414 Nicollet Mall
Minneapolis, Minnesota 55401

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**

October 31, 2014

**—Via Electronic Filing—**

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

RE: SUPPLEMENTAL FILING
CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-14-654

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits this Supplemental Filing in response to the September 2, 2014 Comments of the Minnesota Department of Commerce, Division of Energy Resources.

The Department recommended that the Commission:

- approve Xcel [Energy's] proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2014 supplemental filing;
- allow Xcel [Energy] to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2014 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2014;
- the Company provide in its November 1, 2014 supplemental filing, an update on any hedging transactions that are entered into for the 2014-2015 heating season.

We include the following revised attachments:

Attachment 1, Schedule 2, Pages 1 and 2
Attachment 1, Schedule 5

Attachment 2, Schedule 1, Pages 1 and 2
Attachment 2, Schedule 2, Pages 1-4
Attachment 3, Schedule 1

<u>Changes to Demand Entitlement Levels</u>
There are several changes to the firm transport entitlement levels provided in the Petition filed August 1, 2014 in Docket No. G002/M-14-654. These changes are summarized below and presented in the revised Attachment 1, Schedule 2, Pages 1 and 2, Attachment 1, Schedule 5, and Attachment 2, Schedule 1, Pages 1 and 2.

1. In the Petition, we planned to purchase 10,646 Dth/day of firm, winter-only capacity on Viking Gas Transmission (Viking) to supplement our total design day capacity of 856,048 Dth/day. Viking informed us in mid-October that incremental capacity will not be available this coming heating season because of pressure restrictions imposed by the Pipeline and Hazardous Materials Safety Administration (PHMSA) related to a Viking pipeline rupture that occurred last May. Viking is required to reduce its operating pressure while the pipeline undergoes safety testing. The reduced pressure decreases the amount of gas that can be transported by Viking; hence no incremental capacity can be acquired at this time.

   We studied several short-term options to replace this capacity and elected to subscribe to additional capacity on Northern Natural Gas (Northern) as the most flexible option. We purchased all of the available capacity on Northern from Carlton, MN to Chisago, MN to offset the need for additional capacity on Viking. This 5,629 Dth/day of capacity will provide for supply receipts from Great Lakes Gas Transmission at Carlton redelivered to Chisago for ultimate distribution within NSPM's Northern Minnesota service areas. The Northern capacity increases winter costs by $286,000 over the Viking capacity projected in our Petition due to the higher reservation rates on Northern.

   The remaining de minimus amount of capacity discussed in the Petition will be offset using existing reserve capacity on the NSPM system. These changes will reduce our reserve margin slightly to 5.7%, which is within our normal operating range.

2. We renewed a package of transportation and storage contracts on ANR Pipeline, ANR Storage, and Great Lakes Gas Transmission that are necessary to continue to meet our design day requirements. By extending the term of these agreements, we were able to negotiate some lower costs

for the package. For this winter, we will realize a minor cost decrease of $13,000. However, when considering reservation and usage costs over the next three years, we will realize a cost decrease of roughly $560,000 from current costs.

3. Pursuant to a filing submitted by Viking on August 15th and approved by the Federal Energy Regulatory Commission on October 1st in Docket No. RP14-1185, Viking's demand rates will increase beginning January 1, 2015 for all shippers. The rate increase is due to a number of contract terminations on Viking's system. The rate change results in an annual cost increase of $1,298,000 for NSPM.

Supplier Entitlement Changes

Supplier entitlement changes are shown on Attachment 1, Schedule 2. We replaced several firm supply transactions to address peak day needs at Emerson and Chisago where supply was limited on a few days last winter.

Update on Hedging Transactions

Updated hedging transactions are presented on the revised Attachment 3, Schedule 1. We executed seven call options for the 2014-2015 heating season covering the entire supply quantity we targeted. The two hedging transactions that were reported in the Petition were incorrect. Attachment 3, Schedule 1 now reflects all of the current hedging transactions. Total hedging costs for the 2014-2015 heating season are $5,047,175.

Changes in Resources to Meet Design Day

Attachment 1, Schedule 2 shows the demand cost component changes for this winter. The schedule shows a decrease of demand related total costs of approximately $1.7 million over last year primarily due to allocating storage capacity demand charges to commodity costs as explained in the Petition.

Miscellaneous

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 list.

Please contact Richard Derryberry at (303) 571-7104 or richard.derryberry@xcelenergy.com or 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

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Northern States Power Company
**DEMAND COST OF GAS IMPACT - NOVEMBER 2014**
**Revised from previous filing**

