414 Nicollet Mall
Minneapolis, MN 55401

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August 30, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: NORTHERN STATES POWER COMPANY
NATURAL GAS OPERATION – STATE OF MINNESOTA
2019 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT - GAS
DOCKET NO. G999/AA-19-401

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission its annual report pursuant to Minnesota Rules 7825.2800 to 7825.2840 governing the Automatic Adjustment of Charges. This report covers the Company's natural gas operations.

In working with our auditors to put together this AAA report, we discovered an error in our calculation of the Monthly Demand True-up calculation in the monthly PGA calculations during the course of this year. The impact of this error was that the Company credited back to customers an additional $876,013 in demand cost over-recovery through this mechanism than would have otherwise been. ($3,772,919 of demand over-recovery was credited back to customers through the mechanism instead of $2,896,906.) For purposes of the Monthly Demand True-up mechanism, we inadvertently used Minnesota Company sales (including both MN and ND sales) instead of Minnesota state sales to allocate the PGA year sales to month. In other words, the "calculated sales" were incorrect, with more sales allocated to commercial and less to residential than should have been. This error produced incorrect sales differences and corresponding monthly demand true-up rates for credit or recovery. The Monthly Demand True-up rate caps were not affected by this error. No other monthly PGA calculations were affected by this error. The "as filed" and "corrected" versions of the calculation can be found in Appendix 1 of both this report and the

True-up filing. We apologize for this error and note that we have put measures in place to eliminate this error in future PGA calculations.

The Company does not intend to rebill customers at this time. Essentially the error accelerated a credit of $876,013, which was expected in the 2019-20 PGA true-up, to the 2018-19 year. The alternative-rebilling customers to remove the credit at this time only to provide the credit over the next twelve months could lead to customer confusion and serves no practical purpose. We have disclosed this issue in the September Purchased Gas Adjustment filing (filed August 29, 2019) and the Purchased Gas Adjustment True-up filing (filed concurrently in Docket No. G002/AA-19-__) in addition to this AAA report. The Company is available for questions on this matter.

Various attachments to this filing contain information that Xcel Energy considers trade secret data. We provide justification for the identification of the data designated as Trade Secret in Attachment F of this filing.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies of the summary have been served on the parties on the attached service lists. Please contact me at (612) 330-7681 or lisa.r.peterson@xcelenergy.com, or Hui Chen at (612) 330-6749 or hui.chen@xcelenergy.com, if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS NATURAL GAS OPERATION

DOCKET NO. G999/AA-19-401

ANNUAL REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, hereby submits for filing the attached annual report required in Minnesota Public Utilities Commission Rules Parts 7825.2800 to 7825.2840 governing Annual Automatic Adjustment of Charges (AAA) for natural gas utilities, for the period July 1, 2018 to June 30, 2019.

I. SUMMARY OF FILING

Pursuant to Minn. Rule 7829, subp. 1, a one-paragraph summary of the filing accompanies this Report.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Rule 7829.1300, subp. 2, the Company has served a copy of this Report on the Department of Commerce and the Office of the Attorney General – Antitrust and Utilities Division. A summary of the filing has been served on all parties on Xcel Energy's Annual Automatic Gas Adjustment Report service list pursuant to Rule 7825.2840. (See Attachment E).

III. GENERAL FILING INFORMATION

Pursuant to Minnesota Rules 7829.1300, Subp. 3, Xcel Energy provides the following required information.

A. Name, Address, and Telephone Number of Utility

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

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

Mara K. Ascheman
Senior Attorney
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55401
(612) 215-4605

C. Date of Filing and Date Modified Rates Take Effect

Consistent with the filing requirement in Minn. Rules 7825.2840, the date of this filing is August 30, 2019. The Company will implement the new natural gas purchased gas adjustment (PGA) true-up factors with rates in effect on and after September 1, 2019.

D. Statute Controlling Schedule for Processing the Filing

No statute establishes a schedule for processing this filing. The rules applicable to the report are Minn. Rules 7825.2800 through 7825.2840.

E. Utility Employee Responsible for Filing

Lisa Peterson
Manager, Regulatory Analysis
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
(612) 330-7681

IV. DESCRIPTION OF FILING

This filing contains the annual reporting requirements specified in the following rule sections:

7825.2800	Annual Reports: Policies and Actions	Attachment A
7825.2810	Annual Reports: Automatic Adjustment Charges	Attachment B
7825.2820	Annual Auditor's Report	Attachment C
7825.2830	Annual One-Year Price Projection	Attachment D
7825.2840	Annual Notice of Reports Availability	Attachment E

In addition to the required schedules in Attachments A through E, we provide a brief discussion for each of the rules or their applicable subparts.

We have also included two additional attachments in the filing. Attachment F contains the justification for trade secret treatment of certain information contained in the filing. Attachment G contains information pertaining to various compliance filings required by the Commission in prior orders.

7825.2800 Annual Reports: Policies and Actions
Attachment A includes the following schedules and a brief summary of the topics listed in the rule.

Attachment A, Schedule 1	Procurement Policies
Attachment A, Schedule 2	Dispatching Policies and Procedures
Attachment A, Schedule 3	Actions Taken to Minimize Cost
Attachment A, Schedule 4	Conservation Policies
Attachment A, Schedule 5	Price Volatility Strategy

7825.2810 Annual Report: Automatic Adjustment of Charges
Attachment B contains a summary of the annual reporting (by month) of all natural gas automatic adjustment charges for each customer class for the prior year commencing July 1, 2018 and ending June 30, 2019. It includes the following schedules as set forth in Subpts. 1 and 2:

Subpt. 1
Attachment B, Schedule 1, Base Cost of Gas and Purchased Gas Adjustments …………….….… (A/B)
Attachment B, Schedule 2, Billing Adjustment Amounts by Gas Suppliers Used to Bill Utility…….....(C)
Attachment B, Schedule 3, Total Cost of Fuel or Gas Delivered to Customers …………………... (D)
Attachment B, Schedule 3, Revenues Collected from Customers for Energy Delivered to Customers (E)
Attachment B, Schedule 4, Refunds Received from Gas Suppliers…………………………………... (F)
Attachment B, Schedule 4, Amount of Refunds to be Credited to Customers ……………………… (G)
Subpt. 2
Attachment B, Schedule 5, Additional Information from Gas Utilities ………………………………(G)

The base cost of gas rates in effect during the reporting period became effective through a Commission Order dated December 21, 2009, and were reaffirmed on April 29, 2011, in Docket Nos. G002/GR-09-1153 and G002/MR-09-1324.

7825.2820 Attachment C: Annual Auditor's Report
Attachment C contains the independent auditor's report evaluating the Company's accounting for automatic adjustments for the 12 months ending June 30, 2019. Deloitte and Touche LLP prepared this report. In addition, Attachment C contains the Company's letter of instruction to the independent auditor.

7825.2830 Attachment D: One-Year Projection Price Report
Attachment D contains a report that provides a brief statement of the Company's opinion regarding the impact of market forces on purchased natural gas costs for the coming year.

7825.2840 Attachment E: Annual Notice of Reports Availability
Minn. Rules part 7825.2840 requires utilities to provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all interveners in the utility's two previous general rate cases. In compliance with this rule, the Company is providing notice to all interveners to the Company's 2006[1] and 2009[2] natural gas rate cases who have requested to remain on Company's service list. Xcel Energy's notice is submitted as Attachment E and includes the following schedules:

[1] Docket No. G002/GR-06-1429.
[2] Docket No. G002/GR-09-1153.

Attachment E, Schedule 1	Notice of Reports Availability
Attachment E, Schedule 2	Certificate of Service
Attachment E, Schedule 3	Service List, Including List of Interveners in Company's Previous Two Gas General Rate Cases in Minnesota who Have Requested to Remain on the Service List

V. OTHER SUBMITTALS

As noted earlier, we have included two additional attachments (F and G) that provide information that falls outside the requirements of the Commission's rules concerning the AAA.

Attachment F: Justification of Trade Secret Data Protection

Pursuant to Rule 7829.0500, the Company is requesting that certain parts of this report be considered trade secret information. In lieu of providing this information in the cover letter for the non-public version of the filing, the Company submits Attachment F as justification for this request.

Attachment G: Miscellaneous Compliance Reports

Attachment G contains responses related to various compliance reports required by Commission Orders issued in prior Company miscellaneous rate filings, annual purchased gas adjustment true-up filings (PGA True-up filings), and AAA Reports.

Purchased Gas Adjustment True-Up

The complete Company PGA True-Up required by Minnesota Rule 7825.2910, subp. 4, including supporting calculations and schedules, is being submitted under separate cover as requested by the Department.

VI. MISCELLANEOUS INFORMATION

A. Service List

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

Lisa Peterson
Manager, Regulatory Analysis
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
lisa.r.peterson@xcelenergy.com

Lynnette Sweet
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

CONCLUSION

The Company submits this Annual Report for its natural gas operation relative to the Commission's rules regarding Automatic Adjustment of Charges.

Dated: August 30, 2019

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS NATURAL GAS OPERATION

DOCKET NO. G999/AA-19-401

ANNUAL REPORT

SUMMARY OF FILING

Please take notice that on August 30, 2019, Northern States Power Company, doing business as Xcel Energy, filed with the Minnesota Public Utilities Commission the annual report for its natural gas operation pursuant to the Commission's rules (Minn. R. Parts 7825.2800 to 7825.2840) regarding Automatic Adjustment of Charges. The Company also filed its annual Purchased Gas Adjustment (PGA) true-up. The revised PGA true-up factors will be provisionally reflected in the PGA effective September 1, 2019, subject to later Commission approval.

GAS PROCUREMENT

Our natural gas procurement policy is to secure and dispatch an economic mix of long- and short-term firm natural gas supplies consisting of the following resources:

- Firm baseload supplies;
- Firm swing supplies;
- Contract underground storage;
- Company-owned liquefied natural gas supplies for peak shaving; and
- Company-owned propane-air supplies for peak shaving.

We make decisions concerning sources of supply by carefully considering the cost, reliability, logistics, adequacy, and suitability of each source. As described below, the Company uses financial hedges to limit supply cost volatility. Our policy results in a market-based gas supply at a reasonable cost and a reserve margin consistent with system reliability requirements.

For the 2018-2019 heating season, we slightly increased our natural gas pipeline service portfolio to ensure we had sufficient capacity and reliable gas supplies available to serve our growing peak winter demand. We described changes in demand entitlements in our filings[1] in Docket No. G002/M-18-528.

We have contracts with Northern Natural Gas Company (Northern) under its various firm transportation rate schedules for storage and transportation of natural gas to our communities connected to the Northern system. We also have contracts with Viking Gas Transmission Company (Viking) under its Rate Schedule FT-A for transportation of gas supplies to customers in the Fargo/Moorhead and Grand Forks/East Grand Forks areas as well as Chisago, Isanti and Sherburne Counties in Minnesota for delivery into Northern. We have small contracts with WBI Energy Transmission, Inc. (WBI) under its Rate Schedule FT-1 for transportation of gas supplies to a few small communities west of Fargo. In addition, we contract for upstream storage and transportation capacity on ANR Pipeline Company (ANR) and storage on ANR Storage Company (ANRS) with transportation on Great Lakes Gas Transmission Limited Partnership (Great Lakes) for deliveries into Northern and Viking.

During the reporting period, we contracted with approximately 28 domestic and Canadian producers and marketers to purchase natural gas. We use firm and

[1] Petition submitted August 1, 2018 and Supplement submitted November 1, 2018.

interruptible transportation service on Northern, Viking, WBI, and the upstream pipelines to transport gas supply volumes to Xcel Energy service areas.

CHANGES IN GAS SUPPLY AND TRANSPORTATION AGREEMENTS

As a result of current peak winter demand and our supply and transportation contracts, we made, pursuant to Minnesota Rule 7825.2910, subp. 2, the changes, summarized below, to our 2018-2019 natural gas resource portfolio. These changes were filed with the Commission in Docket No. G002/M-18-528.

- **Changes to Entitlements on Northern, Great Lakes and Viking**
  We renewed two portions of our Northern storage (FDD) capacity for a five and four-year term, now terminating in 2023. Northern's storage service provides reliability through its load-following capabilities as well as the ability to potentially avoid higher priced gas in the intra-day spot market.

  We renewed one contract on Viking for an additional five-year term to continue to meet design day requirements. Additionally, we acquired a new contract on Viking for a five-year term in order to reduce the amount of seasonal capacity needed each year as the system continues to grow. Finally, rather than acquire seasonal Viking capacity, we purchased equivalent delivered supply, providing capacity for our winter peaking needs and providing customer savings.

- **New Firm Supply Contracts**
  We executed new gas supply agreements to replace expiring agreements and to serve the system requirements with reliable firm supplies.

PROPANE PROCUREMENT

We use propane for peak shaving. We procure wholesale supplies of propane from a reliable independent supplier.

GAS HEDGING

In Docket No. G002/M-16-88, the Commission approved our petition to extend the variance to allow recovery of the costs of financial instruments through the PGA clause through June 30, 2020 (*see* Order dated April 22, 2016).

Attachment A, Schedule 5 is the January 2018 hedge plan which was used to set the strategy for 2018-2019 (the reporting period). Attachment A, Schedule 5, page 6 represents the overall volume and monthly volumes we planned to hedge. Attachment G, Schedule 3 shows the transactions we executed.

DISPATCHING POLICY

Xcel Energy's policy is to dispatch natural gas supply in a manner that provides for the best long-term economics and system reliability. We accomplish this goal by using a mix of third-party natural gas supplies, underground natural gas storage, interstate gas pipeline balancing services, and our liquefied natural gas and propane-air peak-shaving facilities. We use Ventyx SENDOUT® model as part of our annual supply planning process. SENDOUT® uses a linear program algorithm along with network optimization to dispatch resources necessary to meet the physical and contractual capabilities of current and potential gas supply resources. In addition, the Gas Supply department evaluates the portfolio dispatch on a monthly and daily basis as monthly and daily prices change to determine the least cost dispatch while maintaining adequate inventories to meet the varied customer demand requirements.

DISPATCHING PROCEDURES

Xcel Energy's gas control dispatchers use an extensive supervisory control and data acquisition (SCADA) system that provides real time information on gas deliveries, gas flow rates, peaking plant output, and system pressures. Alarms notify the dispatcher of monitored variables that exceed or fall below pre-determined limits, indicating a problem or malfunction on the system. The dispatcher then takes corrective action to return the system to normal.

The SCADA system provides real-time send-out trending that allows the dispatcher to use the available daily gas supply to meet customer load requirements. We also use SCADA to assist with dispatching peak shaving operation and curtailment orders.

The dispatch office is located in St. Paul. This office has also performed the load dispatching for Northern States Power Company-Wisconsin (NSPW) for a number of years and the expenses of operating the dispatching office are shared equitably. The Commission order approving the SCADA Agreements between Northern States Power Company-Minnesota and NSPW was issued on December 5, 1995 in Docket No. G002/AI-94-831.

GENERAL BACKGROUND

Approximately 60 percent of the Company's retail natural gas revenues in Minnesota during the reporting period were related to purchased gas, storage and transportation costs paid to wholesale gas producers and marketers, pipelines and storage providers. Xcel Energy continued its efforts to minimize the wholesale gas costs to its retail customers through the following means:

- Xcel Energy's gas procurement policy is to give consideration to cost, reliability, logistics, adequacy, and suitability of each supply source. We also use financial hedges to mitigate wholesale cost volatility pursuant to our Gas Hedging Policy. The effect of this policy is a market-based, best-cost gas supply and a reasonable supply reserve margin consistent with system reliability requirements, while mitigating the effects of wholesale natural gas cost volatility. The Gas Hedging Policy for the 2018-2019 heating season is discussed in Attachment A, Schedule 5.

- Xcel Energy has developed supply and transportation options to increase negotiating leverage, contracted for firm physical deliverability (storage and transportation) to insure supply reliability, and is directly connected to three interstate gas pipelines, resulting in competitive transportation rates and access to multiple supply sources. We use gas optimization and accounting software to assist in planning and least cost dispatch. Specific information about this software is provided in Attachment A, Schedule 2.

- Xcel Energy actively pursued non-traditional gas supply activities (i.e., capacity releases, capacity sharing) to reduce jurisdictional system gas supply costs. Specific information regarding the capacity release activities is provided in Attachment G, Schedule 1.

- Xcel Energy has continued to actively and successfully represent the interests of its Minnesota natural gas customers before national regulatory agencies, both as an individual intervenor and through our membership in the American Gas Association (AGA), which actively represents its local distribution company (LDC) members in major policy proceedings (such as rulemakings).

A discussion of Xcel Energy's activities follows. Please note that in this section, references to the Commission refer to the Federal Energy Regulatory Commission (FERC), not the Minnesota Public Utilities Commission.

ACTIONS AFFECTING COST OR TERMS AND CONDITIONS OF SERVICE TAKEN TO MINIMIZE COST IN PROCEEDINGS OF NATURAL GAS PIPELINES

A number of the FERC dockets covered in this report have been active for quite some time and, consequently, have been discussed extensively in prior Company AAA reports and updates. Therefore, in this report we will primarily summarize the new proceedings we participated in during the July 1, 2018 to June 30, 2019 reporting period. In addition, Xcel Energy hereby incorporates Attachment A, Schedule 3 to its 2011 through 2018 AAA Reports by reference.

I. NORTHERN NATURAL GAS COMPANY (NORTHERN) PROCEEDINGS

The Company has intervened and participated in every Northern general rate case filed since 1970. We have also intervened in the significant Northern certificate and tariff filings since about 1970. In addition, we have filed expert testimony or presented alternatives to Northern's proposals in various dockets.

CP09-465: Certificate Application by Northern to Expand the Buffer Zone Around its Cunningham Storage Field

This Natural Gas Act of 1938 (NGA) section 7 certificate application, filed in September 2009, was discussed in detail in the Company's 2011-2018 AAA reports. The case involves Northern's effort to protect the gas in its Cunningham storage field in Kansas from migration by expanding the certificated protective boundary, or buffer zone, around the field by 14,240 acres (Extension Area).

On September 28, 2017 the Kansas Corporation Commission (KCC), the state regulatory body with jurisdiction over the sale of electricity and natural gas to Kansas consumers, filed a Motion to Show Cause in the above docket. The KCC noted an incident which occurred on April 26, 2017 in which a wellhead within the Extension Area was struck by an operating piece of farm equipment, resulting in a "blow out" and requested the Commission order Northern to acquire and/or plug several remaining privately owned wells within the Extension Area to prevent future incidents. On September 20, 2018 the Commission issued an order requiring Northern to secure the specific wells mentioned in the KCC's motion, identify all remaining third party wells with access to the storage field and gain control of those wells and prevent access to the storage field.

On January 23, 2019, Northern submitted its annual report on all actions it had taken and an assessment of the results of those actions on preventing gas migration. Northern reported that the containment plan appears to continue to reduce the gas migration issue. Northern also reported on its progress in securing third-party wells and isolating them from the storage field. Northern reported that it identified six wells requiring work, and had to date successfully isolated four of them from the storage formation. Northern reported that they continue to negotiate for access or purchase of the two remaining wells.

On February 12, 2019 FERC Staff issued a letter accepting the report.

RP19-59: Form 501-G Filing & Section 5 Rate Complaint &
RP19-1353: General Section 4 Rate Filing

On October 11, 2018 Northern filed its FERC Form 501-G, in accordance with Commission Order 849. The form indicated a reduction of income tax allowance as a result of the income tax cut in from the Tax Cut and Jobs Act of approximately $44 million. With the form, Northern filed an explanatory statement for why it believed no rate change was necessary. Northern pointed to historical spending, modernization costs, and large planned capital expenditures in the near future as a reason rates should remain at their current level.

NSP and twelve other parties each filed comments or protests in the docket, objecting to the idea that Northern did not need to reduce rates as a result of the tax cut, as was indicated by their 501-G form. Many commenters, including NSP argued that the tax savings, along with the Accumulated Deffered Income balances, should be passed on to customers through lower rates.

On January 16, 2019 the Commission issued an Order initiating a Section 5 rate investigation, and requiring Northern to file a Cost and Revenue Study by April 1, 2019. In the Order the Commission stated that Northern may be over-recovering their cost of service. Northern subsequently filed its study on April 1, and all participants in the case participated in a settlement conference on May 16. On June 25, 2019 NSP, among others, filed prepared direct testimony and exhibits. All intervenors in the case's testimony supported a rate reduction from the currently filed tariff rates.

