Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

November 1, 2019

—Via Electronic Filing—

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

RE: SUPPLEMENTAL FILING
CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-19-498

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits this filing to supplement our August 2, 2019 Petition in the above referenced docket.

In accordance with the Department's Comments, and our Reply Comments, we are including two periods of entitlement costs with this Supplemental Filing. The first period shows annual costs effective November 1, 2019 and does not include the prospective interstate pipeline rate changes discussed in our original Petition. The second period includes interstate pipeline rate increases to be effective January 1, 2020 subject to refund.

We include two additional adjustments with this Supplemental Filing, which reduces costs by $9,466 for Minnesota and $10,810 for the total system in the November 1 scenario, and by $8,434 in Minnesota and $9,631 for the total system in the January 1 scenario from our initial petition.

In total, these adjustments result in a total annual cost, effective November 1, 2019, of $58,204,612 and a total annual cost of $72,720,289 effective with the interstate pipeline rate changes on January 1, 2020.

As a result, we include the following revised attachments:

Attachment 1, Schedule 2, Pages 1-2
Attachment 1, Schedule 3, Page 1
Attachment 1, Schedule 5, Page 1
Attachment 2, Schedule 1, Pages 1-3
Attachment 2, Schedule 2, Pages 1-4
Attachment 3, Schedule 1, Page 2

Changes to Reflect Pipeline Rates November 1, 2019

Our initial Petition noted Federal Energy Regulatory Commission Section 4 rate case filings by both Northern Natural Gas (Northern Natural) and Viking Gas Transmission Co (Viking), with increased rates to become effective January 1, 2020. Our initial Petition incorporated these increased rates beginning in January 2020. The Department noted in its Comments, and we agreed in our Reply Comments, to separate these costs into two periods before and after the effectiveness of the FERC rate change. As a result, we have included two versions of **Attachment 1, Schedule 2, Pages 1 and 2.**

The first version (2019 version) displays the annual costs effective November 1 through the end of December 2019. It does not include the effects of the increase in Northern Natural and Viking tariff rates effective January 1, 2020. Thus, it reflects the costs which will be effective in November and December, 2019. The second version (2020 version) reflects all demand costs effective on January 1, 2020. These costs include the federal rate changes by Northern Natural and Viking, as well as the adjustment discussed below. Together, these changes result in a proposed cost increase of $14,515,677 for the total system from the first 2019 version.

Changes to Demand Entitlement Levels

There are two updates to the cost level provided in the Petition filed August 2, 2019 in Docket No. G002/M-19-498. The change is summarized below and presented in both version of the revised **Attachment 1, Schedule 2, Pages 1 and 2**, and **Attachment 2, Schedule 1, Page 1**. The change reflects an increase in transportation entitlements and a cost decrease from those identified in the Petition.

First the Petition noted a need to acquire an additional 10,794 Dth/day of delivered supply service on Viking, for December through February to meet seasonal peaking needs. Market conditions on Viking have been driven by favorable spot price differences between Emerson, Manitoba, Canada and the Chicago market resulting in Viking capacity being sold out for full-path transportation. Since filing the Petition, we have acquired a delivered supply agreement for 11,000 Dth/day in lieu of the seasonal Viking Capacity. This is 206 Dth/day more than reflected in the Petition, as shown on both versions of **Attachment 2, Schedule 1, Pages 1 and 2** due to contracting in round numbers. The increase in capacity is also reflected in **Attachment 1, Schedule 3, Page 1**, **Attachment 1, Schedule 5**, and **Attachment 2, Schedule 1, Page 3**.

Delivered supply provides a service comparable to holding firm pipeline capacity by obtaining a firm commitment for gas at the Town Border Station (TBS). In this arrangement the gas supplier holds firm transportation capacity on Viking, and commits to deliver gas to NSP at our TBS thereby performing the transportation themselves. In return for this commitment, we agree to pay the supplier a demand charge. Our payment of the demand charge typically offsets some of the demand charge the supplier owes to Viking. As a result a delivered supply contract, then, functions similarly to a pipeline transportation contract. This allows us the assurance of firm gas supply needed to meet our design requirements, while also being cost effective. The agreement reduces total system costs by $96,322 which includes $84,349 in cost savings for Minnesota over the amount estimated in the Petition of the Viking maximum tariff rate as reflected in **Attachment 1, Schedule 2, Page 1 and 2**.

The Department noted in its comments that we contemplated this arrangement. We would note that our delivered supply agreements are split into two categories, a demand charge reserving the counterparties transportation capacity for our use; and a commodity charge for the physical gas. The demand component of the contract is reflected in the demand cost of the PGA and under supplier entitlement changes on **Attachment 1, Schedule 2, Page 2**.

The second cost update stems froma change in customer circumstances. In October a large interruptible customer in Grand Forks indicated a need to move to firm sales service due to a failure of its backup system. To serve the additional requirements, we looked to acquire additional capacity. While Viking is fully subscribed across its system, limited capacity was available from Emerson to Grand Forks at the beginning of Viking's system. As a result, we contracted an additional 1,500 Dth/day of Viking Firm Transportation capacity for a term of one-year. The total cost impact is an additional $85,512 on an annual basis effective November 1, 2019.

Attachment 2, Schedule 2, Pages 1 through 3 show the rate impacts revised to include the changes noted in the above paragraphs. **Attachment 2, Schedule 2, Page 4** shows the revised derivation of current PGA costs.

Changes to Interstate Pipeline Tariff Rates

In our original Petition we noted that WBI had filed a Section 4 rate case in November 2018, in which the parties including Xcel Energy reached a Settlement in principle in May 2019. The Settlement rates were implemented May 1, 2019 subject to refund pending Federal Energy Regulatory Commission (FERC) approval. The Settlement was approved by FERC on September 30, 2019. As rates were implemented in May, there is no further rate change.

Update on Hedging Transactions

Updated hedging transactions are presented on the revised **Attachment 3, Schedule 1**. We completed hedging for the 2019-2020 heating season by executing a total of six call options. **Attachment 3, Schedule 1** now reflects all of the current hedging transactions. Total hedging costs for the 2019-2020 heating season are $3,287,505.

