442	2,609	21,258	**155,309**
Industrial	75	Contract Demand	-	-		-	-	-	-	**11,864**	11,443	421	-	**11,864**
	306,957	0.0142736		2.057390475			3,775	398,705	20,774	**435,119**	431,606	3,512	67,120	**502,239**
												0.8%		
BRAINERD														
Total Residential	13,133	0.0090974	91	1.0947156	0.9827	0.0090	102	10,872	473	**11,447**	NA	11,447	1,815	**13,263**
Total Commercial	1,127	0.0291971	91	11.0009173	0.9445	0.0090	31	2,994	408	**3,432**	NA	3,432	544	**3,977**
Industrial	3	Contract Demand	-	-		-	-	-	-	**348**	NA	348	-	**348**
	14,263	0.0106834		1.877107439			133	13,866	881	**15,228**	NA	15,228	2,360	**17,588**
MAINLINE														
Total Residential	13,194	0.0097188	88	1.4726056	0.9682	0.0090	107	11,284	639	**12,031**	12,241	(210)	1,908	**13,938**
Total Commercial	1,415	0.0567630	88	10.3146901	0.9267	0.0090	68	7,067	480	**7,614**	7,529	86	1,208	**8,822**
Industrial	10	Contract Demand	-	-		-	-	-	-	**2,435**	2,070	364	-	**2,435**
	14,618	0.0142648		2.327279092			175	18,351	1,119	**22,080**	21,840	240	3,115	**25,195**
												1.1%		
MAINLINE-WELCOME														
Total Residential	2,082	0.0094528	88	0.9047986	0.9721	0.0090	16	1,732	62	**1,810**	1,770	41	287	**2,097**
Total Commercial	130	0.0287103	88	9.6238861	0.8733	0.0090	3	327	41	**372**	350	22	59	**431**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,212	0.0105812		1.415693232			19	2,060	103	**2,182**	2,120	62	346	**2,528**
												2.9%		
WILLMAR														
Total Residential	8,921	0.0093020	88	1.0036221	0.9822	0.0090	68	7,303	295	**7,666**	7,597	69	1,216	**8,881**
Total Commercial	714	0.0368158	88	4.8253729	0.9787	0.0090	22	2,314	113	**2,450**	2,434	16	388	**2,838**
Industrial	1	Contract Demand	-	-		-	-	-	-	**90**	90	-	-	**90**
	9,637	0.0113405		1.286802273			90	9,617	408	**10,205**	10,120	84	1,604	**11,809**
												0.8%		
PAYNESVILLE														
Total Residential	35,535	0.0091225	94	1.1498934	0.9837	0.0090	286	30,472	1,344	**32,103**	43,804	(11,701)	5,091	**37,194**
Total Commercial	4,412	0.0547287	94	8.9551825	0.9825	0.0090	216	22,699	1,300	**24,215**	27,302	(3,087)	3,840	**28,055**
Industrial	19	Contract Demand	-	-		-	-	-	-	**2,212**	2,605	(393)	-	**2,212**
	39,967	0.0141531		2.011045689			502	53,172	2,644	**58,530**	73,711	(15,181)	8,931	**67,461**
												-20.6%		
VGT-CHISAGO														
Total Residential	2,791	0.0086264	91	1.2941723	0.9828	0.0090	21	2,191	119	**2,330**	2,399	(69)	370	**2,700**
Total Commercial	142	0.0367953	91	2.8689867	0.8584	0.0090	4	475	13	**493**	485	8	78	**571**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	2,933	0.0099902		1.370416766			25	2,666	132	**2,823**	2,884	(61)	448	**3,271**
												-2.1%		
WATKINS														
Total Residential	6,674	0.0086574	94	1.3123514	0.9807	0.0090	51	5,431	288	**5,771**	5,714	57	915	**6,686**
Total Commercial	244	0.0512770	94	13.1096674	0.9527	0.0090	12	1,175	105	**1,292**	1,271	21	205	**1,497**
Industrial	1	Contract Demand	-	-		-	-	-	-	**252**	252	-	-	**252**
	6,919	0.0101583		1.727961005			63	6,606	393	**7,314**	7,236	78	1,120	**8,434**
												1.1%		
TOMAH														
Total Residential	13,694	0.0099534	88	0.5765184	0.9790	0.0090	110	11,995	260	**12,365**	12,359	6	1,961	**14,326**
Total Commercial	1,582	0.0515113	88	5.9926772	0.9606	0.0090	67	7,171	312	**7,550**	7,628	(78)	1,197	**8,747**
Industrial	10	Contract Demand	-	-		-	-	-	-	**1,419**	1,528	(109)	-	**1,419**
	15,286	0.0142472		1.136606773			178	19,165	572	**21,333**	21,514	(181)	3,158	**24,491**
												-0.8%		
RED WING														
Total Residential	6,733	0.0094519	88	1.1862469	0.9779	0.0090	53	5,600	263	**5,915**	6,002	(87)	938	**6,854**
Total Commercial	749	0.0459459	88	8.4954223	0.9248	0.0090	29	3,028	209	**3,267**	3,332	(65)	518	**3,785**
Industrial	5	Contract Demand	-	-		-	-	-	-	**848**	833	15	-	**848**
	7,486	0.0130973		1.916800813			82	8,628	472	**10,030**	10,167	(137)	1,456	**11,486**
												-1.4%		
GRAND FORKS MN														
Total Residential	2,546	0.0088956	98	0.3476411	0.9749	0.0090	20	2,220	29	**2,269**	2,259	10	360	**2,629**
Total Commercial	295	0.0459459	98	6.3701114	0.9658	0.0090	13	1,330	62	**1,404**	1,393	11	223	**1,627**
Industrial	1	Contract Demand	-	-		-	-	-	-	**63**	63	-	-	**63**
	2,843	0.0127429		0.973319118			33	3,550	91	**3,737**	3,716	21	583	**4,320**
												0.6%		
FARGO MN														
Total Residential	9,509	0.0080340	98	0.3279993	0.9708	0.0090	68	7,487	103	**7,658**	7,507	151	1,214	**8,872**
Total Commercial	1,066	0.0456936	98	7.3772087	0.9569	0.0090	45	4,774	259	**5,078**	4,887	191	805	**5,884**
Industrial	2	Contract Demand	-	-		-	-	-	-	**909**	909	-	-	**909**
	10,577	0.0118284		1.038468102			114	12,261	361	**13,645**	13,302	342	2,020	**15,665**
												2.6%		
MN COMPANY														
Total Residential	**400,485**									**390,568**	**390,373**	**196**	**61,937**	**452,506**
Total Commercial	**33,086**									**191,219**	**188,052**	**3,166**	**30,324**	**221,542**
Contract Demand	**127**									**20,439**	**19,793**	**647**	**0**	**20,439**
	433,698									**602,226**	**598,218**	**4,009**	**92,261**	**694,487**
												-0.8%		