On July 1, 2019 Northern filed a general Section 4 rate case. NSP submitted a protest of Northern's filing and will participate fully in the proceeding. Northern has filed two motions to terminate the Section 5 proceeding, and has stated its belief that the Section 4 moots the open Section 5. Northern's filed cost of service in the Section 4 is more than $1 billion, a 77 percent increase to its 501-G cost of service. As of this filing, both cases remain open.

II. ANR STORAGE COMPANY (ANRS) PROCEEDINGS

RP12-479/Case No. 16-1285: ANRS Petition for Declaratory Order Authorizing Market-Based Rates and Request for Expedited Action

On March 6, 2012, ANRS petitioned the Commission for a declaratory order authorizing ANRS to charge market-based rates. NSP protested the petition and contines to oppose the request throughout the subsequent hearing process. This proceeding was discussed at length in the 2012 through 2018 AAAs.

On September 21, 2018 the United States Court of Appeals for the District of Columbia issued an Order remanding the Commission's order denying ANRS market based rate authority for further consideration. The Court determined that the Commission did not supply adequate reasoning supporting the denial, specifically in regards to a similar competitor in the area already having market based rates, and the appropriate alternatives present in the market. As of the date of this filing, FERC has not issued an order on the remanded case.

III. GREAT LAKES GAS TRANSMISSION LP (Great Lakes) PROCEEDINGS

RP19-399/RP19-409: Form 501-G Filing & Limited Section 4 Rate Filing

On December 6, 2018, in compliance with Commission Order 849, Great Lakes filed its Form 501-G, an abbreviated cost and revenue study to determine the impact of the Tax Cut and Jobs Act. In the form, Great Lakes removed its income tax allowance, citing its corporate structure as a pass-through entity not directly responsible for income taxes. The result of the form was an approximately two percent rate increase, however Great Lakes also filed concurrently a Limited Section 4 Rate Case (see description below) to reduce rates by two percent beginning February 1, 2019.

On January 31, 2019 the Commission issued an order accepting Great Lakes' rate decrease, and closing the Form 501-G docket. NSP considers this matter to be closed.

IV. VIKING GAS TRANSMISSION (VIKING) PROCEEDINGS

RP19-1340: General Section 4 Rate Filing

On June 28, 2019 Viking filed a general Section 4 rate proceeding in compliance with the settlement of the previous rate case. Viking proposed an average rate increase of seven percent to shippers with contract terms greater than five years. On July 10, 2019 NSP filed an intervention and protest of the filing requesting suspension and hearing proceedures to determine if Vikings proposed rates are just and reasonable. As one of the largest shippers on Viking, NSP will be an active participant in the ongoing proceeding to ensure just and reasonable rates for our customers.

V. WBI TRANSMISSION (WBI) PROCEEDINGS

RP19-165: General Section 4 Rate Filing

On October 31, 2018 WBI filed a general Section 4 rate proceeding in compliance with a requirement in the settlement of the pipeline's previous rate proceeding. WBI's filing requested a twenty-seven percent rate increase based on increased depreciation rates, return on equity, and increased costs, among other items.

NSP filed an intervention and protest, requesting suspension and hearing procedures to determine the just and reasonableness of WBI proposed rates. On November 30, 2018 the Commission issued an order accepting the filing, suspending the rates for the maximum five-months, to be effective May 1, 2019 and set all issues raised in the proceeding for hearing.

WBI, NSP and other customers participated in variour settlement discussions, both in Washington DC and by phone. On May 20, 2019 all parties in the case reached a settlement-in-principle, reflecting rates of fifteen percent lower than the filed rates.

WBI moved on May 28, 2019 to make the proposed settlement rates effective May 1, 2019 subject to refund, and the Chief Administrative Law Judge accepted those rates on May 30, 2019.

All parties participated in the drafting of the stipulation and agreement memorializing the settlement terms, which was filed with the Commission on June 28, 2019. The settlement is currently awaiting Commission approval as of the date of this filing.

VI. GENERAL RULEMAKINGS

RM18-11: Rate Changes Related to Federal Income Tax Rate

On July 18, 2018, the Commission issued its final rule in Order No. 849. The final rule required pipelines to file a new Form 501-G, which is an abbreviated cost and revenue study. In addition, the Commission laid out 4 options pipelines had with their filing; (1) file a limited Section 4 rate reduction, (2) commit to file a general Section 4 rate proceeding or pre-packaged settlement in the "near future," (3) explain why no rate change is necessary, or (4) take no action. NSP filed protests or comments in each case, arguing that the benefits of reduced income case expenses should be returned to customers.

Of the eight interstate pipelines from which NSP takes firm service, Great Lakes (RP19-399) and Northern Border Pipeline (RP19-414) filed limited Section 4 cases to reduce rates. (Due to our contract portfolio, our rate on Northern Border was not affected and our rate remains well below the maximum tariff rate.) WBI was not required to file the Form, as it filed a general Section 4 rate case prior to the 501-G deadline. Viking (RP19-386) took no action other than to note its requirement under a previous settlement to file a general Section 4 rate case by July 1, 2019 (see above).

Northern (RP19-59), ANR (RP19-403), and ANRS (RP19-405) each filed the Form 501-G with an explanatory statement arguing that no rate change is necessary or appropriate. As discussed above, Northern argued that its ongoing modernization spending actually necessitated a rate increase rather than decrease, and the Commission initiated a Section 5 rate complaint in the docket.

ANR and ANRS each referenced existing settlments which prohibited rate changes prior to August 1, 2019 and January 1, 2019 respectively. NSP filed protests in both dockets stating that the savings from reduced income tax expense should be returned to customers. As of the date of this filing, the Commission has taken no action in the ANR or ANRS proceedings.

Conservation Program

Our conservation program is designed to help customers manage their energy use and preserve resources. In response to market needs and legal requirements, we have developed conservation and load management programs subject to regulation by the Department and the Commission. These programs provide opportunities for customers to save energy and money on their monthly utility bills.

We offer a comprehensive portfolio of programs that educates and assists customers in implementing conservation measures. The programs range from prescriptive and custom rebates for high efficiency equipment to energy audits for buildings and homes. By helping our customers conserve energy, we also reduce the annual gas supply purchasing needs and, as a result, decrease the pass-through cost to our customers. In some cases, our Conservation Improvement Program (CIP) portfolio may supplement or leverage other public or private programs and funds, such as Low Income Home Energy Assistance Program (LIHEAP) or tax credits.

Minnesota Statute § 216B.241 requires certain Minnesota utilities, including our gas operation, to invest in cost-effective conservation improvements through CIP. To achieve CIP goals, we adhere to the following principles:

- Comply with the gas energy savings goal requirements set forth in statute;
- Comply with the minimum gas CIP spending requirements set forth in statute;
- Work with the Department and the Commission to maximize energy savings (and thus customer bill savings) per CIP dollar the Company spends;
- Evaluate programs on the basis of cost-effectiveness of the total investment; and
- Balance the needs of all customers in the allocation of CIP resources.

We are also required to file with the Department, no more than every three years, a CIP Plan detailing our goals, budgets and cost-effectiveness analyses for the next planning cycle. A detailed description and analysis of our gas conservation policy and programs may be found in our current 2017-2019 CIP Triennial Plan.[1] Per a recent Department order, we also filed a 2020 Extension to our 2017-2019 CIP Triennial Plan on July 1, 2019.[2]

[1] Docket No. E,G002/CIP-16-115, filed with the Department on June 1, 2016 and approved on November 3, 2016.
[2] Docket No. E,G002/CIP-16-115, filed with the Department on July 1, 2019.

By April 1 of each year, the Company is required to file with the Department an Annual Status Report, which details the cost-effectiveness and spending for the prior year's CIP program. The Department Staff recommended approval of the Company's 2018 Electric and Gas CIP Status Report on June 24, 2019 and the Decision was issued on August 29, 2019.[3]

Also by April 1 of each year, the Company files for Commission authorization to adjust the CIP cost recovery factor included in the Resource Adjustment on customer bills to true-up prior calendar year recoveries with costs incurred. Our 2017 CIP gas cost recovery request (2018-2019 CIP adjustment factor) was approved on September 4, 2018.[4] The gas cost recovery request for 2018 was approved on July 19, 2019.[5]

[3] Docket No. E,G002/CIP-16-115.07.
[4] Docket No. G002/M-18-246.
[5] Docket No. G002/M-19-259.

Gas Price Volatility Mitigation Plan
Northern States Power Company-Minnesota (LDC)
January 2018
Current and Forward Market Outlook

According to the latest Energy Information Administration's (EIA) Short-term Energy Outlook, U.S. dry natural gas production is forecast to increase by 6.1 Bcf from an average of 73.5 billion cubic feet per day (Bcf/d) in 2017 to 79.6 Bcf in 2018 as the result of increased drilling activity and infrastructure build out connecting natural gas production to pipeline transportation facilities. In addition, domestic gas supply could actually surpass current forecasts as a result of infrastructure development out of the Marcellus shale play.

The major drivers for U.S. demand continue to be increased domestic consumption for gas fired power generation, exports into Mexico and LNG exports. The increasing use of renewable energy will continue to put pressure on gas fired generation demand levels in 2018. And while the EIA expects increases in both Mexican and LNG exports, recent delays in construction projects mostly in Mexico and delays in LNG terminal projects, have prompted analysts to push the bulk of demand growth back into 2019. As a result, we are expecting flat to slightly weaker natural gas prices in 2018 as gas supply growth outweighs demand. Reflecting the increased supply and the potential for a moderation in demand growth, the EIA is predicting natural gas storage inventories of 3.86 Tcf at the end of October 2018, which is higher than the five-year average for October.

Despite the fundamental price drivers noted above, gas prices are still heavily tied to weather and subject to potentially significant upward volatility in the short term during the winter heating seasons. Spot Prices at the Northern Natural Gas Pipeline (NNG) Ventura location have traded between $2.50 and $100 per Dth this winter since November, 2017, underscoring the continued need for a seasonal gas price volatility mitigation effort by the Company as set forth in the Gas Price Volatility Mitigation Plan (GPVM) for the Gas Department.

Definition of Volatility

This plan is titled "Gas Price Volatility Mitigation Plan", however it should be noted that the academic definition of the word volatility is not being used in the title or throughout this document. For purposes of this document, the "volatility" that the plan is mitigating against is sharp upward price movement only. It is assumed in this document that downward price "volatility" is considered beneficial to the ratepayers and therefore the plan does not specifically attempt to mitigate downward price volatility.

Price Volatility Mitigation Goals

The overall goal of the Company's Price Volatility Mitigation Plan is to reduce the exposure to and the magnitude of gas price spikes at a reasonable cost to Northern States Power Company – Minnesota's (NSPM) customers. The goal of the plan is not to attempt to outguess the market or to speculate on the future direction of energy prices. In the development and implementation of the plan, the Company realizes that the final result of the Company's efforts may be higher prices than purchasing all gas supply on the monthly spot market. However, the Company maintains that price volatility mitigation is important to protect the Company and its customers from the risk of paying very high gas prices due to unforeseeable market conditions or events.

The targeted hedge volume for NSPM's gas portfolio is approximately 50% normal requirements for the months of November 2018 through March 2019. The Company will use storage to hedge approximately 25% of the normal winter requirements and financial instruments to hedge the remaining 24%. Due to the limited amount of gas used in the summertime by the LDC customers, no summer volumes have been included in the seasonal hedging plan.

Budget

The proposed Annual Gas Hedging Budget for NSP gas sales customers shall be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** as approved in Docket NO. G002/M-16-88. Docket No. G002/M-16-88 extends the hedge variance through June 30, 2020. The Annual Gas Hedging Budget is based on the Northern Natural Gas Ventura (NNG) At-the-Money call option premium for November through March of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** per MMBtu times the proposed financial hedge quantity of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** Bcf (discussed below). The Ventura November through March At-the-Money call option premium was determined by the lowest of three third-party quotes received by NSP on January 19, 2016.

Price Volatility Mitigation Long-Term Strategy

The ability to export natural gas, the potential increase in gas fired generation and future economic conditions create uncertainty and the potential for fundamental market changes leading to long term price increases. Therefore the Company proposes to make a separate filing requesting approval of hedges beyond the upcoming winter season in a separate docket when it identifies such long-term (two to five years) hedging opportunities

The long-term price volatility mitigation strategy will focus on a time horizon of two to five years. This time horizon and corresponding strategy will allow customers to avoid a portion of the price risk related to significant increases in gas prices that may last for longer periods of time.

The utilization of a long-term strategy will allow the Company to mitigate the effects of this type of price risk while allowing the seasonal strategy to mitigate the effects of the shorter-term, peak demand month price spikes.

Note: The settlement costs of any hedges entered into as part of the long-term plan will be counted against the annual budget for the heating season in which the hedges are settled.

Price Volatility Mitigation Seasonal Strategy

The purpose of the seasonal component of the strategy is to reduce the potential risk of short-term upsets in the wholesale gas markets and the resulting gas price spikes. The seasonal strategy will allow for gas prices to be hedged between the months of April 2018 through October 2018. This timeframe allows the Company to analyze market data regarding production trends, demand trends and storage inventory levels in making its hedging decisions. The seasonal nature of the strategy is intended to provide a desired level of price risk protection while maintaining a balance between market premiums and overall plan costs.

The overall hedge volumes and monthly volumes to be hedged are identified on the monthly volume schedule (Schedule PVM-1) of this document. To allow for a more cost-effective approach to the hedging activity, the targeted volume may be modified for any month to allow a more even volume to be hedged. A minimum monthly hedge volume of three contracts with a volume of no less than 5,000 MMBtu per day will be executed per month. Schedule PVM-1 incorporates a dollar cost averaging approach where the Company will layer in the volume over the planned implementation period. The layering approach spreads the timing risks of the hedging decision over the full plan horizon and ensures that the Company will not enter into all or a very large percentage of the hedged volume at the peak of the market.

The Company will use a mix of call options, costless collars, and put options to implement the financial component of the hedge plan. The **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** budget for financial instruments will be managed by adjusting the strike prices of both the call and put options to ensure that settlement costs do not exceed the budgeted amount.

Implementation Strategy

In implementing the Company's Price Volatility Mitigation Plan, the Company will use its best judgment to select the days to complete the hedging activity. On the selected day(s) the Company will complete the hedging transaction as identified in the Volume Schedule. In order to provide flexibility to deal with the timing of weather events at the beginning or end of a month, the Company may hedge the monthly volumes ten days before and ten days after the original targeted month.

Adjustment as a result of Counterparty Default

In the event that counterparty defaults on a hedged transaction, NSPM will apply the following guidelines in determining whether to leave the position open or to replace the position:

a) If the Company, as the result of a default by the counterparty, is required to pay the counterparty to settle a fixed-for-float swap or costless collar, the Company will replace the defaulted position with a new fixed-for-float swap for the same period and in the same quantity of the defaulted position.

b) If the Company, as the result of a default by the counterparty, receives none or only a portion of the positive benefit that would be due as a result of a positive mark on the defaulted hedged position, the Company will replace the hedge with the appropriate instrument for the current price level, provided that it has budget dollars available under the hedge plan. If no hedging dollars are available, the position will be left un-hedged. The available hedging dollars will be the difference between the approved budget for that particular Gas Purchase Year, less any option premiums paid in implementing that year's seasonal hedging strategy.

Conclusion

In conclusion, the overall goal of the program is to reduce the exposure to and magnitude of upward gas prices fluctuations for the 2018-19 heating season at a reasonable cost to NSPM's customers. To accomplish this, the Company is implementing a strategy that will protect approximately 50% of the winter requirements from significant exposure to gas price fluctuations. Also, in order to keep hedging costs within the maximum hedging budget for Northern States Power of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, a mix of hedging instrument including costless collars, put options and call options will be utilized.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

PRICE VOLATILITY MITIGATION (PVM - 1)
Volume Schedule
2018-2019

	Volume Requirements	Storage	Hedge Plan	Total Vol Hedged	% Hedged
	[PROTECTED DATA BEGINS				
June					
July					
August					
September					
October					
November					
December					
January					
February					
March					
April					
May					
Winter Totals					

PROTECTED DATA ENDS]

Monthly Volumes (Seasonal Hedges)

	November	December	January	February	March	Total
	[PROTECTED DATA BEGINS					
April						
May						
June						
July						
August						
September						
October						
Total						

PROTECTED DATA ENDS]

Dth/Day (Seasonal Hedges)

	November	December	January	February	March	Total
	[PROTECTED DATA BEGINS					
April						
May						
June						
July						
August						
September						
October						

PROTECTED DATA ENDS]

Minnesota Rule 7825.2810
July 2018 - June 2019

		Residential			Commercial Firm			Demand Billed			
		Demand	Commodity	True-up	Demand	Commodity	True-up	Demand	Demand True-up	Commodity	Commodity True-up
Subp. 1.A.											
Commission Approved Base											
Cost of Gas per Therm	Summer	$0.04569	$0.55042		$0.04569	$0.54871		$0.59664		$0.53874	
effective 1/11/10 (1)	Winter	$0.10350	$0.55042		$0.10350	$0.54871		$0.59664		$0.53874	
Subp. 1.B.											
Billing Adjustments per Therm											
Begin Date											
7/1/2018		$0.00471	($0.27483)	$0.00286	$0.00471	($0.27312)	$0.00583	($0.02429)	($0.01125)	($0.26315)	$0.01715
8/1/2018		$0.00471	($0.27992)	$0.00286	$0.00471	($0.27821)	$0.00583	($0.02409)	($0.01125)	($0.26824)	$0.01715
9/1/2018		$0.00202	($0.27329)	($0.00533)	$0.00202	($0.27158)	($0.00097)	($0.02409)	($0.02296)	($0.26161)	$0.01195
10/1/2018		($0.00091)	($0.26349)	($0.00533)	$0.00770	($0.26178)	($0.00097)	($0.02409)	($0.02296)	($0.25181)	$0.01195
11/1/2018		($0.00999)	($0.19268)	($0.00533)	($0.01198)	($0.19097)	($0.00097)	($0.03067)	($0.02296)	($0.18100)	$0.01195
12/1/2018		($0.01387)	($0.11281)	($0.00533)	($0.01855)	($0.11110)	($0.00097)	($0.02277)	($0.02296)	($0.10113)	$0.01195
1/1/2019		($0.01855)	($0.18156)	($0.00533)	($0.01855)	($0.17985)	($0.00097)	($0.02277)	($0.02296)	($0.16988)	$0.01195
2/1/2019		($0.00681)	($0.23121)	($0.00533)	($0.01855)	($0.22950)	($0.00097)	($0.02277)	($0.02296)	($0.21953)	$0.01195
3/1/2019		($0.01858)	($0.24232)	($0.00533)	($0.01858)	($0.24061)	($0.00097)	($0.02294)	($0.02296)	($0.23064)	$0.01195
4/1/2019		($0.00923)	($0.30456)	($0.00533)	$0.00110	($0.30285)	($0.00097)	($0.02473)	($0.02296)	($0.29288)	$0.01195
5/1/2019		($0.00897)	($0.32823)	($0.00533)	($0.00897)	($0.32652)	($0.00097)	($0.02234)	($0.02296)	($0.31655)	$0.01195
6/1/2019		$0.00327	($0.33223)	($0.00533)	$0.00327	($0.33052)	($0.00097)	($0.02234)	($0.02296)	($0.32055)	$0.01195

