Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401

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

November 1, 2013

**—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-13-663

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits this Supplemental Filing in response to the August 29, 2013 Comments of the Minnesota Department of Commerce, Division of Energy Resources.

The Department recommended we provide a supplemental filing on November 1, 2013 detailing final demand entitlement levels and costs. They also recommend that we provide an update on any hedging transactions that are entered into for the 2013-2014 heating season.

We include the following revised attachments:

- Attachment 1, Schedule 2
- Attachment 2, page 2 of 2
- Attachment 2, Schedule 1, page 1 of 2
- Attachment 2, Schedule 2
- Attachment 3, Schedule 1

Changes to Demand Entitlement Levels

There have been two changes to firm transport entitlement levels that lower the estimated costs provided in the Petition filed August 1, 2013 in Docket No. G002/M-13-663. These changes are summarized below and presented in the revised Attachment 1, Schedule 2, Pages 1 and 2, and Attachment 2, Schedule 1.

1. In the Petition, we planned to purchase 14, 287 Dth/day of firm backhaul capacity on Viking Gas Transmission from Marshfield, WI to the Moorhead/Fargo area and 5,713 Dth/day of firm forward haul capacity from Emerson, Manitoba to the Moorhead/Fargo area for the months of December - February. After further review, we identified a less expensive option that does not require the purchase of the backhaul capacity. Instead, we plan to purchase 10,542 Dth/day of forward haul capacity from Emerson to Moorhead/Fargo and use 9,458 Dth/day of existing Northern Natural Gas upstream capacity at Chisago, MN to meet design day requirements. The upstream capacity is used to feed Northern on an average day; however, on a peak day, the capacity may be used to serve the Moorhead/Fargo area. This change reduces estimated costs $90,328 from those reported in the Petition. We plan to purchase this capacity in November for a December 1 start date.

2. We released upstream capacity on ANR that is not needed for design day requirements for this winter. This change will further reduce costs by $85,500.

Update on Hedging Transactions
Updated hedging transactions are presented on the revised Attachment 3, Schedule 1. To date, we have executed two call options and plan to purchase one more call option for the 2013-2014 heating season.

Miscellaneous
A revised Attachment 2, Page 2 contains a small change to the 2012-2013 peak day sendout to add the throughput delivered on Viking. The previously reported quantity reflected only Northern natural throughput. The prior number reported in the Petition did not contain throughput delivered on Viking. In addition, Supplier Entitlement Changes on Attachment 1, Schedule 2, Page 1 were revised to correct the MIECO contract which was originally reported as having a term of three months. The correct term is five months.

At the Commission's hearing of the 2012 Gas Annual Automatic Adjustment (Docket No. G999/AA-756) on September 12, 2013, all regulated gas utilities were ordered to treat all pipeline balancing charges as commodity costs beginning in the November 2013 PGA. The reduction of $890,604 in demand costs is reflected in Attachment 1, Schedule 2, Page 2. This change is also included in the rate impacts in the revised Attachment 2, Schedule 2. $890,604 of pipeline balancing costs were removed from the 12-month demand costs and will be included with commodity costs monthly as appropriate for the month (not as a twelfth of the $890,000). The column "Estimated Nov. 2013 PGA with some Dmd costs moved to IR" now just contains the storage capacity demand costs. As mentioned in our original filing, when the written order in the 2012 Gas AAA is received, we will file an updated proposal in the 2007 – 2013

Contract Demand Entitlement filings to revise our proposal to move some demand costs to interruptible customers to only include storage capacity demand costs.

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

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

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

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

Please contact 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

**PUBLIC DOCUMENT**
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Northern States Power Company
**DEMAND COST OF GAS IMPACT - NOVEMBER 2013**
**REVISED**

Docket No. G002/M-13-663
November 1, 2013 Supplement
Attachment 1
Schedule 2


**CHANGE IN CONTRACT DEMAND ENTITLEMENTS**

| Contract Demand Entitlement Changes | Volume Dth/Day | Current Monthly Demand Rates | No. of Months | Total Annual Cost |
|---|---|---|---|---|
| NNG TFX (Nov - Mar)[1] | 4,839 | $ 15.1530 | 5 | $ 366,626.84 |
| NNG TFX (Nov - Mar)[1] | (4,603) | $ 15.1530 | 5 | $ (348,746.30) |
| NNG TFX (Apr - Oct)[1] | 4,839 | $ 5.6830 | 7 | $ 192,500.26 |
| NNG TFX (Apr - Oct)[1] | (4,603) | $ 5.6830 | 7 | $ (183,111.94) |
| NNG TFX (Jan - Dec)[1] | 2,078 | $ 3.8000 | 12 | $ 94,756.80 |
| NNG TFX (Nov - Mar)[1] | 1,498 | $ 8.6272 | 5 | $ 64,617.73 |
| NNG TFX (Apr - Oct)[1] | 1,498 | $ 4.0000 | 7 | $ 41,944.00 |
| VGT FT-A (Dec - Feb)[2] | 10,542 | $ 3.7671 | 3 | $ 119,138.30 |
| VGT FT-A (Dec - Feb)[2] | (14,287) | $ 4.8871 | 3 | $ (209,465.99) |
| VGT FT-A (Dec - Feb)[2] | 5,713 | $ 3.7671 | 3 | $ 64,564.33 |
| GLGT FT (Nov - Mar)[3] | 6,706 | $ 9.4560 | 5 | $ 317,059.68 |
| ANR FTS (Jan - Dec)[4] | (4,895) | $ 4.1700 | 7 | $ (142,885.05) |
| ANR FTS (Jan - Dec)[4] | 4,855 | $ 4.1600 | 7 | $ 141,377.60 |
| ANR FSS (Jan - Dec)[5] | 17 | $ 2.0400 | 12 | $ 416.16 |
| ANR FSS (Jan - Dec)[5] | 88 | $ 0.4000 | 12 | $ 421.60 |
| Total | | | | $ 519,214.01 |