Northern States Power Company, a Minnesota corporation

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR

2009-2010 Heating Season

Division/Region (1)	Projected Firm Jan 2010 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) 2010 Unacc. Volume	Load Variation	Day Base	Total	2009 Design Day	Mcf Difference % Diff.	Gross-up to Peak Day Method	Peak Day Method Totals
GRAND FORKS ND														
Total Residential	12,410	0.0084973	98	0.5842862	0.9803	0.0090	95	10,335	239	**10,668**	11,016	(348)	1,692	**12,360**
Total Commercial	1,844	0.0567741	98	10.8462876	0.9735	0.0090	98	10,262	658	**11,018**	11,082	(63)	1,747	**12,766**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	14,255	0.0147438		1.912084764			193	20,597	897	**21,687**	22,098	(411)	3,439	**25,126**
												-1.9%		
FARGO ND														
Total Residential	26,223	0.0081358	98	0.6694311	0.9763	0.0090	193	20,908	577	**21,679**	22,244	(566)	3,438	**25,117**
Total Commercial	4,723	0.0508175	98	10.7237382	0.9780	0.0090	227	23,519	1,666	**25,412**	25,657	(245)	4,030	**29,441**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	30,946	0.0146493		2.203791905			420	44,427	2,243	**47,090**	47,901	(811)	7,468	**54,558**
												-1.7%		
WBI ND														
Total Residential	815	0.0087108	98	0.4605333	0.9464	0.0090	6	696	12	**715**	707	8	113	**828**
Total Commercial	127	0.0325123	98	0.3866292	0.9225	0.0090	4	405	2	**410**	402	8	65	**475**
Industrial	-	Contract Demand	-	-		-	-	-	-	**-**	-	-	-	**-**
	942	0.0119188		0.450572526			10	1,101	14	**1,125**	1,109	16	178	**1,303**
												1.4%		
ND COMPANY														
Total Residential	**39,449**									**33,062**	**33,968**	**-906**	**5,243**	**38,305**
Total Commercial	**6,694**									**36,840**	**37,140**	**-300**	**5,842**	**42,682**
Contract Demand	**0**									**-**	**-**	**-**	**-**	**-**
	46,143									**69,902**	**71,108**	**-1,206**	**11,085**	**80,987**
												-6.3%		
Grand Total														
Total Residential	**439,934**									**423,630**	**424,340**	**(710)**	**67,180**	**490,810**
Total Commercial	**39,780**									**228,059**	**225,192**	**2,866**	**36,166**	**264,225**
Contract Demand	**127**									**20,439**	**19,793**	**647**	**-**	**20,439**
	479,841									**672,128**	**669,325**	**2,803**	**103,346**	**775,474**
												0.5%		

DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
2009-2010 Heating Season

CUSTOMERS BY AREA (EXCLUDING DEMAND BILLED)

Area	2010 FORECAST	2009 FORECAST	Difference	%Diff
METRO	306,882	303,708	3,174	1.0%
BRAINERD	14,260	NA	NA	NA
MAINLINE	14,609	14,714	(106)	-0.7%
MAINLINE-WELCOME	2,212	2,151	61	2.8%
WILLMAR	9,636	9,508	128	1.3%
PAYNESVILLE	39,948	53,129	(13,181)	-24.8%
VGT-CHISAGO	2,933	2,945	(13)	-0.4%
WATKINS	6,918	6,783	135	2.0%
TOMAH	15,276	15,223	53	0.3%
RED WING	7,482	7,574	(93)	-1.2%
GRAND FORKS MN	2,842	2,795	47	1.7%
FARGO MN	10,575	10,196	379	3.7%
MN STATE	433,571	428,727	4,844	1.1%
GRAND FORKS ND	14,255	14,253	2	0.0%
FARGO ND	30,946	30,682	264	0.9%
WBI ND	942	940	2	0.2%
ND STATE	46,143	45,875	268	0.6%
TOTAL NSP MN	479,714	474,602	5,112	**1.1%**

2010 Customer #s

	MN	ND	
Res	400,485	39,449	**439,934**
Com	33,086	6,694	**39,780**
Ind	127	0	**127**
	433,698	46,143	**479,841**

2010 Design Day Use By Customer Class

	MN	ND	
Res	452,506	38,305	**490,810**
Com	221,542	42,682	**264,225**
Ind	20,439	0	**20,439**
	694,487	80,987	**775,474**

DESIGN DAY MMBTU DEMAND BY AREA

Area	2010 FORECAST	2009 FORECAST	Difference	%Diff
METRO	502,239	494,648	7,591	1.5%
BRAINERD	17,588	NA	NA	NA
MAINLINE	25,195	24,806	389	1.6%
MAINLINE-WELCOME	2,528	2,438	90	3.7%
WILLMAR	11,809	11,626	184	1.6%
PAYNESVILLE	67,461	84,380	(16,919)	-20.1%
VGT-CHISAGO	3,271	3,317	(46)	-1.4%
WATKINS	8,434	8,284	150	1.8%
TOMAH	24,491	24,513	(21)	-0.1%
RED WING	11,486	11,568	(82)	-0.7%
GRAND FORKS MN	4,320	4,264	56	1.3%
FARGO MN	15,665	15,162	503	3.3%
MN STATE	694,487	685,005	9,482	1.4%
GRAND FORKS ND	25,126	25,414	(288)	-1.1%
FARGO ND	54,558	55,088	(530)	-1.0%
WBI ND	1,303	1,275	28	2.2%
ND STATE	80,987	81,777	(790)	-1.0%
TOTAL NSP MN	775,474	766,782	8,693	1.1%

MN / ND Allocation Factors

2010 DD	2009 DD	
0.8956	0.8934	**MN State Allocation**
0.1044	0.1066	**ND State Allocation**

NNG SYSTEM	2010 FORECAST	2009 FORECAST	Difference	%Diff
METRO	502,239	494,648	7,591	1.5%
BRAINERD	17,588	NA	NA	NA
MAINLINE	25,195	24,806	389	1.6%
MAINLINE-WELCOME	2,528	2,438	90	3.7%
WILLMAR	11,809	11,626	184	1.6%
PAYNESVILLE	67,461	84,380	(16,919)	-20.1%
WATKINS	8,434	8,284	150	1.8%
TOMAH	24,491	24,513	(21)	-0.1%
RED WING	11,486	11,568	(82)	-0.7%
NNG SUBTOTAL	671,232	662,262	8,970	1.4%