Miscellaneous

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

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

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

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

Please contact me at (612) 330-7681 or lisa.r.peterson@xcelenergy.com or Jennifer Roesler at (612) 330-1925 or jennifer.roesler@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service List

Docket No. G002/M-19-498
Supplement

Revised Attachments
Effective November 1, 2019

Northern States Power Company
DEMAND COST OF GAS IMPACT - NOVEMBER 2019
Revised from 8/2/19 filing

Docket No. G002/M-19-498
REVISED Attachment 1
Schedule 2

ANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
ANR FSS (Jan - Dec)[1]	(19)	$ 1.7820	12	$ (406.30)
ANR FTS-1 (Apr - Oct)[2]	4	$ 5.7290	7	$ 160.41
ANR FTS-1 (Jan-Dec)[2]	(66,500)	$ 5.3660	12	$ (4,282,068.00)
ANR FTS-1 (Jan-Dec)[2]	66,500	$ 5.7290	12	$ 4,571,742.00
GLT FT (Nov - Mar)[3]	(9,248)	$ 8.3530	5	$ (386,242.72)
GLT FT (Nov - Mar)[3]	9,248	$ 8.1860	5	$ 378,520.64
GLT FT (Nov - Mar)[3]	(3,509)	$ 8.3530	5	$ (146,553.39)
GLT FT (Nov - Mar)[3]	3,509	$ 8.1860	5	$ 143,623.37
GLT FT (Apr - Oct)[3]	(4,475)	$ 8.3530	7	$ (261,657.73)
GLT FT (Apr - Oct)[3]	5,370	$ 8.1860	7	$ 307,711.74
GLT FT (Apr - Oct)[3]	(895)	$ 8.3530	7	$ (52,331.55)
WBI FT-1 (Jan-Dec)[4]	(8,000)	$ 9.2100	12	$ (884,160.00)
WBI FT-1 (Jan-Dec)[4]	8,000	$ 9.8417	12	$ 944,798.40
WBI FT-1 (Jan-Dec)[4]	(461)	$ 9.2100	12	$ (50,949.72)
WBI FT-1 (Jan-Dec)[4]	461	$ 9.8417	12	$ 54,444.01
NNG TFX (Nov-Mar)[7]	3,382	$ 9.3568	5	$ 158,223.49
NNG TFX (Apr-Oct)[7]	3,382	$ 4.0000	7	$ 94,696.00
NNG TFX (Jan-Dec)[7]	3,767	$ 4.5600	12	$ 206,130.24
NNG TFX (Nov-Mar)[7]	3,333	$ 6.1032	5	$ 101,709.83
NNG TFX (Apr-Oct)[7]	3,333	$ 4.5000	7	$ 104,989.50
VGT FT-A (Jan-Dec)[5]	1,500	$ 4.7507	12	$ 85,512.60
Total				$ 1,087,892.83

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Total	5,600	$15,560.00
Total MN & ND Demand Cost Adjustment		**$1,103,452.83**
Minnesota Allocation Factor (MN/ND Allocated Demand)		87.57%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 966,293.65**

[1]ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v.1.1.0, Effective August 1, 2016
[2]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 2.0.0, Effective April 1, 2017
[3]GLT Third Revised Volume No. 1, Part 4 Statement of Rates, v.1.0.0, Effective June 1, 2018
[4]WBI Third Revised Volume No. 1, Fifteenth Revised Sheet No. 12, Effective May 1, 2019
[5]VGT Volume No. 1, Part 5.0 - Statement of Rates v33.0.0, Effective April 1, 2019

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year
Revised from 8/2/19 filing

Docket No. G002/M-19-498
REVISED Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2018 SUPPLEMENTAL FILED COSTS				**$33,161,575.83**	**$23,939,582.41**	**$57,101,158.24**				
2018 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2018 ACTUAL COSTS				**$ 33,161,575.83**	**$ 23,939,582.41**	**$ 57,101,158.24**				
CHANGES FOR 2019 FILING										
Contract Demand Entitlement Changes										
ANR FSS (Jan - Dec)	(19)	$ 1.7820	12		$ (406.30)	$ (406.30)			$ (406.30)	1
ANR FTS-1 (Apr - Oct)	4	$ 5.7290	7		$ 160.41	$ 160.41			$ 160.41	1
ANR FTS-1 (Jan-Dec)	(66,500)	$ 5.3660	12	$ (4,282,068.00)		$ (4,282,068.00)			$ (4,282,068.00)	
ANR FTS-1 (Jan-Dec)	66,500	$ 5.7290	12	$ 4,571,742.00		$ 4,571,742.00			$ 4,571,742.00	
GLT FT (Nov - Mar)	(9,248)	$ 8.3530	5		$ (386,242.72)	$ (386,242.72)			$ (386,242.72)	2
GLT FT (Nov - Mar)	9,248	$ 8.1860	5		$ 378,520.64	$ 378,520.64			$ 378,520.64	2
GLT FT (Nov - Mar)	(3,509)	$ 8.3530	5		$ (146,553.39)	$ (146,553.39)			$ (146,553.39)	2
GLT FT (Nov - Mar)	3,509	$ 8.1860	5		$ 143,623.37	$ 143,623.37			$ 143,623.37	2
GLT FT (Apr - Oct)	(4,475)	$ 8.3530	7	$ (261,657.73)		$ (261,657.73)			$ (261,657.73)	2
GLT FT (Apr - Oct)	5,370	$ 8.1860	7	$ 307,711.74		$ 307,711.74			$ 307,711.74	2
GLT FT (Apr - Oct)	(895)	$ 8.3530	7	$ (52,331.55)		$ (52,331.55)			$ (52,331.55)	2
WBI FT-1 (Jan-Dec)	(8,000)	$ 9.2100	12	$ (884,160.00)		$ (884,160.00)		$ (884,160.00)		3
WBI FT-1 (Jan-Dec)	8,000	$ 9.8417	12	$ 944,798.40		$ 944,798.40		$ 944,798.40		3
WBI FT-1 (Jan-Dec)	(461)	$ 9.2100	12	$ (50,949.72)		$ (50,949.72)		$ (50,949.72)		3
WBI FT-1 (Jan-Dec)	461	$ 9.8417	12	$ 54,444.01		$ 54,444.01		$ 54,444.01		3
NNG TFX (Nov-Mar)	3,382	$ 9.3568	5		$ 158,223.49	$ 158,223.49	$ 158,223.49			4
NNG TFX (Apr-Oct)	3,382	$ 4.0000	7	$ 94,696.00		$ 94,696.00	$ 94,696.00			4
NNG TFX (Jan-Dec)	3,767	$ 4.5600	12	$ 206,130.24		$ 206,130.24	$ 206,130.24			4
NNG TFX (Nov-Mar)	3,333	$ 6.1032	5		$ 101,709.83	$ 101,709.83				4
NNG TFX (Apr-Oct)	3,333	$ 4.5000	7	$ 104,989.50		$ 104,989.50				4
VGT FT-A (Jan-Dec)	1,500	$ 4.7507	12	$ 85,512.60		$ 85,512.60		$ 85,512.60		5
Total				$ 838,857.50	$ 249,035.34	$ 1,087,892.83	$ 459,049.73	$ 64,132.69	$ 272,498.49	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										6
										6
										7
										8
									PROTECTED DATA ENDS]	
Total				$ -	$ 15,560.00	$ 15,560.00	$ (15,000.00)	$ 45,760.00	$ -	
TOTAL OF 2019 CHANGES				**$ 838,857.50**	**$ 264,595.34**	**$ 1,103,452.83**	**$ 444,049.73**	**$ 109,892.69**	**$ 272,498.49**	
2019 COSTS				**$ 34,000,433.33**	**$ 24,204,177.75**	**$ 58,204,611.08**				
2019 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							80%	20%		9

Footnote
1. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
2. Rate change pursuant to Limited Section 4, Result of Tax Cuts and Jobs Act (RP19-409)
3. Rate change pursuant to rate case settlement (RP19-165)
4. Acquisition of new capacity in Northern Lights 2019 to meet Design Day requirements
5. Acquisition of new capacity on Viking to meet Design Day requirements.
6. Expired peaking supply contract with demand charges in effect November 1, 2018 through March 31, 2019.
7. Acquired peaking supply contract with demand charges in effect November 1, 2019 through March 31, 2020
8. Delivered supply in lieu of seasonal Viking capacity purchase.
9. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purposes of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.