Docket No. G002/M-14-654
REVISED Attachment 1
Schedule 2
Page 1 of 2

**\NGE 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 |
| NNG TFX (Nov - Mar)[1] | 5,629 | $ 15.1530 | 5 | $ 426,481.19 |
| VGT FT-A (Jan - Dec)[2] | (72,213) | $ 4.4954 | 12 | $ (3,895,515.84) |
| VGT FT-A (Jan - Dec)[2] | 72,213 | $ 4.4954 | 2 | $ 649,252.64 |
| VGT FT-A (Jan - Dec)[2] | 72,213 | $ 5.3593 | 10 | $ 3,870,111.31 |
| VGT FT-A (Jan - Dec)[2] | (29,002) | $ 3.3978 | 12 | $ (1,182,515.95) |
| VGT FT-A (Jan - Dec)[2] | 29,002 | $ 3.3978 | 2 | $ 197,085.99 |
| VGT FT-A (Jan - Dec)[2] | 29,002 | $ 4.3706 | 10 | $ 1,267,561.41 |
| VGT FT-A (Nov - Mar)[2] | (4,239) | $ 3.3978 | 5 | $ (72,016.37) |
| VGT FT-A (Nov - Mar)[2] | 4,239 | $ 3.3978 | 2 | $ 28,806.55 |
| VGT FT-A (Nov - Mar)[2] | 4,239 | $ 4.3706 | 3 | $ 55,580.92 |
| VGT FT-A (Jan - Dec)[2] | (10,000) | $ 3.3978 | 12 | $ (407,736.00) |
| VGT FT-A (Jan - Dec)[2] | 10,000 | $ 3.3978 | 2 | $ 67,956.00 |
| VGT FT-A (Jan - Dec)[2] | 10,000 | $ 4.3706 | 10 | $ 437,060.00 |
| VGT FT-A (Jan - Dec)[2] | (15,600) | $ 4.4954 | 12 | $ (841,538.88) |
| VGT FT-A (Jan - Dec)[2] | 15,600 | $ 4.4954 | 2 | $ 140,256.48 |
| VGT FT-A (Jan - Dec)[2] | 15,600 | $ 5.3593 | 10 | $ 836,050.80 |
| VGT FT-A (Jan - Dec)[2] | (1,903) | $ 3.3978 | 12 | $ (77,592.16) |
| VGT FT-A (Jan - Dec)[2] | 1,903 | $ 3.3978 | 2 | $ 12,932.03 |
| VGT FT-A (Jan - Dec)[2] | 1,903 | $ 4.3706 | 10 | $ 83,172.52 |
| VGT FT-A (Jan - Dec)[2] | 15,000 | $ 4.4954 | 2 | $ 134,862.00 |
| VGT FT-A (Jan - Dec)[2] | 15,000 | $ 5.3593 | 10 | $ 803,895.00 |
| VGT FT-A (Dec - Feb)[2] | (10,542) | $ 3.7671 | 3 | $ (119,138.30) |
| 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)[3] | 9,248 | $ 14.6460 | 5 | $ 677,231.04 |
| GLGT FT (Nov - Mar)[3] | 895 | $ 11.4420 | 7 | $ 71,684.13 |
| ANR FTS (Jan - Dec)[4] | 80 | $ 4.1600 | 7 | $ 2,329.60 |
| ANR FSS (Jan - Dec)[5] | 84 | $ 2.0400 | 12 | $ 2,056.32 |
| ANR FSS (Jan - Dec)[5] | 434 | $ 0.4000 | 12 | $ 2,083.20 |
| ANR FSS (Jan - Dec)[5] | (15,310) | $ 2.0400 | 12 | $ (374,788.80) |
| ANR FSS (Jan - Dec)[5] | 15,310 | $ 2.0400 | 5 | $ 156,162.00 |
| ANR FSS (Jan - Dec)[5] | 15,310 | $ 1.7820 | 7 | $ 190,976.94 |
| ANRS FS (Jan - Dec)[6] | (6,049) | $ 1.0924 | 12 | $ (79,295.13) |
| ANRS FS (Jan - Dec)[6] | 170,880 | $ 0.0133 | 12 | $ 27,169.92 |
| Total | | | | $ 3,397,639.54 |

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

**TRADE SECRET ENDS]**

| | | |
|---|---|---|
| Total | 15,000 | $167,700.00 |
| **Total MN & ND Demand Cost Adjustment** | | **$3,565,339.54** |
| Minnesota Allocation Factor (MN/ND Allocated Demand) | | 88.42% |
| **MN only Demand Cost Adjustment due to MN/ND Allocated Demand** | | **$ 3,152,473.22** |

[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. New rates effective January 1, 2015.
[3]GLT Third Revised Volume No. 1, Part 4.1 Statement of Rates, Effective August 1, 2011
[4]ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v. 0.0.0, Effective September 30, 2010
[5]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 0.0.0, Effective September 30, 2010
[6]ANRS First Revised Volume No. 1, Part 4.2 - Statement of Rates, v. 3.0.0, Effective October 1, 2013

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Northern States Power Company
**Demand Cost Changes from Prior Year**
**Revised from previous filing**