Grand Forks Allocation Factors

2010 DD	2009 DD	**Grand Forks Demand Allocator**
0.1467	0.1437	MN Grand Forks Demand Allocator
0.8533	0.8563	ND Grand Forks Demand Allocator

VGT SYSTEM				
VGT-CHISAGO	3,271	3,317	(46)	-1.4%
GRAND FORKS MN	4,320	4,264	56	1.3%
FARGO MN	15,665	15,162	503	3.3%
GRAND FORKS ND	25,126	25,414	(288)	-1.1%
FARGO ND	54,558	55,088	(530)	-1.0%
WBI ND	1,303	1,275	28	2.2%
VGT SUBTOTAL	104,242	104,520	(277)	-0.3%
VGT & NNG Total	775,474	766,782	8,693	1.1%

PUBLIC DOCUMENT
TRADE SECRET DATA REMOVED

Docket No. G002/M-09-____
Attachment 1
Schedule 2
Page 1 of 1

Northern States Power Company, a Minnesota corporation
DEMAND COST OF GAS IMPACT - NOVEMBER 2009

N CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
VGT FT-A (Jan - Dec)[1]	89,263	$ 4.5871	12	$ 4,913,499.69
VGT FT-A (Dec-Mar)[1]	(220)	$ 3.4671	4	$ (3,051.05)
VGT FT-A (Dec-Mar)[1]	(600)	$ 3.4671	3.5	$ (7,280.91)
VGT FT-A (Jan - Dec)[1]	(5,450)	$ 3.4671	12	$ (226,748.34)
VGT FT-A (Nov - Mar)[1]	(6,550)	$ 3.4671	5	$ (113,547.53)
NNG TFX (Jan - Dec)[2]	10,000	$ 4.8640	12	$ 583,680.00
NNG TFX (Jan - Dec)[2]	10,000	$ 3.0400	12	$ 364,800.00
NNG TFX (Nov - Mar)[2]	(10,084)	$ 15.1530	5	$ (764,014.26)
NNG TF12 (Jan - Dec)[2]	(2,359)	$ 10.2300	5	$ (120,662.85)
NNG TF12 (Jan - Dec)[2]	2,359	$ 13.8660	5	$ 163,549.47
NNG TF12 (Jan - Dec)[2]	(2,359)	$ 5.6830	7	$ (93,843.38)
NNG TF12 (Jan - Dec)[2]	2,359	$ 5.6830	7	$ 93,843.38

Total for Change in Pipeline Entitlement $ 4,790,224.22

[TRADE SECRET BEGINS

Change in Supplier Reservation Fees

Total MN & ND Demand Cost Adjustment

Minnesota Allocation Factor (MN/ND Allocated Demand)

MN only Demand Cost Adjustment due to MN/ND Allocated Demand $ -

TRADE SECRET ENDS]

[1]VGT First Revised Volume No. 1, Twelfth Revised Sheet No. 5, Effective January 1, 2006

[2]NNG Fifth Revised Volume No. 1, Seventy-Eighth Revised Sheet No. 78, Effective October 1, 2008

Northern States Power Company, a Minnesota corporation

SUMMARY OF DESIGN DAY DEMAND BY CUSTOMER CLASS

Design Day: Heating Season 2009-2010

DESIGN DAY CALCULATION

State of Minnesota	Jan-2010 Budget Customer	2010 MMBtu Design Day[1]	2009 MMBtu Design Day[1]	MMBtu Change
Residential	400,485	452,506	448,944	3,561
Commercial	33,086	221,542	216,268	5,275
Demand Billed	127	20,439	19,793	647
State of Minnesota Total	**433,698**	**694,487**	**685,005**	**9,482**
State of North Dakota Total	46,143	80,987	81,777	(790)
Total Xcel Energy - Gas Utility Operations	479,841	775,474	766,782	8,693

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

Minnesota Company	Jan-2010 Budget Customer	Jan-2009 Budget Customer	Change
Residential	439,934	435,436	4,498
Commercial	39,780	39,166	614
TOTAL	479,714	474,602	5,112
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	755,035	746,989	
Demand Billed Customers	127	125	
Contracted Billing Demand of Demand Billed Customers	20,439	19,793	
Projected Design Day (Dth)	775,474	766,782	8,692

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

ENTITLEMENT ESTIMATE PER CUSTOMER

	Jan-2010 Budget	Jan-2009 Budget
Reserve Margin	60,018	52,886
Total Available Capacity	835,492	819,668
Entitlement per Customer	1.7412	1.7266

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TRADE SECRET DATA REMOVED

Docket No. G002/M-09-____
Attachment 1
Schedule 3
Page 2 of 2

Northern States Power Company, a Minnesota corporation

DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER

Design Day: Heating Season 2009-2010

	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

MINNESOTA STATE HISTORICAL SALES - SEASONAL USAGE

(Dth)

