Direct Testimony and Schedules
Michelle M. Terwilliger

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Natural Gas Service in Minnesota

Docket No. G002/GR-21-678
Exhibit___(MMT-1)

Rate Design

November 1, 2021

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michelle M. Terwilliger. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Northern States Power Company, a Minnesota corporation (Xcel Energy or the Company). My title is Principal Rate Analyst.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Company.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for the Company as a Principal Rate Analyst in Regulatory Affairs for more than eight years. Previously, I worked for Midwest Energy, Inc. as Manager of Customer Accounting and North Central Public Service Co., a gas utility, as a Rate Analyst and rate witness before the Iowa Public Utilities Commission. I received my bachelor's degree in Accounting from the University of Minnesota. A statement of my qualifications and experience is provided as Exhibit___(MMT-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony presents the Company's proposed rate design for recovering the revenue requirement provided by Company witness Mr. Benjamin Halama in his Direct Testimony for the Test Year ending December 31, 2022 for Xcel Energy's State of Minnesota natural gas jurisdiction. The CCOSS provided by

Company witness Mr. Christopher J. Barthol was the starting point for the apportionment of the retail Test Year revenue requirement among the rate classes. I also describe certain proposed tariff changes. Finally, I provide information on rate design related compliance requirements.

II. RATE DESIGN GOALS

Q. WHAT ARE THE COMPANY'S PRIMARY PRICING OBJECTIVES IN THE DESIGN OF NATURAL GAS RATES?

A. The primary natural gas rate design objectives are:

1) To collect total revenues sufficient to recover the Company's Test Year cost of service, including a reasonable return on investment;
2) To reflect the cost of providing service to each customer class, as supported by the Class Cost of Service Study (CCOSS);
3) To encourage efficient and economic energy use;
4) To moderate billing impacts; and
5) To provide value-based pricing and service conditions, where needed, to allow Xcel Energy's natural gas services to be competitive with other energy sources.

III. TEST YEAR REVENUES

Q. WHAT ARE THE TEST YEAR REVENUES AT PRESENT AND PROPOSED RATES?

A. The 2022 Test Year Revenues, applying present and proposed rates for the Company's Gas Utility-Minnesota jurisdiction, are $541.02 million and $576.65 million respectively. The $35.6 million difference between the two revenue levels is the revenue deficiency supported by Mr. Halama's testimony. Present rates refer to the rates authorized in the Company's last natural gas rate case, Docket No. G002/GR-09-1153. The proposed rates are designed to produce an increase in retail revenues of $35.6 million. Forecasted sales and transportation service volumes for the 2022 Test Year, provided by Company witness Ms. Jannell E. Marks, were applied to both the present and proposed rates to obtain these Test Year Revenues.

As Mr. Halama explains in his direct testimony, an adjustment was made to the level of Conservation Improvement Program (CIP) expenditures in the jurisdictional cost-of-service study to equal the level of CIP revenues in base rates. The amount of Test Year CIP revenues in base rates is included in Exhibit___(MMT-1), Schedule 2.

IV. DESCRIPTION OF XCEL ENERGY REGULATED NATURAL GAS SERVICES

Q. WHAT GENERAL CATEGORIES OF SERVICE DOES XCEL ENERGY PROVIDE TO ITS NATURAL GAS CUSTOMERS IN MINNESOTA?

A. The Company provides sales service and transportation service. Sales service is a "bundled" gas utility service offering, where Xcel Energy procures wholesale natural gas for customers, procures the necessary interstate gas pipeline transportation, and distributes and resells the gas to these customers. Transportation service customers acquire their own gas supplies via an unregulated gas supplier and procure their own pipeline transportation to Xcel Energy's town border station(s). Xcel Energy then delivers this third-party gas to the Transportation customers' premises through the Company's gas distribution system.

Customers, whether Sales or Transportation, can take either Firm or Interruptible service. Firm service is typically not subject to curtailment and is priced to include the costs of providing this reliability. Service to customers taking Interruptible service can be curtailed as needed to maintain system reliability and is priced to reflect both the potential for interruption and the competitive alternatives. The vast majority of the Company's customers take firm, bundled sales service.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S SERVICES.