Docket No. G002/M-14-654
REVISED Attachment 1
Schedule 2
Page 2 of 2

| | Volume | Rate | Months | Annual Cost | Winter Cost | Total Cost | Minnesota Deliverable | North Dakota Deliverable | Upstream/System Supply | Footnote |
|---|---|---|---|---|---|---|---|---|---|---|
| **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 |
| NNG TFX (Nov - Mar) | 5,629 | $15.1530 | 5 | | $ 426,481.19 | $ 426,481.19 | $ 426,481.19 | | | 6 |
| VGT FT-A (Jan - Dec) | (72,213) | $ 4.4954 | 12 | $ (3,895,515.84) | | $ (3,895,515.84) | $ (3,444,415.11) | $ (451,100.73) | | 7 |
| VGT FT-A (Jan - Dec) | 72,213 | $ 4.4954 | 2 | $ 649,252.64 | | $ 649,252.64 | $ 574,069.18 | $ 75,183.46 | | 7 |
| VGT FT-A (Jan - Dec) | 72,213 | $ 5.3593 | 10 | $ 3,870,111.31 | | $ 3,870,111.31 | $ 3,421,952.42 | $ 448,158.89 | | 7 |
| VGT FT-A (Jan - Dec) | (29,002) | $ 3.3978 | 12 | $ (1,182,515.95) | | $ (1,182,515.95) | $ (1,045,580.60) | $ (136,935.35) | | 7 |
| VGT FT-A (Jan - Dec) | 29,002 | $ 3.3978 | 2 | $ 197,085.99 | | $ 197,085.99 | $ 174,263.43 | $ 22,822.56 | | 7 |
| VGT FT-A (Jan - Dec) | 29,002 | $ 4.3706 | 10 | $ 1,267,561.41 | | $ 1,267,561.41 | $ 1,120,777.80 | $ 146,783.61 | | 7 |
| VGT FT-A (Nov - Mar) | (4,239) | $ 3.3978 | 5 | | $ (72,016.37) | $ (72,016.37) | $ (63,676.88) | $ (8,339.50) | | 7 |
| VGT FT-A (Nov - Mar) | 4,239 | $ 3.3978 | 2 | | $ 28,806.55 | $ 28,806.55 | $ 25,470.75 | $ 3,335.80 | | 7 |
| VGT FT-A (Nov - Mar) | 4,239 | $ 4.3706 | 3 | | $ 55,580.92 | $ 55,580.92 | $ 49,144.65 | $ 6,436.27 | | 7 |
| VGT FT-A (Jan - Dec) | (10,000) | $ 3.3978 | 12 | $ (407,736.00) | | $ (407,736.00) | $ (360,520.17) | $ (47,215.83) | | 7 |
| VGT FT-A (Jan - Dec) | 10,000 | $ 3.3978 | 2 | $ 67,956.00 | | $ 67,956.00 | $ 60,086.70 | $ 7,869.30 | | 7 |
| VGT FT-A (Jan - Dec) | 10,000 | $ 4.3706 | 10 | $ 437,060.00 | | $ 437,060.00 | $ 386,448.45 | $ 50,611.55 | | 7 |
| VGT FT-A (Jan - Dec) | (15,600) | $ 4.4954 | 12 | $ (841,538.88) | | $ (841,538.88) | $ (744,088.68) | $ (97,450.20) | | 7 |
| VGT FT-A (Jan - Dec) | 15,600 | $ 4.4954 | 2 | $ 140,256.48 | | $ 140,256.48 | $ 124,014.78 | $ 16,241.70 | | 7 |
| VGT FT-A (Jan - Dec) | 15,600 | $ 5.3593 | 10 | $ 836,050.80 | | $ 836,050.80 | $ 739,236.12 | $ 96,814.68 | | 7 |
| VGT FT-A (Jan - Dec) | (1,903) | $ 3.3978 | 12 | $ (77,592.16) | | $ (77,592.16) | $ (68,606.99) | $ (8,985.17) | | 7 |
| VGT FT-A (Jan - Dec) | 1,903 | $ 3.3978 | 2 | $ 12,932.03 | | $ 12,932.03 | $ 11,434.50 | $ 1,497.53 | | 7 |
| VGT FT-A (Jan - Dec) | 1,903 | $ 4.3706 | 10 | $ 83,172.52 | | $ 83,172.52 | $ 73,541.14 | $ 9,631.38 | | 7 |
| VGT FT-A (Jan - Dec) | 15,000 | $ 4.4954 | 2 | $ 134,862.00 | | $ 134,862.00 | $ 31,018.26 | $ 103,843.74 | | 8 |
| VGT FT-A (Jan - Dec) | 15,000 | $ 5.3593 | 10 | $ 803,895.00 | | $ 803,895.00 | $ 184,895.85 | $ 618,999.15 | | 8 |
| VGT FT-A (Dec - Feb) | (10,542) | $ 3.7671 | 3 | | $ (119,138.30) | $ (119,138.30) | | $ (119,138.30) | | 9 |
| VGT FT-A (Apr - Oct) | (5,000) | $ 3.4671 | 7 | $ (121,348.50) | | $ (121,348.50) | $ (107,296.34) | $ (14,052.16) | | 10 |
| GLGT FT (Nov - Mar) | (6,706) | $ 9.4560 | 5 | | $ (317,059.68) | $ (317,059.68) | | | $ (317,059.68) | 11 |
| GLGT FT (Nov - Mar) | 9,248 | $14.6460 | 5 | | $ 677,231.04 | $ 677,231.04 | | | $ 677,231.04 | 12 |
| GLGT FT (Nov - Mar) | 895 | $11.4420 | 7 | $ 71,684.13 | | $ 71,684.13 | | | $ 71,684.13 | 12 |
| ANR FTS (Jan - Dec) | 80 | $ 4.1600 | 7 | | $ 2,329.60 | $ 2,329.60 | | | $ 2,329.60 | 13 |
| ANR FSS (Jan - Dec) | 84 | $ 2.0400 | 12 | | $ 2,056.32 | $ 2,056.32 | | | $ 2,056.32 | 13 |
| ANR FSS (Jan - Dec) | 434 | $ 0.4000 | 12 | | $ 2,083.20 | $ 2,083.20 | | | $ 2,083.20 | 13 |
| ANR FSS (Jan - Dec) | (15,310) | $ 2.0400 | 12 | | $ (374,788.80) | $ (374,788.80) | | | $ (374,788.80) | 14 |
| ANR FSS (Jan - Dec) | 15,310 | $ 2.0400 | 5 | | $ 156,162.00 | $ 156,162.00 | | | $ 156,162.00 | 14 |
| ANR FSS (Jan - Dec) | 15,310 | $ 1.7820 | 7 | | $ 190,976.94 | $ 190,976.94 | | | $ 190,976.94 | 14 |
| ANRS FS (Jan - Dec) | (6,049) | $ 1.0924 | 12 | | $ (79,295.13) | $ (79,295.13) | | | $ (79,295.13) | 15 |
| ANRS FS (Jan - Dec) | 170,880 | $ 0.0133 | 12 | | $ 27,169.92 | $ 27,169.92 | | | $ 27,169.92 | 15 |
| ANR Capacity Release | | | | | $ 85,500.00 | $ 85,500.00 | | | $ 85,500.00 | 16 |
| VGT Rate Changes | | | | $ (130,646.03) | $ (1,468.81) | $ (132,114.84) | $ (116,815.94) | $ (15,298.90) | | 17 |
| WBI Rate Changes | | | | $ (153,608.14) | | $ (153,608.14) | | $ (153,608.14) | | 17 |
| ANRP Storage Capacity Demand Charge Reallocation | 79,102 | $ 0.4000 | 12 | | $ (379,688.00) | $ (379,688.00) | | | $ (379,688.00) | 18 |
| ANRS Storage Capacity Demand Charge Reallocation | 1,165,185 | $ 0.0133 | 12 | | $ (185,264.42) | $ (185,264.42) | | | $ (185,264.42) | 18 |
| NNG Storage Capacity Demand Charge Reallocation | 2,516,995 | $ 0.3567 | 5 | | $ (4,489,060.58) | $ (4,489,060.58) | | | $ (4,489,060.58) | 18 |
| Total | | | | $ 2,019,532.07 | $ (3,916,389.64) | $ (1,896,857.56) | $ 2,157,000.56 | $ 556,105.34 | $ (4,609,963.46) | |
| Supplier Entitlement Changes | | | | | | | | | | |
| **[TRADE SECRET BEGINS** | | | | | | | | | | |
| | | | | | | | | | | 19 |
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| | | | | | | | | | | 20 |
| | | | | | | | | | **TRADE SECRET ENDS]** | |
| Total | | | | $ - | $ 167,700.00 | $ 167,700.00 | $ 167,700.00 | $ - | $ - | |
| **TOTAL OF 2014 CHANGES** | | | | **$ 2,019,532.07** | **$ (3,748,689.64)** | **$ (1,729,157.56)** | **$ 2,324,700.56** | **$ 556,105.34** | **$ (4,609,963.46)** | |
| **2014 COSTS** | | | | **$30,819,929.19** | **$ 23,413,065.11** | **$ 54,232,994.30** | | | | |
| **2014 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES** | | | | | | | 81% | 19% | | 21 |