Customer Class	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008	Jan-2009	Feb-2009	Mar-2009	Apr-2009	May-2009	Jun-2009	Total	Winter	Summer
Residential	779,286	625,506	749,119	1,180,751	2,087,401	5,652,335	7,896,390	6,306,122	5,486,144	3,480,038	1,560,657	1,048,832	36,852,581	27,428,392	9,424,188
Interdepartmental	9	7	(1,597)	687	334	863	1,492	1,276	3,002	1,427	585	141	8,227	6,968	1,259
Small Commercial Firm	191,491	148,118	185,865	236,778	441,638	1,203,270	1,722,385	1,420,656	1,243,162	728,197	344,068	214,721	8,080,351	6,031,112	2,049,240
Large Commercial Firm	250,476	213,650	290,167	337,397	618,922	1,523,782	2,210,865	1,858,942	1,671,994	1,127,948	574,428	332,313	11,010,886	7,884,505	3,126,381
Commercial Firm	441,976	361,775	474,435	574,862	1,060,895	2,727,916	3,934,742	3,280,873	2,918,159	1,857,573	919,082	547,175	19,099,464	13,922,585	5,176,879
Small Commercial Demand Billed	11,053	10,422	11,778	11,245	10,679	17,665	18,611	19,532	18,751	14,802	11,869	9,938			
Large Commercial Demand Billed	140,475	130,922	130,997	143,027	167,360	246,457	299,644	304,839	265,286	254,736	169,051	133,393	2,386,185	1,283,585	1,102,600
Large Demand Billed - Generation	1,596	1,242	1,373	1,670	1,540	1,745	1,906	1,671	1,807	1,220	1,014	1,138	17,921	8,669	9,252
Commercial Demand Billed	153,124	142,585	144,147	155,942	179,579	265,867	320,161	326,041	285,844	270,758	181,934	144,468	2,570,450	1,377,492	1,192,958
Total Commercial Firm	595,100	504,361	618,583	730,804	1,240,473	2,993,783	4,254,903	3,606,915	3,204,003	2,128,330	1,101,016	691,644	21,669,914	15,300,077	6,369,837
Total Firm	1,374,386	1,129,867	1,367,701	1,911,555	3,327,875	8,646,118	12,151,294	9,913,037	8,690,147	5,608,368	2,661,672	1,740,476	58,522,495	42,728,469	15,794,026
Small Interruptible	85,364	68,814	85,179	117,940	209,691	423,608	577,473	488,683	453,792	328,940	212,508	132,397	3,184,388	2,153,246	1,031,143
Medium Interruptible	484,248	360,087	395,929	442,610	646,772	693,802	830,567	689,990	717,015	258,998	812,307	371,668	6,703,993	3,578,145	3,125,847
Large Interruptible	276,391	241,242	249,553	303,409	327,655	266,277	242,219	247,496	263,048	246,632	134,156	144,546	2,942,622	1,346,694	1,595,928
Med. & Lg. Interruptible - Generation	29,911	4,468	20,325	11,357	4,374	46,465	60,057	3,825	21,761	6,860	35,078	39,633	284,114	136,483	147,632
Total Interruptible	875,914	674,611	750,986	875,316	1,188,492	1,430,152	1,710,316	1,429,994	1,455,615	841,430	1,194,049	688,244	13,115,118	7,214,568	5,900,550
Total Firm and Interruptible	2,250,301	1,804,478	2,118,688	2,786,871	4,516,366	10,076,270	13,861,609	11,343,030	10,145,762	6,449,798	3,855,721	2,428,720	71,637,613	49,943,037	21,694,576
Firm Transportation	17,290	17,512	17,857	20,007	20,090	19,311	24,222	17,624	20,874	18,498	15,354	15,626	224,265	102,121	122,144
Interruptible Transportation	31,423	32,160	34,360	37,226	51,578	57,497	56,439	43,932	40,834	37,158	31,856	29,818	484,281	250,280	234,001
Negotiated Transporation	355,664	419,792	457,354	438,164	495,799	513,891	592,971	460,727	519,194	517,498	395,138	337,505	5,503,697	2,582,582	2,921,115
Interdepartmental Transport - Generation	537,672	356,625	226,608	106,361	483,574	1,173,997	904,632	709,907	549,103	400,083	94,117	647,044	6,189,723	3,821,212	2,368,510
Total Transportation	942,049	826,089	736,179	601,758	1,051,041	1,764,696	1,578,264	1,232,190	1,130,005	973,237	536,465	1,029,993	12,401,966	6,756,195	5,645,770
Total Customer Sales	3,192,350	2,630,567	2,854,867	3,388,628	5,567,407	11,840,965	15,439,873	12,575,220	11,275,767	7,423,035	4,392,187	3,458,713	84,039,579	56,699,233	27,340,346
Monthly Heating Degree Days	0	0	112	464	907	1,583	1,746	1,231	1,002	514	157	68	7,784	6,469	1,315

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TRADE SECRET DATA REMOVED

Docket No. G002/M-09-____
Attachment 1
Schedule 5

Northern States Power Company, a Minnesota corporation
FIRM SUPPLY ENTITLEMENTS

Firm Supplies (1)	Current Quantity Effective 11/1/2008 Dth/Day	Proposed Quantity Effective 11/1/2009 Dth/Day	Proposed Quantity Change 11/1/2009 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	819,668	835,492	15,824	
C. Minnesota State Delivered Supply				
State of MN Allocators	89.34%	89.56%		
TOTAL	732,291	748,267	15,975	

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

ATTACHMENT 2

Northern States Power Company,
a Minnesota corporation

Proposal for Entitlement Changes

Information provided in response to the Office of Energy Security letter dated October 1, 1993

PROPOSAL FOR ENTITLEMENT CHANGE
OES 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: 2009/2010	433,698	694,487	748,267	Unknown	Unknown	Unknown
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	64.8	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.

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

See Attachment 1, Schedule 3.

4 Demand Profile:

See Attachment 2, Schedule 1.

5 Rate Impact:

See Attachment 2, Schedule 2.