Northern States Power Company

SUMMARY OF DESIGN DAY DEMAND BY CUSTOMER CLASS

Design Day: Heating Season 2019-2020

Revised from 8/2/19 filing

DESIGN DAY CALCULATION

State of Minnesota	Jan-2020 Budget Customer	2020 MMBtu Design Day[1]	2019 MMBtu Design Day[1]	MMBtu Change
Residential	429,943	452,392	452,071	321
Commercial	35,304	265,247	259,201	6,046
Demand Billed	135	26,056	24,469	1,587
State of Minnesota Total	**465,382**	**743,696**	**735,741**	**7,955**
State of North Dakota Total	57,771	105,553	104,968	585
Total Xcel Energy - Gas Utility Operations	523,153	849,248	840,708	8,540

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

UPC DD Method

Minnesota Company	Jan-2020 Budget Customer	Jan-2019 Budget Customer	Change
Residential	479,125	474,906	4,219
Commercial	43,893	43,695	198
TOTAL	523,018	518,601	4,417
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	823,192	816,240	
Demand Billed Customers	135	138	
Contracted Billing Demand of Demand Billed Customers	26,056	24,469	
Projected Design Day (Dth)	849,248	840,708	8,540

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

MINNESOTA COMPANY ENTITLEMENT ESTIMATE PER CUSTOMER

	Jan-2020 Budget	Jan-2019 Budget
Reserve Margin	56,123	50,462
Total Available Capacity	905,371	891,171
Entitlement per Customer	1.7306	1.7180

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Docket No. G002/M-19-498
REVISED Attachment 1
Schedule 5

Northern States Power Company
FIRM SUPPLY ENTITLEMENTS
2019-2020 Heating Season
Revised from 8/2/19 filing

Firm Supplies (1)	**Current Quantity Effective Nov-19 Dth/Day**	**Proposed Quantity Effective Nov-20 Dth/Day**	**Proposed Quantity Change Nov-20 Dth/Day**
A. Upstream Supply			
	[PROTECTED DATA BEGINS		
ANR Firm 3rd Party (2)			
ANRP Storage (2)			
ANR Storage Company (3)			
GLGT Firm 3rd Party (3)			
B. Minnesota Company Delivered Supply			
WBI Firm 3rd Party			
VGT Firm 3rd Party			
NNG Firm 3rd Party			
NNG FDD Storage			**PROTECTED DATA ENDS]**
LP Peak Shaving	90,000	90,000	-
LNG Peak Shaving	156,000	156,000	-
TOTAL	891,084	905,371	14,287
C. Minnesota State Delivered Supply			
State of MN Allocators	87.51%	87.57%	
TOTAL	779,788	792,833	13,046

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

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
COMPANY DEMAND PROFILE
2019-2020 Heating Season
Revised from 8/2/19 filing

Contract No.	Type of Capacity or Entitlement	Current Amount Dth or MMBtu	Proposed Change Dth or MMBtu	Proposed Amount Dth or MMBtu	Contract Length and Expiration Date	Change Description	% of Peak Day Entitlement
	Capacity Entitlements						
112183	NNG TF12 BASE (Max)	104,117	0	104,117	10 yrs - 10/31/27		11.50%
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27		0.00%
112182	NNG TF12 BASE (Disc)	18,674	667	19,341	10 yrs - 10/31/27		2.14%
112182	NNG TF12 VARIABLE (Disc.)	75,853	(667)	75,186	10 yrs - 10/31/27		8.30%
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27		6.89%
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27		3.27%
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 10/31/22		3.15%
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27		6.43%
112185	NNG TFX (Disc. 12-month)	29,554	7,100	36,654	10 yrs - 10/31/27	Growth Election	4.05%
112185	NNG TFX 5 (Disc)	6,493	0	6,493	10 yrs - 10/31/27		Summer Only
112185	NNG TFX 2 (Disc)	2,168	0	2,168	10 yrs - 10/31/27		Summer Only
112186	NNG TFX (Max)	57,491	0	57,491	10 yrs - 10/31/27		6.35%
112186	NNG TFX 2 (Max)	16,436	0	16,436	10 yrs - 10/31/27		Summer Only
112186	NNG TFX 5 (Max)	35,739	0	35,739	10 yrs - 10/31/27		Summer Only
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27		2.76%
122067	NNG TFX (Disc. Nov-Mar)	10,291	3,382	13,673	10 yrs - 10/31/27	Growth Election	1.51%
122067	NNG TFX 7 (Disc)	10,291	3,382	13,673	10 yrs - 10/31/27	Growth Election	Summer Only
122068	NNG TFX (Nov-Mar)	8,875	0	8,875	10 yrs - 10/31/27		0.98%
122068	NNG TFX 7 (Max)	8,875	0	8,875	10 yrs - 10/31/27		Summer Only
		[PROTECTED DATA BEGINS					
	VGT to NNG Chisago (1)						
	VGT Pierz to NNG (2)						
	Capacity Release						**PROTECTED DATA ENDS]**
AF0044	VGT FT-A 12 Mos.	29,002	0	29,002	5 yrs - 10/31/23		3.20%
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/23		0.47%
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/24	Contract Extension	1.10%
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	5 yrs - 10/31/22		1.72%
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/21		0.21%
AF0217	VGT FT-A 12 Mos.	72,213	0	72,213	5 yrs - 10/31/24	Contract Extension	7.98%
AF0218	VGT FT-A 12 Mos.	15,000	0	15,000	5 yrs - 10/31/24	Contract Extension	1.66%
AF0329	VGT FT-A 12 Mos.	20,200	0	20,200	5 yrs - 10/31/23		2.23%
AF0353	VGT FT-A 12 Mos.	0	1,500	1,500	1 yrs - 10/31/20	Contract Acquisition	0.17%
	WBI FT-1097	8,000	0	8,000	6.5 yrs - 10/31/25		0.88%
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%
	City Gate Deliveries	24,000	0	24,000	10 yrs - 10/31/22		2.65%
	City Gate Deliveries	5,400	(5,400)	0	1 yrs - 2/28/19	Contract expiration	0.00%
	City Gate Deliveries		11,000	11,000	3 mos - 2/29/20	Seasonal Acquisition	1.21%
	LP Peak Shaving	90,000	0	90,000			9.94%
	LNG Peak Shaving	156,000	0	156,000			17.23%
	Total Design Day Capacity	**891,171**		**905,371**			**100%**
	Heating Season Total	891,171		905,371			
	Non-Heating Season Total	480,579		491,061			

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
COMPANY DEMAND PROFILE
2019-2020 Heating Season
Revised from 8/2/19 filing