(1) Approved in Docket Nos. G002/GR-09-1153 and G002/MR-09-1324

Minnesota Rule 7825.2810
July 2018 - June 2019

		Small Interruptible		Medium Interruptible		Large Interruptible	
		Commodity	True-up	Commodity	True-up	Commodity	True-up
Subp. 1.A.							
Commission Approved Base							
Cost of Gas per Therm	Summer	$0.54926		$0.54696		$0.55006	
effective 1/11/10 (1)	Winter	$0.54926		$0.54696		$0.55006	
Subp. 1.B.							
Billing Adjustments per Therm							
Begin Date							
7/1/2018		($0.27367)	$0.00751	($0.27137)	$0.01606	($0.27447)	$0.01606
8/1/2018		($0.27876)	$0.00751	($0.27646)	$0.01606	($0.27956)	$0.01606
9/1/2018		($0.27213)	$0.01583	($0.26983)	$0.02126	($0.27293)	$0.02126
10/1/2018		($0.26233)	$0.01583	($0.26003)	$0.02126	($0.26313)	$0.02126
11/1/2018		($0.19152)	$0.01583	($0.18922)	$0.02126	($0.19232)	$0.02126
12/1/2018		($0.11165)	$0.01583	($0.10935)	$0.02126	($0.11245)	$0.02126
1/1/2019		($0.18040)	$0.01583	($0.17810)	$0.02126	($0.18120)	$0.02126
2/1/2019		($0.23005)	$0.01583	($0.22775)	$0.02126	($0.23085)	$0.02126
3/1/2019		($0.24116)	$0.01583	($0.23886)	$0.02126	($0.24196)	$0.02126
4/1/2019		($0.30340)	$0.01583	($0.30110)	$0.02126	($0.30420)	$0.02126
5/1/2019		($0.32707)	$0.01583	($0.32477)	$0.02126	($0.32787)	$0.02126
6/1/2019		($0.33107)	$0.01583	($0.32877)	$0.02126	($0.33187)	$0.02126

(1) Approved in Docket Nos. G002/GR-09-1153 and G002/MR-09-1324

Northern States Power Company
Gas Operations - State of Minnesota

Summary of Pipeline Adjustments
Bills Paid July 2018 to June 2019
(for production months June '18-May '19)

Item	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
ANR Pipeline													
Demand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Commodity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
GLT Pipeline													
Demand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Commodity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Northern Natural Gas													
Demand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Commodity	$8,193.78	-$2,128.59	$4,356.07	-$3,691.16	-$894,370.39	$891,376.54	-$163.99	$2,275.75	-$2,219.94	-$188.63	$15,255.10	-$15,396.02	$3,298.52
Viking Gas Trans													
Demand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Commodity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Williston Basin Inter													
Demand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Commodity	-$12.80	-$44.11	-$8.83	$8.83	-$0.35	$0.35	$0.00	-$736.80	$736.80	-$716.47	-$1,294.93	$2,011.40	-$56.91

Northern States Power Company
Gas Operations - State of Minnesota

Summary of 3rd Party Adjustments
Bills Paid July 2018 to June 2019
(for production months June '18-May '19)

Item	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
3rd Party Demand:													
Supplier A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
													$0.00
3rd Party Commodity:													
Supplier	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
													$0.00

3rd Party Demand:
NOT APPLICABLE

3rd Party Commodity:
NOT APPLICABLE

Minnesota Rule 7825.2810
July 2018 - June 2019

	Total Gas Cost Incurred	Total Gas Cost Recovered	Recovery Balance Over (Under)	% Deviation
Commodity and Peak Shaving				
Residential	$140,754,361	$138,133,713	($2,620,648)	-1.86%
Small & Large Commercial Firm	$81,696,174	$79,776,511	($1,919,663)	-2.35%
Demand Billed	$10,488,704	$9,941,192	($547,512)	-5.22%
Small Interruptible	$8,101,909	$7,817,889	($284,020)	-3.51%
Medium & Large Interruptible	$30,110,245	$28,094,280	($2,015,965)	-6.70%
Total	$271,151,393	$263,763,585	($7,387,808)	-2.72%
Demand				
Residential	$29,615,777	$31,861,377	$2,245,600	7.58%
Small & Large Commercial Firm	$17,167,217	$17,976,329	$809,112	4.71%
Demand Billed	$1,815,300	$1,859,049	$43,749	2.41%
Small Interruptible	n/a	n/a	n/a	n/a
Large Interruptible	n/a	n/a	n/a	n/a
Total	$48,598,294	$51,696,755	$3,098,460	6.38%
Total	$319,749,687	$315,460,340	($4,289,348)	-1.34%

Northern States Power Company
Gas Operations - State of Minnesota
TOTAL COST OF GAS AND REVENUES RECOVERED
SUMMARY BY COST COMPONENT, BY MONTH

Minnesota Rule 7825.2810
July 2018 - June 2019

	2018						2019						
Expense	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Commodity & Peaking	$6,008,776	$6,366,388	$6,660,244	$7,151,302	$18,054,580	$34,361,071	$46,496,037	$49,268,526	$38,878,111	$34,894,729	$15,453,029	$7,558,598	$271,151,393
Demand	$2,599,614	$2,660,835	$2,658,036	$2,774,393	$2,742,026	$6,096,032	$6,109,262	$4,631,012	$6,680,358	$6,018,573	$2,799,750	$2,828,403	$48,598,294
Total	$8,608,390	$9,027,223	$9,318,280	$9,925,695	$20,796,606	$40,457,104	$52,605,299	$53,899,538	$45,558,470	$40,913,303	$18,252,779	$10,387,000	$319,749,687

	2018						2019						
Revenue	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Commodity & Peaking	$4,767,588	$4,913,915	$5,003,972	$10,192,400	$21,446,077	$38,943,049	$50,714,758	$45,366,146	$41,569,533	$23,311,161	$11,759,355	$5,775,631	$263,763,585
Demand	$712,892	$726,371	$658,735	$1,498,694	$3,865,757	$7,797,082	$9,520,486	$9,938,769	$10,090,621	$4,303,151	$1,626,859	$957,339	$51,696,755
Total	$5,480,480	$5,640,286	$5,662,707	$11,691,093	$25,311,834	$46,740,130	$60,235,244	$55,304,915	$51,660,154	$27,614,312	$13,386,214	$6,732,971	$315,460,340

	2018						2019						
(Over) Under	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Commodity & Peaking	$1,241,189	$1,452,473	$1,656,272	($3,041,098)	($3,391,497)	($4,581,977)	($4,218,721)	$3,902,380	($2,691,422)	$11,583,568	$3,693,674	$1,782,966	$7,387,808
Demand	$1,886,721	$1,934,464	$1,999,301	$1,275,699	($1,123,731)	($1,701,050)	($3,411,223)	($5,307,757)	($3,410,262)	$1,715,422	$1,172,890	$1,871,064	($3,098,460)
Total	$3,127,910	$3,386,937	$3,655,573	($1,765,399)	($4,515,227)	($6,283,027)	($7,629,945)	($1,405,376)	($6,101,684)	$13,298,990	$4,866,565	$3,654,030	$4,289,348

Demand Costs

Xcel Energy over-recovered demand costs by 6.38 percent, or $3,098,460, from July 2018 through June 2019. During this period, actual sales were approximately 9.56 percent higher than forecasted sales in the monthly PGA (forecasted sales defined by Minn. Rule 7825.2700, Subp. 5). The Company recovers transportation, storage, and supplier demand costs in retail commodity rates (e.g., all demand costs except those collected from demand-billed customers). Because PGA factors are calculated on a forecasted weather normalized basis each month, but collected on actual usage, Xcel Energy will typically under-recover demand costs during periods when actual customer usage is less than forecasted and over-recover when usage is greater.

The over-recovery was minimized by the Monthly Demand Cost True-up. The calculations for this mechanism are based on the difference between actual and forecasted sales data with a cap on the amount of the adjustment per month. As such, the mechanism calculation spreadsheet[1] shows that demand was over-recovered for the period due to cooler than normal weather during the period, causing actual sales to be more than forecasted sales. The Monthly Demand Cost True-up factor calculation has a cap on it that limits the amount that can be charged or credited. The Monthly Demand Cost True-up Mechanism credited an additional $3,772,919[2] of demand costs to customers during the 2018-2019 heating season. Without this mechanism the demand cost over-recovery would have been approximately 14.14 percent.

Demand Billed Demand Costs

Xcel Energy over-recovered demand costs from the demand billed customers by 2.41 percent, or about $43,749, from July 2018 through June 2019. The recovery was also affected by the difference between customer forecasted demand levels used in calculating the monthly PGA and actual demand billed demand levels that change as customers join and exit the demand billed customer class and as demand levels rise for some customers during the period.

[1] Based on Calendar Month information provided in the 2018 True-up Filing, Schedule I, being filed concurrently with the Company's natural gas AAA report.

[2] As noted in the cover letter of this report and shown in Appendix 1 of this report, due to a calculation error, this credit was $876,013 higher than the $2,896,906 that would have otherwise been credited. MN Company forecast sales were inadvertently used instead of MN state sales to allocate the PGA annual sales to month.

Commodity Costs

Xcel Energy under-recovered commodity and peakshaving costs by 2.84 percent, or $7,664,535 million, during the July 2018 through June 2019 period. The under-recovery is due to deviations between monthly forecasted price and actual wholesale commodity gas prices. The price deviations between monthly price estimates and actual unit cost were the result of price volatility in the wholesale natural gas commodity market. On an average unit basis, the under-recovery is approximately 1.0 cents per therm. Because customer consumption varies by class from month to month and price deviation varies from month to month, individual classes had varying results.

Northern States Power Company, a Minnesota corporation	Docket No. G999/AA-19-401
Gas Operations - State of Minnesota	Attachment B
PURCHASED GAS COST REFUND REPORT	Schedule 4
Month Ending June 2019	Page 1 of 1

Account #10.2349999	Year-To-Date
Balance From 2018 AAA Filing	$0
<u>**Plus:**</u>	
Total Pipeline Refunds	$0
Miscellanous Customer Cancel/Rebill	$0
Total Inflow	$0
<u>**Less**</u>	
Refunded via Bill Credit	$0
Write off balance	$0
Total Outflow	$0
ENDING REFUND ACCOUNT BALANCE	$0

ADDITIONAL REQUIRED INFORMATION

In accordance with Minn. Rule 7825.2810, subp. 2, Xcel Energy provides the following information.

I. PGA RULE VARIANCES

- **Financial Instrument Cost Recovery**

In an Order dated January 23, 2002, in Docket No. G002/M-01-1336, the Commission granted variances to Minn. Rules 7825.2400, 7825.2500 and 7825.2700 that allowed the Company to recover the costs of financial instruments through the Purchased Gas Adjustment for a period of two years. Subsequent extensions were granted as follows:

Docket No.	Order Date	Extended through
G002/M-03-1627	January 23, 2004	June 30, 2008
G002/M-08-46	May 27, 2008	June 30, 2012
G002/M-12-519	September 23, 2013	June 30, 2016
G002/M-16-88	April 22, 2016	June 30, 2020

Additional compliance information regarding the Company's costs of financial instruments is included in Attachment G of this AAA report. Reasons supporting the granting of the variances are described in the above-listed filings.

- **Monthly Demand True-up Mechanism**

In Docket No. G002/M-03-843, in an Order dated June 11, 2004, the Commission granted a two-year variance to Minn. Rule 7825.2700, subp. 5 allowing the Company to true-up PGA demand costs monthly. Subsequent extensions were granted as follows:

Docket No.	Order Date	Extended through
G002/M-06-681	September 11, 2007	September 30, 2008
G002/M-08-456	September 2, 2008	September 30, 2011
G002/M-11-203	June 24, 2011	September 30, 2014
G002/M-14-171	July 28, 2014	September 30, 2017
G002/M-17-101	April 21, 2017	September 30, 2020

Additional compliance information regarding the Company's monthly PGA Demand True-up is included in Attachment G of this AAA report. Reasons supporting the granting of the variances are described in the above-listed filings.

- **Storage-Related Ad Valorem Tax Recovery**

In Docket No. G002/M-15-149, in an Order dated October 21, 2015, the Commission granted a variance to Minn. Rule 7825.2400, subp. 12, allowing the Company to recover the 2009-2014 lump-sum assessed Kansas natural gas storage tax through the Purchase Gas Adjustment factor over a period of five years. In the same Order, the Commission granted a variance to Minn. Rule 7825.2400, subp. 12, allowing the Company to recover the current year's assessed Kansas natural gas storage tax through the Purchase Gas Adjustment for a period of one year.

The Commission granted a variance of one-year to Minn. Rule 7825.2400, subp. 12 to allow recovery in the Purchase Gas Adjustment of ad valorem taxes related to natural gas storage for retail natural gas operations, in the following dockets.

Docket No.	Order Date	Extended through
G002/M-15-149	October 21, 2015	November 1, 2016
G002/M-16-396	July 19, 2016	November 1, 2017
G002/M-17-510	November 1, 2017	November 1, 2018
G002/M-18-323	August 29, 2018	Collection of 2018 Tax
G002/M-18-631	February 6, 2019	Collection of 2021 Tax

Additional compliance information regarding the Company's lump sum and current year Kansas Tax expense and recovery is included in Attachment G of this AAA report. Reasons supporting the granting of the variances are described in the above-listed filings.

II. CHANGES IN CONTRACTED DEMAND

- On August 1, 2018, the Company filed their Petition for Approval of Changes in Contract Demand Entitlements for the 2018-2019 Heating Season (Docket No. G002/M-18-528). That docket is pending Commission action.

- On August 2, 2019, we filed a Petition seeking approval of our 2019-2020 Contract Demand Entitlement Plan in Docket No. G002/M-19-498. We are awaiting comments in this docket.

III. CUSTOMER-OWNED GAS VOLUMES

Xcel Energy transported approximately 42.6 million dekatherms of gas for Minnesota transportation customers over the reporting period, or approximately 34.87percent of total Minnesota throughput.

IV. GAS COST AND COST RECOVERY

See Attachment B, Schedule 3, Page 3-4.

Northern States Power Company, a Minnesota corporation

Schedule of Monthly and Annual Purchased Gas Cost Adjustment Factors of Northern States Power Company, a Minnesota corporation, for the period from July 1, 2018 to June 30, 2019, and Independent Accountants' Report

Deloitte.

Deloitte & Touche LLP
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USA

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INDEPENDENT ACCOUNTANTS' REPORT

To the Board of Directors of
Northern States Power Company, a Minnesota corporation

We have examined the accompanying Schedule of Monthly and Annual Purchased Gas Cost Adjustment Factors ("the Schedule") of Northern States Power Company, a Minnesota Corporation (the "Company"), for the period from July 1, 2018 to June 30, 2019, to determine whether it has been calculated in accordance with the Minnesota Public Utilities Commission (the "Commission") Rules 7825.2390 to 7825.3000 governing automatic adjustment of energy charges, and with the Purchased Gas Adjustment Rider and Dockets as defined on Sheet Nos. 5-40, 5-41, and 5-42 of the Minnesota Gas Rate Book. The Company's management is responsible for the Schedule. Our responsibility is to express an opinion on the Schedule based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the examination to obtain reasonable assurance about whether the Schedule is presented fairly, in all material respects, with the accounting for the Purchased Gas Adjustment (PGA) in accordance with the Commission's rules governing automatic adjustment of energy charges, and with the PGA Riders as defined in the Minnesota Gas Rate Book. An examination involves performing procedures to obtain evidence about the Schedule. The nature, timing, and extent of the procedures selected depend on our judgment, including an assessment of the risks of material misstatement of the Schedule, whether due to fraud or error. We believe that the evidence we obtained is sufficient and appropriate to provide a reasonable basis for our opinion.

In our opinion, the Schedule for the period from July 1, 2018 to June 30, 2019, is calculated in accordance with the criteria established by the Commission rules 7825.2390 to 7825.3000 governing automatic adjustment of energy charges, and with the PGA Riders as defined on Sheet Nos. 5-40, 5-41, and 5-42 of the Minnesota Gas Rate Book, in all material respects.

This report is intended solely for the information and use of the Board of Directors of the Company and the Commission and is not intended to be and should not be used by anyone other than the specified parties.

Deloitte & Touche LLP

August 28, 2019

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION
SCHEDULE OF MONTHLY AND ANNUAL PURCHASED GAS ADJUSTMENT FACTORS
FOR THE PERIOD FROM JULY 1, 2018 TO JUNE 30, 2019
(DOLLARS PER THERM)

	State of Minnesota						
	Residential	Small & Large Commercial	Demand Billed Commodity	Demand Billed Demand	Small Interruptible	Medium Interruptible	Large Interruptible
July 1, 2018	($0.26726)	($0.26258)	($0.24600)	($0.03554)	($0.26616)	($0.25531)	($0.25841)
August 1, 2018	($0.27235)	($0.26767)	($0.25109)	($0.03534)	($0.27125)	($0.26040)	($0.26350)
September 1, 2018	($0.27660)	($0.27053)	($0.24966)	($0.04705)	($0.25630)	($0.24857)	($0.25167)
October 1, 2018	($0.26973)	($0.25505)	($0.23986)	($0.04705)	($0.24650)	($0.23877)	($0.24187)
November 1, 2018	($0.20800)	($0.20392)	($0.16905)	($0.05363)	($0.17569)	($0.16796)	($0.17106)
December 1, 2018	($0.13201)	($0.13062)	($0.08918)	($0.04573)	($0.09582)	($0.08809)	($0.09119)
January 1, 2019	($0.20544)	($0.19937)	($0.15793)	($0.04573)	($0.16457)	($0.15684)	($0.15994)
February 1, 2019	($0.24335)	($0.24902)	($0.20758)	($0.04573)	($0.21422)	($0.20649)	($0.20959)
March 1, 2019	($0.26623)	($0.26016)	($0.21869)	($0.04590)	($0.22533)	($0.21760)	($0.22070)
April 1, 2019	($0.31912)	($0.30272)	($0.28093)	($0.04769)	($0.28757)	($0.27984)	($0.28294)
May 1, 2019	($0.34253)	($0.33646)	($0.30460)	($0.04530)	($0.31124)	($0.30351)	($0.30661)
June 1, 2019	($0.33429)	($0.32822)	($0.30860)	($0.04530)	($0.31524)	($0.30751)	($0.31061)

	State of Minnesota					
	Residential	Small & Large Commercial	Demand Billed Commodity	Demand Billed Demand	Small Interruptible	Medium & Large Interruptible
Annual true-up filing June 30, 2019	$0.00122	$0.00463	$0.01640	($0.01494)	$0.01259	$0.02412

This Schedule of Monthly and Annual Purchased Gas Cost Adjustment Factors is based on the requirements of the Minnesota Public Utilities Commission Rules 7825.2390 to 7825.3000 governing automatic adjustment of energy charges, and with the Purchased Gas Adjustment Rider and Dockets as defined on Sheet Nos. 5-40, 5-41, and 5-42 of the Minnesota Gas Rate Book.

414 Nicollet Mall
Minneapolis, Minnesota 55401

July 3, 2019

Andrew Pederson
Auditor
Deloitte and Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

Kevin Reich
Auditor
Deloitte and Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

RE: XCEL ENERGY 2019 MINNESOTA AUTOMATIC ADJUSTMENT OF CHARGES REPORT (GAS OPERATIONS)

Dear Andrew and Kevin:

With reference to our meeting on July 16th, I am sending this letter to notify Deloitte and Touche LLP, external auditor for Northern States Power Company, doing business as Xcel Energy, of certain requirements established by the Minnesota Public Utilities Commission for the upcoming natural gas Annual Automatic Adjustment of Charges Report and Purchased Gas Adjustment (PGA) true-up filing. The Company's 2019 natural gas AAA Report and PGA true-up must be filed with the MPUC and the Minnesota Department of Commerce by September 1, 2019.

Background on AAA Report/PGA True-up:

The Company's AAA Report, among other things, will provide detailed results of the Company's PGA clause (costs incurred and costs recovered, etc.) for the reporting period July 1, 2018 to June 30, 2019. The PGA true-up filing calculates the annual rate adjustments required to prospectively collect or refund any under- and/or over-recoveries of purchased commodity natural gas, pipeline transportation, upstream storage and other costs to provide dollar for dollar recovery from retail gas customers on an on-going basis. The DOC will then prepare a comprehensive analysis of the AAA reports filed by all regulated gas and electric utilities, and the MPUC will hold a meeting to review and act on the AAA Reports, PGA true-up filings, and DOC recommendations.

AAA Report Independent Audit Requirements

MPUC rules govern the automatic adjustment clauses for Minnesota natural gas utilities, AAA Reports and PGA true-up calculations, and are set forth in Minn. Rule 7825.2700 *et seq*. Minn. Rule 7825.2820 requires an annual independent auditor's report evaluating the utility's accounting for automatic adjustments for the reporting year.