A. The Company's Services include the following:

<u>Services</u>

Firm Sales
Residential
Small Commercial Firm
Large Commercial Firm
Small Commercial Demand Billed
Large Commercial Demand Billed

Interruptible Sales
Small Volume Interruptible
Medium Volume Interruptible
Large Volume Interruptible

Firm and Interruptible Transportation
Large Firm Transportation
Small Interruptible Transportation
Medium Interruptible Transportation
Large Interruptible Transportation

V. REVENUE REQUIREMENT APPORTIONMENT

Q. HOW WAS THE PROPOSED REVENUE REQUIREMENT APPORTIONMENT DEVELOPED?

A. As mentioned above, the CCOSS provided by Company witness Mr. Christopher J. Barthol was the starting point for the apportionment of the retail Test Year revenue requirement among the rate classes. The CCOSS indicates that the majority of classes should receive a rate decrease, and the Residential class should receive an increase larger than the deficiency in this case. However, I tempered the goal of setting rates at embedded costs by applying the other goals I described earlier, such as emphasizing value/competitive-based pricing for competitive services, market considerations and limiting rate increases to moderate levels. Consequently, I used the CCOSS as a guideline, but not as a final determinant for revenue apportionment by class. A summary page from the CCOSS showing the difference between current revenues and costs is provided in Exhibit___(MMT-1), Schedule 3.

My first step in developing the class apportionment was to review the market price forecasts of the customers' typical competitive alternatives and consider the value of Interruptible service compared to Firm service, and then determine the revenue responsibility for the Interruptible classes. I balanced the increase to the Interruptible class with the corresponding increase to the Interruptible Transportation class, as I describe later in my testimony. The value-based approach to pricing Interruptible service results in the recovery of more than this class's embedded cost of service. I discuss the specific procedure I used to develop Interruptible prices later in my testimony.

I then apportioned the remaining revenue requirement among the Firm classes. I propose an 8.6 percent increase to the Residential class. The CCOSS results indicated that the Demand class rates were currently set further above costs than the Commercial class. Based on this, I propose a Commercial class increase of 3.7 percent and a lower increase of 1.6 percent for the Demand class. While the average Firm customer increase is 6.8 percent, I propose different non-gas revenue percent increases for each of the Firm service classes. My goal was to recover as closely as possible the costs imposed by each class, while avoiding unacceptably high billing impacts. My proposed revenue responsibility allocation for the Residential class will eliminate more than 68 percent of the difference between present rates and the Test Year embedded cost of service.

Finally, I reviewed the apportionment to ensure that longstanding rate relationships between Firm and Interruptible rate classes, as well as between Sales Service and Transportation rate classes, were maintained. For example, Interruptible rates must be set at a discount relative to firm rates to reflect the less reliable nature of service. In addition, relationships within the small, medium and large categories of a class should be maintained. Also, the Company's goal is to remain indifferent to a customer's choice regarding gas supplier, and therefore the proposed non-gas margins for corresponding Sales and Transportation Service are equal. The resulting apportionment is provided in Exhibit___(MMT-1), Schedule 4.

Q. PLEASE PROVIDE THE OVERALL CLASS IMPACTS OF THE COMPANY'S PROPOSED REVENUE APPORTIONMENT AND COMPARE THEM TO THE CCOSS-INDICATED REVENUE APPORTIONMENT.

A. Table 1 provides the overall class impacts of the Company-proposed apportionment and compares it to the CCOSS-indicated apportionment. The apportionment with gas costs is provided in Exhibit___(MMT-1), Schedule 4.