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

**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] NNG Sixth Revised Volume No. 1, Fifth Revised Sheet No. 51, Effective April 1, 2013
[2] VGT Volume No. 1, Part 5.0 - Statement of Rates, v. 12.0.0, Effective April 1, 2013, demand rate are reduced 2% beginning January 1, 20
per Docket No. RP13-185.
[3] GLGT Third Revised Volume No. 1, Part 4.1 - Statement of Rates, v. 2.0.0, Effective August 1, 2011
The GLGT contract for 15,266 Dth as reported in Docket. No. 12-0862 was never entered into.
[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] The Tenaska Exchange supply contract was effectuated instead of the GLGT contract for 15,266 Dth as reported in Docket No. 12-0862.

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

Northern States Power Company
**Demand Cost Changes from Prior Year**
**REVISED**

Docket No. G002/M-13-663
November 1, 2013 Supplement
Attachment 1
Schedule 2


| | Volume | Rate | Months | Annual Cost | Winter Cost | Total Cost | Minnesota Deliverable | North Dakota Deliverable | Upstream/System Supply | Footnote |
|---|---|---|---|---|---|---|---|---|---|---|
| **2012 FILED COSTS** | | | | $29,648,751.08 | $27,470,718.55 | $57,119,469.64 | | | | |
| **2012 CHANGES FILED TO ACTUAL COSTS** | | | | | | | | | | |
| Contract Demand Entitlement Changes | | | | | | | | | | |
| GLGT FT (Nov - Mar) | (15,266) | $ 3.6240 | 5 | | $ (276,619.92) | $ (276,619.92) | $ (276,619.92) | | | 1 |
| Supplier Entitlement Changes | | | | | | | | | | |
| **[TRADE SECRET BEGINS** | | | | | | | | | | |
| | | | | | | | | | | 2 |
| | | | | | | | | **TRADE SECRET ENDS]** | | |
| **2012 ACTUAL COSTS** | | | | $29,648,751.08 | $27,253,756.93 | $56,902,508.02 | $ (216,961.62) | | | |
| **CHANGES FOR 2013 SUPPLEMENTAL FILING** | | | | | | | | | | |
| Contract Demand Entitlement Changes | | | | | | | | | | |
| NNG TFX (Nov-Mar) | 4,839 | $ 15.1530 | 5 | | $ 366,626.84 | $ 366,626.84 | $ 366,626.84 | | | 3 |
| NNG TFX (Nov-Mar) | (4,603) | $ 15.1530 | 5 | | $ (348,746.30) | $ (348,746.30) | $ (348,746.30) | | | 3 |
| NNG TFX (Apr-Oct) | 4,839 | $ 5.6830 | 7 | $ 192,500.26 | | $ 192,500.26 | $ 192,500.26 | | | 3 |
| NNG TFX (Apr-Oct) | (4,603) | $ 5.6830 | 7 | $ (183,111.94) | | $ (183,111.94) | $ (183,111.94) | | | 3 |
| NNG TFX (Nov-Mar) | 2,078 | $ 3.8000 | 5 | | $ 39,482.00 | $ 39,482.00 | $ 39,482.00 | | | 4 |
| NNG TFX (Apr-Oct) | 2,078 | $ 3.8000 | 7 | $ 55,274.80 | | $ 55,274.80 | $ 55,274.80 | | | 4 |
| NNG TFX (Nov-Mar) | 1,498 | $ 8.6272 | 5 | | $ 64,617.73 | $ 64,617.73 | $ 64,617.73 | | | 5 |
| NNG TFX (Apr-Oct) | 1,498 | $ 4.0000 | 7 | $ 41,944.00 | | $ 41,944.00 | $ 41,944.00 | | | 5 |
| VGT FT-A (Dec-Feb) | (14,287) | $ 4.8871 | 3 | | $ (209,465.99) | $ (209,465.99) | | $ (37,254.73) | $ (172,211.27) | 6 |
| VGT FT-A (Dec-Feb) | 10,542 | $ 3.7671 | 3 | | $ 119,138.30 | $ 119,138.30 | | $ 119,138.30 | | 7 |
| GLGT FT (Nov - Mar) | 6,706 | $ 9.4560 | 5 | | $ 317,059.68 | $ 317,059.68 | $ 317,059.68 | | | 8 |
| ANR FTS (Apr - Oct) | 4,895 | $ 4.1700 | 7 | | $ (142,885.05) | $ (142,885.05) | | | $ (142,885.05) | 9 |
| ANR FTS (Apr - Oct) | 4,855 | $ 4.1600 | 7 | | $ 141,377.60 | $ 141,377.60 | | | $ 141,377.60 | 9 |
| ANR FSS (Jan - Dec) | 17 | $ 2.0400 | 12 | | $ 416.16 | $ 416.16 | | | $ 416.16 | 9 |
| ANR FSS (Jan - Dec) | 88 | $ 0.4000 | 12 | | $ 421.60 | $ 421.60 | | | $ 421.60 | 9 |
| NNG Rate Changes | | | | $ (28,916.16) | $ (20,654.40) | $ (49,570.56) | $ (49,570.56) | | | 10 |
| ANR Rate Changes | | | | $ (579.48) | $ (758.55) | $ (1,338.03) | | | $ (1,338.03) | 10 |
| ANRS Rate Changes | | | | | $ (374,134.64) | $ (374,134.64) | | | $ (374,134.64) | 10 |
| WBI Rate Changes | | | | $ (34,861.44) | | $ (34,861.44) | | $ (34,861.44) | | 10 |
| ANR Capacity Release | | | | | $ (85,500.00) | $ (85,500.00) | | | $ (85,500.00) | 11 |
| NNG SMS (12-Month) | 30,650 | $ 2.1800 | 12 | $ (801,804.00) | | $ (801,804.00) | | | $ (801,804.00) | 12 |
| VGT OBA (12-Month) | 7,200 | $ 1.0000 | 12 | $ (86,400.00) | | $ (86,400.00) | | | $ (86,400.00) | 12 |
| VGT OBA (12-Month) | 200 | $ 1.0000 | 12 | $ (2,400.00) | | $ (2,400.00) | | | $ (2,400.00) | 12 |
| Total | | | | $ (848,353.96) | $ (133,005.02) | $ (981,358.98) | $ 496,076.50 | $ 47,022.14 | $ (1,524,457.62) | |
| Supplier Entitlement Changes | | | | | | | | | | |
| **[TRADE SECRET BEGINS** | | | | | | | | | | |
| | | | | | | | | | | 13 |
| | | | | | | | | **TRADE SECRET ENDS]** | | |
| Total | | | | $ - | $ 741.70 | $ 741.70 | $ 741.70 | $ - | $ - | |
| **TOTAL OF 2013 CHANGES** | | | | $ (848,353.96) | $ (132,263.32) | $ (980,617.28) | $ 496,818.20 | $ 47,022.14 | $ (1,524,457.62) | |
| **2013 COSTS** | | | | $28,800,397.12 | $27,121,493.61 | $55,921,890.73 | | | | |
| **2013 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES** | | | | | | | 91% | 9% | | 14 |