Northern States Power Company, a Minnesota corporation
COMPANY DEMAND PROFILE
2009-2010 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)	130,141	(2,359)	127,782	10 yrs - 10/31/17		15.29%	
112183	NNG TF12 VARIABLE (Max)	4,094	2,359	6,453	10 yrs - 10/31/17		0.77%	
112182	NNG TF12 VARIABLE (Disc.)	64,409	0	64,409	10 yrs - 10/31/17		7.71%	
112183	NNG TF5 (Max)	63,443	0	63,443	10 yrs - 10/31/17		7.59%	
112182	NNG TF5 (Disc.)	28,571	0	28,571	10 yrs - 10/31/17		3.42%	
111739	NNG TFX (Nov-Mar)	38,584	(10,084)	28,500	3 yrs - 3/31/12	Contract expiration	3.41%	
112185	NNG TFX (Disc. Nov-Mar)	50,846	0	50,846	10 yrs - 10/31/17		6.09%	
112185	NNG TFX (Disc. 12-month)	1,680	20,000	21,680	10 yrs - 10/31/17	Contract growth election	2.59%	
112186	NNG TFX (Max)	52,025	0	52,025	10 yrs - 10/31/17		6.23%	
112186	NNG TFX 2 (Max)	5,800	0	5,800	10 yrs - 10/31/17		Summer Only	
112186	NNG TFX 5 (Max)	29,428	0	29,428	10 yrs - 10/31/17		Summer Only	
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/17		2.99%	
		[TRADE SECRET BEGINS						
	VGT to NNG Chisago (1)							
	Upstream of Fargo (1)							
	Incremental Fargo capacity							
	VGT to NNG Pierz NNG (2)							**TRADE SECRET ENDS]**
AF0044	VGT FT-A 12 Mos.	29,002	0	29,002	5 yrs - 10/31/13		3.47%	
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/13		0.51%	
AF0036	VGT FT-A 12 Mos.	5,000	0	5,000	15 yrs - 10/31/11		0.60%	
AF0036	VGT FT-A (Nov-Mar)	16,105	0	16,105	15 yrs - 10/31/11		1.93%	
AF0103	VGT FT-A (Apr-Oct)	5,000	0	5,000	15 yrs - 10/31/14		Summer Only	
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	15 yrs - 10/31/14		1.20%	
AF0035	VGT FT-A 12 Mos.	5,450	(5,450)	0	10 yrs - 10/31/10	Contract Expired	0.00%	
AF0035	VGT FT-A (Nov-Mar)	6,550	(6,550)	0	10 yrs - 10/31/10	Contract Expired	0.00%	
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	3 yrs - 5/31/12		1.87%	
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/11		0.23%	
AF0156	VGT FT-A 12 Mos.	0	89,263	89,263	8 yrs - 10/31/17		10.68%	
Capacity Acquisition	VGT FT-A 4 Mos.	220	(220)	0	4 mos - 3/31/09	Contract Expired	0.00%	
Capacity Acquisition	VGT FT-A 3.5 Mos.	600	(600)	0	3.5 mos - 3/31/09	Contract Expired	0.00%	
	WBI X-13	8,000	0	8,000	20 yrs - 10/31/12		0.96%	
	WBI FT-1	461	0	461	20 yrs - 07/01/13		0.06%	
	City Gate Deliveries	34,850	(850)	34,000	10 yrs - 10/31/17	850 contract expired	4.07%	
	LP Peak Shaving	90,000	0	90,000		Grand Forks LPG not operational	10.77%	
	LNG Peak Shaving	156,000	0	156,000			18.67%	
	Total Design Day Capacity	**819,668**		**835,492**			**100%**	
	Heating Season Total	819,668		835,492				
	Non-Heating Season Total	315,968		419,781				
	Miscellaneous Entitlements with Reservation Fees							
	Additional Pipeline Entitlements							
	ANR FT-106209 12 Mos. (1)	4,829		4,829	7 yrs - 03/31/15			
	ANR FT-106211 (Summer) (1)	4,916	15	4,931	7 yrs - 03/31/15	Capacity increase w/ fuel filing		
	ANR FT-106211 (Winter) (1)	15,171		15,171	7 yrs - 03/31/15			
	GLT FT-043 (2)	3,799		3,799	16 yrs - 03/31/10			
	GLT FT-142 (Nov-Apr) (2)	15,195		15,195	17 yr - 04/30/11			
	GLT FT-6187 (2)	960		960	7 month 10/31/09			
	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)	15,250	8	15,258	7 yrs - 3/31/15	**Capacity increase w/ fuel filing**		
	ANR Storage (.994 MMcf)	15,297		15,297	7 yrs - 3/31/14			
	FDD Service (8.085 MMcf)	140,230		140,230	3 yrs - 5/31/11 (6.5 MMcf expires 5/31/11)			
	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.

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2009

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	819,668	15,824	835,492
Non-Heating Season	315,968	103,813	419,781
Heating Season Forecasted Design Day	766,782	8,693	775,474
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	52,886	7,131	60,018
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	6.9%	0.8%	7.7%
Total MN State Available Capacity:			
State of MN Allocation Factor	89.34%	0.22%	89.56%
State of MN Heating Season Capacity	732,291	15,975	748,267
State of MN Design Day Demand	685,005	9,482	694,487
State of MN Heating Season Capacity Reserve/(Shortage)	47,286	6,493	53,779
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	6.9%	0.8%	7.7%

(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, a Minnesota corporation
MINNESOTA STATE RATE IMPACT

Please use the following table to illustrate the financial effects of the poposed change, based on the most recent Purchased Gas Adjustment (PGA), the first PGA which implemented the most recently approved demand change and the last rate case for residential customers and all firm customers. If interruptible customers are affected, please identify the rate impact in the same format as specified bleow.

Date to implement proposed change: November 1, 2009
Docket No. of most recently approve demand change: G002/M-06-1454
Date of last rate case: November 9, 2006, 2007 Test Year
Docket No. of last rate case: G002/GR-06-1429

RESIDENTIAL FIRM

All Cost $/Dth	2007 Rate Case Base Cost of Gas (7)	Last Approved Demand Adjustment: November 2006	Last Month PGA: October 2009 (8)	Current PGA without Adjustment: November 2009 (8)	Current PGA with Adjustment: November 2009 (8)	Change From Last Rate Case Base Cost	Change From Last Approved Demand Adjustment	Change From Last Month PGA	Change From Current PGA
Commodity Cost of Gas (WACOG) (1)	$7.2073	$7.0824	$3.9971	$5.0477	$5.0477	-30.0%	-28.7%	26.3%	0.0%
Demand Cost of Gas -Summer (4)	$0.6030	$0.6608	$0.3586	$0.4563	$0.4572	-24.2%	-30.8%	27.5%	0.2%
Demand Cost of Gas - Winter (4, 5)	$1.1856	$1.2166	$0.9486	$1.0438	$1.0459	-11.8%	-14.0%	10.3%	0.2%
Total Cost of Gas - Summer (2)	$7.8103	$7.7432	$4.3557	$5.5040	$5.5049	-29.5%	-28.9%	26.4%	0.0%
Total Cost of Gas - Winter (2)	$8.3929	$8.2990	$4.9457	$6.0915	$6.0936	-27.4%	-26.6%	23.2%	0.0%
Average Annual Total Usage (6)	35,410,972	36,533,488	35,410,972	35,410,972	35,410,972	0.0%	-3.1%	0.0%	0.0%
Average Annual Total Cost of Gas (2)	$292,314,298	$298,381,973	$170,183,530	$210,778,390	$210,842,688	-27.9%	-29.3%	23.9%	0.0%

ALL FIRM CUSTOMERS (3)

All Cost $/Dth	2007 Rate Case Base Cost of Gas (7)	Last Approved Demand Adjustment: November 2006	Last Month PGA: October 2009 (8)	Current PGA without Adjustment: November 2009 (8)	Current PGA with Adjustment: November 2009 (8)	Change From Last Rate Case Base Cost	Change From Last Approved Demand Adjustment	Change From Last Month PGA	Change From Current PGA
Commodity Cost of Gas (WACOG) (1)	$7.1744	$7.0824	$3.9971	$5.0477	$5.0477	-29.6%	-28.7%	26.3%	0.0%
Demand Cost of Gas -Summer (4)	$0.6030	$0.6608	$0.3586	$0.4563	$0.4572	-24.2%	-30.8%	27.5%	0.2%
Demand Cost of Gas - Winter (4, 5)	$1.1856	$1.2166	$0.9486	$1.0438	$1.0459	-11.8%	-14.0%	10.3%	0.2%
Total Cost of Gas - Summer (2)	$7.7774	$7.7432	$4.3557	$5.5040	$5.5049	-29.2%	-28.9%	26.4%	0.0%
Total Cost of Gas - Winter (2)	$8.3600	$8.2990	$4.9457	$6.0915	$6.0936	-27.1%	-26.6%	23.2%	0.0%
Average Annual Total Usage	53,437,474	55,131,424	53,437,474	53,437,474	53,437,474	0.0%	-3.1%	0.0%	0.0%
Average Annual Total Cost of Gas (2)	$439,038,540	$449,958,270	$256,489,185	$317,750,879	$317,847,240	-27.6%	-29.4%	23.9%	0.0%