Table 1

Revenue Apportionment

	($000)		
Customer Class	**Present Revenues**	**CCOSS Costs of Service**	**Proposed Revenue**
Residential	$316,793	$356,746	$344,093
% increase		12.6%	8.6%
Commercial	$153,749	$148,947	$159,363
% increase		-3.1%	3.7%
Demand	$17,962	$16,101	$18,249
% increase		-10.4%	1.6%
Interruptible	$40,149	$36,712	$40,733
% increase		-8.6%	1.5%
Transport	$5,248	$4,681	$6,233
% increase		-10.8%	18.8%
Generation	$7,115	$13,457	$7,216
% increase		89.1%	1.4%
Other Revenues	$4,908		$5,665
% increase			15.4%
Total	$545,924	$576,645	$581,553
% increase		6.6%	6.5%

Q. WHAT FACTORS CONTRIBUTE TO THE NON-GAS INCREASE?

A. Both the increased revenue requirement and the transfer, or roll-in, of rider expenditures to base rates impact the non-gas increase. As Mr. Halama explains in his direct testimony, an adjustment was made to the Present Revenues to include revenues related to the CIP, Gas Utility Infrastructure Cost (GUIC), and State Energy Policy (SEP) expenditures that are being moved into base rates. The roll-in of GUIC, CIP, and SEP Rider costs resulted in increased distribution charges to recover those rider charges. Customers have currently been paying for these costs through these riders, so the portion of the base rate increase associated with the rider roll-ins doesn't increase their overall bill. The CIP/SEP/GUIC Test Year Revenue adjustments are provided in Exhibit___(MMT-1), Schedule 2.

Q. DO YOU PROPOSE A REVENUE APPORTIONMENT FOR GAS COST REVENUES?

A. No. The Base Cost of Gas establishes the apportionment of gas cost revenues. Gas cost revenues are shown on certain schedules in my testimony to demonstrate the overall bill impact of the non-gas rate increase.

VI. OVERALL CLASS IMPACTS

Q. PLEASE DESCRIBE EXHIBIT___(MMT-1), SCHEDULES 5, 6 AND 7.

A. In compliance with the requirements of Minn. R. 7825.4300, Exhibit___(MMT-1), Schedule 5 summarizes the present and proposed Test Year revenues and contains the Test Year number of customers, sales, present and proposed Test Year rates, the Base Cost of Gas rates, and the resulting revenues. This information is provided in summary for each class (page 1); and for each rate component charged to each class (pages 2 through 5). Exhibit___(MMT-1), Schedule 6 contains the present and proposed rates for the Test Year revenue requirement. Exhibit___(MMT-1), Schedule 7 provides the resulting revenues under the proposed Test Year revenue requirement compared to the class revenue requirements as determined by the CCOSS.

VII. REVENUE RECOVERY

Q. PLEASE DESCRIBE HOW XCEL ENERGY STRUCTURES RATES CURRENTLY.

A. The Company's current rates are structured as either two- or three-part rates. Two-part rates consist of a monthly fixed Customer Charge and a volumetric Distribution Charge applied to a customer's use during the billing period. Three-part rates add a Demand Charge that is assessed on a customer's peak day demand. In addition, the Company collects a Cost of Gas charge that reflects the Base Cost of Gas plus the Purchased Gas Adjustment (PGA) for changes in wholesale gas, transportation, and storage costs in each month. Although the Base Cost of Gas will be restated in conjunction with this proceeding, the fundamental rate design issues in this proceeding relate to recovery of the Company's non-commodity costs of providing retail distribution service.

Q. WHY DO YOU RECOMMEND CHANGES TO THE RELATIONSHIP BETWEEN RATE COMPONENTS?

A. The shortcoming of our current pricing is that we recover a significant percentage of fixed costs through volumetric charges, which is not the case for other market participants and in other jurisdictions. In North Dakota, we recover all residential costs through the fixed customer charge with no distribution charge. Similarly, interstate natural gas pipelines recover 100 percent of their fixed costs through fixed charges. By contrast, under our present gas rate design, the Company collects only 32 percent of its fixed costs through fixed charges such as the Customer Charge resulting in intra-class subsidy discussed in the Residential Service section below. This deficiency causes several problems; for example, an artificially low customer charge could lead to customers choosing to install natural gas as a backup energy source along with another primary source of heat. These choices could frustrate the goal of efficient and economic energy use.