Footnote
1. Great Lakes backhaul contract reported last year in Docket No. 12-0862. Another contract was used in lieu of this proposed contract.
2. Tenaska exchange contract that was enetred into in place of the Great Lakes backhaul contract in footnote 1.
3. Firm transport capacity serving Brainerd, MN starting November 1, 2013.
4. Firm transport capacity serving Hugo, MN starting November 1, 2013.
5. Firm transport capacity serving St. Cloud, MN starting November 1, 2013.
6. Incremental capacity of 14,287 Dth/day on Viking expired February 28, 2013.
7. Incremental transport capacity on Viking for December 1, 2013 through February 28, 2014.
8. Incremental backhaul transport capacity on Great Lakes for November 1, 2013 through March 28, 2014. Will be used for ANRS storage withdrawals.
9. Volume reductions on ANR transport and storage agreements. Upstream capacity serves demand in either MN or ND.
10. Miscellaneous demand rate changes on NNG, ANR, ANRS and WBI contracts. These rate changes did not impact transport capacity volumes.
11. Capacity release contract effective November 1, 2013 through March 31, 2014.
12. The NNG SMS and VGT OBA agreements are used for system balancing and will be reallocated as commodity costs and no longer reported as demand costs effective November 1, 2013.
13. New peaking supply contract with demand charges. Will be in effect November, 1, 2013 through March 31, 2014, originally reported effective December 1, 2013 through February 28, 2014.
14. 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.

**PROPOSAL FOR ENTITLEMENT CHANGE**
**Department Format dated October 1, 1993**

**REVISED**

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

1 Per Annual Financial Reports.

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

See Attachment 1, Schedule 1.

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

See Attachment 1, Schedule 5.

4 Demand Profile:

See Attachment 2, Schedule 1.

5 Rate Impact:

See Attachment 2, Schedule 2.