In 1998 and 1999, the MPUC, by order, expanded the independent auditor reporting requirements for natural gas utilities, including Xcel Energy. In the orders in MPUC Docket Nos. G999/AA-97-1212 and G999/AA-98-1130, the Commission required natural gas utilities to:

1. Direct their independent auditors to include, as one of their procedures, an examination of any significant variations between purchase volumes (per invoices) and sales volumes per the general ledger sales journal;

2. Meet with their independent auditors prior to the auditor's examinations to review audit procedures and Minn. Rules, part 7825.2820. This is the purpose of our meeting on July 16th.

The Company intends to fully comply with the MPUC rules, including the supplemental requirements established in the MPUC orders. The assistance and cooperation of Deloitte and Touche LLP will, of course, be required to ensure this compliance.

Please do not hesitate to call me at 612-330-1925 with any questions.

Sincerely,

/s/

JENNIFER ROESLER
REGULATORY CASE SPECIALIST

c: Lisa Peterson

<u>Impact of Market Forces on Gas Costs for the Coming Year</u>

The July price forecasts for wholesale natural gas at Henry Hub for the 2019-2020 heating season as published by various energy industry analysts range from $2.73 per Dth to $2.93 per Dth. The basis adjustment to the regional price point (Ventura, Iowa), is approximately $0.42 per Dth, for a forecasted regional range of $3.15 per Dth to $3.35 per Dth, which is approximately 15 percent to 23 percent lower than last year's actual average index price of $3.87 per Dth.

Natural gas prices are expected to remain near the $2.50 to $3 level for the next several years. Weather patterns will dictate the volatility outside of this range. This year's cost of gas in storage is projected to be approximately 20 percent lower than the winter of 2018-2019. The EIA projects natural gas inventories to be 3.8 Bcf at the end of 2019 injection season, 2 percent higher than the five year average.

The U.S. Energy Information Administration (EIA) expects production to continue to rise for the remainder of 2019 in response to improved drilling efficiency and expects production to flatten by forth quarter of 2020 due to lower market prices.

Future U.S. pipeline expansions will continue to drive regional increases in production for the next couple of years and support increased LNG exports. In addition, wind energy continues to be a viable energy producer which will challenge future demand levels for coal and natural gas, and change the mix of resources to meet future carbon reduction goals.

As the heating season approaches, the price forecasts will continue to be refined. Changes in demand due to weather, production and national storage inventory levels, will all have an impact on winter prices.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS GAS OPERATION

DOCKET NO. G999/AA-19-401

NOTICE OF REPORT AVAILABILITY

On August 30, 2019, Northern States Power Company, doing business as Xcel Energy, filed its natural gas Annual Automatic Adjustment of Charges (AAA) report with the Minnesota Public Utilities Commission for the 12-month period ending June 30, 2019, in accordance with the following Commission Rules:

7825.2800 Annual Report: Policies and Actions
7825.2810 Annual Report: Automatic Adjustment Charges
7825.2820 Annual Auditor's Report
7825.2830 Annual Five-Year Projection

The aforementioned report is available for public inspection at the Commission offices, 121 East 7th Place, Suite 350, St. Paul, MN 55101 or upon written request to Xcel Energy at the following address:

Xcel Energy
Regulatory Administration
414 Nicollet Mall
Minneapolis, MN 55401

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies or summaries 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. **G999/AA-19-401**
G999/AA-18-374
G002/GR-09-1153
G002/GR-06-1429

Dated this 30th day of August 2019

/s/
____
Lynnette Sweet
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_19-401_AA-19-401
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_19-401_AA-19-401
Steven	Clay	Steven.Clay@CenterPointEnergy.com	CenterPoint Energy Minnesota Gas	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-401_AA-19-401
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-401_AA-19-401
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_19-401_AA-19-401
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_19-401_AA-19-401
Brian	Gardow	bgardow@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_19-401_AA-19-401
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.	202 South Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_19-401_AA-19-401
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 202 South Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_19-401_AA-19-401
Lisa	Peterson	lisa.r.peterson@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-401_AA-19-401

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Catherine	Phillips	catherine.phillips@we-energies.com	We Energies	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-401_AA-19-401
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-401_AA-19-401
Peggy	Sorum	peggy.sorum@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-401_AA-19-401
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Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-401_AA-19-401
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_19-401_AA-19-401
Mary	Wolter	mary.wolter@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-401_AA-19-401

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_18-374_AA-18-374
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-374_AA-18-374
Steven	Clay	Steven.Clay@CenterPointEnergy.com	CenterPoint Energy Minnesota Gas	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-374_AA-18-374
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-374_AA-18-374
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_18-374_AA-18-374
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_18-374_AA-18-374
Brian	Gardow	bgardow@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-374_AA-18-374
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.	202 South Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-374_AA-18-374
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 202 South Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-374_AA-18-374
Lisa	Peterson	lisa.r.peterson@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-374_AA-18-374

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Catherine	Phillips	catherine.phillips@we-energies.com	We Energies	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_18-374_AA-18-374
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_18-374_AA-18-374
Peggy	Sorum	peggy.sorum@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-374_AA-18-374
Kristin	Stastny	kstastny@briggs.com	Briggs and Morgan, P.A.	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-374_AA-18-374
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_18-374_AA-18-374
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-374_AA-18-374
Mary	Wolter	mary.wolter@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_18-374_AA-18-374

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Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_9-1153_Official
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Paper Service	No	OFF_SL_9-1153_Official
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
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Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_9-1153_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_9-1153_Official
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_9-1153_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_9-1153_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_9-1153_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_9-1153_Official
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David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_9-1153_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_9-1153_Official
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Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1153_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_9-1153_Official

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Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_6-1429_1
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_6-1429_1
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_6-1429_1
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_6-1429_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_6-1429_1
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Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_6-1429_1
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_6-1429_1
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 202 South Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_6-1429_1
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_6-1429_1
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_6-1429_1
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_6-1429_1
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_6-1429_1
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_6-1429_1

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_6-1429_1
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_6-1429_1

REQUEST FOR TRADE SECRET PROTECTION

Pursuant to Minn. Stat. § 13.37, trade secret information is defined in part as government data, including a compilation that: 1) was supplied by the affected individual or organization, 2) is subject to efforts by the individual or organization that are reasonable under the circumstances to maintain secrecy, and 3) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. The information on gas supplies and costs designated as Trade Secret Data of the Company's natural gas AAA report meets this definition for the following reasons:

1. Xcel Energy, the affected organization, is supplying the information.

2. Xcel Energy and Xcel Energy Services Inc. (XES), the service company for the Xcel Energy Inc. utility operating companies, make 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 AAA reports and in the monthly PGA filings only in the non-public trade secret versions of the reports.

3. The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known or being readily ascertainable in at least three ways. First, if suppliers know the terms of the Company's supply and transportation contracts, they may be able to use this knowledge to fashion bids to the Company. These bids may be competitive with existing contracts, but at a price higher than the best price the supplier would have otherwise offered but for the additional knowledge gained from access to this information. Second, 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. Third, competitors of Xcel Energy such as other LDCs also purchase their services. These competitors may be able to leverage knowledge of the Company's costs to gain similar terms or may offer slightly better prices to the supplier, denying Xcel Energy access to this gas or other service.

Any of these results would harm Xcel Energy and its retail natural gas customers in Minnesota. Because the Company 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 the Company's supply costs rise, our retail natural gas customers would have to pay higher rates. This result would not serve the public interest.

For all of these reasons, the data included in various attachments in the AAA Report must be treated as Trade Secret information.

In its orders in Docket Nos. E,G999/AA-02-950 *et al.*,[1] the Commission stated that gas utilities shall limit the designation "trade secret" to words, numbers, or phrases that are actually trade secret and shall not designate entire paragraphs or pages which contain the trade secret words, numbers, or phrases. As described in Attachment G, in preparing this 2018-2019 AAA report, the Company has limited the trade secret data designation as provided in the Commission orders.

[1] Docket Nos. E,G999/AA-97-1212, E,G999/AA-03-1264, E,G999/AA-04-1279, E,G999/AA-05-1403, E,G999/AA-06-1208, E,G999/AA-07-1130 and E,G999/AA-08-1011.

COMPLIANCE REQUIREMENTS

Attachment G contains the Company's responses related to various compliance or reporting requirements established in prior Commission orders. The compliance requirements and the Company's responses are provided below.

I. DOCKET NO. G002/M-94-103

ORDER REGARDING TREATMENT OF REVENUES FROM NSP'S OFF-SYSTEM END-USER SALES PROGRAM (March 20, 1995).

Requirement

Return all past, present, and future capacity release revenue from all sources to firm customers using FERC Account 805.1.

Response

The Company's 2018-2019 annual PGA True-up filing (filed concurrently under separate cover) contains the Company's demand expenses by month; see Schedule H. These demand expenses have been reduced by the amount of capacity release revenues from general system releases on the electronic bulletin boards (EBBs) for the Company's upstream interstate pipelines plus "capacity release" revenues associated with Agency Gas services. Attachment G, Schedule 1, contains the amount of capacity release revenues from general system releases and Agency Gas service sales for the period.

II. DOCKET NO. E,G999/AA-97-1212

ORDER ACCEPTING ANNUAL AUTOMATIC ADJUSTMENT REPORTS (May 28, 1998).

Requirement

The gas utilities shall direct their independent auditors to include, as one of their procedures, an examination of any significant variations between purchase volumes (per invoices) and sale volumes per the general ledger sales journal.

Response

As required, Xcel Energy directed its independent auditor (Deloitte and Touche), as one of their procedures, to examine any significant variations between purchase volumes (per invoices) and sales volumes per the general ledger sales journal; see Attachment C, Schedule 2. Purchased volumes were 3.5 percent higher than sales volumes for the 2018-2019 true-up period.

On average, the Company would expect to experience fuel loss of approximately 2 percent and distribution losses of approximately 1 percent in a year. However, several factors can influence the annual variance between purchased volumes and sales volumes for a particular year. Since purchases are recorded on a calendar month basis, but customers are billed on multiple billing cycles throughout the month, there can be timing differences due to changes in customer usage, meters read, or weather. In this particular year, the Company attributes 1.6 percent of the variance to fuel loss and 1.8 percent to distribution losses.

III. Docket No. G002/M-98-1429

Order Approving Miscellaneous Tariff Change (March 5, 1999).

Requirement

Any "additional charges" monies received should be returned to ratepayers in the same way as penalties are currently handled. (Additional charges are defined as any charges to firm transportation customers who fail to curtail when their gas does not arrive at the town border station.)

Response

No firm transportation customers incurred "additional charges" for unauthorized use of gas. Therefore, the Company did not receive any "additional charges" monies during the 2018-2019 true-up period.

IV. Docket Nos. G002/M-01-1336, G002/M-03-1627, G002/M-08-46, E,G999/AA-06-1208, G002/M-12-519 and G002/M-16-88

Order Approving Variances To Recover Costs of Financial Instruments (January 23, 2002), Orders Extending Variances with Conditions (January 23, 2004 and May 27, 2008), Order Acting on Gas Utilities 2006 Automatic Adjustment Reports (February 6, 2008), Order Extending Variance with Conditions (September 23, 2013) and Order (April 22, 2016).

Requirement

In its Annual Automatic Adjustment of Charges (AAA) report, Xcel [Energy] shall include data on the relative benefits of price hedging contracts, including the average cost per dekatherm for natural gas purchased under financial instruments compared to the comparable monthly and daily spot index prices, as well as –

- a list of each hedging instrument entered into,

- the total volumes contracted for, for each instrument,
- the net gain or loss, including all transaction costs for each instrument in comparison to the appropriate monthly and daily spot prices, and
- a schedule of hedging costs like the one included on page two of Xcel [Energy]'s September 7, 2012 reply comments in this docket [Docket No. G002/M-12-519].

Xcel Energy shall include in future true-up reports detailed explanations of its hedging activities, including but not necessarily limited to, all applicable fees, gains or losses on commodity and net gains or losses on hedging.

Response:
Attachment G, Schedule 2 contains the Company's response to this requirement. The Company entered into 6 hedging transactions for the 2018-2019 heating season. The Company's strategy for purchasing financial instruments to mitigate wholesale commodity cost volatility during the 2018-2019 reporting period is described in detail in Attachment A, Schedule 5 of this filing. The hedge plan was executed in accordance with Docket No. G002/M-16-88. The written order was issued on April 22, 2016 extending the hedging variance through June 30, 2020.

As required in the Commission's Order on the Company's 2005-2006 AAA filing, Docket No. E,G999/AA-06-1208, the Company has included requested hedging detail in Schedule H of the True-up being submitted under separate cover.

Table 2 below is provided in a similar manner to our September 7, 2012 reply comments in Docket No. G002/M-12-519, per the fourth bullet point listed in the requirement above.

Table 2: Minnesota Hedging Costs

Hedge Year	NSPM - Hedged Volumes (Dth)	MN State Actual Costs[1]	MN State Cost Excluding Hedging[2]	Hedging Cost - MN State	MN State Hedge Cost/Dth[3]	MN State Cost as % of Annual
2007-2008	12,790,000	$576,571,051	$566,843,252	$9,727,799	$0.13	1.69%
2008-2009	13,960,000	$458,654,791	$443,825,881	$14,828,910	$0.21	3.23%
2009-2010	14,675,000	$312,671,414	$311,675,493	$995,921	$0.01	0.32%
2010-2011	14,235,000	$325,282,768	$308,084,365	$17,198,404	$0.24	5.29%
2011-2012	14,310,000	$225,568,004	$205,124,054	$20,443,950	$0.35	9.06%
2012-2013	4,530,000	$251,190,939	$251,190,939	$0	$0.00	0.00%
2013-2014	4,530,000	$430,082,253	$438,254,092	($8,171,840)	($0.10)	-1.90%
2014-2015	13,590,000	$293,231,053	$289,910,496	$3,320,557	$0.05	1.13%
2015-2016	11,850,000	$165,547,394	$160,868,283	$4,679,112	$0.07	2.83%
2016-2017	13,590,000	$204,075,061	$202,972,529	$1,102,532	$0.02	0.54%
2017-2018	13,590,000	$227,286,024	$,226,926,737	$359,287	$0.00	0.16%
	[PROTECTED DATA BEGINS				**[PROTECTED DATA BEGINS**	
2018-2019		$271,151,393	$272,590,506	($1,439,114)		
	PROTECTED DATA ENDS]					**PROTECTED DATA ENDS]**

V. DOCKET NOS. E,G999/AA-02-950 AND E,G999/AA-03-1264

ORDERS ACTING ON GAS UTILITIES' ANNUAL AUTOMATIC ADJUSTMENT REPORTING AND SETTING FURTHER REQUIREMENTS (August 7, 2003 and August 10, 2004).

Requirement

All gas utilities shall meet with their independent auditors to review the requirements of Minn. R. 7825.2820 and proposed auditing procedures before the auditors begin their work in preparation for the utilities' next annual automatic adjustment reports.

Response

We sent a letter to the Deloitte and Touche[4] audit team on July 3, 2019 including the audit requirements and procedures. On July 16, 2019, we met with personnel from

[1] These costs consist of gas commodity and peak shaving (LNG, propane) commodity supply costs. These values do not include any demand charges associated with gas supply, transportation, or storage.

[2] These costs were calculated by subtracting the Minnesota state allocated jurisdictional share of hedging costs from the values in the "MN State Actual Costs" column.

[3] Cost per Dth for all volumes delivered, not the cost per Dth for the volume hedged.

[4] External auditor for Xcel Energy Inc.

Deloitte and Touche to review audit procedures and the requirements of Minn. R. 7825.2820 prior to the auditor's examination of the Company's natural gas AAA report. The letter to Deloitte and Touche and the Deloitte and Touche annual auditors report required by Minn. Rule 7825.2820 are included as Attachment C, Schedules 1 and 2 to this report.

VI. DOCKET NOS. G002/M-03-843, G002/M-06-681, G002/M-08-456, G002/M-11-203, G002/M-14-171 AND G002/M-17-101

ORDERS GRANTING TEMPORARY VARIANCES PERMITTING USE OF A MONTHLY DEMAND COST TRUE-UP MECHANISM WITH REQUIREMENTS (June 11, 2004, September 11, 2007, September 2, 2008, June 24, 2011 July 28, 2014 and April 21, 2017).

Requirement
Xcel [Energy] shall separately identify (by customer class) the monthly demand true-up revenues and summarize the following for each firm non-demand billed customer class in the Company's annual true-up filings:

- the annual demand cost recovery absent the adjustments;
- the total annual adjustment recovery; and
- the remaining current year demand cost recovery true-up balance.

Response
The orders in the referenced dockets granted variances to the PGA rules to allow the Company to implement a Monthly Demand Cost True-up Mechanism to true-up demand cost over- or under-recovery on a timelier basis. The Order in Docket No. G002/M-17-101 granted a three-year variance that will expire September 30, 2020. The Order retained existing reporting requirements.

Detailed information required by the Commission's Orders is provided in Attachment B, Schedule 3 of this filing and is included on Schedule I[5] of our 2018-2019 PGA True-up filing being submitted under separate cover.

[5] As noted in the cover letter of this report and shown in the "as filed" and "corrected" versions of MN True-up Schedule I in Appendix 1 of this report, due to a calculation error, this credit was $876,013 higher than the $2,896,906 that would have otherwise been credited. MN Company forecasted sales were inadvertently used instead of MN state sales to allocate the PGA annual sales to month.

VII. Last Ordered in Docket No. G999/AA-10-885

ORDER ACCEPTING GAS UTILITIES' AUTOMATIC ADJUSTMENT REPORTS AND TRUE-UP PROPOSALS AND SETTING FURTHER REQUIREMENTS (April 3, 2012).

Requirement

All regulated gas utilities shall provide a specific justification for each piece of information designated as a trade secret in future annual reports and true-up filings. All companies shall limit the designation trade secret to words, numbers, or phrases that are actually trade secret, and none may designate entire paragraphs or pages which contain the trade secret words, numbers, or phrases.

Response

Attachment F of this filing contains the justification for Trade Secret protection of each piece of information claimed as Trade Secret Data in the Company's 2018-2019 natural gas AAA report and PGA true-up filing. As stated in Attachment F, the Company has limited the data designated as trade secret to the words, numbers, or phrases that are actually trade secret.

VIII. Docket Nos. E,G999/AA-08-1011 and G999/AA-14-580

ORDER ACTING ON CERTAIN GAS UTILITIES' ANNUAL REPORTS AND TRUE-UP PROPOSALS AND SETTING FURTHER REQUIREMENTS (March 2, 2010)[6] AND ORDER ACCEPTING GAS UTILITIES' ANNUAL AUTOMATIC ADJUSTMENT REPORTS AND 2013-2014 TRUE-UP PROPOSALS AND SETTING FURTHER REQUIREMENTS (August 24, 2015).

Requirement

The Commission directs CenterPoint, Xcel [Energy], and MERC-PNG, and MERC-NMU to provide the OES with the following information about their hedging programs, beginning in fiscal-year 2010:

(a) A clearly defined and quantified description of the risk (i.e., catastrophic or other type of event) the companies are insuring against by implementing the hedging strategies. The Company shall include a clearly defined and quantified estimate of the probability of these events occurring.

[6] Items (d) and (e) were only required for one filing, but the Company was informally requested to continue them.

(b) A quantitative analysis of the value of reducing price volatility and managing price risk (the cost and benefit of these programs to all customers and the companies) that includes:

> (1) A comparison of what actual low, average, and high usage customer bills (on a monthly basis) would have been with and without the use of the hedging strategies as implemented during the relevant time period.
>
> (2) A comparison of what these customer bills would have been under budget billing, assuming normal gas usage for low, average, and high usage customers, and assuming catastrophically high prices.

(c) A quantitative definition of "catastrophically high prices" (in absolute and relative terms), and a bill analysis that shows how these prices would impact low, average and high usage customer bills.

(d) Require Xcel [Energy] to provide in its next Annual Automatic Adjustment filing a complete post-mortem review of its fiscal-year 2009 heating season natural gas purchasing strategy, including all information, data, and assumptions (in Microsoft Excel format where applicable) necessary to replicate this analysis.

(e) Require Xcel [Energy] to provide in its next Annual Automatic Adjustment filing a discussion of how the Company has chosen the level of acceptable volatility, and minimized the level of cost for this level of volatility.