Q. HOW DO YOU PROPOSE TO ADDRESS THE CURRENT DEFICIENCY IN THE RATE STRUCTURE?

A. The Company proposes an increase in the Residential, Small and Large Commercial Firm, and Small Interruptible Customer Charges because the Customer Charges in these classes are below the appropriate cost-based levels. If the Commission were to adopt a lower Customer Charge than the Company proposes, the Distribution Charge would need to be higher than the Company's proposal to achieve the same level of overall revenue increase.

VIII. SUMMARY OF RATE DESIGN PROPOSALS

A. Residential Service

Q. WHAT CHANGE IS XCEL ENERGY PROPOSING TO THE RESIDENTIAL CHARGES?

A. The Company is proposing to increase the monthly Residential Customer Charge from $9.00 to $11.00 and increase the Distribution Charge from $0.175996 per therm to $0.285785 per therm. I note that $0.06705 per therm of the proposed Distribution Charge is a result of present rider rates being rolled into our proposed rates. This combination of changes will be referred to herein as the "proposed rate structure."

Q. WHY ARE YOU RECOMMENDING A RESIDENTIAL CUSTOMER CHARGE THAT FALLS WELL SHORT OF THE COSTS IMPOSED BY THESE CUSTOMERS?

A. The customer related cost of providing service to Residential customers is $24.12. I am recommending an increase from $9.00 to $11.00. Raising the Customer Charge from $9.00 to the cost-based level of $24.12, while appropriate from a cost-causation perspective, would impose a significant percentage increase in the monthly bill for low-use customers. Therefore, my proposal strikes a balance between reducing the inefficiencies in our current Residential pricing, *i.e.,* recovering an inadequate amount of fixed costs through the Customer Charge, and moderating the billing impacts on low-use customers. The CCOSS indicated Customer Charges are shown on line 8 of Exhibit___(MMT-1), Schedule 3.

Q. WHY IS IT IMPORTANT TO RECOVER MORE CUSTOMER COSTS IN THE CUSTOMER CHARGE?

A. Recovering customer costs in Customer Charges creates more efficient pricing, promotes stability, and reduces intra-class subsidies.

Customer costs are caused by all customers connected (or being connected) to the Company's gas system (*i.e.,* metering, service lines, meter reading, billing, etc.). Thus, customer costs are not related to the amount of gas a customer uses. Even if a customer uses no gas, the Company incurs essentially the same (or "fixed") level of customer-related costs just to have the customer connected to the gas distribution system.

Q. HOW DOES THE PROPOSED RATE STRUCTURE CREATE MORE EFFICIENT PRICING?

A. When the Customer Charge does not recover an appropriate level of fixed customer costs, the remaining fixed customer costs are recovered in the volumetric Distribution Charge. As a result, even though all customers are causing the fixed costs to be incurred, those who use more gas subsidize the fixed costs of other customers. Recovering more customer costs in the Customer Charge reduces the subsidization, and thus adheres more closely to the principle of cost causation, by allowing each customer to pay a more equitable portion of the fixed costs incurred by the Company to serve them.

For example, even under the Company's present rates, although two customers each impose annual customer costs of $289, a customer using 40 Dekatherm (Dkt)/year would pay for only $178 of these costs, while a customer using 120 Dkt/year would pay $319. In other words, an intra-class subsidy exists.

Q. DOES THE PROPOSED RATE STRUCTURE PROMOTE STABILITY?

A. Yes. By moving the recovery of more fixed costs to the fixed charge, the proposed rate structure creates more stable bills and cost recovery. A lower percentage of the customer's bill would be affected by variability in weather compared to the current structure.

Q. WOULD A MODERATE INCREASE IN THE RESIDENTIAL CUSTOMER CHARGE UNFAIRLY BURDEN LOW-VOLUME USERS?

A. No. As noted above, an increase in the Residential Customer Charge would result in a reduction to the existing subsidy currently provided by high-volume to low-volume Residential users. The gradual elimination of this pricing distortion should not be construed as a burden. It would be more accurate to conclude that high-volume customers are currently burdened because they pay more than their cost of service. Therefore, failing to address this problem would continue to impose an unreasonable burden on high-volume customers.