Miscellaneous Entitlements with Reservation Fees

Additional Pipeline Entitlements					
ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/21	
ANR FTS-106211 (Summer) (1)	5,448	4	5,452	3 yrs - 03/31/21	Fuel Adjustment
ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/21	
ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	5 yrs - 10/31/2023	Contract Extension
GLT FT1718539 (2)	3,509	0	3,509	2 yrs - 03/31/21	Contract Extension
GLT FT1718539 (2)	4,475	895	5,370	2 yrs - 03/31/21	Contract Extension
GLT Backhaul FT18130 (2)	895	(895)	0	3 yrs. - 10/31/19	Contract Expired & Combined
GLT Backhaul FT18129 (2)	9,248	0	9,248	4 yrs. - 03/31/21	Contract Extension
NNG SMS (3)	30,650		30,650	5 yrs - 10/31/22	
VGT OBA (3)	7,400		7,400	month-to-month	
Supply Entitlements (4)					
[PROTECTED DATA BEGINS					
					PROTECTED DATA ENDS]
Storage Entitlements - Deliverability					
ANR Pipeline Storage	15,295	(19)	15,276	3 yrs - 3/31/21	Fuel adjustment
ANR Storage	9,248	0	9,248	4 yrs - 3/31/21	Contract Extension
FDD Service (5)	140,230	0	140,230	5 yrs - 5/31/23	
FDD Service	78,050	0	78,050	15 yrs - 5/31/27	
Storage Entitlements - Capacity					
ANR Pipeline Storage	948,290	(1,178)	947,112	3 yrs - 3/31/21	Fuel adjustment
ANR Storage	1,165,000	0	1,165,000	4 yrs - 3/31/21	
FDD Service (5)	8,084,975	0	8,084,975	5 yrs - 5/31/23	
FDD Service	4,500,000	0	4,500,000	15 yrs - 5/31/27	

(1) Not included in total peak deliverability -- feeds VGT (capacity not additive)
(2) Not included in total peak deliverability -- feeds NNG (capacity not additive).
(3) Not included in total peak deliverability -- entitlement delivered by or associated with TF or FT-A service.
(4) Supply contracts containing reservation fees.
(5) Capacity expires 155,000 Dth in May 2022, 1,400,000 Dth in May 2023 & 6,529,975 Dth in May 2023

Northern States Power Company

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2019

Revised from 8/2/19 filing

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	891,171	14,200	905,371
Non-Heating Season	480,579	10,482	491,061
Heating Season Forecasted Design Day	840,709	8,540	849,248
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	50,462	5,660	56,123
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	6.0%	0.6%	6.6%
Total MN State Available Capacity:			
State of MN Allocation Factor	87.51%	0.06%	87.57%
State of MN Heating Season Capacity	779,864	12,970	792,833
State of MN Design Day Demand	735,741	7,955	743,696
State of MN Heating Season Capacity Reserve/(Shortage)	44,123	5,015	49,137
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	6.0%	0.6%	6.6%

(1) Entitlement changes for November are included in Available Capacity.
Please reference Attachment 1 Schedule 5 for the detail on supply entitlement changes.

$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-18-528)	Last Month PGA: Oct 2019	Estimated Nov. 2019 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$5.5042	$2.7649	$2.0942	$2.0982	-61.88%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.9008	$0.8296	$0.8041	$0.8095	-10.14%	-2.42%	0.67%	$0.0054
Distribution Margin	$1.8591	$1.8591	$1.7600	$1.7600	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$5.4536	$4.6583	$4.6677	-43.52%	-14.41%	0.20%	$0.0094
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$474.21	$405.05	$405.87	-43.52%	-14.41%	0.20%	$0.82
Average Annual Total Demand Cost of Gas	$78.33	$72.14	$69.92	$70.39				**$0.47**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.7649	$2.0942	$2.0982	-61.76%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.8984	$0.8395	$0.8204	$0.8258	-8.08%	-1.63%	0.66%	$0.0054
Distribution Margin	$1.2331	$1.2331	$1.1673	$1.1673	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.8375	$4.0819	$4.0913	-46.30%	-15.42%	0.23%	$0.0094
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,373.97	$1,159.37	$1,162.04	-46.30%	-15.42%	0.23%	$2.67
Average Annual Total Demand Cost of Gas	$255.17	$238.44	$233.01	$234.55				**$1.53**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.7649	$2.0942	$2.0982	-61.76%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.8917	$0.8168	$0.7904	$0.7958	-10.75%	-2.57%	0.68%	$0.0054
Distribution Margin	$1.2315	$1.2315	$1.1658	$1.1658	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.8132	$4.0504	$4.0598	-46.65%	-15.65%	0.23%	$0.0094
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$7,039.99	$5,924.30	$5,938.05	-46.65%	-15.65%	0.23%	$13.75
Average Annual Total Demand Cost of Gas	$1,304.24	$1,194.68	$1,156.07	$1,163.97				**$7.90**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-18-528)	Last Month PGA: Oct 2019	Estimated Nov. 2019 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible								
Commodity Cost of Gas (WACOG)	$5.4926	$2.7649	$2.0942	$2.0982	-61.80%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9121	$0.9121	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$3.7284	$3.0063	$3.0103	-53.37%	-19.26%	0.13%	$0.0040
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$29,589.28	$23,858.62	$23,890.36	-53.37%	-19.26%	0.13%	$31.74
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible								
Commodity Cost of Gas (WACOG)	$5.4696	$2.7649	$2.0942	$2.0982	-61.64%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4498	$0.4498	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$3.2400	$2.5440	$2.5480	-57.14%	-21.36%	0.16%	$0.0040
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$209,659.18	$164,618.97	$164,877.81	-57.14%	-21.36%	0.16%	$258.84
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible								
Commodity Cost of Gas (WACOG)	$5.5006	$2.7649	$2.0942	$2.0982	-61.86%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4114	$0.4114	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$3.1995	$2.5056	$2.5096	-57.72%	-21.56%	0.16%	$0.0040
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$2,386,768.28	$1,869,148.15	$1,872,132.07	-57.72%	-21.56%	0.16%	$2,983.92
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$0.0040	0.19%	$0.0054	0.67%	$0.47	$0.82	0.20%
Small Commercial	$0.0040	0.19%	$0.0054	0.66%	$1.53	$2.67	0.23%
Large Commercial	$0.0040	0.19%	$0.0054	0.68%	$7.90	$13.75	0.23%
Small Interruptible	$0.0040	0.19%	$0.0000	NA	$0.00	$31.74	0.13%
Medium Interruptible	$0.0040	0.19%	$0.0000	NA	$0.00	$258.84	0.16%
Large Interruptible	$0.0040	0.19%	$0.0000	NA	$0.00	$2,983.92	0.16%

Northern States Power Company
DERIVATION OF CURRENT PGA COSTS
Nov. 2019 - Projected Costs (Actual prices will be determined Nov.1, 2019)*
Revised from 8/2/19 filing