(1) Commodity costs include Peakshaving.
(2) Total cost of gas excludes distribution margin
(3) Excludes Demand Billed Customers firm sales.
(4) Rate for Rate Case is a weighted average firm rate since each class has a unique cost of gas.
(5) Not applicable during the summer months
(6) Residential Total Usage for October and November colums were imputed by taking the Residental % of usage in the 2004 Rate Case usage multiplied by the annual usage filed in the PGA for specific months.
(7) As in the compliance filing
(8) Does not include the monthly demand true-up surcharge(credit)

Northern States Power Company, a Minnesota corporation — Docket No. G002/M-09-____

DERIVATION OF CURRENT PGA COSTS — Attachment 2

November 2009 - Projected Costs (Actual prices will be determined Nov.1, 2009)* — Schedule 2

Demand Cost (Res, Sm & Lg Commercial Firm)		Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$28,059,954	$27,179,223	
2.	x Minnesota Design Day Ratio (2009 Demand Entitlement Filing)	89.56%	89.56%	
3.	Annual System Demand Allocation to MN	$25,130,494	$24,341,712	
4.	Grand Forks Total Demand	$275,226	$369,376	
5.	x Minnesota Allocator (2009 Demand Entitlement Filing)	14.67%	14.67%	
6.	Annual Grand Forks Demand Allocation to MN	$40,376	$54,187	
7.	Minnesota Total Demand (3 + 6)	$25,170,870	$24,395,899	
8.	MN State Design Day (2009 Demand Entitlement Filing)	694,487	694,487	
9.	- Small & Large Demand Billed Dth (2009 Demand Entitlement Filing)	20,439	20,439	
10.	Non-Demand Billed Design Day Dkt (8 - 9)	674,048	674,048	
11.	Non-Demand Billed Allocation (7 x 10 / 8)	$24,430,072	$23,677,909	
12.	Demand Billed Cost Allocation (7 - 11)	$740,798	$717,990	
13.	MN Annual / Seasonal Firm Therm Sales (2007 Rate Case)	534,374,742	402,230,147	
14.	Demand Unit Cost $/Therm (11 / 13)	$0.04572	$0.05887	$0.10459
15.	Demand Cost True-up - Residential, Oct-May			$0.00000
16.	Demand Cost True-up - Commercial, Oct-May			$0.00000
17.	Total Demand Rate - Residential (14 + 15)			$0.10459
18.	Total Demand Rate -Commercial (14 + 16)			$0.10459
Demand Cost (Demand Billed)				
19.	Cost Allocated to Demand Billed (12)	$740,798	$717,990	$1,458,788
20.	/ Annual Contract Billing Demand (2009 Demand Entitlement Filing)			2,452,715
21.	Monthly Commercial Demand Billed Demand Rate			$0.59476
Commodity Costs				Monthly Cost
22.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv			$48,484,195
23.	x MN Portion of Monthly Retail Sales			89.42%
24.	MN Portion of Monthly Commodity Costs			$43,354,568
25.	MN Budgeted Calendar Month Retail Therm Sales			85,889,698
26.	Commodity Unit Cost $/Therm (24 / 25)			$0.50477
Total Gas Cost per Therm				
27.	Residential (17 + 26)			**$0.60936**
28.	Small & Large Commercial (18 +26)			**$0.60936**
29.	Small & Large Demand Billed - Demand (21)			**$0.59476**
30.	Small & Large Demand Billed - Commodity; All Interruptible (26)			**$0.50477**

*Commodity costs are projected and for illustrative purposed only.

ATTACHMENT 3

**Northern States Power Company,
a Minnesota corporation**

Information provided in response to reporting requirements in Docket No. G002/M-03-1627 (order dated January 23, 2004) Regarding use of financial instruments to limit price volatility.

Northern States Power Company, a Minnesota corporation
SUMMARY OF COMPANY HEDGE TRANSACTIONS
2009-2010 Heating Season

								30	31	31	28	31		
								Monthly Volumes (Dth)						
Transaction Date	**Hedge Instrument**	**Counterparty**	**Premium ($/Dth)**	**Call Strike Price**	**Put Strike Price**	**Daily Vol (Dth)**	**Basis Point**	**November**	**December**	**January**	**February**	**March**	**Total Volume (Dth)**	**Total Dollars**
[TRADE SECRET BEGINS														
Totals	***Actual Hedge Activity***													

TRADE SECRET ENDS]

ATTACHMENT 4

Northern States Power Company,
a Minnesota corporation

Economic Analysis of 2009 Fargo Lateral Construction Project

Fargo Lateral Pipeline Project
Project Cost Estimate and Payment Options

CIAC Option

Estimated Project Cost	$ 14,692,000

Capacity Option

			Forecast Cost	
Service	**Rate (Cat. 3)**	**Capacity Factor**	**Volume**	**Ann. Cost**
Zone 1-2 Backhaul (8 yr)	$4.59	0.0060756	89,263	$4,913,500
Zone 1 Backhaul (10 yr)	$3.47	0.0067464	99,118	$4,123,829
Zone 2 Backhaul (10 yr)	$1.84	0.0127121	186,766	$4,123,797

Negotiated Rate Option

		Forecast Cost	
Service	**Rate (Cat. 3)**	**Volume**	**Ann. Cost**
Zone 1-2 Backhaul (8 yr)	$7.16	57,178	4,913,500
Zone 1 Backhaul (10 yr)	$6.01	57,178	4,123,829
Zone 2 Backhaul (10 yr)	$6.01	57,178	4,123,797

Northern Discount Economics

Assumptions
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Volume Requirements	**2009-10**	**2010-11**	**2011-12**	**2012-13**
ANR Capacity		50,000	57,500	66,500
Viking Capacity	-	35,094	42,594	51,594
NNG Capacity (Hugo Summer)		34,443	34,443	34,443
NNG Capacity (Hugo Winter)		36,316	36,316	36,316
NNG Capacity (Hugo Expansion)		3,884	7,962	12,245
NNG Capacity (St Cloud Expansion)		2,401	4,921	6,067

Project Economics **Daily Rate**
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Annual Cost Savings	**$ -**	**$ 323,206**	**$ 886,855**	**$ 1,134,339**