Docket No. G002/M-13-663
November 1, 2013 Supplement
Attachment 2
Schedule 1


Northern States Power Company
**COMPANY DEMAND PROFILE**
2013-2014 Heating Season
**REVISED**

| 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 | | 12.36% | |
| 112183 | NNG TF12 VARIABLE (Max) | 0 | 0 | 0 | 10 yrs - 10/31/17 | | 0.00% | |
| 112182 | NNG TF12 BASE (Disc) | 11,937 | 0 | 11,937 | 10 yrs - 10/31/17 | | 1.42% | |
| 112182 | NNG TF12 VARIABLE (Disc.) | 82,590 | 0 | 82,590 | 10 yrs - 10/31/17 | | 9.80% | |
| 112183 | NNG TF5 (Max) | 62,415 | 0 | 62,415 | 10 yrs - 10/31/17 | | 7.41% | |
| 112182 | NNG TF5 (Disc.) | 29,599 | 0 | 29,599 | 10 yrs - 10/31/17 | | 3.51% | |
| 111739 | NNG TFX (Nov-Mar) | 28,500 | 0 | 28,500 | 8 yrs - 10/31/17 | | 3.38% | |
| 112185 | NNG TFX (Disc. Nov-Mar) | 56,106 | 2,078 | 58,184 | 10 yrs - 10/31/17 | Incremental capacity | 6.91% | |
| 112185 | NNG TFX (Disc. 12-month) | 21,680 | 0 | 21,680 | 10 yrs - 10/31/17 | | 2.57% | |
| 112185 | NNG TFX 5 (Disc) | 4,415 | 2,078 | 6,493 | 10 yrs - 10/31/17 | Incremental capacity | Summer Only | |
| 112185 | NNG TFX 2 (Disc) | 90 | 2,078 | 2,168 | 10 yrs - 10/31/17 | Incremental capacity | Summer Only | |
| 112186 | NNG TFX (Max) | 46,855 | 0 | 46,855 | 10 yrs - 10/31/17 | | 5.56% | |
| 112186 | NNG TFX 2 (Max) | 5,800 | 0 | 5,800 | 10 yrs - 10/31/17 | | Summer Only | |
| 112186 | NNG TFX 5 (Max) | 25,103 | 0 | 25,103 | 10 yrs - 10/31/17 | | Summer Only | |
| 112184 | NNG TFX (Disc.) | 25,000 | 0 | 25,000 | 10 yrs - 10/31/17 | | 2.97% | |
| 122067 | NNG TFX (Disc. Nov-Mar) | 4,800 | 1,498 | 6,298 | 10 yrs - 10/31/17 | Growth election | 0.75% | |
| 122067 | NNG TFX 7 (Disc) | 4,800 | 1,498 | 6,298 | 10 yrs - 10/31/17 | Growth election | Summer Only | |
| 122068 | NNG TFX (Nov-Mar) | 4,603 | 236 | 4,839 | 10 yrs - 10/31/24 | Incremental capacity | 0.57% | |
| 122068 | NNG TFX 7 (Max) | 4,603 | 236 | 4,839 | 10 yrs - 10/31/24 | Incremental capacity | Summer Only | |
| | | **[TRADE SECRET BEGINS** | | | | | | |
| | VGT to NNG Chisago (1) | | | | | | | |
| | VGT Pierz to NNG (2) | | | | | | | |
| | Capacity Release | | | | | | | **TRADE SECRET ENDS]** |
| AF0044 | VGT FT-A 12 Mos. | 29,002 | 0 | 29,002 | 5 yrs - 10/31/18 | Contract renewal | 3.44% | |
| AF0044 | VGT FT-A (Nov-Mar ) | 4,239 | 0 | 4,239 | 5 yrs - 10/31/18 | Contract renewal | 0.50% | |
| 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 | | 1.19% | |
| AF0037 | VGT FT-A 12 Mos. | 15,600 | 0 | 15,600 | 8.5 yrs - 10/31/17 | | 1.85% | |
| AF0116 | VGT FT-A 12 Mos. | 1,903 | 0 | 1,903 | 5 yrs - 5/31/16 | | 0.23% | |
| AF0156 | VGT FT-A 12 Mos. | 72,213 | 0 | 72,213 | 8 yrs - 10/31/17 | | 8.57% | |
| AF0195 | VGT FT-A (Dec-Feb) | 14,287 | (14,287) | 0 | 3 mos - 2/28/2013 | Capacity expired | 0.00% | |
| TBD | VGT FT-A (Dec-Feb) | 0 | 10,542 | 10,542 | 3 mos - 2/28/2014 | Capacity acquisition | 1.25% | |
| | WBI FT-1097 | 8,000 | 0 | 8,000 | 26.5 yrs - 10/31/19 | | 0.95% | |
| | 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 | | 2.85% | |
| | LP Peak Shaving | 90,000 | 0 | 90,000 | | | 10.68% | |
| | LNG Peak Shaving | 156,000 | 0 | 156,000 | | | 18.52% | |
| | **Total Design Day Capacity** | **836,698** | | **842,411** | | | **100%** | |
| | Heating Season Total | 836,698 | | 842,411 | | | | |
| | Non-Heating Season Total | 407,314 | | 411,126 | | | | |
| | **Miscellaneous Entitlements with Reservation Fees** | | | | | | | |
| | Additional Pipeline Entitlements | | | | | | | |
| | ANR FTS-106209 12 Mos. (1) | 4,829 | | 4,829 | 7 yrs - 03/31/15 | | | |
| | ANR FTS-106211 (Summer) (1) | 4,895 | (40) | 4,855 | 7 yrs - 03/31/15 | Capacity decrease w/ fuel filing | | |
| | ANR FTS-106211 (Winter) (1) | 15,171 | | 15,171 | 7 yrs - 03/31/15 | | | |
| | ANR FTS-114492 12 Mos. (1) | 66,500 | 0 | 66,500 | 9 yrs - 10/31/2019 | | | |
| | GLT FT14739 (2) | 3,509 | 0 | 3,509 | 4 yrs - 03/31/14 | | | |
| | GLT FT14739 (2) | 4,475 | 0 | 4,475 | 4 yrs - 03/31/14 | | | |
| | GLT Backhaul (2) | 0 | 6,706 | 6,706 | 5 mos. - 03/31/13 | Capacity acquisition | | |
| | 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) | 15,209 | 17 | 15,226 | 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 | 5 yrs - 5/31/17 (1.4 MMcf expires 5/31/13) | | | |
| | 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
**MINNESOTA STATE RATE IMPACT**