		Annual Cost	Winter Cost	Total
Demand Cost (Res, Sm & Lg Commercial Firm)				
1.	MN & ND Total Demand	$34,000,433	$24,204,178	
2.	x Minnesota Design Day Ratio (2019 Demand Entitlement Filing)	87.57%	87.57%	
3.	Annual System Demand Allocation to MN	$29,774,179	$21,195,598	
4.	MN State Design Day (2019 Demand Entitlement Filing)	743,696	743,696	
5.	- Small & Large Demand Billed Dth (2019 Demand Entitlement Filing)	26,056	26,056	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	717,640	717,640	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$28,731,016	$20,452,993	
8.	Demand Billed Cost Allocation (3 - 7)	$1,043,163	$742,605	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	609,479,653	463,406,847	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.04714	$0.04414	$0.09128
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.09128
14.	Total Demand Rate -Commercial (10 + 12)			$0.09128
Demand Cost (Demand Billed)				
15.	Cost Allocated to Demand Billed (8)	$1,043,163	$742,605	$1,785,768
16.	/ Annual Contract Billing Demand (2019 Demand Entitlement Filing)			3,126,720
17.	Monthly Commercial Demand Billed Demand Rate			$0.57113

		Monthly Cost
Commodity Costs		
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$19,510,723
19.	x MN Portion of Monthly Retail Sales	85.92%
20.	MN Portion of Monthly Commodity Costs	$16,763,613
21.	MN Budgeted Calendar Month Retail Therm Sales	79,895,174
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.20982
Total Gas Cost per Therm		
23.	Residential (13 + 22)	**$0.30110**
24.	Small & Large Commercial (14 +22)	**$0.30110**
25.	Small & Large Demand Billed - Demand (17)	**$0.57113**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.20982**

*Commodity costs are projected and for illustrative purposed only.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

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

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Revised Attachments
Effective January 1, 2020

Northern States Power Company
DEMAND COST OF GAS IMPACT - NOVEMBER 2019
Revised from 8/2/19 filing

Docket No. G002/M-19-498
REVISED Attachment 1
Schedule 2
Page 1 of 2

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
ANR FSS (Jan - Dec)[1]	(19)	$ 1.7820	12	$ (406.30)
ANR FTS-1 (Apr - Oct)[2]	4	$ 5.7290	7	$ 160.41
ANR FTS-1 (Jan-Dec)[2]	(66,500)	$ 5.3660	12	$ (4,282,068.00)
ANR FTS-1 (Jan-Dec)[2]	66,500	$ 5.7290	12	$ 4,571,742.00
GLT FT (Nov - Mar)[3]	(9,248)	$ 8.3530	5	$ (386,242.72)
GLT FT (Nov - Mar)[3]	9,248	$ 8.1860	5	$ 378,520.64
GLT FT (Nov - Mar)[3]	(3,509)	$ 8.3530	5	$ (146,553.39)
GLT FT (Nov - Mar)[3]	3,509	$ 8.1860	5	$ 143,623.37
GLT FT (Apr - Oct)[3]	(4,475)	$ 8.3530	7	$ (261,657.73)
GLT FT (Apr - Oct)[3]	5,370	$ 8.1860	7	$ 307,711.74
GLT FT (Apr - Oct)[3]	(895)	$ 8.3530	7	$ (52,331.55)
WBI FT-1 (Jan-Dec)[4]	(8,000)	$ 9.2100	12	$ (884,160.00)
WBI FT-1 (Jan-Dec)[4]	8,000	$ 9.8417	12	$ 944,798.40
WBI FT-1 (Jan-Dec)[4]	(461)	$ 9.2100	12	$ (50,949.72)
WBI FT-1 (Jan-Dec)[4]	461	$ 9.8417	12	$ 54,444.01
VGT FT-A (Jan - Dec)[5]	(20,200)	$ 4.3706	10	$ (882,861.20)
VGT FT-A (Jan - Dec)[5]	20,200	$ 4.6653	10	$ 942,390.60
VGT FT-A (Jan - Dec)[5]	(29,002)	$ 4.3706	10	$ (1,267,561.41)
VGT FT-A (Jan - Dec)[5]	29,002	$ 4.6653	10	$ 1,353,030.31
VGT FT-A (Nov-Mar)[5]	(4,239)	$ 4.3706	3	$ (55,580.92)
VGT FT-A (Nov-Mar)[5]	4,239	$ 4.6653	3	$ 59,328.62
VGT FT-A (Jan - Dec)[5]	(10,000)	$ 4.3706	10	$ (437,060.00)
VGT FT-A (Jan - Dec)[5]	10,000	$ 4.6653	10	$ 466,530.00
VGT FT-A (Jan - Dec)[5]	(15,600)	$ 5.3593	10	$ (836,050.80)
VGT FT-A (Jan - Dec)[5]	15,600	$ 5.6540	10	$ 882,024.00
VGT FT-A (Jan - Dec)[5]	(1,903)	$ 4.3706	10	$ (83,172.52)
VGT FT-A (Jan - Dec)[5]	1,903	$ 4.6653	10	$ 88,780.66
VGT FT-A (Jan - Dec)[5]	(72,213)	$ 5.3593	10	$ (3,870,111.31)
VGT FT-A (Jan - Dec)[5]	72,213	$ 5.6540	10	$ 4,082,923.02
VGT FT-A (Jan - Dec)[5]	(15,000)	$ 5.3593	10	$ (803,895.00)
VGT FT-A (Jan - Dec)[5]	15,000	$ 5.6540	10	$ 848,100.00
VGT FT-A (Jan - Dec)[5]	1,500	$ 4.7507	2	$ 14,252.10
VGT FT-A (Jan - Dec)[5]	1,500	$ 4.8293	10	$ 72,439.50
NNG TFX (Nov-Mar)[7]	3,382	$ 9.3568	5	$ 158,223.49
NNG TFX (Apr-Oct)[7]	3,382	$ 4.0000	7	$ 94,696.00
NNG TFX (Jan-Dec)[7]	3,767	$ 4.5600	12	$ 206,130.24
NNG TFX (Nov-Mar)[7]	3,333	$ 6.1032	5	$ 101,709.83
NNG TFX (Apr-Oct)[7]	3,333	$ 4.5000	7	$ 104,989.50
NNG TF12-Base (Nov-Mar)[6]	(104,117)	$ 10.2300	3	$ (3,195,350.73)
NNG TF12-Base (Nov-Mar)[6]	104,117	$ 10.3207	3	$ 3,223,680.97
NNG TF12-Base (Apr-Oct)[6]	(104,117)	$ 5.6830	7	$ (4,141,878.38)
NNG TF12-Base (Apr-Oct)[6]	104,117	$ 10.3207	7	$ 7,521,922.25
NNG TF5 (Nov-Mar)[6]	(62,415)	$ 15.1530	3	$ (2,837,323.49)
NNG TF5 (Nov-Mar)[6]	62,415	$ 24.2448	3	$ 4,539,717.58
NNG TFX (Nov-Mar)[7]	(28,500)	$ 15.1530	3	$ (1,295,581.50)
NNG TFX (Nov-Mar)[7]	28,500	$ 28.8810	3	$ 2,469,325.50
NNG TFX (Nov-Mar)[7]	(57,491)	$ 15.1530	3	$ (2,613,483.37)
NNG TFX (Nov-Mar)[7]	20,861	$ 28.8810	3	$ 1,807,459.62
NNG TFX (Nov-Mar)[7]	36,630	$ 22.1055	3	$ 2,429,173.40
NNG TFX (Jul-Aug)[7]	(16,436)	$ 5.6830	2	$ (186,811.58)
NNG TFX (Jul-Aug)[7]	15,436	$ 10.8300	2	$ 334,343.76
NNG TFX (Jul-Aug)[7]	1,000	$ 10.0000	2	$ 20,000.00
NNG TFX (Apr-Jun/Sept-Oct)[7]	(35,739)	$ 5.6830	5	$ (1,015,523.69)
NNG TFX (Apr-Jun/Sept-Oct)[7]	15,436	$ 10.8300	5	$ 835,859.40
NNG TFX (Apr-Jun/Sept-Oct)[7]	20,303	$ 10.0000	5	$ 1,015,150.00
NNG TFX (Nov-Mar)[7]	(8,875)	$ 15.1530	3	$ (403,448.63)
NNG TFX (Nov-Mar)[7]	8,875	$ 28.8810	3	$ 768,956.63
NNG TFX (Apr-Oct)[7]	(8,875)	$ 5.6830	7	$ (353,056.38)
NNG TFX (Apr-Oct)[7]	8,875	$ 10.8300	7	$ 672,813.75
NNG FDD (Jan-Dec)[8]	(140,230)	$ 1.7140	10	$ (2,403,542.20)
NNG FDD (Jan-Dec)[8]	140,230	$ 3.7443	10	$ 5,250,631.89
NNG FDD (Jan-Dec)[8]	(78,050)	$ 1.7140	10	$ (1,337,777.00)
NNG FDD (Jan-Dec)[8]	78,050	$ 3.7443	10	$ 2,922,426.15
Total				$ 15,603,569.85