Northern States Power Company, a Minnesota corporation

Docket No. G002/M-09_____
Attachment 4
Page 3 of 3

Combined Fargo Project Costs and Northern Discount Savings

Fargo Project Costs	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**
Zone 1-2 Backhaul (8 yr)	$4,913,500	$4,913,500	$4,913,500	$4,913,500	$4,913,500	$4,913,500	$4,913,500	$4,913,500

Northern Discount Savings

Assumptions
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Volume Requirements	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**
ANR Capacity		50,000	57,500	66,500	66,500	66,500	66,500	66,500
Viking Capacity - excess Fargo summer	32,085	32,085	32,085	32,085	32,085	32,085	32,085	32,085
Viking Capacity - incremental backhaul		3,009	10,509	19,509	19,509	19,509	19,509	19,509
NNG Capacity (Hugo Summer)		34,443	34,443	34,443	34,443	34,443	34,443	34,443
NNG Capacity (Hugo Winter)		36,316	36,316	36,316	36,316	36,316	36,316	36,316
NNG Capacity (Hugo Expansion)		3,884	7,962	12,245	12,245	12,245	12,245	12,245
NNG Capacity (St Cloud Expansion)		2,401	4,921	6,067	6,067	6,067	6,067	6,067

The costs associated with this Viking capacity are shown above in the Fargo Project Costs line item. Costs for incremental backhaul capacity are included below.

Project Economics **Daily Rate**
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Annual Cost Savings	**$ -**	**$ 616,319**	**$ 1,179,968**	**$ 1,427,451**	**$ 1,427,451**	**$ 1,427,451**	**$ 1,427,451**	**$ 1,427,451**

CERTIFICATE OF SERVICE

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

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

<u>xx</u> electronic filing

Docket No. **G002/M-09-____**

Dated this 2nd day of November 2009

/s/
____
Carole Wallace
Regulatory Coordinator

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Burl W.	Haar	burl.haar@state.mn.us	MN Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	David W.	Niles		Avant Energy Services	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Jeffrey A.	Daugherty	jeffrey-daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	John	Moir	N/A	City of Minneapolis	City Hall Rm 301 M 350 South 5th Street Minneapolis, MN 55415-1376	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	John	Lindell	agorud.ecf@state.mn.us	OAG-RUD	900 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	Joseph V.	Plumbo		Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Julia	Anderson	Julia.Anderson@state.mn.us	MN Office Of The Attorney General	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Karen Finstad	Hammel	Karen.Hammel@state.mn.us	MN Office Of The Attorney General	1400 BRM Tower 445 Minnesota Street St. Paul, MN 551012131	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Kathleen D.	Sheehy	kathleen.sheehy@state.mn.us	Office Of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Lloyd W.	Grooms	lgrooms@winthrop.com	Winthrop & Weinstine	Suite 3500 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Michael	Sarafolean	MSarafolean@gerdauameristeel.com	Gerdau Ameristeel US, Inc.	4221 W Boy Scout Blvd Ste 600 Tampa, FL 33607	Paper Service	No

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
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 Center80 South 8th Street Minneapolis, MN 55402	Electronic Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Richard	Johnson	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street Minneapolis, MN 55402	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Avenue Minneapolis, MN 554022859	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Roger	Boehner	lorenbrft@aol.com		6511 Humboldt Avenue N., #210 Brooklyn Center, MN 55430	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Ronald M.	Giteck	ron.giteck@state.mn.us	Office Of Attorney General	Residential Utilities Division 445 Minnesota Street, 900 BRM Tower St. Paul, MN 55101	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Sandra	Hofstetter	N/A	MN Chamber of Commerce	1140 Mary Hill Cir. Hartland, WI 53029-8009	Paper Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Sharon	Ferguson	sharon.ferguson@state.mn.us	State of MN - DOC	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No
GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas	Todd J.	Guerrero	tguerrero@fredlaw.com	Fredrikson & Byron, P.A.	Suite 4000 200 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_04-1511_1	Burl W.	Haar	burl.haar@state.mn.us	MN Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes
OFF_SL_04-1511_1	Catarina	Zuber		Avant Energy Services	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_04-1511_1	Gary D.	Satterfield		Marathon Petroleum Company LLC	P.O. Box 3128 Houston, TX 77253	Paper Service	No
OFF_SL_04-1511_1	James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_04-1511_1	James R.	Talcott		Northern Natural Gas Company	1111 South 103rd Street Omaha, NE 68124	Paper Service	No
OFF_SL_04-1511_1	John	Lindell	agorud.ecf@state.mn.us	OAG-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes
OFF_SL_04-1511_1	Joseph V.	Plumbo		Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Paper Service	No
OFF_SL_04-1511_1	Julia	Anderson	Julia.Anderson@state.mn.us	MN Office Of The Attorney General	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes
OFF_SL_04-1511_1	Karen Finstad	Hammel	Karen.Hammel@state.mn.us	MN Office Of The Attorney General	1400 BRM Tower 445 Minnesota Street St. Paul, MN 551012131	Paper Service	No
OFF_SL_04-1511_1	Kathleen D.	Sheehy	kathleen.sheehy@state.mn.us	Office Of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Paper Service	No
OFF_SL_04-1511_1	Megan	Hertzler	megan.hertzler@xcelenergy.com	Xcel Energy	414 Nicollet Mall 5th Floor Minneapolis, MN 554011993	Paper Service	No

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_04-1511_1	Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Paper Service	No
OFF_SL_04-1511_1	Michael	Sarafolean	MSarafolean@gerdauameristeel.com	Gerdau Ameristeel US, Inc.	4221 W Boy Scout Blvd Ste 600 Tampa, FL 33607	Paper Service	No
OFF_SL_04-1511_1	Michael	Franklin	mfranklin@mnchamber.com	Minnesota Chamber Of Commerce	400 Robert Street North Suite 1500 St. Paul, MN 55101	Paper Service	No
OFF_SL_04-1511_1	Richard	Savelkoul	rsavelkoul@felhaber.com	Felhaber, Larson, Fenlon & Vogt, P.A.	444 Cedar St Ste 2100 St. Paul, MN 55101-2136	Paper Service	No
OFF_SL_04-1511_1	Richard	Johnson	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_04-1511_1	Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Avenue Minneapolis, MN 554022859	Paper Service	No
OFF_SL_04-1511_1	Ronald M.	Giteck	ron.giteck@state.mn.us	Office Of Attorney General	Residential Utilities Division 445 Minnesota Street, 900 BRM Tower St. Paul, MN 55101	Paper Service	No
OFF_SL_04-1511_1	SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No
OFF_SL_04-1511_1	Sharon	Ferguson	sharon.ferguson@state.mn.us	State of MN - DOC	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes
OFF_SL_04-1511_1	William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Paper Service	No