<u>Response</u>
(a) The Company's hedging strategy is designed to insure against sharp upward price movements, which can be defined as monthly prices increasing over forward prices at the time the hedges were put in place. These price spikes can be caused by various events such as supply disruptions (i.e., pipeline issues or loss of production), and adverse weather events (i.e., hurricanes or colder than normal temperatures). These events do not need to occur in the region to have an effect on gas prices. For example, if the eastern part of the country is experiencing below normal temperatures, it drives prices higher in the Midwest due to the markets in the Midwest having to compete with the east for the natural gas. Due to the randomness of these types of events the Company cannot determine the probability of these types of events in a meaningful way.

(b) The Company's Gas Supply department used a Monte Carlo simulation to evaluate the appropriate levels of hedging. The study indicates that the expected portfolio cost decreases with each incremental volume interval hedged. These results are indicative that upward price movement is theoretically unlimited while downward price movements are capped at zero. The results of the study are included in Attachment G, Schedule 4.

(1) & (2) Billing Comparisons are shown in Attachment G, Schedule 5.

(c) For purposes of responding to this question, the Company has defined "catastrophically high prices" as prices at or above $4.356 per Dth during the winter months. This pricing level was derived by using the average of the highest November through March price from the previous five heating seasons. See Attachment G, Schedule 5 for bill analysis. During the 2018-2019 heating season, the Company experienced daily spot prices above the catastrophically high price 19 days during the period of November 1, 2018 through March 31, 2019. The Company minimized spot prices during this period by curtailment of interruptible customers, use of gas storage and the use of peaking facilities. The daily price spikes do not affect the Company's hedge program as the financial hedges are settled against first of month settlements.

(d) During the 2018-2019 heating season, the Company used "out-of-the-money" (OTM) call options to implement the hedging program. An OTM call option has a strike price that is higher than the current forward market price of gas and as such has a lower premium cost. Attachment G, Schedule 4 provides an analysis of various hedging instruments impact on the portfolio cost of gas. OTM call options were selected due to their lower expected cost relative to other strategies. The use of these instruments provides Customers with the opportunity to participate in downward price movement, while still providing upside protection from a catastrophic price spike.

The financial portion of our 2018-2019 hedging plan resulted in a net benefit of $1,669,620 as compared to the approved hedging budget of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. The post-mortem review as described in more detail below will compare the actual total system settlement costs incurred against alternative hedging strategies.

In our post-mortem review, we compared the Price Volatility Mitigation Plan that was implemented, which consisted of the purchase of OTM call options to a strategy that would have exclusively used "at-the-money" (ATM) call options and costless collars. The post-mortem review was limited to these three strategies as they are the only currently approved strategies in the Company's variance.

Table 3: Alternative Hedging Strategy Analysis

Strategy	Cost (in million $)	More(Less) than Actual Cost
Actual Strategy	$(1.7)	
ATM Call Options	$(4.2)	$(2.5)
Costless Collar Alternative	$(2.1)	$(0.4)

The strategy that was implemented resulted in a lower overall benefit as compared to a strategy that would have used costless collars and ATM call options exclusively. Attachment G, Schedule 3 contains the data used in the alternative hedging strategy analysis.

(e) The Company's hedge plan defines volatility as "the customer's exposure to sharp upward price movements." Our plan is designed to limit the customer's exposure to rising pricing while still allowing them to realize some of the benefits during periods of falling prices. This is achieved by setting the targeted hedge volume at 50% of the customer's normal winter requirements. This level of protection was selected to reduce customers' exposure to a sharp upward price movement to $0.50 per Dth for each one dollar change in the price of gas, while still providing customers the opportunity to participate in downward price movements. The Company designs its program so that the costs do not exceed the budget that was approved in Docket No. G002/M-16-88.

IX. DOCKET NO. E,G002/M-09-852

ORDER APPROVING PROGRAM, WITH MODIFICATIONS AND REQUIRING REPORT (February 18, 2010).

DOCKET NO. E,G002/M-15-618

ORDER (October 16, 2015)

<u>Requirement</u>
In the report on the Gas Utilization Program that Xcel Energy includes in the AAA report, the Company shall list each individual transaction showing quantities and cost, the specific accounting entries and a brief explanation of the transaction. In Docket No. E,G002/M-15-618, the Commission ordered:

1) approved Xcel's [Energy] Capacity Utilization Plan as a permanent program;

2) accepted Xcel's [Energy] agreement to report the two categories of capacity sharing transactions – those used to not curtail interruptible customers and other transactions that benefit the whole system;
3) accepted Xcel's [Energy] agreement to continue to report on the transactions related to the Capacity Utilization Plan annually in its annual automatic adjustment (AAA) Report and include both the gas and electric transactions; and
4) Directed Xcel [Energy] to meet with Commission staff and the Department to discuss the arrangements in effect between Xcel's [Energy] business units for the use of its transportation and storage contracts and how Xcel [Energy] ensures that the assignment and allocation of costs and credits reflects how each Xcel [Energy] business unit is actually using the interstate pipeline transportation capacity storage.

Response

The report showing quantities, costs, accounting entries, and an explanation for each individual transaction for the 2018-2019 true-up period is included as Attachment G, Schedule 6. Table 4 below summarizes the savings the LDC and NSP Generation recognized in the true-up period.

Table 4: Capacity Utilization Program – LDC & NSP Generation Savings

	LDC Approximate Savings	**NSP Generation Approximate Savings**
Capacity sharing transactions	$200,558	$0
Storage netting	$0	$0
Total	$200,588	$0

X. DOCKET NO. G999/AA-10-885

ORDER ACCEPTING GAS UTILITIES' AUTOMATIC ADJUSTMENT REPORTS AND TRUE-UP PROPOSALS AND SETTING FURTHER REQUIREMENTS (April 3, 2012)

Requirement

In future initial Annual Automatic Adjustment reports, in addition to all information currently required concerning gas-price hedging practices, all regulated gas utilities shall provide additional information on the embedded cost/benefit associated with physical hedges used in the procurement of gas supplies.

Response
We did not have any physical hedges used in the procurement of gas supplies.

XI. DOCKET NO. G999/AA-10-885

ORDER ACCEPTING PROGRESS REPORTS AND METER TESTING PLANS (October 11, 2012).

DOCKET NO. G999/AA-14-580

REVIEW OF THE 2013-2014 ANNUAL AUTOMATIC ADJUSTMENT REPORT (May 5, 2015)

Requirement
(a) All gas utility companies shall file, as part of their annual AAA reports, a schedule reflecting the contractor main strikes during the corresponding annual period billings to at-fault contractors. The Commission will require that the schedules reflect the date, party involved, repair cost amount, and gas lost amount for each incident. In Docket No. G999/AA-14-580, the Department recommended that all utilities total the gas costs in its Contractor Main Strikes Report and also provide the allocation of the gas costs credited to each class in its true-up of commodity costs.

(b) All gas utility companies shall file any updates regarding meter testing within an annual period in the AAA reports. Test metering reports were incorporated into the AAA report starting in 2012.

Response
(a) Included as Attachment G, Schedule 7 is our contractor main strike report, which includes total gas costs and the allocation of the gas costs credited to each class in its true-up of commodity costs.

(b) There were no changes regarding meter testing within the annual reporting period of July 1, 2018 and June 30, 2019.

XII. Docket Nos. G002/M-15-149, G002/M-16-396 and G002/M-17-510

ORDER VARYING MINN. R. PART 7825.2400 AND REQUIRING FILINGS (October 21, 2015), ORDER (July 19, 2016) and ORDER (November 1, 2017).

Requirement

(a) Xcel [Energy] shall list the Kansas natural gas storage tax costs and revenues as separate line items in the Annual Automatic Adjustment (AAA) and PGA true-up reports as well as in true-up report Schedules C and D (page 1-2 of 4, and page 4 of 4).

(b) With its annual AAA and true-up reports, Xcel [Energy] shall submit a report detailing the total amount paid to Kansas and collected from ratepayers during the gas year.

Response

The Minnesota share of the Kansas natural gas storage-related ad valorem tax costs for the years 2009-2014 is $5,006,347, of which $1,000,465 was amortized for the July 2018 to June 2019 gas year. The total amount of tax recovered from Minnesota gas ratepayers for this lump sum tax assessment during the July 2018 to June 2019 gas year is $1,102,478.

The Company was assessed $689,942 in Kansas natural gas storage-related ad valorem tax costs in 2018, of which $593,001 was allocated to Minnesota. Table 5 below shows the 2018 estimated and actual tax, as well as the true-up by jurisdiction.

Table 5: Calendar Year 2018 Kansas Tax Expenses by Jurisdiction

	MN	ND	Total
2018 Estimated Tax in PGA	$703,837	$115,510	$819,348
2018 Actual Tax	$593,001	$96,940	$689,942
2018 Tax True-up to Actual Bill	$-110,836	$-18,570	$-129,406

The annual Kansas tax expense is recorded on a current basis. However, because the PGA gas year captures 12-months of tax expense recorded during July – June period, it reflects a portion of the KS taxes assessed in 2018 and estimated for 2019. Using the 2018 tax level as a proxy for 2019, $744,778 was included in the PGA rate for the current natural gas AAA year. $639,759 was allocated to Minnesota. The current reporting period also includes a $110,836 decrease in Kansas tax for Minnesota due to a true-up for 2018 actual billed tax. Table 6 below shows the Kansas tax expenses included in the 2018-2019 PGA True-up by jurisdiction.

Table 6: 2018-2019 Kansas Tax Expenses by Jurisdiction

	MN	ND	Total
2018-2019 Estimated Tax in PGA	$639,759	$105,019	$744,778
2018 Tax True-up	$-110,836	$-18,570	$-129,406
Total 2018-2019 Tax in PGA True-up	$528,922	$86,449	$615,372

The total amount of tax collected from Minnesota gas ratepayers during the July 2018 to June 2019 gas year is $703,637. Table 7 below provides a line item summary of the Kansas natural gas storage-related ad valorem tax expenses and revenues. Additional details are provided on Schedules A, C and D (pages 1, 2, and 4) of the 2018-19 PGA true-up report filed concurrently.

Table 7: Kansas Tax Expenses and Recoveries in 2018-2019 PGA True-up
State of Minnesota

	Prior Year 2017-2018 PGA True-up Balance	2009-2014 Lump Sum Amortization	Current Year 2018-2019	Total
Expense	$46,062	$1,000,465	$528,922	$1,575,449
Revenue	$59,860	$1,102,478	$703,637	$1,865,975
Over (Under) Recovery	$13,798	$102,013	$174,715	$290,526

XIII. Docket No. G999/AA-17-394

Order Accepting Gas Utilities' Annual Automatic Adjustment Reports and 2016-2017 True-Up Proposals and Setting Further Requirements (February 27, 2019).

<u>Requirement</u>
Each utility shall provide, in the next three AAA reports (2017 – 2018), (2018 – 2019), and (2019 – 2020), the following information on unauthorized gas use for each customer that did not comply with a called interruption during the heating season:

a. The volume of gas consumed by the non-compliant customer during the curtailment period.
b. The specific commodity rate charged for the unauthorized gas used and how that rate is determined.
c. The financial penalty, if any, assessed by the company to the customer, including calculations in determining the penalty or penalties.

d. A discussion about utility communication with each customer regarding noncompliance with interruptions (excluding invoices).

<u>Response</u>
a-c. See Attachment G, Schedule 8.

d. We communicate with our interruptible customers in a variety of ways, including:
- Account Managers meet with our customers frequently to discuss the program, their responsibilities as a program participant and any program changes that may have occurred.
- Direct contact with customers regarding penalties and their impacts to customers. "Direct contact" could mean e-mail, phone conversations, or site visits. Meetings with customers are held for many reasons and we have an ongoing relationship with the customer; some as often as daily, or multiple times per day. Our discussions regarding gas penalties are to help customers understand the financial impact of using unauthorized gas during a curtailment and how that can quickly negate annual rate savings from being on the interruptible gas rate. We also explain the capacity constraints that unauthorized gas use can cause on our system.
- Offer a Limited Firm program to help customers who have difficulty curtailing (offer some insurance). This is typically offered at the start of the winter season. There is a capacity check we must evaluate to understand whether or not we can offer this option.
- Annual mailing to help customer ready themselves for the upcoming season in conjunction with gas curtailment events.
- Annual testing of our automated notification system to help customers prepare for the upcoming season.
- Gas Curtailment hotline number.

Some examples of those communications include the following:
1. Each October we host customer meetings in several cities throughout the service territories to discuss any changes to the Interruptible Gas programs, customer responsibilities, the system outlook for the upcoming season, and penalties for any unauthorized gas use.
2. In 2018 we reminded customers of the increase in the penalties as part of our annual fall mailing and also at the customer meetings held in October.
3. Xcel Energy sponsors a 24-hour curtailment hotline, which can help customers plan for gas curtailments.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Gas Operations - State of Minnesota

Docket No. G999/AA-19-401
Attachment G
Schedule 1

Capacity Release Credits from Agency, General System, and Standby Service Sales
June 2018 - May 2019

Month	Volumes	Dollars	Capacity Volumes	Capacity Dollars	Volumes	Dollars
	[PROTECTED DATA BEGINS					
Jun-18						
Jul-18						
Aug-18						
Sep-18						
Oct-18						
Nov-18						
Dec-18						
Jan-19						
Feb-19						
Mar-19						
Apr-19						
May-19						
Total						

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Transaction Date	Hedge Instrument	Production Month	Volume	Premium Paid	Call Strike Price	Put Strike Price	Monthly Index Price	Hedge Price	Net Gain/ (Loss)	Monthly Totals
[PROTECTED DATA BEGINS										
										PROTECTED DATA ENDS]
										$ 1,669,620.00

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Positive values are costs, negative values are gains

Possession Date	Start Date	End Date	Qty	Location	Call Strike	Option Type	Market Price on Trade Date	Avg ATM Market Price on Trade Date	Settlement Price	ACTUAL RESULTS OTM Premium Paid	COMPARISON SCENARIOS Calls Purchase OTM Exersized	Puts Purchase OTM Exersized	ATM Premium Estimate	Calls Purchase ATM Exersized	Puts Purchase ATM Exersized	Call on Collar Exersized ($1 Premium)	Put on Collar Exersized ($0.50 Premium)	SAVINGS Actual Less ATM Call Purchase	Actual Less Costless Collar ($1.00 Call/$0.50 Put)
November Total										$ 455,400	$ -	$ -	$ 871,987	$ (906,480)	$ -	$ -	$ -	$ 489,893	$ 455,400
December Total										$ 470,580	$ (3,031,800)	$ -	$ 901,053	$ (4,776,666)	$ -	$ (1,986,666)	$ -	$ 1,314,393	$ (574,554)
January Total										$ 470,580	$ (930,000)	$ -	$ 901,053	$ (2,549,316)	$ -	$ (289,230)	$ -	$ 1,188,843	$ (170,190)
February Total										$ 425,040	$ -	$ -	$ 813,854	$ (304,080)	$ -	$ -	$ -	$ (84,734)	$ 425,040
March Total										$ 470,580	$ -	$ -	$ 901,053	$ (19,530)	$ -	$ -	$ 191,580	$ (410,943)	$ 279,000
WINTER TOTAL										**$ 2,292,180**	**$ (3,961,800)**	**$ -**	**$ 4,388,999**	**$ (8,556,072)**	**$ -**	**$ (2,275,896)**	**$ 191,580**	**$ 2,497,453**	**$ 414,696**

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

November Total	**$ 455,400**	**$ -**	**$ -**	**$ 871,987**	**$ (906,480)**	**$ -**	**$ -**	**$ -**	**$ 489,893**	**$ 455,400**

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

December Total	**$ 470,580**	**$ (3,031,800)**	**$ -**	**$ 901,053**	**$ (4,776,666)**	**$ -**	**$ (1,986,666)**	**$ -**	**$ 1,314,393**	**$ (574,554)**

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

January Total	**$ 470,580**	**$ (930,000)**	**$ -**	**$ 901,053**	**$ (2,549,316)**	**$ -**	**$ (289,230)**	**$ -**	**$ 1,188,843**	**$ (170,190)**

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

February Total	**$ 425,040**	**$ -**	**$ -**	**$ 813,854**	**$ (304,080)**	**$ -**	**$ -**	**$ -**	**$ (84,734)**	**$ 425,040**

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

March Total	**$ 470,580**	**$ -**	**$ -**	**$ 901,053**	**$ (19,530)**	**$ -**	**$ -**	**$ 191,580**	**$ (410,943)**	**$ 279,000**

Analysis of Various Hedge Ratios for NSPM LDC

5/9/2019
Xcel Energy Gas Supply

Purpose: Determine an optimal percent of the LDC winter gas requirements to hedge during the preceding spring/summer, and the hedging strategy that is expected to yield the lowest overall system cost.

Methodology: Monte Carlo simulation model in Crystal Ball™ using a composite index of historical NNG Ventura, NNG Demarc and NYMEX forward and settlement price data.

Assumptions:

- For the purposes of the model, an average winter forward price for November 2019 through March 2020 using the composite index was used to capture possible price swings across the entire winter rather than by month. The composite index was calculated as the average of NNG Ventura, NNG Demarc and NYMEX forward and settlement prices for each month. These indices were weighted equally because NSPM purchases gas from each of these hubs in roughly equal proportions compared to the entire winter gas portfolio.
- To calculate the price distribution used in the model, the analysis assumed seven purchase dates during the summer months for the past seven years. Purchase dates were the 15th of each month, April through October, for the period 2012-2018. The distribution for expected price movement was based on the differences between the average first-of-month price and the average winter forward price for the heating season following each purchase date using the composite index. Finally, the average forward price for the upcoming winter season used in the model was based on ICE prices as of May 6, 2019.
- Expected consumption was kept static using the most recent LDC forecast of 62.56 Bcf for the 2019-2020 heating season, thus volumetric risk was not incorporated.
- For the target hedging level analysis, fixed-for float swaps are used to fix a portion of the portfolio gas cost in 5% increments from a minimum of 25% hedged (the currently contracted physical storage portfolio) to a maximum of 75% hedged. The maximum is based on practical limitations due to uncertainty in the demand forecast and desire to avoid potential long positions (overhedged).
- For the hedging strategy analysis, the target hedging level is set at 50% of winter requirements. Four hedging strategies are evaluated; 1) Fixed-for-float Swaps, 2) ATM call options, 3) OTM call options +$0.75/Dth, and 4) Costless Collars with an assumed skew of 2-to-1 (+$0.75/Dth ,- $0.375/Dth).

Section 1 – Market Volatility:
The base prices and volumes, as well as the standard deviation for the 2018-2019 heating season are shown below in *Table 1*:

	Avg Winter Fwd Price	Standard Deviation – Below Mean	Standard Deviation – Above Mean	Forecast Volume (Bcf)	Forecast Base Cost ($M)
2019-2020	$2.906	$0.531	$0.720	62.56	$181.799

Table 1

After simulation, the average cost for the winter strip of gas (weighted by the monthly demand) is shown in *Figure 1*.