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Total	5,600	$15,560.00
Total MN & ND Demand Cost Adjustment		**$15,619,129.85**
		$1,103,452.83
Minnesota Allocation Factor (MN/ND Allocated Demand)		87.57%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 13,677,672.01**
		$966,293.65

[1]ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v.1.1.0, Effective August 1, 2016
[2]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 2.0.0, Effective April 1, 2017
[3]GLT Third Revised Volume No. 1, Part 4 Statement of Rates, v.1.0.0, Effective June 1, 2018
[4]WBI Third Revised Volume No. 1, Fifteenth Revised Sheet No. 12, Effective May 1, 2019
[5]VGT Volume No. 1, Part 5.0 Statement of Rates, (RP19-1340) Effective January 1, 2020
[6]NNG Sixth Revised Volume No. 1, Fifteenth Revised Sheet No. 50 (RP19-1353), Effective January 1, 2020
[7]NNG Sixth Revised Volume No. 1, Eighteenth Revised Sheet No. 51 (RP19-1353), Effective January 1, 2020
[8]NNG Sixth Revised Volume No. 1, Second Revised Sheet No. 55 (RP19-1353), Effective January 1, 2020

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year
Revised from 8/2/19 filing

Docket No. G002/M-19-498
REVISED Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2018 SUPPLEMENTAL FILED COSTS				**$33,161,575.83**	**$23,939,582.41**	**$57,101,158.24**				
2018 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2018 ACTUAL COSTS				**$ 33,161,575.83**	**$ 23,939,582.41**	**$ 57,101,158.24**				
CHANGES FOR 2019 FILING										
Contract Demand Entitlement Changes										
ANR FSS (Jan - Dec)	(19)	$ 1.7820	12		$ (406.30)	$ (406.30)			$ (406.30)	1
ANR FTS-1 (Apr - Oct)	4	$ 5.7290	7		$ 160.41	$ 160.41			$ 160.41	1
ANR FTS-1 (Jan-Dec)	(66,500)	$ 5.3660	12	$ (4,282,068.00)		$ (4,282,068.00)			$ (4,282,068.00)	
ANR FTS-1 (Jan-Dec)	66,500	$ 5.7290	12	$ 4,571,742.00		$ 4,571,742.00			$ 4,571,742.00	
GLT FT (Nov - Mar)	(9,248)	$ 8.3530	5		$ (386,242.72)	$ (386,242.72)			$ (386,242.72)	2
GLT FT (Nov - Mar)	9,248	$ 8.1860	5		$ 378,520.64	$ 378,520.64			$ 378,520.64	2
GLT FT (Nov - Mar)	(3,509)	$ 8.3530	5		$ (146,553.39)	$ (146,553.39)			$ (146,553.39)	2
GLT FT (Nov - Mar)	3,509	$ 8.1860	5		$ 143,623.37	$ 143,623.37			$ 143,623.37	2
GLT FT (Apr - Oct)	(4,475)	$ 8.3530	7	$ (261,657.73)		$ (261,657.73)			$ (261,657.73)	2
GLT FT (Apr - Oct)	5,370	$ 8.1860	7	$ 307,711.74		$ 307,711.74			$ 307,711.74	2
GLT FT (Apr - Oct)	(895)	$ 8.3530	7	$ (52,331.55)		$ (52,331.55)			$ (52,331.55)	2
WBI FT-1 (Jan-Dec)	(8,000)	$ 9.2100	12	$ (884,160.00)		$ (884,160.00)		$ (884,160.00)		3
WBI FT-1 (Jan-Dec)	8,000	$ 9.8417	12	$ 944,798.40		$ 944,798.40		$ 944,798.40		3
WBI FT-1 (Jan-Dec)	(461)	$ 9.2100	12	$ (50,949.72)		$ (50,949.72)		$ (50,949.72)		3
WBI FT-1 (Jan-Dec)	461	$ 9.8417	12	$ 54,444.01		$ 54,444.01		$ 54,444.01		3
VGT FT-A (Jan - Dec)	(20,200)	$ 4.3706	10	$ (882,861.20)		$ (882,861.20)		$ (882,861.20)		4
VGT FT-A (Jan - Dec)	20,200	$ 4.6653	10	$ 942,390.60		$ 942,390.60		$ 942,390.60		4
VGT FT-A (Jan - Dec)	(29,002)	$ 4.3706	10	$ (1,267,561.41)		$ (1,267,561.41)	$ (1,267,561.41)			4
VGT FT-A (Jan - Dec)	29,002	$ 4.6653	10	$ 1,353,030.31		$ 1,353,030.31	$ 1,353,030.31			4
VGT FT-A (Nov-Mar)	(4,239)	$ 4.3706	3		$ (55,580.92)	$ (55,580.92)	$ (55,580.92)			4
VGT FT-A (Nov-Mar)	4,239	$ 4.6653	3		$ 59,328.62	$ 59,328.62	$ 59,328.62			4
VGT FT-A (Jan - Dec)	(10,000)	$ 4.3706	10	$ (437,060.00)		$ (437,060.00)	$ (437,060.00)			4
VGT FT-A (Jan - Dec)	10,000	$ 4.6653	10	$ 466,530.00		$ 466,530.00	$ 466,530.00			4
VGT FT-A (Jan - Dec)	(15,600)	$ 5.3593	10	$ (836,050.80)		$ (836,050.80)	$ (836,050.80)			4
VGT FT-A (Jan - Dec)	15,600	$ 5.6540	10	$ 882,024.00		$ 882,024.00	$ 882,024.00			4
VGT FT-A (Jan - Dec)	(1,903)	$ 4.3706	10	$ (83,172.52)		$ (83,172.52)	$ (83,172.52)			4
VGT FT-A (Jan - Dec)	1,903	$ 4.6653	10	$ 88,780.66		$ 88,780.66	$ 88,780.66			4
VGT FT-A (Jan - Dec)	(72,213)	$ 5.3593	10	$ (3,870,111.31)		$ (3,870,111.31)		$ (3,870,111.31)		4
VGT FT-A (Jan - Dec)	72,213	$ 5.6540	10	$ 4,082,923.02		$ 4,082,923.02		$ 4,082,923.02		4
VGT FT-A (Jan - Dec)	(15,000)	$ 5.3593	10	$ (803,895.00)		$ (803,895.00)	$ (803,895.00)			4
VGT FT-A (Jan - Dec)	15,000	$ 5.6540	10	$ 848,100.00		$ 848,100.00	$ 848,100.00			4
VGT FT-A (Jan - Dec)	1,500	$ 4.7507	2	$ 14,252.10		$ 14,252.10				