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 NNG customers downstream of Chisago, MN starting November 1, 2014.
7. Entires to account for rate changes on Viking effective January 1, 2015.
8. Incremental capacity serving Fargo, ND area and new communities in Barnesville and Holdingford, MN starting November 1, 2014. Costs are allocated based on contract quantity in each state.
9. Expired firm transport capacity serving Fargo ND, December 1, 2013 through February 28, 2014.
10. Expired summer capacity on Viking, not renewed.
11. Expired winter backhaul capacity on Great Lakes, not renewed.
12. Incremental backhaul and forward-haul transport capacity on Great Lakes for November 1, 2014 through March 28, 2015, and April 1, 2015 through October 31, 2015 respectively.
    Will be used for ANRS storage withdrawals and injections.
13. Volume additions on ANR transport and storage agreements. Upstream capacity serves demand in either MN or ND.
14. Entires to account for rate reduction on ANR Pipeline storage agreement effective April 1, 2015.
15. Volume changes on ANR Storage contract. Withdrawal capacity aligns with backhaul capacity on Great Lakes.
16. ANR capacity release in effect November 1, 2013 through March 31, 2014.
17. Miscellaneous demand rate changes on VGT and WBI contracts. These rate changes did not impact transport capacity volumes.
18. Storage capacity demand charges have been reallocated to commodity charges effective July 1, 2014 per MN PUC order.
19. Expired peaking supply contract with demand charges in effect November 1, 2013 through March 31, 2014.
20. New peaking supply contracts for the 2014-2015 heating season.
21. 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.