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_06-1429_1	Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No
OFF_SL_06-1429_1	Annette	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	Suite 208 400 Robert St. N. St.Paul, MN 551012002	Paper Service	No
OFF_SL_06-1429_1	Bill	Bullard		South Dakota Public Utilities Commiss	Capitol Building Pierre, SD 575015070	Paper Service	No
OFF_SL_06-1429_1	Bob	Bridges	bob.bridges@versopaper.com	Verso Paper	</p> 100 East Sartell Street Sartell, MN 56377	Paper Service	No
OFF_SL_06-1429_1	Brian	Elliott		Clean Water Action Alliance	326 Hennepin Ave. E. Minneapolis, MN 55414	Paper Service	No
OFF_SL_06-1429_1	Burl W.	Haar	burl.haar@state.mn.us	MN Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes
OFF_SL_06-1429_1	Catarina	Zuber		Avant Energy Services	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_06-1429_1	Christopher	Anderson	canderson@allete.com	Minnesota Power	30 West Superior Street Duluth, MN 558022093	Electronic Service	No
OFF_SL_06-1429_1	Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	No
OFF_SL_06-1429_1	Gary D.	Satterfield		Marathon Petroleum Company LLC	P.O. Box 3128 Houston, TX 77253	Paper Service	No
OFF_SL_06-1429_1	George	Crocker		North American Water Office	PO Box 174 Lake Elmo, MN 55042	Paper Service	No

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_06-1429_1	James J.	Bertrand	james.bertrand@leonard.com	Leonard Street & Deinard	Suite 2300 150 South Fifth Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_06-1429_1	James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_06-1429_1	James P.	Johnson	james.p.johnson@xcelenergy.com	Xcel Energy	5th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Paper Service	No
OFF_SL_06-1429_1	James R.	Talcott		Northern Natural Gas Company	1111 South 103rd Street Omaha, NE 68124	Paper Service	No
OFF_SL_06-1429_1	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Paper Service	No
OFF_SL_06-1429_1	Jeffrey A.	Daugherty	jeffrey-daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Paper Service	No
OFF_SL_06-1429_1	John	Lindell	agorud.ecf@state.mn.us	OAG-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes
OFF_SL_06-1429_1	John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance	1313 5th St SE Ste 303 Minneapolis, MN 55414	Electronic Service	No
OFF_SL_06-1429_1	Joseph V.	Plumbo		Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Paper Service	No
OFF_SL_06-1429_1	Julia	Anderson	Julia.Anderson@state.mn.us	MN Office Of The Attorney General	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_06-1429_1	Karen Finstad	Hammel	Karen.Hammel@state.mn.us	MN Office Of The Attorney General	1400 BRM Tower 445 Minnesota Street St. Paul, MN 551012131	Paper Service	No
OFF_SL_06-1429_1	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No
OFF_SL_06-1429_1	Leslie	Davis		Earth Protector, Inc.	PO Box 11688 Minneapolis, MN 554110688	Paper Service	No
OFF_SL_06-1429_1	Lisa	Veith		City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Paper Service	No
OFF_SL_06-1429_1	Lloyd W.	Grooms	lgrooms@winthrop.com	Winthrop & Weinstine	Suite 3500 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No
OFF_SL_06-1429_1	Mary Jo	Woolf	mary.j.woolf@xcelenergy.com	Xcel Energy	7th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Paper Service	No
OFF_SL_06-1429_1	Megan	Hertzler	megan.hertzler@xcelenergy.com	Xcel Energy	414 Nicollet Mall 5th Floor Minneapolis, MN 554011993	Paper Service	No
OFF_SL_06-1429_1	Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center80 South 8th Street Minneapolis, MN 55402	Electronic Service	No
OFF_SL_06-1429_1	Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Paper Service	No
OFF_SL_06-1429_1	Michael	Sarafolean	MSarafolean@gerdauameristeel.com	Gerdau Ameristeel US, Inc.	4221 W Boy Scout Blvd Ste 600 Tampa, FL 33607	Paper Service	No

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_06-1429_1	Michael	Franklin	mfranklin@mnchamber.com	Minnesota Chamber Of Commerce	400 Robert Street North Suite 1500 St. Paul, MN 55101	Paper Service	No
OFF_SL_06-1429_1	Michael	Loeffler		Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Paper Service	No
OFF_SL_06-1429_1	Peter G.	Mikhail	pmikhail@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_06-1429_1	Richard	Savelkoul	rsavelkoul@felhaber.com	Felhaber, Larson, Fenlon & Vogt, P.A.	444 Cedar St Ste 2100 St. Paul, MN 55101-2136	Paper Service	No
OFF_SL_06-1429_1	Richard	Johnson	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_06-1429_1	Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Avenue Minneapolis, MN 554022859	Paper Service	No
OFF_SL_06-1429_1	Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No
OFF_SL_06-1429_1	Ronald M.	Giteck	ron.giteck@state.mn.us	Office Of Attorney General	Residential Utilities Division 445 Minnesota Street, 900 BRM Tower St. Paul, MN 55101	Paper Service	No
OFF_SL_06-1429_1	SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No
OFF_SL_06-1429_1	Sharon	Ferguson	sharon.ferguson@state.mn.us	State of MN - DOC	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_06-1429_1	Steven	Bosacker		City of Minneapolis	City Hall, Room 301M 350 South Fifth Street Minneapolis, MN 554151376	Paper Service	No
OFF_SL_06-1429_1	Steven H.	Alpert	steve.alpert@state.mn.us	Minnesota Attorney General'S Office	1100 BRM Tower 445 Minnesota Street St. Paul, MN 551012131	Electronic Service	No
OFF_SL_06-1429_1	Tim	Barth		Marathon Petroleum Company	P.O. Box 3128 Houston, TX 77253	Paper Service	No
OFF_SL_06-1429_1	Todd J.	Guerrero	tguerrero@fredlaw.com	Fredrikson & Byron, P.A.	Suite 4000 200 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No
OFF_SL_06-1429_1	Valerie	Means	valerie.means@state.mn.us	Office of the Attorney General	1400 BRM Tower445 Minnesota Street St. Paul, MN 55101	Electronic Service	No
OFF_SL_06-1429_1	William	Grant	bgrant@iwla.org	Izaak Walton League, Midwest Office	1619 Dayton Ave Ste 202 St. Paul, MN 551046206	Paper Service	No
OFF_SL_06-1429_1	William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Paper Service	No