Docket No. G002/M-13-663
November 1, 2013 Supplement
Attachment 2
Schedule 2


Date to implement proposed changes: November 1, 2013
**REVISED**

| | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-06-1454) | Last Month PGA: October 2013 | Nov. 2013 PGA with Proposed Demand Entitlement Changes (2) | Estimated Nov. 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395) (3) | 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 | $7.0824 | $3.6381 | $3.8426 | $3.8426 | -30.19% | -45.74% | 5.62% | $0.2045 |
| Demand Cost of Gas (1) | $0.9008 | $1.0716 | $0.9355 | $0.9166 | $0.9036 | 1.75% | -14.46% | -2.02% | ($0.0189) |
| Distribution Margin | $1.8591 | $1.6263 | $1.8591 | $1.8591 | $1.8591 | 0.00% | 14.32% | 0.00% | $0.0000 |
| Total per Dth Cost | $8.2641 | $9.7803 | $6.4327 | $6.6183 | $6.6053 | -19.91% | -32.33% | 2.89% | $0.1856 |
| Average Annual Usage (Dk) | 87 | 87 | 87 | 87 | 87 | | | | |
| Average Annual Total Cost | $718.60 | $850.43 | $559.35 | $575.49 | $574.36 | -19.91% | -32.33% | 2.89% | $16.14 |
| Average Annual Total Demand Cost of Gas | $78.33 | $93.18 | $81.35 | $79.70 | $78.57 | | | **Current Allocation** | **($1.64)** |
| | | | | | | | | **With Demand Costs moved to Interruptible** | **($2.77)** |
| **Small Commercial** | | | | | | | | | |
| Commodity Cost of Gas (WACOG) | $5.4871 | $7.0824 | $3.6381 | $3.8426 | $3.8426 | -29.97% | -45.74% | 5.62% | $0.2045 |
| Demand Cost of Gas (1) | $0.8984 | $1.0873 | $0.9331 | $0.9142 | $0.9012 | 1.76% | -15.92% | -2.03% | ($0.0189) |
| Distribution Margin | $1.2331 | $1.1366 | $1.2331 | $1.2331 | $1.2331 | 0.00% | 8.49% | 0.00% | $0.0000 |
| Total per Dth Cost | $7.6186 | $9.3063 | $5.8043 | $5.9899 | $5.9769 | -21.38% | -35.64% | 3.20% | $0.1856 |
| Average Annual Usage (Dk) | 284 | 284 | 284 | 284 | 284 | | | | |
| Average Annual Total Cost | $2,163.87 | $2,643.22 | $1,648.57 | $1,701.28 | $1,697.59 | -21.38% | -35.64% | 3.20% | $52.72 |
| Average Annual Total Demand Cost of Gas | $255.17 | $308.82 | $265.02 | $259.66 | $255.96 | | | **Current Allocation** | **($5.37)** |
| | | | | | | | | **With Demand Costs moved to Interruptible** | **($9.06)** |
| **Large Commercial** | | | | | | | | | |
| Commodity Cost of Gas (WACOG) | $5.4871 | $7.0824 | $3.6381 | $3.8426 | $3.8426 | -29.97% | -45.74% | 5.62% | $0.2045 |
| Demand Cost of Gas (1) | $0.8917 | $1.0569 | $0.9264 | $0.9075 | $0.8947 | 1.77% | -14.14% | -2.04% | ($0.0189) |
| Distribution Margin | $1.2315 | $1.1324 | $1.2315 | $1.2315 | $1.2315 | 0.00% | 8.75% | 0.00% | $0.0000 |
| Total per Dth Cost | $7.6103 | $9.2717 | $5.7960 | $5.9816 | $5.9688 | -21.40% | -35.49% | 3.20% | $0.1856 |
| Average Annual Usage (Dk) | 1,463 | 1,463 | 1,463 | 1,463 | 1,463 | | | | |
| Average Annual Total Cost | $11,131.14 | $13,561.15 | $8,477.47 | $8,748.94 | $8,730.22 | -21.40% | -35.49% | 3.20% | $271.47 |
| Average Annual Total Demand Cost of Gas | $1,304.24 | $1,545.86 | $1,354.99 | $1,327.35 | $1,308.62 | | | **Current Allocation** | **($27.64)** |
| | | | | | | | | **With Demand Costs moved to Interruptible** | **($46.37)** |