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**

Docket No. G002/M-14-654
REVISED Attachment 1
Schedule 5


Northern States Power Company
**FIRM SUPPLY ENTITLEMENTS**
2014-2015 Heating Season
**Revised from previous filing**

| **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 | 856,048 | 13,637 |
| C. Minnesota State Delivered Supply | | | |
| State of MN Allocators | 88.95% | 88.42% | |
| TOTAL | 749,325 | 756,918 | 7,593 |

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

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**

Docket No. G002/M-14-654
REVISED Attachment 2
Schedule 1
Page 1 of 2

Northern States Power Company
**COMPANY DEMAND PROFILE**
2014-2015 Heating Season
**Revised from previous filing**

| 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 | | 12.16% |
| 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 | | 9.97% |
| 112183 | NNG TF5 (Max) | 62,415 | 0 | 62,415 | 10 yrs - 10/31/17 | | 7.29% |
| 112182 | NNG TF5 (Disc.) | 29,599 | 0 | 29,599 | 10 yrs - 10/31/17 | | 3.46% |
| 111739 | NNG TFX (Nov-Mar) | 28,500 | 0 | 28,500 | 8 yrs - 10/31/17 | | 3.33% |
| 112185 | NNG TFX (Disc. Nov-Mar) | 58,184 | 0 | 58,184 | 10 yrs - 10/31/17 | | 6.80% |
| 112185 | NNG TFX (Disc. 12-month) | 21,680 | 0 | 21,680 | 10 yrs - 10/31/17 | | 2.53% |
| 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 | | 5.72% |
| 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 | | 2.92% |
| 122067 | NNG TFX (Disc. Nov-Mar) | 6,298 | 431 | 6,729 | 10 yrs - 10/31/17 | Growth election | 0.79% |
| 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 | 1.04% |
| 122068 | NNG TFX 7 (Max) | 4,839 | 4,036 | 8,875 | 10 yrs - 10/31/24 | Incremental capacity | Summer Only |
| TBD | NNG TFX (Nov-Mar) | 0 | 5,629 | 5,629 | 5 mos. - 3/31/15 | Incremental capacity | 0.66% |
| | | **[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 | | 3.39% |
| AF0044 | VGT FT-A (Nov-Mar ) | 4,239 | 0 | 4,239 | 5 yrs - 10/31/18 | | 0.50% |
| 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 | 1.17% |
| AF0037 | VGT FT-A 12 Mos. | 15,600 | 0 | 15,600 | 8.5 yrs - 10/31/17 | | 1.82% |
| 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 | | 8.44% |
| AF0218 | VGT FT-A 12 Mos. | 0 | 15,000 | 15,000 | 5 yrs - 10/31/19 | Capacity acquisition | 1.75% |
| AF0202 | VGT FT-A (Dec-Feb) | 10,542 | (10,542) | 0 | 3 mos - 2/28/2015 | Not renewed | 0.00% |
| | 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 | | 2.80% |
| | LP Peak Shaving | 90,000 | 0 | 90,000 | | | 10.51% |
| | LNG Peak Shaving | 156,000 | 0 | 156,000 | | | 18.22% |
| | **Total Design Day Capacity** | **842,411** | | **856,048** | | | **100%** |
| | Heating Season Total | 842,411 | | 856,048 | | | |
| | 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 FT17836 (2) | 3,509 | 0 | 3,509 | 3 yrs - 03/31/17 | Contract renewal | |
| | GLT FT17836 (2) | 4,475 | 0 | 4,475 | 3 yrs - 03/31/17 | Contract renewal | |
| | GLT FT17827 (2) | 6,706 | (6,706) | 0 | 5 mos. - 03/31/14 | Contract expired | |
| | GLT FT18129 (2) | 0 | 9,248 | 9,248 | 2 yrs - 03/31/17 | Contract renewal | |
| | GLT FT18130 (2) | 895 | 0 | 895 | 2 yrs - 03/31/17 | Contract renewal | |
| | 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**

**Revised from previous filing**

| | Current Amount Dth | Proposed Change Dth | Proposed Amount Dth |
|---|---|---|---|
| **Total MN Company Available Capacity:** | | | |
| Heating Season | 842,411 | 13,637 | 856,048 |
| 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 | (1,262) | 46,377 |
| Non-Heating Season Capacity Reserve/(Shortage) | N/A | N/A | N/A |
| Heating Season Capacity Reserve/(Shortage) Margin % | 6.0% | -0.3% | 5.7% |
| **Total MN State Available Capacity:** | | | |
| State of MN Allocation Factor | 88.95% | -0.53% | 88.42% |
| State of MN Heating Season Capacity | 749,325 | 7,593 | 756,918 |
| State of MN Design Day Demand | 706,935 | 9,010 | 715,945 |
| State of MN Heating Season Capacity Reserve/(Shortage) | 42,390 | (1,417) | 40,973 |
| State of MN Heating Season Capacity Reserve/(Shortage) Margin % | 6.0% | -0.3% | 5.7% |