VGT FT-A (Jan - Dec)	1,500	$ 4.8293	10	$ 72,439.50		$ 72,439.50				
NNG TFX (Nov-Mar)	3,382	$ 9.3568	5		$ 158,223.49	$ 158,223.49	$ 158,223.49			5
NNG TFX (Apr-Oct)	3,382	$ 4.0000	7	$ 94,696.00		$ 94,696.00	$ 94,696.00			5
NNG TFX (Jan-Dec)	3,767	$ 4.5600	12	$ 206,130.24		$ 206,130.24	$ 206,130.24			5
NNG TFX (Nov-Mar)	3,333	$ 6.1032	5		$ 101,709.83	$ 101,709.83				5
NNG TFX (Apr-Oct)	3,333	$ 4.5000	7	$ 104,989.50		$ 104,989.50				5
NNG TF12-Base (Nov-Mar)	(104,117)	$10.2300	3	$ (3,195,350.73)		$ (3,195,350.73)	$ (3,195,350.73)			6
NNG TF12-Base (Nov-Mar)	104,117	$10.3207	3	$ 3,223,680.97		$ 3,223,680.97	$ 3,223,680.97			6, 11
NNG TF12-Base (Apr-Oct)	(104,117)	$ 5.6830	7	$ (4,141,878.38)		$ (4,141,878.38)	$ (4,141,878.38)			6
NNG TF12-Base (Apr-Oct)	104,117	$10.3207	7	$ 7,521,922.25		$ 7,521,922.25	$ 7,521,922.25			6, 11
NNG TF5 (Nov-Mar)	(62,415)	$15.1530	3		$ (2,837,323.49)	$ (2,837,323.49)	$ (2,837,323.49)			6
NNG TF5 (Nov-Mar)	62,415	$24.2448	3		$ 4,539,717.58	$ 4,539,717.58	$ 4,539,717.58			6, 11
NNG TFX (Nov-Mar)	(28,500)	$15.1530	3		$ (1,295,581.50)	$ (1,295,581.50)	$ (1,295,581.50)			6
NNG TFX (Nov-Mar)	28,500	$28.8810	3		$ 2,469,325.50	$ 2,469,325.50	$ 2,469,325.50			6
NNG TFX (Nov-Mar)	(57,491)	$15.1530	3		$ (2,613,483.37)	$ (2,613,483.37)	$ (2,613,483.37)			6
NNG TFX (Nov-Mar)	20,861	$28.8810	3		$ 1,807,459.62	$ 1,807,459.62	$ 1,807,459.62			6
NNG TFX (Nov-Mar)	36,630	$22.1055	3		$ 2,429,173.40	$ 2,429,173.40	$ 2,429,173.40			6, 11
NNG TFX (Jul-Aug)	(16,436)	$ 5.6830	2	$ (186,811.58)		$ (186,811.58)	$ (186,811.58)			6
NNG TFX (Jul-Aug)	15,436	$10.8300	2	$ 334,343.76		$ 334,343.76	$ 334,343.76			6
NNG TFX (Jul-Aug)	1,000	$10.0000	2	$ 20,000.00		$ 20,000.00	$ 20,000.00			6, 11
NNG TFX (Apr-Jun/Sept-Oct)	(35,739)	$ 5.6830	5	$ (1,015,523.69)		$ (1,015,523.69)	$ (1,015,523.69)			6
NNG TFX (Apr-Jun/Sept-Oct)	15,436	$10.8300	5	$ 835,859.40		$ 835,859.40	$ 835,859.40			6
NNG TFX (Apr-Jun/Sept-Oct)	20,303	$10.0000	5	$ 1,015,150.00		$ 1,015,150.00	$ 1,015,150.00			6, 11
NNG TFX (Nov-Mar)	(8,875)	$15.1530	3		$ (403,448.63)	$ (403,448.63)	$ (403,448.63)			6
NNG TFX (Nov-Mar)	8,875	$28.8810	3		$ 768,956.63	$ 768,956.63	$ 768,956.63			6
NNG TFX (Apr-Oct)	(8,875)	$ 5.6830	7	$ (353,056.38)		$ (353,056.38)	$ (353,056.38)			6
NNG TFX (Apr-Oct)	8,875	$10.8300	7	$ 672,813.75		$ 672,813.75	$ 672,813.75			6
NNG FDD (Jan-Dec)	(140,230)	$ 1.7140	10		$ (2,403,542.20)	$ (2,403,542.20)			$ (2,403,542.20)	6
NNG FDD (Jan-Dec)	140,230	$ 3.7443	10		$ 5,250,631.89	$ 5,250,631.89			$ 5,250,631.89	6
NNG FDD (Jan-Dec)	(78,050)	$ 1.7140	10		$ (1,337,777.00)	$ (1,337,777.00)			$ (1,337,777.00)	6
NNG FDD (Jan-Dec)	78,050	$ 3.7443	10		$ 2,922,426.15	$ 2,922,426.15			$ 2,922,426.15	6
Total				$ 6,054,252.23	$ 9,549,317.62	$ 15,603,569.85	$ 10,269,467.79	$ 336,473.80	$ 4,704,237.33	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										7
										7
										8
										9
								PROTECTED DATA ENDS]		
Total				$ -	$ 15,560.00	$ 15,560.00	$ (15,000.00)	$ 45,760.00	$ -	
TOTAL OF 2019 CHANGES				**$ 6,054,252.23**	**$ 9,564,877.62**	**$ 15,619,129.85**	**$ 10,254,467.79**	**$ 382,233.80**	**$ 4,704,237.33**	
2019 COSTS				**$ 39,215,828.06**	**$ 33,504,460.03**	**$ 72,720,288.09**				
2019 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							96%	4%		10

Footnote
1. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
2. Rate change pursuant to Limited Section 4, Result of Tax Cuts and Jobs Act (RP19-409)
3. Rate change pursuant to rate case settlement (RP19-165)
4. Rate change due to ongoing Rate Case (RP19-1340), Rates to be effective January 1, 2020
5. Acquisition of new capacity in Northern Lights 2019 to meet Design Day requirements
6. Rate change due to ongoing Rate Case (RP19-1353), Rates to be effective January 1, 2020
7. Expired peaking supply contract with demand charges in effect November 1, 2018 through March 31, 2019.
8. Acquired peaking supply contract with demand charges in effect November 1, 2019 through March 31, 2020
9. Delivered supply in lieu of seasonal Viking capacity purchase.
10. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purposes of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.
11. Rate increase triggers discount provisision in two contracts for original capacity, limiting increase