It is appropriate for low-volume users to pay lower bills to the extent their lower usage results in a lower cost of service; but it is not appropriate for low-volume customers to benefit from a subsidy provided by higher-volume customers in the same class.

Q. WHAT EFFECT WOULD THE COMPANY'S PROPOSED RESIDENTIAL RATE DESIGN HAVE ON CONSERVATION?

A. More appropriate cost-based rates should lead to more informed decision-making regarding natural gas usage. Since wholesale gas costs are approximately 60 percent of customers' bills, customers who conserve natural gas usage will continue to be rewarded with lower bills. Rates that better reflect cost should encourage conservation.

Q. WHAT ARE THE RESIDENTIAL CUSTOMER CHARGES IN THE COMPANY'S OTHER JURISDICTIONS?

A. The Residential Customer Charge in North Dakota is $18.48 per month and there is no volumetric Distribution Charge. The proposed Residential Customer Charge is also lower than those currently authorized by the Company's affiliates: Northern States Power Company, a Wisconsin corporation, has a $14.00 per month Residential monthly charge in Wisconsin and for Public Service Company of Colorado, the Residential monthly charge is $12.21 in Colorado.

Q. NORTH DAKOTA HAS THE HIGHEST CUSTOMER CHARGE AND NO DISTRIBUTION CHARGE. HAS THE COMPANY SEEN EVIDENCE IN NORTH DAKOTA THAT THIS RATE STRUCTURE DISCOURAGES CONSERVATION?

A. No. In fact, this rate structure has been in place in North Dakota since 2005, and the Residential decline in use in North Dakota is similar to that experienced in Minnesota. North Dakota Residential average annual usage has decreased from 834 therms in 2006 to 779 therms in 2020 or 7 percent. In Minnesota, Residential average annual usage has decreased from 974 therms in 2006 to 892 therms in 2020 or 8 percent.

Q. HOW DOES THE COMPANY ADDRESS CONCERNS REGARDING THE IMPACT OF INCREASED CUSTOMER CHARGES ON CUSTOMERS WITH LOW INCOME?

A. The Company offers a natural Gas Affordability Program, which targets customers with low income who may have difficulties making payments. The Company made changes to this program through Docket No. G002/M-21-220 to increase the amount of credits to eligible customers.

Q. DO LOW-INCOME CUSTOMERS HAVE USAGE DIFFERENT FROM THE AVERAGE RESIDENTIAL CUSTOMER?

A. No, low-income usage patterns mirror the average Residential usage pattern. Some low-income customers have low energy usage, but other low-income customers have very high energy use. Low-income customers that are high use are better off with a higher customer charge.

Q. WHAT IS THE BILL IMPACT OF THIS PROPOSAL FOR THE RESIDENTIAL CLASS?

A. The average Residential customer will experience an 8.6 percent increase in their bill. A comparison of bills for various usage levels under present and proposed rates is shown on Exhibit___(MMT-1), Schedule 8. The average non-gas increase for the Residential class is 19.1 percent.

Q. WHY IS AN OVERALL NON-GAS INCREASE OF 19.1 PERCENT APPROPRIATE FOR THE RESIDENTIAL CLASS?

A. This non-gas percent revenue increase is slightly higher than the average non-gas 15.8 percent increase, but was selected because this increase moves the Residential class closer to cost by eliminating approximately 96 percent of the interclass subsidy that currently exists with the present rates. More appropriate cost-based rates should lead to more informed customer decision-making regarding natural gas usage. A reasonable movement towards cost requires the Residential class increase be higher than the average. To keep the Residential increase at a reasonable level, however, the Company is also proposing increases to some classes that would otherwise receive a decrease under cost-based rates.

B. Commercial Firm Service

Q. WHAT CHANGES ARE YOU PROPOSING TO THE FIRM COMMERCIAL RATES?

A. The Company is proposing to increase the Small Commercial Customer Charge from $25.00 to $30.00 and the Large Commercial Customer Charge from $50.00 to $70.00. The increase in the Small Commercial Customer Charge is justified by the Company's CCOSS. To achieve overall rate apportionment goals, I am proposing to increase the per therm Distribution Charges from $0.116732 to $0.168025 for Small Commercial service and from $0.116582 to $0.167725 for Large Commercial service.