(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
**MINNESOTA STATE RATE IMPACT**



Date to implement proposed changes: November 1, 2014
$/Dth

| | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | Last Month PGA: October 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 | $4.0675 | $4.4059 | -19.95% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.9008 | $0.9347 | $0.8215 | $0.8447 | -6.23% | -9.63% | 2.82% | $0.0232 |
| 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 | $6.7481 | $7.1097 | -13.97% | 8.93% | 5.36% | $0.3616 |
| Average Annual Usage (Dth) | 87 | 87 | 87 | 87 | | | | |
| Average Annual Total Cost | $718.60 | $567.55 | $586.77 | $618.22 | -13.97% | 8.93% | 5.36% | $31.44 |
| Average Annual Total Demand Cost of Gas | $78.33 | $81.28 | $71.43 | $73.45 | | | | **$2.02** |
| **Small Commercial** | | | | | | | | |
| Commodity Cost of Gas (WACOG) | $5.4871 | $3.7332 | $4.0675 | $4.4059 | -19.70% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.8984 | $0.9323 | $0.8246 | $0.8479 | -5.62% | -9.05% | 2.83% | $0.0233 |
| 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 | $6.1252 | $6.4869 | -14.85% | 9.97% | 5.91% | $0.3617 |
| Average Annual Usage (Dth) | 284 | 284 | 284 | 284 | | | | |
| Average Annual Total Cost | $2,163.87 | $1,675.35 | $1,739.71 | $1,842.44 | -14.85% | 9.97% | 5.91% | $102.73 |
| Average Annual Total Demand Cost of Gas | $255.17 | $264.80 | $234.21 | $240.82 | | | | **$6.62** |
| **Large Commercial** | | | | | | | | |
| Commodity Cost of Gas (WACOG) | $5.4871 | $3.7332 | $4.0675 | $4.4059 | -19.70% | 18.02% | 8.32% | $0.3384 |
| Demand Cost of Gas (1) | $0.8917 | $0.9116 | $0.8097 | $0.8324 | -6.65% | -8.69% | 2.80% | $0.0227 |
| 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 | $6.1087 | $6.4698 | -14.99% | 10.10% | 5.91% | $0.3611 |
| Average Annual Usage (Dth) | 1,463 | 1,463 | 1,463 | 1,463 | | | | |
| Average Annual Total Cost | $11,131.14 | $8,594.92 | $8,934.84 | $9,463.00 | -14.99% | 10.10% | 5.91% | $528.16 |
| Average Annual Total Demand Cost of Gas | $1,304.24 | $1,333.34 | $1,184.30 | $1,217.50 | | | | **$33.20** |

(1) Includes demand smoothing

**MINNESOTA STATE RATE IMPACT**

| | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-13-663) | Last Month PGA: October 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 | $4.0675 | $4.4059 | -19.78% | 18.02% | 8.32% | $0.3384 |
| 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 | $5.0310 | $5.3694 | -16.83% | 14.32% | 6.73% | $0.3384 |
| | | | | | | | | |
| Average Annual Usage (Dth) | 7,936 | 7,936 | 7,936 | 7,936 | | | | |
| Average Annual Total Cost | $51,236.58 | $37,273.81 | $39,926.85 | $42,612.42 | -16.83% | 14.32% | 6.73% | $2,685.58 |
| 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 | $4.0675 | $4.4059 | -19.45% | 18.02% | 8.32% | $0.3384 |
| 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 | $4.5426 | $4.8810 | -17.89% | 15.99% | 7.45% | $0.3384 |
| | | | | | | | | |
| Average Annual Usage (Dth) | 64,709 | 64,709 | 64,709 | 64,709 | | | | |
| Average Annual Total Cost | $384,678.21 | $272,317.12 | $293,949.41 | $315,847.01 | -17.89% | 15.99% | 7.45% | $21,897.60 |
| 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 | $4.0675 | $4.4059 | -19.90% | 18.02% | 8.32% | $0.3384 |
| 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 | $4.5021 | $4.8405 | -18.44% | 16.14% | 7.52% | $0.3384 |
| | | | | | | | | |
| Average Annual Usage (Dth) | 745,979 | 745,979 | 745,979 | 745,979 | | | | |
| Average Annual Total Cost | $4,427,543.89 | $3,109,100.05 | $3,358,480.93 | $3,610,920.33 | -18.44% | 16.14% | 7.52% | $252,439.40 |
| 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 | $0.3384 | 8.32% | $0.0232 | 2.82% | $2.02 | $31.44 | 5.36% |
| Small Commercial | $0.3384 | 8.32% | $0.0233 | 2.83% | $6.62 | $102.73 | 5.91% |
| Large Commercial | $0.3384 | 8.32% | $0.0227 | 2.80% | $33.20 | $528.16 | 5.91% |
| Small Interruptible | $0.3384 | 8.32% | $0.0000 | NA | $0.00 | $2,685.58 | 6.73% |
| Medium Interruptible | $0.3384 | 8.32% | $0.0000 | NA | $0.00 | $21,897.60 | 7.45% |
| Large Interruptible | $0.3384 | 8.32% | $0.0000 | NA | $0.00 | $252,439.40 | 7.52% |