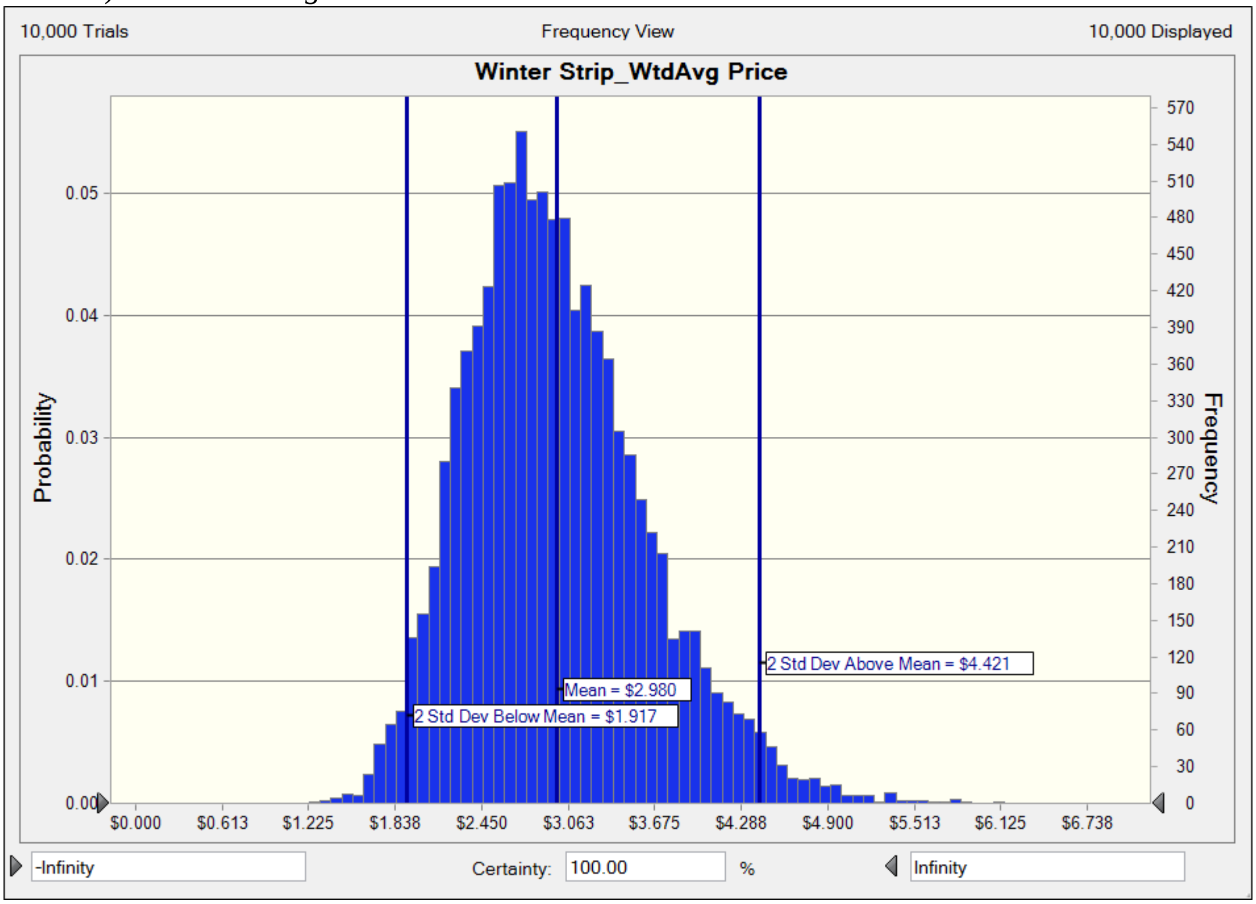

Figure 1

The simulation shows that the price of gas could settle as low as $1.241/Dth and as high as $6.117/Dth while the range we would expect with 95% confidence (2 standard deviations from the mean) is $1.917 to $4.421. The distribution is lognormal such that the average of all potential price outcomes, $2.98/Dth, is skewed to the right of the median $2.909 (forward) price of gas in the market. The extent to which we can expect prices to vary from the forward market price in the summer for the upcoming winter, or the volatility of the commodity, is 20%.

Section 2 – Target Hedging Level Results

As each increment of hedging is implemented (5% intervals), that portion of gas cost is fixed at the weighted average cost ($2.98/mmbtu) instead of coming from the distribution of expected prices in *Figure 1*. The mathematics can be visualized by imagining 100 of the distributions averaged together, then comparing that to averaging 75 of the distributions and 25 straight lines at the median $2.98 (for the case of going from unhedged to 25% hedged). Each increase in hedged volume is taking away one "risky" portion and replacing it with one "fixed" portion. A chart of the resulting distributions for total winter gas cost for various hedge ratios (0%, 25%, 50% and 75%) is shown in *Figure 2*.

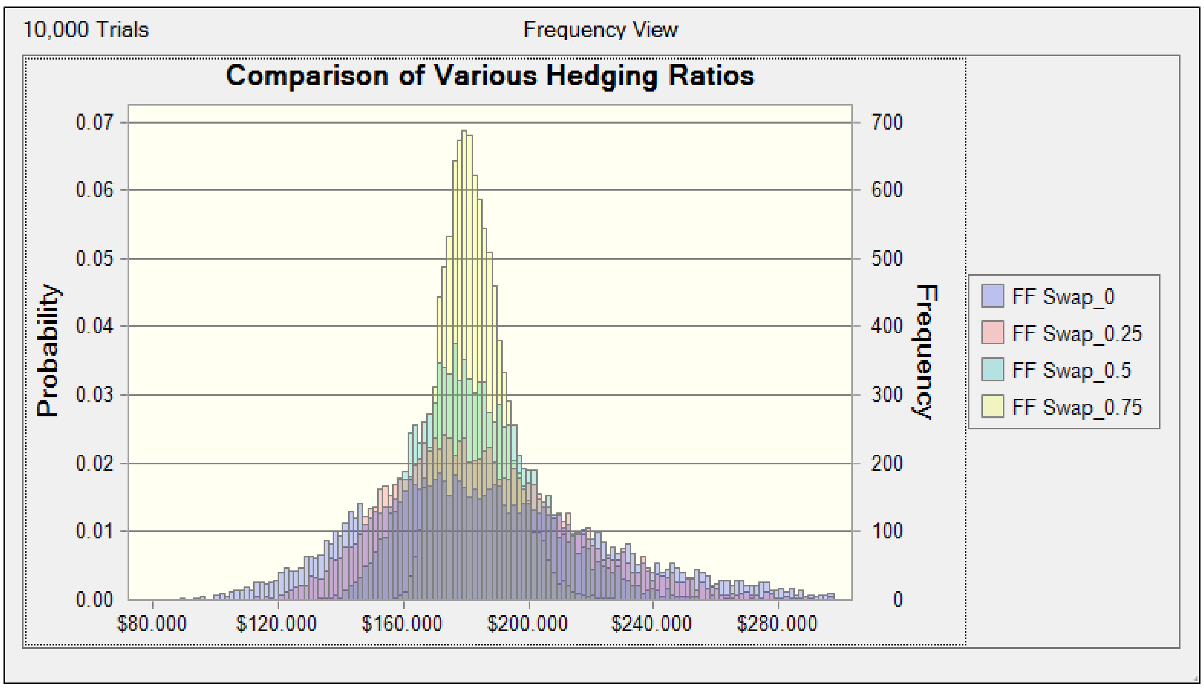

Figure 2

Table 2 shows the portfolio statistics for the various hedge percents. For each increment of hedging, a certain amount of potential benefit from falling prices (the difference in the shaded portions of *Figure 2* to the left of the median) is given up in exchange for a certain amount of reduction in risk from high prices (the shaded portion to the right of the median in *Figure 2*). <u>For every 5% increase in hedging, around $1.32 million is given up in potential benefit for every $1.79 million in reduced exposure, for a risk/reward ratio of around 1.35</u>. These results are linear - the amounts reduced/gained are the same for each increment of hedging above the 25% level.

		Unhedged	Hedge 25%	Hedge 30%	Hedge 35%	Hedge 40%	Hedge 45%	Hedge 50%	Hedge 55%	Hedge 60%	Hedge 65%	Hedge 70%	Hedge 75%
Mean	$M	186.45	185.29	185.05	184.82	184.59	184.36	184.12	183.89	183.66	183.43	183.19	182.96
Median	$M	182.00	181.95	181.94	181.93	181.92	181.91	181.90	181.89	181.88	181.87	181.86	181.85
Avg Cost for Draws Below Median	$M	**155.34**	**161.96**	**163.28**	**164.60**	**165.93**	**167.25**	**168.57**	**169.89**	**171.22**	**172.54**	**173.86**	**175.19**
Stdev of Cost (Draws Below Median)		18.43	13.82	12.90	11.98	11.06	10.14	9.22	8.29	7.37	6.45	5.53	4.61
Avg Cost for Draws Above Median	$M	**217.56**	**208.62**	**206.83**	**205.04**	**203.25**	**201.47**	**199.68**	**197.89**	**196.10**	**194.31**	**192.53**	**190.74**
Stdev of Cost (Draws Above Median)		29.43	22.08	20.60	19.13	17.66	16.19	14.72	13.25	11.77	10.30	8.83	7.36
Reduction in Benefit	$M		6.61	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32
Reduction in Risk	$M		8.94	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79
Delta Benefit to Risk	$M		2.32	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Risk to Benefit Ratio			1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35

Table 2

Again, due to the lognormal shape of the price distribution the cost impact of prices above the median is greater than the impact of prices on the low side. Thus, the unhedged portfolio has an expected cost of $186.45M as compared to the 50% expectation of $182.00M. For every higher increment of hedging, the expected value goes down, moving closer to the base price, ultimately converging at 100% hedged.

Hedging Strategy Results:

That analysis above looked only at swaps to evaluate the benefit of hedging in general. Next we evaluate the impact of specific hedging instruments on the portfolio cost of gas. Using the same distribution for natural gas prices from *Figure 1*, the cumulative probability of portfolio gas costs for the 50% of winter requirements hedged under each strategy is shown in *Figure 3*:

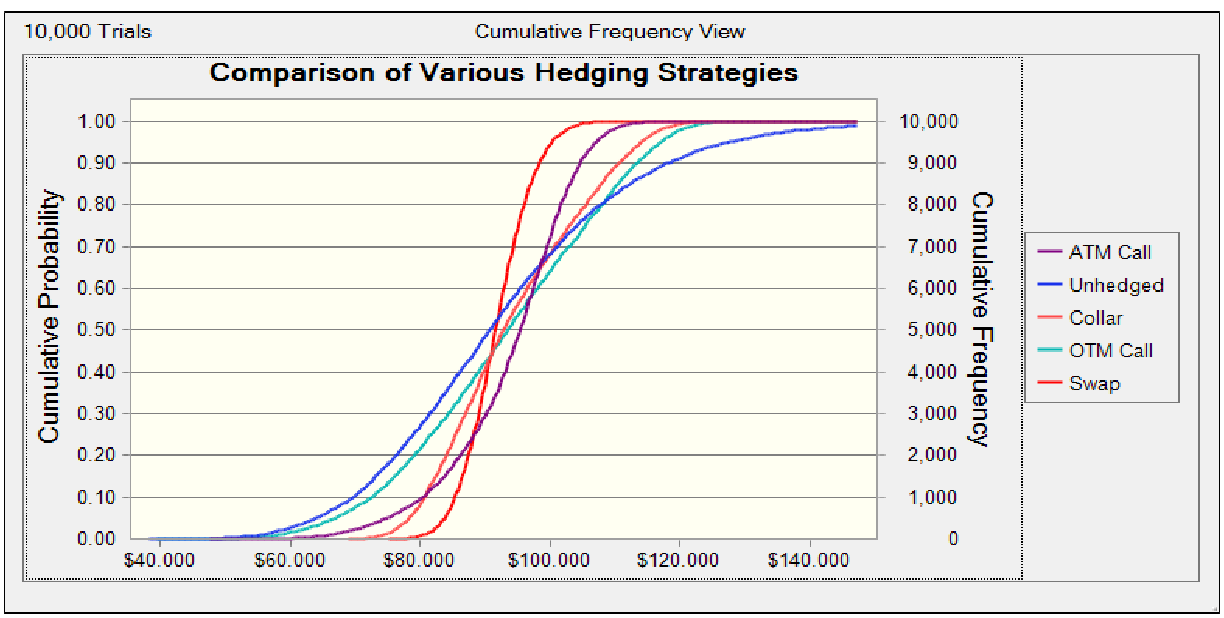

Figure 3

The extent to which the exposure to variability in gas costs is mitigated by each hedging strategy can be seen through the range of potential outcomes. As expected, the unhedged (blue) curve has the widest range of potential cost outcomes as the portfolio is exposed to the entire distribution of gas prices. The Swap (red) curve has the narrowest range of potential cost outcomes as the price of gas is fixed at the forward price at the time the hedge is executed. If the entire portfolio was hedged on the same day using swaps, the curve would be a vertical line, but because hedges are procured throughout the summer months, volatility in forward market prices from one trade date to the next introduces some variability in cost back into the portfolio. Other scenarios using Costless Collars, at the money (ATM) call options, and out of the money (OTM) call options are also shown.

Table 3 shows the average and median portfolio costs under each hedging scenario. Most hedged scenarios result in a lower average cost of gas over time given the skewed risk and impact of significant price spikes, but a higher expected (median) cost in any single year reflecting the "cost" of hedging. Based on model results, the Swap scenario has the lowest expected cost of all the hedged scenarios. This is primarily because of the higher volatility of other hedging instruments when compared to historical levels as indicated by the higher costs of ATM and OTM call options. Volatility was estimated using the Black-Scholes Option Pricing Model along with option premium and strike price quotes gathered from a sampling of financial institutions offering natural gas hedging option instruments.

		Unhedged	ATM Call	Swap	OTM Call	Collar
Mean	$M	$92.720	$93.870	$91.853	$93.194	$94.496
Median	$M	$90.789	$95.520	$91.696	$93.587	$92.902

Table 3

Conclusion: Natural gas price volatility continues to be significant in today's market. Each increment of hedging results in a benefit in terms of reducing the expected portfolio cost. Further, this proportionately reduces more high gas price risk compared to the reduction in low gas price benefits. However, how much hedging is appropriate is a more subjective problem as utilities balance the need for reduced price volatility with the cost to hedge and desire to capture potential downward movement in prices. Also, the inherent uncertainty in the gas demand forecast due to atypical weather or economic conditions sets a practical upper limit on the amount that should be hedged. As such, a target hedging level of 50% of winter requirements strikes an appropriate balance between risk mitigation and program cost.

Although the unhedged scenario above projects lower estimated costs for the coming heating season when compared to other hedging scenarios, NSPM plans to hedge 50% of winter purchases because of price uncertainty risk. Under current market conditions, a hedge portfolio of primarily OTM call options, because of lower premiums and costs than ATM call options, and swaps can be expected to provide the lowest overall cost of gas across the wide range of potential price outcomes for the upcoming winter while maintaining the lowest amount of price risk for NSPM's gas customer base.

Docket No. G999/AA-08-1011, Order Point 14:

b.1) A comparison of what actual low, average, and high usage customer bills (on a monthly basis) would have been with and without the use of the hedging strategies as implemented during the relevant time period.

b.2) A comparison of what these customer bills would have been under [Averaged Monthly Payment Plan], assuming normal gas usage for low, average, and high usage customers, and assuming catastrophically high prices.

c) ... a bill analysis that shows how [catastrophically high] prices would impact low, average and high usage customer bills.

	Average Monthly Bill			Total Annual
Minnesota Residential Average Use Customer Bill*	Winter	Summer	Annual True-up	Payment
b.1) 2018-2019 true-up year with hedging	$106.55	$28.94	$0.00	$735.35
b.1) 2018-2019 true-up year without hedging	$106.91	$28.94	$0.00	$737.15
c) Catastrophically High Prices with hedging	$120.77	$27.75	$0.00	$798.08
c) Catastrophically High Prices without hedging	$121.97	$27.95	$0.00	$805.51
b.2) 2018-2019 true-up year with hedging - AMP Plan	$54.23	$54.23	$84.59	$735.35
b.2) 2018-2019 true-up year without hedging - AMP Plan	$54.23	$54.23	$86.39	$737.15
b.2) Catastrophically High Prices with hedging - AMP Plan	$54.23	$54.23	$147.32	$798.08
b.2) Catastrophically High Prices without hedging - AMP Plan	$54.23	$54.23	$154.75	$805.51

	Average Monthly Bill			Total Annual
Minnesota Residential Low Use Customer Bill*	Winter	Summer	Annual True-up	Payment
b.1) 2018-2019 true-up year with hedging	$82.16	$23.96	$0.00	$578.51
b.1) 2018-2019 true-up year without hedging	$82.43	$23.96	$0.00	$579.86
c) Catastrophically High Prices with hedging	$92.83	$23.06	$0.00	$625.56
c) Catastrophically High Prices without hedging	$93.73	$23.21	$0.00	$631.13
b.2) 2018-2019 true-up year with hedging - AMP Plan	$42.93	$42.93	$63.35	$578.51
b.2) 2018-2019 true-up year without hedging - AMP Plan	$42.93	$42.93	$64.70	$579.86
b.2) Catastrophically High Prices with hedging - AMP Plan	$42.93	$42.93	$110.40	$625.56
b.2) Catastrophically High Prices without hedging - AMP Plan	$42.93	$42.93	$115.97	$631.13

	Average Monthly Bill			Total Annual
Minnesota Residential High Use Customer Bill*	Winter	Summer	Annual True-up	Payment
b.1) 2018-2019 true-up year with hedging	$130.93	$33.93	$0.00	$892.19
b.1) 2018-2019 true-up year without hedging	$131.38	$33.93	$0.00	$894.44
c) Catastrophically High Prices with hedging	$148.72	$32.43	$0.00	$970.61
c) Catastrophically High Prices without hedging	$150.21	$32.69	$0.00	$979.89
b.2) 2018-2019 true-up year with hedging - AMP Plan	$65.54	$65.54	$105.71	$892.19
b.2) 2018-2019 true-up year without hedging - AMP Plan	$65.54	$65.54	$107.96	$894.44
b.2) Catastrophically High Prices with hedging - AMP Plan	$65.54	$65.54	$184.13	$970.61
b.2) Catastrophically High Prices without hedging - AMP Plan	$65.54	$65.54	$193.41	$979.89

*The following definitions are used for the purposes of this example:
Average Use = MN Residential average non weather-normalized billing use per customer for July 2018 - June 2019.
Low Use = 75% of MN Residential average non weather-normalized billing use per customer for July 2018 - June 2019.
High Use = 125% of MN Residential average non weather-normalized billing use per customer for July 2018 - June 2019.

Shared Transport Capacity

Transportation Sharing was utilized to avoid overrun charges that would have been incurred when either the Generation or LDC usage exceeded its firm transportation capacity on Northern Natural Gas or on Viking Gas Transmission and either the LDC or Generation portfolios had unutilized firm transport capacity.

DATE	Pipeline	DELIVERED	VOLUME	NNG MAX TARIFF RATE	VGT MAX TARIFF RATE	GEN	LDC
Jan-19	NNG	Highbridge	19,000	$0.2517		$11,582.40	($11,582.40)
Feb-19	NNG	Highbridge	117,000	$0.2517		$71,323.20	($71,323.20)
Feb-19	NNG	Riverside	30,000	$0.2517		$18,288.00	($18,288.00)
Feb-19	NNG	Mankato	16,000	$0.2517		$9,753.60	($9,753.60)
Mar-19	NNG	Highbridge	147,000	$0.2517		$89,611.20	($89,611.20)
			1,116,416			**$ 200,558.40**	**$ (200,558.40)**
							(+Amt Due / -Amt Owed)

200,558.40 GEN Shared Capacity
- LDC Shared Capacity
200,558.40

NNG and VGT Max Tariff rates were used for savings calculation.

Storage Diversion*

Storage Diversion was utilized to save counter-seasonal withdrawal or injection charges when one portfolio was injecting into storage and the other portfolio was withdrawing during the same Gas Day.