C. Demand Billed Service

Q. WHAT CHANGES ARE YOU PROPOSING FOR DEMAND BILLED RATES?

A. The Company is proposing to increase the Small Demand Billed Customer Charge from $150.00 to $175.00 and no change to the Large Demand Billed Customer Charge based on the cost levels indicated by the CCOSS.

The Distribution Charges for the Demand Billed Services were set at the Distribution Charge for the Medium Interruptible customers. This general relationship has been in effect since the Company's 1992 rate case (Docket No. G002/GR-92-1186) and is reasonable. The rates on the two tariffs should be comparable except for the Demand Charge, which reflects the firm nature of the Demand Billed Service. The Demand Charge was increased from $0.80947 to $0.882000 per therm of billing demand justified by the Company's CCOSS to achieve an overall non-gas average rate increase of 5.8 percent. The average bill will increase 1.9 percent.

D. Interruptible Sales Service

Q. WHAT ARE THE GOALS OF THE COMPANY'S PROPOSED INTERRUPTIBLE GAS RATES?

A. The primary goals are as follows:

- First, Interruptible rates should reflect the anticipated value of service to the customer. This goal was accomplished by pricing Interruptible service at a rate competitive with the cost of alternate fuels available to these customers. The upper limit used for the Interruptible commodity pricing was the price of No. 2 fuel oil, since most of these customers use No. 2 fuel oil as their primary alternate fuel.
- Second, Interruptible prices should reflect a reasonable discount from Firm prices because Interruptible service is of lower value. If No. 2 fuel oil is priced higher than Firm gas service, then the corresponding Firm rates, less a reasonable discount, become the upper limits for Interruptible rates.
- Third, Interruptible customers should not be subsidized by other classes of service. Therefore, Interruptible rates should recover at least the

Company's base cost of gas plus variable operating and maintenance expenses.

Q. HOW WERE THE INTERRUPTIBLE RATES DEVELOPED BASED ON THESE GOALS?

A. First, looking at the alternate fuel prices of No. 2 fuel oil of $1.29345 per therm, it far exceeds the Interruptible commodity pricing. Therefore, the Firm rates become the upper limit for Interruptible rates and as shown in Table 2 below, I have maintained a similar level of discount as current rates. Next, I looked at the CCOSS results. The current Customer Charges for the Medium and Large Interruptible Service classes slightly exceed the CCOSS average of customer-related expenses. Consequently, I propose no increase in these charges. I am proposing to increase the Small Interruptible Customer Charge from $145 to $150 to reflect the indicated CCOSS customer related cost.

The proposed Distribution Charge established for the Medium Interruptible Service was designed to generate a non-gas 4.9 percent overall rate increase for the class. The proposed Distribution Charge established for the Large Interruptible Service was designed to reflect a lower cost of service than the Medium Interruptible Service class and to generate an overall increase of non-gas revenue of 3.6 percent for the class. The Distribution Charge for the Small Interruptible Service class was increased from $0.091214 to $0.144125 per therm. These increases were designed to maintain a reasonable discount, similar to that reflected in present rates, from the corresponding Firm service options available to these customers. The various components of the Interruptible rates are identified in Exhibit___(MMT-1), Schedule 5, Page 4.

Table 2 below illustrates the current and proposed level of discount between Firm and Interruptible Sales Service.

Table 2

Average Bill Comparison-Commercial Firm and Interruptible Classes

Class	Monthly Therm Use	Avg Bill - Present Rates	Avg Bill - Proposed Rates
Large Commercial Firm	1,322	$850	$879
Small Interruptible	1,322	$758	$786
% Discount		11%	11%
Small Commercial Demand	6,573	$3,888	$3,969
Small Interruptible	6,573	$3,195	$3,312
% Discount		18%	17%
Large Commercial Demand	18,854	$11,333	$11,513
Medium Interruptible	18,854	$7,998	$8,077
% Discount		29%	30%

As shown in Table 2, Interruptible discounts are being maintained at the same level as current rates.