(1) Includes demand smoothing
(2) Effective Nov. 1, 2013 - all pipeline balancing charges are included as commodity costs
(3) Proposal only includes moving some storage capacity demand charges to interruptible classes

| | Last Rate Case (G002/GR-09-1153) | Last Approved Demand Change (G002/M-06-1454) | Last Month PGA: October 2013 | Nov. 2013 PGA with Proposed Demand Entitlement Changes (2) | Estimated Nov. 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395) (3) | 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 | $7.0824 | $3.6381 | $3.8426 | $3.8426 | -30.04% | -45.74% | 5.62% | $0.2045 |
| Demand Cost of Gas (1) | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0725 | #DIV/0! | #DIV/0! | #DIV/0! | $0.0000 |
| Distribution Margin | $0.9635 | $0.8675 | $0.9635 | $0.9635 | $0.9635 | 0.00% | 11.07% | 0.00% | $0.0000 |
| Total per Dth Cost | $6.4561 | $7.9499 | $4.6016 | $4.8061 | $4.8061 | -25.56% | -39.54% | 4.44% | $0.2045 |
| Average Annual Usage (Dk) | 7,936 | 7,936 | 7,936 | 7,936 | 7,936 | | | | |
| Average Annual Total Cost | $51,236.58 | $63,091.22 | $36,519.08 | $38,142.02 | $38,142.02 | -25.56% | -39.54% | 4.44% | $1,622.93 |
| Average Annual Total Demand Cost of Gas | $0.00 | $0.00 | $0.00 | $0.00 | $575.37 | | | **Current Allocation** | **$0.00** |
| | | | | | | | | **With Demand Costs moved to Interruptible** | **$575.37** |
| **Medium Interruptible** | | | | | | | | | |
| Commodity Cost of Gas (WACOG) | $5.4696 | $7.0824 | $3.6381 | $3.8426 | $3.8426 | -29.75% | -45.74% | 5.62% | $0.2045 |
| Demand Cost of Gas (1) | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0592 | #DIV/0! | #DIV/0! | #DIV/0! | $0.0000 |
| Distribution Margin | $0.0475 | $0.3900 | $0.0475 | $0.0475 | $0.0475 | 0.00% | -87.82% | 0.00% | $0.0000 |
| Total per Dth Cost | $5.5171 | $7.4724 | $3.6856 | $3.8901 | $3.9493 | -29.49% | -47.94% | 5.55% | $0.2045 |
| Average Annual Usage (Dk) | 64,709 | 64,709 | 64,709 | 64,709 | 64,709 | | | | |
| Average Annual Total Cost | $357,008.03 | $483,533.20 | $238,493.09 | $251,726.13 | $255,556.91 | -29.49% | -47.94% | 5.55% | $13,233.04 |
| Average Annual Total Demand Cost of Gas | $0.00 | $0.00 | $0.00 | $0.00 | $3,830.79 | | | **Current Allocation** | **$0.00** |
| | | | | | | | | **With Demand Costs moved to Interruptible** | **$3,830.79** |
| **Large Interruptible** | | | | | | | | | |
| Commodity Cost of Gas (WACOG) | $5.5006 | $7.0824 | $3.6381 | $3.8426 | $3.8426 | -30.14% | -45.74% | 5.62% | $0.2045 |
| Demand Cost of Gas (1) | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0548 | #DIV/0! | #DIV/0! | #DIV/0! | $0.0000 |
| Distribution Margin | $0.4346 | $0.3565 | $0.4346 | $0.4346 | $0.4346 | 0.00% | 21.91% | 0.00% | $0.0000 |
| Total per Dth Cost | $5.9352 | $7.4389 | $4.0727 | $4.2772 | $4.3320 | -27.93% | -42.50% | 5.02% | $0.2045 |
| Average Annual Usage (Dk) | 862,845 | 862,845 | 862,845 | 862,845 | 862,845 | | | | |
| Average Annual Total Cost | $5,121,167.08 | $6,418,618.68 | $3,514,118.01 | $3,690,569.84 | $3,737,853.76 | -27.93% | -42.50% | 5.02% | $176,451.83 |
| Average Annual Total Demand Cost of Gas | $0.00 | $0.00 | $0.00 | $0.00 | $47,283.91 | | | **Current Allocation** | **$0.00** |
| | | | | | | | | **With Demand Costs moved to Interruptible** | **$47,283.91** |

(1) Includes demand smoothing
(2) Effective Nov. 1, 2013 - all pipeline balancing charges are included as commodity costs
(3) Proposal only includes moving some storage capacity demand charges to interruptible classes