**DERIVATION OF CURRENT PGA COSTS**

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

| | | Annual Cost | Winter Cost | Total |
|---|---|---|---|---|
| **Demand Cost (Res, Sm & Lg Commercial Firm)** | | | | |
| 1. | MN & ND Total Demand | $29,533,804 | $23,428,344 | |
| 2. | x Minnesota Design Day Ratio (2014 Demand Entitlement Filing) | 88.42% | 88.42% | |
| 3. | Annual System Demand Allocation to MN | $26,113,789 | $20,715,342 | |
| 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) | $25,318,536 | $20,084,490 | |
| 8. | Demand Billed Cost Allocation (3 - 7) | $795,253 | $630,852 | |
| 9. | MN Annual / Seasonal Firm Therm Sales (Forecast) | 538,954,024 | 403,492,517 | |
| 10. | Demand Unit Cost $/Therm (7 / 9) | $0.04698 | $0.04978 | $0.09676 |
| 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) | | | $0.09676 |
| 14. | Total Demand Rate -Commercial (10 + 12) | | | $0.09676 |
| **Demand Cost (Demand Billed)** | | | | |
| 15. | Cost Allocated to Demand Billed (8) | $795,253 | $630,852 | $1,426,105 |
| 16. | / Annual Contract Billing Demand (2014 Demand Entitlement Filing) | | | 2,616,352 |
| 17. | Monthly Commercial Demand Billed Demand Rate | | | $0.54507 |

| | | Monthly Cost |
|---|---|---|
| **Commodity Costs** | | |
| 18. | NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv | $37,589,839 |
| 19. | x MN Portion of Monthly Retail Sales | 86.83% |
| 20. | MN Portion of Monthly Commodity Costs | $32,639,258 |
| 21. | MN Budgeted Calendar Month Retail Therm Sales | 74,081,430 |
| 22. | Commodity Unit Cost $/Therm (20 / 21) | $0.44059 |

| | | |
|---|---|---|
| **Total Gas Cost per Therm** | | |
| 23. | Residential (13 + 22) | **$0.53735** |
| 24. | Small & Large Commercial (14 +22) | **$0.53735** |
| 25. | Small & Large Demand Billed - Demand (17) | **$0.54507** |
| 26. | Small & Large Demand Billed - Commodity; All Interruptible (22) | **$0.44059** |

*Commodity costs are projected and for illustrative purposed only.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
**SUMMARY OF COMPANY HEDGE TRANSACTIONS**
2014-2015 Heating Season

Docket No. G002/M-14-654
REVISED Attachment 3
Schedule 1
Page 1 of 1

| | | | | | | | | 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**

**TRADE SECRET ENDS]**

## Certificate of Service

I, SaGonna Thompson, 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/M-14-654**