Q. HOW DOES THE SYSTEM BENEFIT FROM INTERRUPTIBLE CUSTOMERS?

A. The willingness of Interruptible customers to trade firm service for a discount, enhances system reliability and flexibility. In particular, since an Interruptible customer has agreed to not receive service at particular times, the Company's load forecast can be reduced accordingly. This results in greater reliability, because the gas that would have ordinarily been needed can be used to serve other customers. This also reduces costs for all customers since the Company can now plan for less firm gas than would have otherwise been required.

Q. WILL THE PROPOSED INTERRUPTIBLE RATES RECOVER MORE THAN THE COSTS IMPOSED BY THESE CLASSES?

A. Yes. The proposed Interruptible rates would recover $4 million above the CCOSS revenue requirement for these customers, thereby reducing the residual costs that must be recovered from firm customers.

Q. HAS XCEL ENERGY RETAINED THE FLEXIBLE PRICING PROVISIONS FOR ITS INTERRUPTIBLE SALES TARIFFS?

A. Yes. The Company proposes to retain the rate flexibility authorized in the 1985 general gas rate case (Docket No. G002/GR-85-108) for the Flexible Distribution Charge ranges in the Interruptible Service tariff. As stated in the tariff, the Flexible Distribution Charge applies for Customers, who normally would be served on the fixed rate but are placed on the flexible rate because: (1) the customer requests flexible rate service, (2) for pricing reasons, the customer uses a non-gas alternate energy supply/service from a supplier not regulated by the Commission, or (3) the customer uses gas from a supplier not regulated by the Commission.

For those customers on the Flexible Distribution Charge, the midpoint of the proposed range is the applicable fixed rate explained above. The floor has been set at the variable Operation and Maintenance (O&M) cost (which is the incremental cost of providing service), as required by Minn. Stat. § 216B.163, Subd. 4(1)). The ceiling has been designed so that the rate may be increased by as much as it may be discounted from the fixed rate.

E. Firm and Interruptible Transportation Service

Q. WHAT CHANGES ARE YOU PROPOSING FOR THE TRANSPORTATION RATES?

A. Transportation rates are the same as the corresponding Sales rates, except that Transportation customers pay a slightly higher Customer Charge to reflect the additional customer-related cost of serving such customers. This approach ensures that Xcel Energy will be indifferent to the customer's choice of gas procurement (*i.e.,* Xcel Energy sales gas or gas purchased from a third-party marketer). Therefore, my explanation of the proposed Customer Charges, Distribution Charges, and Distribution Demand charges for Sales customers also holds true for the corresponding Transportation rates.

Q. DOES THE CCOSS SUPPORT LINKING TRANSPORTATION RATES TO THE CORRESPONDING SALES SERVICE?

A. Yes. In general, customers eligible for these rate options are similarly sized. The Company provided the Transportation specific category in the CCOSS in response to a compliance requirement. Since there are only three to fifteen customers in these classes, annual results are highly dependent on the specific customers currently in the class, and the results could be very different if one or more customers switched rate classes. Therefore, the Company's approach to link the Transportation rates to the corresponding Sales rate should be continued.

Q. WHY IS THE OVERALL INCREASE IN TRANSPORTATION RATES HIGHER THAN INTERRUPTIBLE RATES?

A. The Transportation class increase is higher than the Interruptible increase for a couple of reasons. First, since the Transportation customers purchase their gas supply from a third party, their Xcel Energy bill only consists of non-gas components causing their increase to appear higher compared to the average sales service increases. Second, and unique to this case, is an actual higher increase to the Transportation Distribution Charge to make the rates consistent between the corresponding sales service. This was necessary due to the GUIC rider roll in of present rider rates that differed between the Transportation and Sales service classes.