**REVISED**

**Current Allocation**

Summary

| Change from most recent PGA<br>Customer Class | Commodity Change ($/Dk) | Commodity Change (Percent) | Demand Change ($/Dk) | Demand Change (Percent) | Demand Annual Change ($/Dk) | Total Annual Change ($/Dk) | Total Annual Change (Percent) |
|---|---|---|---|---|---|---|---|
| Residential | $0.2045 | 5.62% | ($0.0189) | -2.02% | ($1.64) | $16.14 | 2.89% |
| Small Commercial | $0.2045 | 5.62% | ($0.0189) | -2.03% | ($5.37) | $52.72 | 3.20% |
| Large Commercial | $0.2045 | 5.62% | ($0.0189) | -2.04% | ($27.64) | $271.47 | 3.20% |
| Small Interruptible | $0.2045 | 5.62% | $0.0000 | NA | $0.00 | $1,622.93 | 4.44% |
| Medium Interruptible | $0.2045 | 5.62% | $0.0000 | NA | $0.00 | $13,233.04 | 5.55% |
| Large Interruptible | $0.2045 | 5.62% | $0.0000 | NA | $0.00 | $176,451.83 | 5.02% |

**Demand Costs to Non-Firm**

Summary

| Change from most recent PGA<br>Customer Class | Commodity Change ($/Dk) | Commodity Change (Percent) | Demand Change ($/Dk) | Demand Change (Percent) | Demand Annual Change ($/Dk) | Total Annual Change ($/Dk) | Total Annual Change (Percent) |
|---|---|---|---|---|---|---|---|
| Residential | $0.2045 | 5.62% | ($0.0319) | -3.41% | ($2.77) | $15.01 | 2.68% |
| Small Commercial | $0.2045 | 5.62% | ($0.0319) | -3.42% | ($9.06) | $49.02 | 2.97% |
| Large Commercial | $0.2045 | 5.62% | ($0.0317) | -3.42% | ($46.37) | $252.74 | 2.98% |
| Small Interruptible | $0.2045 | 5.62% | $0.0725 | NA | $575.37 | $2,198.30 | 4.44% |
| Medium Interruptible | $0.2045 | 5.62% | $0.0592 | NA | $3,830.79 | $17,063.82 | 7.15% |
| Large Interruptible | $0.2045 | 5.62% | $0.0548 | NA | $47,283.91 | $223,735.74 | 6.37% |

**DERIVATION OF CURRENT PGA COSTS**

November 1, 2013 - Filed Costs

**REVISED**

| | | Annual Cost | Winter Cost | Total |
|---|---|---|---|---|
| **Demand Cost (Res, Sm & Lg Commercial Firm)** | | | | |
| 1. | MN & ND Total Demand | $28,800,397 | $27,121,494 | |
| 2. | x Minnesota Design Day Ratio (2013 Demand Entitlement Filing) | 88.95% | 88.95% | |
| 3. | Annual System Demand Allocation to MN | $25,617,953 | $24,124,569 | |
| 4. | MN State Design Day (2013 Demand Entitlement Filing) | 706,935 | 706,935 | |
| 5. | - Small & Large Demand Billed Dth (2013 Demand Entitlement Filing) | 21,262 | 21,262 | |
| 6. | Non-Demand Billed Design Day Dkt (4 - 5) | 685,673 | 685,673 | |
| 7. | Non-Demand Billed Allocation (3 x 6 / 4) | $24,847,442 | $23,398,975 | |
| 8. | Demand Billed Cost Allocation (3 - 7) | $770,511 | $725,594 | |
| 9. | MN Annual / Seasonal Firm Therm Sales (2010 Rate Case) | 527,615,567 | 403,181,815 | |
| 10. | Demand Unit Cost $/Therm (7 / 9) | $0.04709 | $0.05804 | $0.10513 |
| 11. | Demand Cost True-up - Residential, Oct-May | | | $0.00016 |
| 12. | Demand Cost True-up - Commercial, Oct-May | | | ($0.00029) |
| 13. | Total Demand Rate - Residential (10 +11) | | | $0.10529 |
| 14. | Total Demand Rate -Commercial (10 + 12) | | | $0.10484 |
| **Demand Cost (Demand Billed)** | | | | |
| 15. | Cost Allocated to Demand Billed (8) | $770,511 | $725,594 | $1,496,105 |
| 16. | / Annual Contract Billing Demand (2013 Demand Entitlement Filing) | | | 2,551,496 |
| 17. | Monthly Commercial Demand Billed Demand Rate | | | $0.58636 |

| | | Monthly Cost |
|---|---|---|
| **Commodity Costs** | | |
| 18. | NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv | $31,553,148 |
| 19. | x MN Portion of Monthly Retail Sales | 86.93% |
| 20. | MN Portion of Monthly Commodity Costs | $27,429,151 |
| 21. | MN Budgeted Calendar Month Retail Therm Sales | 71,382,515 |
| 22. | Commodity Unit Cost $/Therm (20 / 21) | $0.38426 |
| **Total Gas Cost per Therm** | | |
| 23. | Residential (13 + 22) | **$0.48955** |
| 24. | Small & Large Commercial (14 +22) | **$0.48910** |
| 25. | Small & Large Demand Billed - Demand (17) | **$0.58636** |
| 26. | Small & Large Demand Billed - Commodity; All Interruptible (22) | **$0.38426** |

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

Northern States Power Company
**SUMMARY OF COMPANY HEDGE TRANSACTIONS**
2013-2014 Heating Season
**REVISED**



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

**[TRADE SECRET BEGINS**

**TRADE SECRET ENDS]**

## CERTIFICATE OF SERVICE

I, SaGonna Thompson, 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-13-663**