Dated this 31st day of October 2014

/s/

______________________________

SaGonna Thompson
Regulatory Administrator

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Tamie A. | Aberle | tamie.aberle@mdu.com | Great Plains Natural Gas Co. | 400 North Fourth Street<br><br>Bismarck,<br>ND<br>585014092 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Julia | Anderson | Julia.Anderson@ag.state.mn.us | Office of the Attorney General-DOC | 1800 BRM Tower<br>445 Minnesota St<br>St. Paul,<br>MN<br>551012134 | Electronic Service | Yes | OFF_SL_14-654_M-14-654 |
| Christopher | Anderson | canderson@allete.com | Minnesota Power | 30 W Superior St<br><br>Duluth,<br>MN<br>558022191 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Kristine | Anderson | kanderson@greatermngas.com | Greater Minnesota Gas, Inc. | 202 S. Main Street<br><br>Le Sueur,<br>MN<br>56058 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Alison C | Archer | alison.c.archer@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 5<br><br>Minneapolis,<br>MN<br>55401 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Gail | Baranko | gail.baranko@xcelenergy.com | Xcel Energy | 414 Nicollet Mall7th Floor<br><br>Minneapolis,<br>MN<br>55401 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| William A. | Blazar | bblazar@mnchamber.com | Minnesota Chamber Of Commerce | Suite 1500<br>400 Robert Street North<br>St. Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Michael | Bradley | mike.bradley@lawmoss.com | Moss & Barnett | 150 S. 5th Street, #1200<br><br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Robert S. | Carney, Jr. | | | 4232 Colfax Ave. S.<br><br>Minneapolis,<br>MN<br>55409 | Paper Service | No | OFF_SL_14-654_M-14-654 |
| George | Crocker | gwillc@nawo.org | North American Water Office | PO Box 174<br><br>Lake Elmo,<br>MN<br>55042 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Jeffrey A. | Daugherty | jeffrey.daugherty@centerpointenergy.com | CenterPoint Energy | 800 LaSalle Ave<br><br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_14-654_M-14-654 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| 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_14-654_M-14-654 |
| Rebecca | Eilers | rebecca.d.eilers@xcelenergy.com | Xcel Energy | 414 Nicollet Mall, 7th Floor Minneapolis, MN 55401 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Sharon | Ferguson | sharon.ferguson@state.mn.us | Department of Commerce | 85 7th Place E Ste 500 Saint Paul, MN 551012198 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Edward | Garvey | garveyed@aol.com | Residence | 32 Lawton St Saint Paul, MN 55102 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Benjamin | Gerber | bgerber@mnchamber.com | Minnesota Chamber of Commerce | 400 Robert Street North Suite 1500 St. Paul, Minnesota 55101 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| 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_14-654_M-14-654 |
| Todd J. | Guerrero | todd.guerrero@kutakrock.com | Kutak Rock LLP | Suite 1750 220 South Sixth Street Minneapolis, MN 554021425 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| 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_14-654_M-14-654 |
| Annete | Henkel | mui@mnutilityinvestors.org | Minnesota Utility Investors | 413 Wacouta Street #230 St.Paul, MN 55101 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Sandra | Hofstetter | N/A | MN Chamber of Commerce | 7261 County Road H Fremont, WI 54940-9317 | Paper Service | No | OFF_SL_14-654_M-14-654 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Michael | Hoppe | il23@mtn.org | Local Union 23, I.B.E.W. | 932 Payne Avenue<br><br>St. Paul,<br>MN<br>55130 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Eric | Jensen | ejensen@iwla.org | Izaak Walton League of America | Suite 202<br>1619 Dayton Avenue<br>St. Paul,<br>MN<br>55104 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Paula | Johnson | paulajohnson@alliantenergy.com | Alliant Energy-Interstate Power and Light Company | P.O. Box 351<br>200 First Street, SE<br>Cedar Rapids,<br>IA<br>524060351 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Richard | Johnson | Rick.Johnson@lawmoss.com | Moss & Barnett | 150 S. 5th Street<br>Suite 1200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Michael | Krikava | mkrikava@briggs.com | Briggs And Morgan, P.A. | 2200 IDS Center<br>80 S 8th St<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Nicolle | Kupser | nkupser@greatermngas.com | Greater Minnesota Gas, Inc. | 202 South Main Street<br>P.O. Box 68<br>Le Sueur,<br>MN<br>56058 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| John | Lindell | agorud.ecf@ag.state.mn.us | Office of the Attorney General-RUD | 1400 BRM Tower<br>445 Minnesota St<br>St. Paul,<br>MN<br>551012130 | Electronic Service | Yes | OFF_SL_14-654_M-14-654 |
| Eric | Lipman | eric.lipman@state.mn.us | Office of Administrative Hearings | PO Box 64620<br><br>St. Paul,<br>MN<br>551640620 | Paper Service | Yes | OFF_SL_14-654_M-14-654 |
| Matthew P | Loftus | matthew.p.loftus@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 5<br><br>Minneapolis,<br>MN<br>55401 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Pam | Marshall | pam@energycents.org | Energy CENTS Coalition | 823 7th St E<br><br>St. Paul,<br>MN<br>55106 | Electronic Service | No | OFF_SL_14-654_M-14-654 |

| 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<br>7th Floor<br>Minneapolis,<br>MN<br>55401 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| David | Moeller | dmoeller@allete.com | Minnesota Power | 30 W Superior St<br><br>Duluth,<br>MN<br>558022093 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Andrew | Moratzka | apmoratzka@stoel.com | Stoel Rives LLP | 33 South Sixth Street<br>Suite 4200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| David W. | Niles | david.niles@avantenergy.com | Minnesota Municipal Power Agency | Suite 300<br>200 South Sixth Street<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Greg | Palmer | gpalmer@greatermngas.com | Greater Minnesota Gas, Inc. | PO Box 68<br>202 South Main Street<br>Le Sueur,<br>MN<br>56058 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Richard | Savelkoul | rsavelkoul@martinsquires.com | Martin & Squires, P.A. | 332 Minnesota Street Ste W2750<br><br>St. Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Janet | Shaddix Elling | jshaddix@janetshaddix.com | Shaddix And Associates | Ste 122<br>9100 W Bloomington Frwy<br>Bloomington,<br>MN<br>55431 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| James M. | Strommen | jstrommen@kennedy-graven.com | Kennedy & Graven, Chartered | 470 U.S. Bank Plaza<br>200 South Sixth Street<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| SaGonna | Thompson | Regulatory.Records@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 7<br><br>Minneapolis,<br>MN<br>554011993 | Electronic Service | No | OFF_SL_14-654_M-14-654 |
| Lisa | Veith | lisa.veith@ci.stpaul.mn.us | City of St. Paul | 400 City Hall and Courthouse<br>15 West Kellogg Blvd.<br>St. Paul,<br>MN<br>55102 | Electronic Service | No | OFF_SL_14-654_M-14-654 |