NO ACTIVITY

NSP GEN			NSP LDC		
GEN W/D	**$/dth**	**Inj/WD Costs Avoided**	**LDC INJ**	**$/dth**	**LDC Inj/WD Costs Avoided**
-	**$0.0000**	**$0.00**	**-**	**$0.0000**	**$0.00**

($200,558.40)
$ (200,558.40) Sch H Summary - Rows: Transmission-Exchange Gas and Capacity Release - Internal
$0.00

Damage Date	Excavator Name	Damage Amount Billed	Date Billed[1,2]	Gas Lost Amount[3]	Gas Lost Volume (MCF)
INCIDENTS THAT OCCURED DURING THE CURRENT TRUE-UP PERIOD AND WERE BILLED DURING THE CURRENT TRUE-UP PERIOD					
July					
7/21/2018	RICE CONTRACTING	not billed yet		$1,746.38	656.83
7/24/2018	Q3 CONTRACTING	not billed yet		$479.06	180.179
7/24/2018	COLLINS ELECTRIC	not billed yet		$402.71	151.463
7/26/2018	Q3 CONTRACTING	not billed yet		$1.69	0.634
7/27/2018	SUPER FRAMING	not billed yet		$11.02	4.102
7/27/2018	TELCOM CONSTRUCTION	not billed yet		$78.30	29.451
7/30/2018	A1 EXCAVATING	not billed yet		$19.40	7.221
7/30/2018	DRESEL CONTRACTING INC	not billed yet		$82.85	30.841
7/31/2018	KUECHLE UNDERGROUND	not billed yet		$247.76	93.186
August					
8/1/2018	PARK CONSTRUCTION	not billed yet		$7.41	2.837
8/6/2018	NORTHERN VISION CONSTRUCTION	not billed yet		$47.23	18.091
8/6/2018	CITY OF NORTH ST PAUL	not billed yet		$78.07	29.596
8/9/2018	SCHMIDT CURB	not billed yet		$110.63	41.943
8/10/2018	MEYER CONTRACTING	not billed yet		$98.09	37.189
8/20/2018	DIRT DYNAMICS	not billed yet		$62.74	23.95
8/21/2018	JR FERCHE INC	not billed yet		$403.23	154.457
8/24/2018	JAMES BROTHERS CONSTRUCTION	not billed yet		$1,277.73	489.432
8/29/2018	SWENKE IMS	not billed yet		$20.06	7.683
8/30/2018	PEMBER COMPANIES	not billed yet		UNABLE TO CACULATE	UNABLE TO CALCULATE
8/30/2018	SWENKE IMS	not billed yet		$4.95	1.896
8/30/2018	KUECHLE UNDERGROUND	not billed yet		$1,263.98	484.166
8/30/2018	Q3 CONTRACTING	not billed yet		$2.08	0.787
8/31/2018	XCEL ENERGY GAS	no bill		UNABLE TO CACULATE	UNABLE TO CALCULATE
September					
9/8/2018	SHARPER MANAGEMENT	not billed yet		$134.56	50.426
9/10/2018	Q3 CONTRACTING	not billed yet		$57.24	21.23
9/11/2018	MCNAMARA CONTRACTING	not billed yet		$259.90	96.399
9/12/2018	THOMAS AND SONS	not billed yet		$139.83	52.402
9/12/2018	SWENKE COMPANY	not billed yet		$93.31	34.968
9/14/2018	DOUGLAS KERR UNDERGROUND	not billed yet		UNABLE TO CALCULATE	UNABLE TO CALCULATE
October					
10/4/2018	MATTISON CONTRACTORS	not billed yet		$151.63	56.822
10/9/2018	R & G WALDHALM	not billed yet		UNABLE TO CALCULATE	UNABLE TO CALCULATE
10/10/2018	ST PAUL REGIONAL WATER	not billed yet		UNABLE TO CALCULATE	UNABLE TO CALCULATE
10/15/2018	ST PAUL REGIONAL WATER	not billed yet		$31.05	11.635
10/18/2018	VALLEY RICH COMPANY	not billed yet		$103.23	38.684
November					
11/2/2018	JACON LLC	not billed yet		$368.05	105.623
11/9/2018	C W HOULE	not billed yet		$127.28	36.528
11/14/2018	RP SCHROEDER CONSTRUCTION	not billed yet		$52.91	15.185
11/27/2018	RP SCHROEDER CONSTRUCTION	not billed yet		$110.09	31.593
11/29/2018	HOMEOWNER	not billed yet		$9.04	2.62
December					
12/10/2018	Q3 CONTRACTING			UNABLE TO CALCULATE	UNABLE TO CALCULATE
January					
1/21/2019	GROUND TECH INC	not billed yet		$202.88	56.486
February					
2/4/2019	TRAX EXCAVATING	not billed yet		$166.17	53.519
March					
3/28/2019	PLAAS INCORPORATED	not billed yet		$20.39	6.826
April					
4/18/2019	MP NEXLEVEL	not billed yet		$41.46	17.375
4/23/2019	MP NEXLEVEL	not billed yet		$56.09	23.67
May					
5/6/2019	C&L EXCAVATING	not billed yet		$179.27	83.826
5/16/2019	VALLEY RICH COMPANY	not billed yet		$44.21	20.46
5/24/2019	TELCOM CONSTRUCTION	not billed yet		UNABLE TO CALCULATE	UNABLE TO CALCULATE
5/30/2019	CREATIVE HOMES	not billed yet		$40.51	18.747
5/30/2019	FITZGERALD EXCAVATING	not billed yet		UNABLE TO CALCULATE	UNABLE TO CALCULATE

Damage Date	Excavator Name	Damage Amount Billed	Date Billed[1,2]	Gas Lost Amount[3]	Gas Lost Volume (MCF)
June					
6/4/2019	MICKMAN BROTHERS INC	not billed yet		$33.51	15.791
6/4/2019	FITZGERALD EXCAVATING	not billed yet		$113.22	53.543
6/5/2019	FLOM SEPTIC AND DRAIN	not billed yet		$94.84	42.162
6/7/2019	MATT BULLOCK CONTRACTING	not billed yet		$75.55	35.607
6/10/2019	FOREST LAKE CONTRACTING	not billed yet		$776.21	365.815
6/11/2019	SM HENTGES & SONS INC	not billed yet		UNABLE TO CALCULATE	UNABLE TO CALCULATE
6/13/2019	CURB MASTERS INC	not billed yet		$35.62	16.789
6/14/2019	GOLIATH TECH	not billed yet		$36.31	17.288
6/17/2019	KUECHLE UNDERGROUND	not billed yet		$76.17	35.899
6/18/2019	TA SCHIFSKY & SONS INC	not billed yet		$71.42	33.661
6/19/2019	SELLIN BROTHERS INC	not billed yet		$251.87	119.519
6/21/2019	OMALLEY CONSTRUCTION	not billed yet		UNABLE TO CALCULATE	UNABLE TO CALCULATE
6/25/2019	Q3 CONTRACTING	not billed yet		$161.50	76.11
Total for True-Up Period July 2018 to June 2019				**$10,560.69**	

Total Gas Lost Amount for the True-Up period July 2018 to June 2019 and Allocation to Class	
Residential	$4,936.75
Commercial Firm	$2,969.99
Demand Billed	$565.44
Small Interruptible	$344.31
Medium and Large Interruptib	$1,744.21
Total	**$10,560.69**

Footnotes

1 "No Bill" - damages for which the Company has chosen not to bill. The Company may choose not to bill when facilities are unlocatable, not mapped, mismapped, we have inadequate documentation, when facilties are only nicked, or when billing ourself.

2 "Not Billed Yet" - In general, it takes at least 2 months to bill for damages, but can take longer because of time to complete repairs and staffing to process the paperwork.

3 "Unable to calculate" - we do not have enough information to calclate the amount of gas lost. This can happen because field personnel did not capture enough information, the the contractor pinched over the line so it is unclear how long the line was blowing, or the hole was obstructed.

Northern States Power Company
Gas Operations - Minnesota State
UNAUTHORIZED GAS USAGE AND PENALTIES

Date Billed (1-2 days after usage)	Customer Name	Priority	Unauthorized Gas Used (thm)	Commodity Rate per Therm	Commodity Calculation (thm*rate)	Penalty per Therm	Financial Penalty Amount
	[PROTECTED DATA BEGINS						
2/22/2019		1A	614	0.096354	$59.16	$5.00	$3,070.00
2/22/2019		1A	437	0.096354	$42.11	$5.00	$2,185.00
3/7/2019		4	7,549.08	0.047512	$358.67	$5.00	$37,745.40
2/11/2019		1A	11.86	0.096354	$1.14	$5.00	$59.30
3/1/2019		1B	1.19	0.096354	$0.11	$5.00	$5.95
3/4/2019		F	479.73	0	$0.00	$5.00	$2,398.65
2/21/2019		1B	1386	0.096354	$133.55	$5.00	$6,930.00
2/11/2019		3	4031.21	0.047512	$191.53	$5.00	$20,156.05
2/15/2019		8	22,063.00	0.43461	$9,588.80	$5.00	$110,315.00
2/19/2019		1B	14	0.096354	$1.35	$5.00	$70.00
3/12/2019		1E	633	0.047512	$30.08	$5.00	$3,165.00
2/7/2019		5	462.96	0.047512	$22.00	$5.00	$2,314.80
2/21/2019		4	10.78	0.047512	$0.51	$5.00	$53.90
2/6/2019		1B	915.51	0.096354	$88.21	$5.00	$4,577.55
2/11/2019		1B	27	0.096354	$2.60	$5.00	$135.00
2/19/2019		3	6	0.047512	$0.29	$5.00	$30.00
2/27/2019		1B	58.61	0.096354	$5.65	$5.00	$293.05
3/4/2019		1A	24	0.096354	$2.31	$5.00	$120.00
2/14/2019		4	129.38	0.047512	$6.15	$5.00	$646.90
2/21/2019		1B	131	0.096354	$12.62	$5.00	$655.00
3/4/2019		1A	18	0.096354	$1.73	$5.00	$90.00
3/4/2019		1B	11.82	0.096354	$1.14	$5.00	$59.10
2/26/2019		1B	10.66	0.096354	$1.03	$5.00	$53.30
2/22/2019		1B	5	0.096354	$0.48	$5.00	$25.00
3/21/2019		2	1929	0.047512	$91.65	$5.00	$9,645.00
2/20/2019		3	119	0.096354	$11.47	$5.00	$595.00
3/7/2019		1B	81.51	0.096354	$7.85	$5.00	$407.55
2/6/2019		1A	50.26	0.096354	$4.84	$5.00	$251.30
3/6/2019		1B	2.38	0.096354	$0.23	$5.00	$11.90
2/25/2019		1B	155.18	0.096354	$14.95	$5.00	$775.90
3/20/2019		3	1735	0.047512	$82.43	$5.00	$8,675.00
2/21/2019		1A	76	0.096354	$7.32	$5.00	$380.00
2/22/2019		1B	14.21	0.096354	$1.37	$5.00	$71.05
2/21/2019		1B	4.74	0.096354	$0.46	$5.00	$23.70
2/13/2019		1B	3	0.096354	$0.29	$5.00	$15.00
2/12/2019		1A	159.87	0.096354	$15.40	$5.00	$799.35
2/18/2019		3	56.81	0.047512	$2.70	$5.00	$284.05
3/6/2019		1A	13	0.096354	$1.25	$5.00	$65.00
2/15/2019		5	10.9	0.047512	$0.52	$5.00	$54.50
2/25/2019		1B	1634.79	0.096354	$157.52	$5.00	$8,173.95
2/15/2019		1B	435.9	0.047512	$20.71	$5.00	$2,179.50
2/21/2019		1B	1491	0.096354	$143.66	$5.00	$7,455.00
3/6/2019		1B	205.71	0.096354	$19.82	$5.00	$1,028.55
2/21/2019		1A	1	0.096354	$0.10	$5.00	$5.00
3/7/2019		1A	246.18	0.096354	$23.72	$5.00	$1,230.90
3/7/2019		1A	22.5	0.096354	$2.17	$5.00	$112.50
3/7/2019		1A	69	0.096354	$6.65	$5.00	$345.00
3/11/2019		1B	1113	0.096354	$107.24	$5.00	$5,565.00
3/6/2019		1B	1320	0.096354	$127.19	$5.00	$6,600.00
2/20/2019		1B	675	0.096354	$65.04	$5.00	$3,375.00
2/15/2019		1B	958.57	0.096354	$92.36	$5.00	$4,792.85
2/18/2019		4	2,038.00	0.047512	$96.83	$5.00	$10,190.00
2/13/2019		1B	228.32	0.096354	$22.00	$5.00	$1,141.60
2/13/2019		1B	9.55	0.096354	$0.92	$5.00	$47.75
2/28/2019		6	43.03	0.043461	$1.87	$5.00	$215.15
2/19/2019		4	324	0.047512	$15.39	$5.00	$1,620.00
2/7/2019		1B	35.31	0.096354	$3.40	$5.00	$176.55
2/21/2019		1B	1054	0.096354	$101.56	$5.00	$5,270.00
2/21/2019		3	78	0.047512	$3.71	$5.00	$390.00
2/15/2019		5	108	0.047512	$5.13	$5.00	$540.00
2/25/2019		1A	586	0.096354	$56.46	$5.00	$2,930.00
2/25/2019		1B	277	0.096354	$26.69	$5.00	$1,385.00
2/7/2019		4	150.35	0.047512	$7.14	$5.00	$751.75
2/19/2019		1A	191.44	0.096354	$18.45	$5.00	$957.20
2/26/2019		1A	22.44	0.096354	$2.16	$5.00	$112.20
2/28/2019		1A	1	0.096354	$0.10	$5.00	$5.00
2/27/2019		1B	2	0.096354	$0.19	$5.00	$10.00
3/8/2019		1B	6	0.096354	$0.58	$5.00	$30.00
2/19/2019		1B	2760.16	0.096354	$265.95	$5.00	$13,800.80
2/19/2019		1B	1.63	0.096354	$0.16	$5.00	$8.15
2/28/2019		1A	1126	0.096354	$108.49	$5.00	$5,630.00
3/8/2019		1B	1466	0.096354	$141.25	$5.00	$7,330.00
3/12/2019		1A	3	0.096354	$0.29	$5.00	$15.00
3/12/2019		1A	6	0.096354	$0.58	$5.00	$30.00
3/12/2019		1A	4	0.096354	$0.39	$5.00	$20.00
	PROTECTED DATA ENDS]						

Northern States Power Company
Gas Operations - Minnesota State
UNAUTHORIZED GAS USAGE AND PENALTIES

Date Billed (1-2 days after usage)	Customer Name	Priority	Unauthorized Gas Used (thm)	Commodity Rate per Therm	Commodity Calculation (thm*rate)	Penalty per Therm	Financial Penalty Amount
	[PROTECTED DATA BEGINS						
2/22/2019		1A	9.49	0.096354	$0.91	$5.00	$47.45
2/8/2019		1B	646.28	0.096354	$62.27	$5.00	$3,231.40
2/11/2019		2	131	0.047512	$6.22	$5.00	$655.00
2/14/2019		1B	574.69	0.096354	$55.37	$5.00	$2,873.45
2/20/2019		1A	1	0.096354	$0.10	$5.00	$5.00
2/5/2019		F	7,796.20	0	$0.00	$5.00	$38,981.00
2/22/2019		1B	1	0.096354	$0.10	$5.00	$5.00
3/1/2019		3	2,596.42	0.047512	$123.36	$5.00	$12,982.10
2/21/2019		1B	35.58	0.096354	$3.43	$5.00	$177.90
2/13/2019		1B	3.39	0.096354	$0.33	$5.00	$16.95
2/19/2019		1A	1355	0.096354	$130.56	$5.00	$6,775.00
2/15/2019		1B	9.36	0.096354	$0.90	$5.00	$46.80
3/1/2019		1B	1	0.096354	$0.10	$5.00	$5.00
2/18/2019		3	255.79	0.047512	$12.15	$5.00	$1,278.95
3/5/2019		1B	41.14	0.096354	$3.96	$5.00	$205.70
2/26/2019		1A	6	0.096354	$0.58	$5.00	$30.00
2/26/2019		1A	1	0.096354	$0.10	$5.00	$5.00
2/26/2019		1A	22	0.096354	$2.12	$5.00	$110.00
2/26/2019		1A	329	0.096354	$31.70	$5.00	$1,645.00
2/26/2019		1A	18	0.096354	$1.73	$5.00	$90.00
2/26/2019		1A	1	0.096354	$0.10	$5.00	$5.00
2/26/2019		1A	27.38	0.096354	$2.64	$5.00	$136.90
2/19/2019		3	26	0.047512	$1.24	$5.00	$130.00
2/13/2019		4	21	0.047512	$1.00	$5.00	$105.00
2/27/2019		1B	53	0.096354	$5.11	$5.00	$265.00
2/27/2019		1A	7.09	0.096354	$0.68	$5.00	$35.45
2/27/2019		1B	10.65	0.096354	$1.03	$5.00	$53.25
3/8/2019		3	676	0.047512	$32.12	$5.00	$3,380.00
3/6/2019		1B	1.18	0.096354	$0.11	$5.00	$5.90
2/6/2019		1B	73.99	0.096354	$7.13	$5.00	$369.95
3/8/2019		1A	246	0.096354	$23.70	$5.00	$1,230.00
2/13/2019		1B	1107.21	0.096354	$106.68	$5.00	$5,536.05
3/7/2019		1B	61.43	0.096354	$5.92	$5.00	$307.15
2/19/2019		3	1091	0.047512	$51.84	$5.00	$5,455.00
2/27/2019		1B	2,473.00	0.096354	$238.28	$5.00	$12,365.00
3/4/2019		1B	7.33	0.096354	$0.71	$5.00	$36.65
2/25/2019		1B	2	0.096354	$0.19	$5.00	$10.00
2/15/2019		7	57,472.13	0.043461	$2,497.80	$5.00	$287,360.65
2/21/2019		1B	178	0.096354	$17.15	$5.00	$890.00
2/21/2019		1B	5	0.096354	$0.48	$5.00	$25.00
3/6/2019		1B	27.28	0.096354	$2.63	$5.00	$136.40
2/28/2019		3	2,082.00	0.047512	$98.92	$5.00	$10,410.00
2/26/2019		1B	802.89	0.096354	$77.36	$5.00	$4,014.45
2/22/2019		1A	59.3	0.096354	$5.71	$5.00	$296.50
2/19/2019		1A	21	0.096354	$2.02	$5.00	$105.00
3/1/2019		1A	1647.87	0.096354	$158.78	$5.00	$8,239.35
2/13/2019		1B	1.63	0.047512	$0.08	$5.00	$8.15
2/15/2019		3	3,435.61	0.047512	$163.23	$5.00	$17,178.05
2/22/2019		1B	441	0.096354	$42.49	$5.00	$2,205.00
2/22/2019		1B	21	0.096354	$2.02	$5.00	$105.00
2/21/2019		1A	26	0.096354	$2.51	$5.00	$130.00
2/22/2019		1A	63	0.096354	$6.07	$5.00	$315.00
2/22/2019		1A	127.87	0.096354	$12.32	$5.00	$639.35
2/22/2019		1A	124	0.096354	$11.95	$5.00	$620.00
2/26/2019		3	75.47	0.047512	$3.59	$5.00	$377.35
2/27/2019		1A	401	0.096354	$38.64	$5.00	$2,005.00
2/21/2019		1B	3,917.14	0.096354	$377.43	$5.00	$19,585.70
2/19/2019		3	174.83	0.047512	$8.31	$5.00	$874.15
2/20/2019		F	60	0.047512	$2.85	$5.00	$300.00
2/20/2019		F	880	0.047512	$41.81	$5.00	$4,400.00
	PROTECTED DATA ENDS]						
Total			153,898.15		$ 16,928.44		$ 769,490.75

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Residential Demand	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h^)	(i)	(j)	(k)
2018 - 2019	Calculated* PGA Sales	Calendar Month Actual Sales	Sales* Difference	Calendar Demand Rate	Demand Cost* Over/(Under)	Capacity Release Over(Under)	Lagged* Over/(Under)	Calculated Demand Rate Adder**	Actual* Demand Rate Adder	Actual* Demand Rate Recovery	Rate Adder* Over/(Under)	Net* Over/(Under)
	Page 2, col. (d)		(b - a)		(c * d)	Page 2, col. (u)	(e[-2] + f[-2] + j[-2])	min(g/a, cap)		(b * h^)	(g + i)	(e + f + i)
Jul	5,897,142	6,308,004	410,862	$0.05040	$20,707	$0						$20,708
Aug	6,095,783	6,733,188	637,405	$0.05040	$32,125	$0						$32,125
Sep	8,095,561	8,200,332	104,771	$0.04771	$4,999	$0						$4,999
Oct	18,014,949	25,087,990	7,073,041	$0.04771	$337,455	$0	$52,833		($0.00293)	($73,508)	($20,675)	$263,947
Nov	38,870,789	52,006,960	13,136,171	$0.09364	$1,230,071	$0	$4,999		($0.00013)	($6,761)	($1,762)	$1,223,310
Dec	60,132,341	58,987,217	(1,145,124)	$0.09490	($108,672)	$0	$316,780		($0.00527)	($310,863)	$5,917	($419,535)
Jan	68,605,146	79,273,121	10,667,975	$0.09490	$1,012,391	$0	$1,228,309		($0.00995)	($788,768)	$439,541	$223,623
Feb	57,450,991	67,341,900	9,890,909	$0.09490	$938,647	$0	($102,755)		$0.00179	$120,542	$17,787	$1,059,189
Mar	45,743,583	54,845,094	9,101,511	$0.09487	$863,460	$0	$1,451,932		($0.00995)	($545,709)	$906,223	$317,752
Apr	24,315,222	28,196,666	3,881,444	$0.04861	$188,677	$4	$956,434		($0.01215)	($342,589)	$613,845	($153,909)
May	11,497,996	17,191,600	5,693,604	$0.04896	$278,759	$4	$1,769,684		($0.01224)	($210,425)	$1,559,259	$68,337
Jun	7,392,084	8,570,314	1,178,230	$0.04896	$57,686	$4	$802,525					$57,690
Tot	352,111,587	412,742,386	60,630,799		$4,856,305					($2,158,080)		$2,698,237