Dated this 1st day of November 2013

/s/

______________________________

SaGonna Thompson
Records Analyst

| 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>Bismarck,<br>ND<br>585014092 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Kristine | Anderson | kanderson@greatermngas.com | Greater Minnesota Gas, Inc. | 202 S. Main Street<br>Le Sueur,<br>MN<br>56058 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| Christopher | Anderson | canderson@allete.com | Minnesota Power | 30 W Superior St<br>Duluth,<br>MN<br>558022191 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Gail | Baranko | gail.baranko@xcelenergy.com | Xcel Energy | 414 Nicollet Mall7th Floor<br>Minneapolis,<br>MN<br>55401 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| Michael | Bradley | mike.bradley@lawmoss.com | Moss & Barnett | Suite 4800<br>90 S 7th St<br>Minneapolis,<br>MN<br>55402-4129 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Robert S. | Carney, Jr. | | | 4232 Colfax Ave. S.<br>Minneapolis,<br>MN<br>55409 | Paper Service | No | OFF_SL_13-663_13-663 |
| George | Crocker | gwillc@nawo.org | North American Water Office | PO Box 174<br>Lake Elmo,<br>MN<br>55042 | Paper Service | No | OFF_SL_13-663_13-663 |
| Jeffrey A. | Daugherty | jeffrey.daugherty@centerpointenergy.com | CenterPoint Energy | 800 LaSalle Ave<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | OFF_SL_13-663_13-663 |

| 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_13-663_13-663 |
| Rebecca | Eilers | rebecca.d.eilers@xcelenergy.com | Xcel Energy | 414 Nicollet Mall, 7th Floor Minneapolis, MN 55401 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| Edward | Garvey | garveyed@aol.com | Residence | 32 Lawton St Saint Paul, MN 55102 | Paper Service | No | OFF_SL_13-663_13-663 |
| Benjamin | Gerber | bgerber@mnchamber.com | Minnesota Chamber of Commerce | 400 Robert Street North Suite 1500 St. Paul, Minnesota 55101 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| Lloyd | Grooms | lgrooms@winthrop.com | Winthrop and Weinstine | Suite 3500 225 South Sixth Street Minneapolis, MN 554024629 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Todd J. | Guerrero | todd.guerrero@kutakrock.com | Kutak Rock LLP | Suite 1750 220 South Sixth Street Minneapolis, MN 554021425 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Richard | Haubensak | RICHARD.HAUBENSAK@CONSTELLATION.COM | Constellation New Energy Gas | Suite 200<br>12120 Port Grace Boulevard<br>La Vista,<br>NE<br>68128 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Annete | Henkel | mui@mnutilityinvestors.org | Minnesota Utility Investors | 413 Wacouta Street<br>#230<br>St.Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Sandra | Hofstetter | N/A | MN Chamber of Commerce | 7261 County Road H<br>Fremont,<br>WI<br>54940-9317 | Paper Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| Richard | Johnson | Rick.Johnson@lawmoss.com | Moss & Barnett | 90 South 7th Street<br>Suite #4800<br>Minneapolis,<br>MN<br>554024129 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Paula N. | Johnson | PaulaJohnson@alliantenergy.com | Interstate Power and Light Company | 200 First Street SE<br>PO Box 351<br>Cedar Rapids,<br>IA<br>524060351 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Nancy | Kelly | bademailnancyk@eurekarecycling.org | Eureka Recycling | 2828 Kennedy Street NE<br>Minneapolis,<br>MN<br>55413 | Paper Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| 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_13-663_13-663 |
| 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_13-663_13-663 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Eric | Lipman | eric.lipman@state.mn.us | Office of Administrative Hearings | PO Box 64620<br>St. Paul,<br>MN<br>551640620 | Electronic Service | Yes | OFF_SL_13-663_13-663 |
| Matthew P | Loftus | matthew.p.loftus@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 5<br>Minneapolis,<br>MN<br>55401 | Electronic Service | No | OFF_SL_13-663_13-663 |
| Pam | Marshall | pam@energycents.org | Energy CENTS Coalition | 823 7th St E<br>St. Paul,<br>MN<br>55106 | Paper Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| David | Moeller | dmoeller@allete.com | Minnesota Power | 30 W Superior St<br>Duluth,<br>MN<br>558022093 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| 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_13-663_13-663 |
| 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_13-663_13-663 |
| Joseph V. | Plumbo | | Local Union 23, I.B.E.W. | 932 Payne Avenue<br>St. Paul,<br>MN<br>55130 | Paper Service | No | OFF_SL_13-663_13-663 |
| Richard | Savelkoul | rsavelkoul@martinsquires.com | Martin & Squires, P.A. | 332 Minnesota Street Ste W2750<br>St. Paul,<br>MN<br>55101 | Electronic Service | No | OFF_SL_13-663_13-663 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Janet | Shaddix Elling | jshaddix@janetshaddix.com | Shaddix And Associates | Ste 122<br>9100 W Bloomington Frwy<br>Bloomington,<br>MN<br>55431 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |
| SaGonna | Thompson | Regulatory.Records@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 7<br>Minneapolis,<br>MN<br>554011993 | Electronic Service | No | OFF_SL_13-663_13-663 |
| 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_13-663_13-663 |