Northern States Power Company
MINNESOTA STATE RATE IMPACT
Revised from 8/2/19 filing
Date to implement proposed changes: January 1, 2020
$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-18-528)	Last Month PGA: Oct 2019	Estimated Jan 2020 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$5.5042	$2.7649	$2.0942	$2.0982	-61.88%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.9008	$0.8296	$0.8041	$1.0117	12.31%	21.95%	25.82%	$0.2076
Distribution Margin	$1.8591	$1.8591	$1.7600	$1.7600	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$5.4536	$4.6583	$4.8699	-41.07%	-10.70%	4.54%	$0.2116
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$474.21	$405.05	$423.45	-41.07%	-10.70%	4.54%	$18.40
Average Annual Total Demand Cost of Gas	$78.33	$72.14	$69.92	$87.97				**$18.05**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.7649	$2.0942	$2.0982	-61.76%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.8984	$0.8395	$0.8204	$1.0343	15.13%	23.20%	26.07%	$0.2139
Distribution Margin	$1.2331	$1.2331	$1.1673	$1.1673	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$4.8375	$4.0819	$4.2998	-43.56%	-11.11%	5.34%	$0.2179
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,373.97	$1,159.37	$1,221.26	-43.56%	-11.11%	5.34%	$61.89
Average Annual Total Demand Cost of Gas	$255.17	$238.44	$233.01	$293.77				**$60.75**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$2.7649	$2.0942	$2.0982	-61.76%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.8917	$0.8168	$0.7904	$0.9928	11.34%	21.55%	25.61%	$0.2024
Distribution Margin	$1.2315	$1.2315	$1.1658	$1.1658	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$4.8132	$4.0504	$4.2568	-44.07%	-11.56%	5.10%	$0.2064
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$7,039.99	$5,924.30	$6,226.19	-44.07%	-11.56%	5.10%	$301.89
Average Annual Total Demand Cost of Gas	$1,304.24	$1,194.68	$1,156.07	$1,452.11				**$296.04**

(1) Includes demand smoothing

Northern States Power Company

MINNESOTA STATE RATE IMPACT

Revised from 8/2/19 filing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-18-528)	Last Month PGA: Oct 2019	Estimated Jan 2020 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible								
Commodity Cost of Gas (WACOG)	$5.4926	$2.7649	$2.0942	$2.0982	-61.80%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9121	$0.9121	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$3.7284	$3.0063	$3.0103	-53.37%	-19.26%	0.13%	$0.0040
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$29,589.28	$23,858.62	$23,890.36	-53.37%	-19.26%	0.13%	$31.74
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible								
Commodity Cost of Gas (WACOG)	$5.4696	$2.7649	$2.0942	$2.0982	-61.64%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4498	$0.4498	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$3.2400	$2.5440	$2.5480	-57.14%	-21.36%	0.16%	$0.0040
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$209,659.18	$164,618.97	$164,877.81	-57.14%	-21.36%	0.16%	$258.84
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible								
Commodity Cost of Gas (WACOG)	$5.5006	$2.7649	$2.0942	$2.0982	-61.86%	-24.11%	0.19%	$0.0040
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4114	$0.4114	-5.33%	-5.33%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$3.1995	$2.5056	$2.5096	-57.72%	-21.56%	0.16%	$0.0040
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$2,386,768.28	$1,869,148.15	$1,872,132.07	-57.72%	-21.56%	0.16%	$2,983.92
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$0.0040	0.19%	$0.2076	25.82%	$18.05	$18.40	4.54%
Small Commercial	$0.0040	0.19%	$0.2139	26.07%	$60.75	$61.89	5.34%
Large Commercial	$0.0040	0.19%	$0.2024	25.61%	$296.04	$301.89	5.10%
Small Interruptible	$0.0040	0.19%	$0.0000	NA	$0.00	$31.74	0.13%
Medium Interruptible	$0.0040	0.19%	$0.0000	NA	$0.00	$258.84	0.16%
Large Interruptible	$0.0040	0.19%	$0.0000	NA	$0.00	$2,983.92	0.16%

DERIVATION OF CURRENT PGA COSTS

Jan 2020 - Projected Costs (Actual prices will be determined Nov.1, 2019)*

Revised from 8/2/19 filing

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$39,215,828	$33,504,460	
2.	x Minnesota Design Day Ratio (2019 Demand Entitlement Filing)	87.57%	87.57%	
3.	Annual System Demand Allocation to MN	$34,341,301	$29,339,856	
4.	MN State Design Day (2019 Demand Entitlement Filing)	743,696	743,696	
5.	- Small & Large Demand Billed Dth (2019 Demand Entitlement Filing)	26,056	26,056	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	717,640	717,640	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$33,138,125	$28,311,910	
8.	Demand Billed Cost Allocation (3 - 7)	$1,203,176	$1,027,946	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	609,479,653	463,406,847	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.05437	$0.06110	$0.11547
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.11547
14.	Total Demand Rate -Commercial (10 + 12)			$0.11547
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$1,203,176	$1,027,946	$2,231,122
16.	/ Annual Contract Billing Demand (2019 Demand Entitlement Filing)			3,126,720
17.	Monthly Commercial Demand Billed Demand Rate			$0.71357

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$19,510,723
19.	x MN Portion of Monthly Retail Sales	85.92%
20.	MN Portion of Monthly Commodity Costs	$16,763,613
21.	MN Budgeted Calendar Month Retail Therm Sales	79,895,174
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.20982

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.32529**
24.	Small & Large Commercial (14 +22)	**$0.32529**
25.	Small & Large Demand Billed - Demand (17)	**$0.71357**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.20982**

*Commodity costs are projected and for illustrative purposed only.

CERTIFICATE OF SERVICE

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

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

xx electronic filing

Docket No. G002/M-19-498

Dated this 1st day of November 2019

/s/

____

Jim Erickson
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_19-498_M-19-498
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-498_M-19-498
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-498_M-19-498
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-498_M-19-498
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-498_M-19-498
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_19-498_M-19-498
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_19-498_M-19-498
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_19-498_M-19-498
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_19-498_M-19-498
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-498_M-19-498

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_19-498_M-19-498
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_19-498_M-19-498
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-498_M-19-498
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_19-498_M-19-498
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_19-498_M-19-498
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_19-498_M-19-498
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	OFF_SL_19-498_M-19-498
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-498_M-19-498
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-498_M-19-498
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-498_M-19-498

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-498_M-19-498
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_19-498_M-19-498
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_19-498_M-19-498
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-498_M-19-498
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-498_M-19-498
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_19-498_M-19-498
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-498_M-19-498
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-498_M-19-498
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_19-498_M-19-498
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-498_M-19-498

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_19-498_M-19-498
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-498_M-19-498
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_19-498_M-19-498
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-498_M-19-498
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-498_M-19-498
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_19-498_M-19-498
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_19-498_M-19-498