Commercial Non-Demand	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h^)	(i)	(j)	(k)
2018 - 2019	Calculated* PGA Sales	Calendar Month Actual Sales	Sales* Difference	Calendar Demand Rate	Demand Cost* Over/(Under)	Capacity Release Over(Under)	Lagged* Over/(Under)	Calculated Demand Rate Adder*	Actual* Demand Rate Adder	Demand Rate* Recovery	Demand* Rate Adder Over/(Under)	Net* Over/(Under)
	Page 2, col. (f)		(b - a)		(c * d)	Page 2, col. (u)	(e[-2] + f[-2] + j[-2])	min(g/a, cap)		(b * h^)	(g + i)	(e + f + i)
Jul	4,870,432	4,142,259	(728,173)	$0.05040	($36,700)	$0						($36,700)
Aug	4,584,202	4,619,227	35,025	$0.05040	$1,765	$0						$1,765
Sep	4,844,213	5,404,414	560,201	$0.04771	$26,727	$0						$26,727
Oct	6,165,378	14,537,094	8,371,716	$0.04771	$399,415	$0	($34,935)		$0.00568	$82,571	$47,636	$481,985
Nov	12,590,506	29,677,720	17,087,214	$0.09364	$1,600,047	$0	$26,727		($0.00212)	($62,917)	($36,190)	$1,537,130
Dec	24,787,847	35,139,065	10,351,218	$0.09490	$982,331	$0	$447,051		($0.00995)	($349,634)	$97,417	$632,697
Jan	38,831,183	43,206,606	4,375,423	$0.09490	$415,228	$0	$1,563,857		($0.00995)	($429,906)	$1,133,951	($14,678)
Feb	43,503,773	36,538,178	(6,965,595)	$0.09490	($661,035)	$0	$1,079,748		($0.00995)	($363,555)	$716,193	($1,024,590)
Mar	36,519,747	33,592,746	(2,927,001)	$0.09487	($277,685)	$0	$1,549,179		($0.00995)	($334,248)	$1,214,931	($611,932)
Apr	30,240,875	17,551,841	(12,689,034)	$0.04861	($616,814)	$2	$55,158		($0.00182)	($31,944)	$23,213	($648,756)
May	15,380,064	10,229,246	(5,150,818)	$0.04896	($252,184)	$2	$937,247		($0.01224)	($125,206)	$812,041	($377,388)
Jun	9,495,022	4,863,918	(4,631,104)	$0.04896	($226,739)	$2	($593,598)					($226,737)
Tot	231,813,242	239,502,315	7,689,073		$1,354,356					($1,614,839)		($260,476)

Total Firm Demand Cost Recovery Revenue (Net)	**$6,210,661**		**($3,772,919)**	**$2,437,761**

*Due to the use of MN Company forecast sales instead of MN only sales to allocate the PGA annual sales to monthly, the demand cost over-recovery credit to customers was $876,013 more than the $2,896,906 actual over-recovery for this period.

Note that Col (g) for Oct reflects the total of Jul and Aug, not just Aug.

Note that Col (h) is adjusted to have the opposite sign of Col (g).

** The "cap" is determined by:

Summer -- 0.25 * Dmd Unit Cost/Thm, Annual (from PGA Sch A, p. 3, Line 10)

Winter -- 1.25 * Levelived Demand - Dmd Unit Cost/Thm, Total (from PGA Sch. A, p. 3, Line 10);

Levelized Demand = (Non-Demand Billed Allocation, Annual + Non-Demand Billed Allocation, Winter)/MN Firm Therm Sales, Annual (from PGA Sch. A, p. 3, Lines 7 & 9)

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As Filed - Schedule I
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PGA CALCULATED SALES CALCULATION

2018 - 2019	(a) Monthly % of Annual Budgeted Sales	(b) Annual PGA Forecasted Sales Per MN Rule	(c) Residential PGA Sales %	(d) **Residential* Calculated PGA Sales**	(e) Non-Demand Billed Commercial PGA Sales %	(f) **Commercial* Calculated PGA Sales**
		(a * Annual Sales	(d / b)	**(thm)**	(f / b)	**(thm)**
July	1.84%	10,767,574	54.8%	**5,897,142**	45.2%	**4,870,432**
August	1.83%	10,679,985	57.1%	**6,095,783**	42.9%	**4,584,202**
September	2.22%	12,939,774	62.6%	**8,095,561**	37.4%	**4,844,213**
October	4.14%	24,180,327	74.5%	**18,014,949**	25.5%	**6,165,378**
November	8.81%	51,461,295	75.5%	**38,870,789**	24.5%	**12,590,506**
December	14.54%	84,920,188	70.8%	**60,132,341**	29.2%	**24,787,847**
January	18.40%	107,436,329	63.9%	**68,605,146**	36.1%	**38,831,183**
February	17.29%	100,954,764	56.9%	**57,450,991**	43.1%	**43,503,773**
March	14.09%	82,263,330	55.6%	**45,743,583**	44.4%	**36,519,747**
April	9.34%	54,556,097	44.6%	**24,315,222**	55.4%	**30,240,875**
May	4.60%	26,878,060	42.8%	**11,497,996**	57.2%	**15,380,064**
June	2.89%	16,887,106	43.8%	**7,392,084**	56.2%	**9,495,022**
Annual	100.00%	583,924,829		**352,111,587**		**231,813,242**

Compliance Reporting Per G002/M-03-843

Description	Actual Demand Recovery	Monthly* Demand Recovery	Demand Recovery Absent Monthly True-up
Residential	$31,861,377	($2,158,080)	$34,019,457
Commercial	$17,976,329	($1,614,839)	$19,591,168
Demand-Billed	$1,815,300	$0	$1,815,300
Total	$51,653,006	($3,772,919)	$55,425,924

Description	Actual Demand Over/(Under)	Monthly Demand Recovery	Demand Recovery Absent Monthly True-up
Residential	$2,245,600	($2,158,080)	$4,403,680
Commercial	$809,112	($1,614,839)	$2,423,950
Demand-Billed	$43,749	$0	$43,749
Total	$3,098,460	($3,772,919)	$6,871,379

CAPACITY RELEASE ADJUSTMENT CALCULATION

2018 - 2019	(j) NSPM** Actual Capacity Release***	(k) NSPM** Capacity Release in PGA	(l) NSPM** Capacity Release not in PGA	(m) MN-State Allocator	(n) MN-state Capacity Release Not in PGA	(o) MN-State Firm Demand Allocator	(p) MN-State Firm Capacity Release Not in PGA	(q) MN-State Residential Calendar Month Actual Sales	(r) MN-State Commercial Calendar Month Actual Sales	(s) MN-State Residential % of Firm Non-Demand Billed Sales	(t) MN-State Commercial % of Firm Non-Demand Billed Sales	(u) **MN-State Residential Capacity Release Not in PGA**	(v) **MN-State Commercial Capacity Release Not in PGA**
			j - k		l * m		n * o	Page 1, col. (b)	Page 1, col. (b)	q / (q + r)	r / (q + r)	**p * s**	**p * t**
July	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	6,308,004	4,142,259	60.36%	39.64%	**($0)**	**($0)**
August	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	6,733,188	4,619,227	59.31%	40.69%	**($0)**	**($0)**
September	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	8,200,332	5,404,414	60.28%	39.72%	**($0)**	**($0)**
October	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	25,087,990	14,537,094	63.31%	36.69%	**($0)**	**($0)**
November	$0	$0	$0	87.51%	$0	96.67%	$0	52,006,960	29,677,720	63.67%	36.33%	**$0**	**$0**
December	$0	$0	$0	87.51%	$0	96.67%	$0	58,987,217	35,139,065	62.67%	37.33%	**$0**	**$0**
January	$0	$0	$0	87.51%	$0	96.67%	$0	79,273,121	43,206,606	64.72%	35.28%	**$0**	**$0**
February	$0	$0	$0	87.51%	$0	96.67%	$0	67,341,900	36,538,178	64.83%	35.17%	**$0**	**$0**
March	$0	$0	$0	87.51%	$0	96.67%	$0	54,845,094	33,592,746	62.02%	37.98%	**$0**	**$0**
April	($25,840)	($25,833)	($7)	87.51%	($6)	96.67%	($6)	28,196,666	17,551,841	61.63%	38.37%	**($4)**	**($2)**
May	($25,840)	($25,833)	($7)	87.51%	($6)	96.67%	($6)	17,191,600	10,229,246	62.70%	37.30%	**($4)**	**($2)**
June	($25,840)	($25,833)	($7)	87.51%	($6)	96.67%	($6)	8,570,314	4,863,918	63.79%	36.21%	**($4)**	**($2)**
Annual	($168,623)	($168,601)	($22)		($19)		($18)	412,742,386	239,502,315			**($12)**	**($7)**

*Due to the use of MN Company forecast sales instead of MN only sales to allocate the PGA annual sales to monthly, the demand cost over-recovery credit to customers was $876,013 more than the $2,896,906 actual over-recovery for this period.
** NSPM includes service to Minnesota and North Dakota
*** Actual Capacity Release data is lagged by two months.

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Residential Demand 2018 - 2019	(a) Calculated PGA Sales	(b) Calendar Month Actual Sales	(c) Sales Difference	(d) Calendar Demand Rate	(e) Demand Cost Over/(Under)	(f) Capacity Release Over(Under)	(g) Lagged Over/(Under)	(h) Calculated Demand Rate Adder*	(h^) Actual Demand Rate Adder	(i) Actual Demand Rate Recovery	(j) Rate Adder Over/(Under)	(k) Net Over/(Under)
	Page 2, col. (d)		(b - a)		(c * d)	Page 2, col. (u)	(e[-2] + f[-2] + j[-2])	min(g/a, cap)		(b * h^)	(g + i)	(e + f + i)
Jul	6,436,761	6,308,004	(128,757)	$0.05040	($6,489)	$0						($6,489)
Aug	6,611,941	6,733,188	121,247	$0.05040	$6,111	$0						$6,111
Sep	8,703,047	8,200,332	(502,715)	$0.04771	($23,985)	$0						($23,984)
Oct	18,925,070	25,087,990	6,162,920	$0.04771	$294,033	$0	($378)		$0.00002	$502	$123	$294,535
Nov	40,683,015	52,006,960	11,323,945	$0.09364	$1,060,374	$0	($23,984)		$0.00059	$30,684	$6,700	$1,091,058
Dec	63,024,149	58,987,217	(4,036,932)	$0.09490	($383,105)	$0	$294,156		($0.00467)	($275,470)	$18,686	($658,575)
Jan	71,778,442	79,273,121	7,494,679	$0.09490	$711,245	$0	$1,067,074		($0.00995)	($788,768)	$278,306	($77,523)
Feb	60,231,402	67,341,900	7,110,498	$0.09490	$674,786	$0	($364,419)		$0.00605	$407,418	$43,000	$1,082,205
Mar	47,787,668	54,845,094	7,057,426	$0.09487	$669,538	$0	$989,551		($0.00995)	($545,709)	$443,843	$123,829
Apr	25,673,687	28,196,666	2,522,979	$0.04861	$122,642	$4	$717,786		($0.01215)	($342,589)	$375,196	($219,944)
May	12,219,791	17,191,600	4,971,809	$0.04896	$243,420	$4	$1,113,381		($0.01224)	($210,425)	$902,956	$32,998
Jun	8,030,283	8,570,314	540,031	$0.04896	$26,440	$4	$497,842					$26,444
Tot	370,105,256	412,742,386	42,637,130		$3,395,010					($1,724,357)		$1,670,665

Commercial Non-Demand 2018 - 2019	(a) Calculated PGA Sales	(b) Calendar Month Actual Sales	(c) Sales Difference	(d) Calendar Demand Rate	(e) Demand Cost Over/(Under)	(f) Capacity Release Over(Under)	(g) Lagged Over/(Under)	(h) Calculated Demand Rate Adder*	(h^) Actual Demand Rate Adder	(i) Demand Rate Recovery	(j) Demand Rate Adder Over/(Under)	(k) Net Over/(Under)
	Page 2, col. (f)		(b - a)		(c * d)	Page 2, col. (u)	(e[-2] + f[-2] + j[-2])	min(g/a, cap)		(b * h^)	(g + i)	(e + f + i)
Jul	4,132,278	4,142,259	9,981	$0.05040	$503	$0						$503
Aug	4,360,007	4,619,227	259,220	$0.05040	$13,065	$0						$13,065
Sep	5,521,362	5,404,414	(116,948)	$0.04771	($5,580)	$0						($5,580)
Oct	11,462,378	14,537,094	3,074,716	$0.04771	$146,695	$0	$13,568		($0.00118)	($17,154)	($3,586)	$129,541
Nov	22,742,900	29,677,720	6,934,820	$0.09364	$649,377	$0	($5,580)		$0.00025	$7,419	$1,840	$656,796
Dec	35,956,949	35,139,065	(817,884)	$0.09490	($77,617)	$0	$143,109		($0.00398)	($139,853)	$3,255	($217,471)
Jan	40,311,768	43,206,606	2,894,838	$0.09490	$274,720	$0	$651,216		($0.00995)	($429,906)	$221,311	($155,186)
Feb	34,107,493	36,538,178	2,430,685	$0.09490	$230,672	$0	($74,362)		$0.00218	$79,653	$5,291	$310,325
Mar	27,859,794	33,592,746	5,732,952	$0.09487	$543,885	$0	$496,031		($0.00995)	($334,248)	$161,783	$209,637
Apr	14,056,558	17,551,841	3,495,283	$0.04861	$169,906	$2	$235,963		($0.01215)	($213,255)	$22,708	($43,347)
May	8,725,593	10,229,246	1,503,653	$0.04896	$73,619	$2	$705,668		($0.01224)	($125,206)	$580,462	($51,585)
Jun	4,582,493	4,863,918	281,425	$0.04896	$13,779	$2	$192,616					$13,781
Tot	213,819,573	239,502,315	25,682,742		$2,033,023					($1,172,549)		$860,481

Total Firm Demand Cost Recovery Revenue (Net)	**$5,428,033**	**($2,896,906)**	**$2,531,146**

Note that Col (g) for Oct reflects the total of Jul and Aug, not just Aug.
Note that Col (h) is adjusted to have the opposite sign of Col (g).
* The "cap" is determined by:
Summer -- 0.25 * Dmd Unit Cost/Thm, Annual (from PGA Sch A, p. 3, Line 10)
Winter -- 1.25 * Levelived Demand - Dmd Unit Cost/Thm, Total (from PGA Sch. A, p. 3, Line 10);
Levelized Demand = (Non-Demand Billed Allocation, Annual + Non-Demand Billed Allocation, Winter)/MN Firm Therm Sales, Annual (from PGA Sch. A, p. 3, Lines 7 & 9)

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PGA CALCULATED SALES CALCULATION

2018 - 2019	(a) Monthly % of Annual Budgeted Sales	(b) Annual PGA Forecasted Sales Per MN Rule	(c) Residential PGA Sales %	(d) **Residential Calculated PGA Sales**	(e) Non-Demand Billed Commercial PGA Sales %	(f) **Commercial Calculated PGA Sales**
		(a * Annual Sales)	(d / b)	**(thm)**	(f / b)	**(thm)**
July	1.81%	10,569,039	60.9%	**6,436,761**	39.1%	**4,132,278**
August	1.88%	10,971,948	60.3%	**6,611,941**	39.7%	**4,360,007**
September	2.44%	14,224,409	61.2%	**8,703,047**	38.8%	**5,521,362**
October	5.20%	30,387,448	62.3%	**18,925,070**	37.7%	**11,462,378**
November	10.86%	63,425,915	64.1%	**40,683,015**	35.9%	**22,742,900**
December	16.95%	98,981,098	63.7%	**63,024,149**	36.3%	**35,956,949**
January	19.20%	112,090,210	64.0%	**71,778,442**	36.0%	**40,311,768**
February	16.16%	94,338,895	63.8%	**60,231,402**	36.2%	**34,107,493**
March	12.96%	75,647,462	63.2%	**47,787,668**	36.8%	**27,859,794**
April	6.80%	39,730,245	64.6%	**25,673,687**	35.4%	**14,056,558**
May	3.59%	20,945,384	58.3%	**12,219,791**	41.7%	**8,725,593**
June	2.16%	12,612,776	63.7%	**8,030,283**	36.3%	**4,582,493**
Annual	100.00%	583,924,829		**370,105,256**		**213,819,573**

Compliance Reporting Per G002/M-03-843

Description	Actual Demand Recovery	Monthly Demand Recovery	Demand Recovery Absent Monthly True-up
Residential	$31,861,377	($1,724,357)	$33,585,734
Commercial	$17,976,329	($1,172,549)	$19,148,878
Demand-Billed	$1,815,300	$0	$1,815,300
Total	$51,653,006	($2,896,906)	$54,549,911

Description	Actual Demand Over/(Under)	Monthly Demand Recovery	Demand Recovery Absent Monthly True-up
Residential	$2,245,600	($1,724,357)	$3,969,957
Commercial	$809,112	($1,172,549)	$1,981,660
Demand-Billed	$43,749	$0	$43,749
Total	$3,098,460	($2,896,906)	$5,995,366

CAPACITY RELEASE ADJUSTMENT CALCULATION

2018 - 2019	(j) NSPM* Actual Capacity Release**	(k) NSPM* Capacity Release in PGA	(l) NSPM* Capacity Release not in PGA	(m) MN-State Allocator	(n) MN-state Capacity Release Not in PGA	(o) MN-State Firm Demand Allocator	(p) MN-State Firm Capacity Release Not in PGA	(q) MN-State Residential Calendar Month Actual Sales	(r) MN-State Commercial Calendar Month Actual Sales	(s) MN-State Residential % of Firm Non-Demand Billed Sales	(t) MN-State Commercial % of Firm Non-Demand Billed Sales	(u) **MN-State Residential Capacity Release Not in PGA**	(v) **MN-State Commercial Capacity Release Not in PGA**
			j - k		l * m		n * o	Page 1, col. (b)	Page 1, col. (b)	q / (q + r)	r / (q + r)	**p * s**	**p * t**
July	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	6,308,004	4,142,259	60.36%	39.64%	**($0)**	**($0)**
August	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	6,733,188	4,619,227	59.31%	40.69%	**($0)**	**($0)**
September	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	8,200,332	5,404,414	60.28%	39.72%	**($0)**	**($0)**
October	($22,776)	($22,776)	($0)	87.57%	($0)	96.65%	($0)	25,087,990	14,537,094	63.31%	36.69%	**($0)**	**($0)**
November	$0	$0	$0	87.51%	$0	96.67%	$0	52,006,960	29,677,720	63.67%	36.33%	**$0**	**$0**
December	$0	$0	$0	87.51%	$0	96.67%	$0	58,987,217	35,139,065	62.67%	37.33%	**$0**	**$0**
January	$0	$0	$0	87.51%	$0	96.67%	$0	79,273,121	43,206,606	64.72%	35.28%	**$0**	**$0**
February	$0	$0	$0	87.51%	$0	96.67%	$0	67,341,900	36,538,178	64.83%	35.17%	**$0**	**$0**
March	$0	$0	$0	87.51%	$0	96.67%	$0	54,845,094	33,592,746	62.02%	37.98%	**$0**	**$0**
April	($25,840)	($25,833)	($7)	87.51%	($6)	96.67%	($6)	28,196,666	17,551,841	61.63%	38.37%	**($4)**	**($2)**
May	($25,840)	($25,833)	($7)	87.51%	($6)	96.67%	($6)	17,191,600	10,229,246	62.70%	37.30%	**($4)**	**($2)**
June	($25,840)	($25,833)	($7)	87.51%	($6)	96.67%	($6)	8,570,314	4,863,918	63.79%	36.21%	**($4)**	**($2)**
Annual	($168,623)	($168,601)	($22)		($19)		($18)	412,742,386	239,502,315			**($12)**	**($7)**

* NSPM includes service to Minnesota and North Dakota
** Actual Capacity Release data is lagged by two months.