Q. WHY WERE THE GUIC RATES DIFFERENT FOR THE TRANSPORTATION AND CORRESPONDING SALES SERVICE CLASSES?

A. The GUIC revenue requirement was ordered to be allocated to class based on how revenues were apportioned in the last rate case. This was done using five separate classes (Residential, Commercial, Demand, Interruptible, and Transportation) instead of combining the corresponding Transportation and Sales service classes. This apportionment, along with the growth in Transportation class sales, has resulted in much lower GUIC rates for Transportation customers than their corresponding sales service classes. The Company is proposing a change to this allocation in the 2022 GUIC rider filing.

IX. OTHER TARIFF CHANGES

Q. WHAT OTHER TARIFF CHANGES DOES XCEL ENERGY PROPOSE?

A. Xcel Energy is proposing a number of changes to tariff sheets in its Minnesota Gas Rate Book. Exhibit___(MMT-1), Schedule 9 contains a list and a summary of the proposed tariff changes. The proposed tariffs are included in redline and non-redline format in the volume entitled "Proposed Tariffs" of our application. These changes are discussed below.

Q. ARE ANY OTHER WITNESSES SPONSORING CHANGES IN THE TARIFF BOOK?

A. Yes. Mr. Hults is addressing several changes in the Gas Rate Book, including:

- Resetting tiered penalties for Interruptible customers unauthorized use of gas during service curtailment;
- Adding a Negotiated Gas Transport Agreement to the rate book; and
- Updates to nomination cycles in Transportation service tariffs and agreement.

For convenience purposes, all proposed tariff changes have been included together in the volume entitled "Proposed Tariffs" of our application.

X. COMPLIANCE REQUIREMENTS

Q. PLEASE ADDRESS ANY COMPLIANCE REQUIREMENTS FROM ORDERS RELATED TO RATE DESIGN.

A. I will address the compliance issues related to the following two items:

- Identify CIP costs not recovered from Flexible rates due to rate discounting, and
- Prepare a separate End User Allocation Service Cost (EUAS) Study.

Q. ARE THERE CIP COSTS THAT ARE NOT BEING RECOVERED DUE TO RATE DISCOUNTING?

A. No. Only customers with an exemption granted by the Commissioner of the Department of Commerce are not required to contribute toward recovery of CIP costs.

Q. DID THE COMPANY PREPARE A SEPARATE EUAS STUDY AS REQUIRED BY DOCKET NO. G002/GR-06-1429?

A. Yes. The cost study is attached as Exhibit___(MMT-1), Schedule 10. The resulting study demonstrates the current charge could be slightly increased, however, since the cost study is very sensitive to the number of customers currently taking EUAS service, I recommend not changing the monthly rate of $75 at this time.

Q. WHAT DO THE CCOSS RESULTS INDICATE FOR THE STAND-ALONE GENERATION CLASS?

A. For the electric Generation customers (two plants) taking Sales service from the Company, the CCOSS indicates they are presently paying more than embedded cost. The CCOSS indicates that the Generation customers (four plants) taking Transportation service from the Company are paying under embedded cost rates. Three of these customers are taking service pursuant to a long-term contract awarded to Xcel Energy's natural gas operations through competitive bidding processes. Service to these three customers required main extensions and Xcel Energy was not the only supplier available to these customers. The long-term contract price justified the Company incurring the cost of the extensions and also provided a reasonable contribution, providing a benefit to our other natural gas customers. The lower gas costs also benefit our electric customers.

XI. CONCLUSION

Q. COULD YOU SUMMARIZE THE PROPOSALS AND RECOMMENDATIONS OF YOUR TESTIMONY?

A. Yes. My testimony included the following proposals:

- The Company has proposed a reasonable apportionment of revenue requirements by customer class that provides a moderate movement toward the cost of service.
- The Company's proposed rates are reasonable, consistent with its rate design objectives, and improve customer equity.
- The Company has also proposed various reasonable changes to its tariff.
- Finally, my testimony discusses how the Company has fulfilled the requirements of two Commission-ordered compliance items.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications and Experience
Michelle M. Terwilliger

OVERVIEW

My qualifications include more than 8 years of experience with Xcel Energy and its predecessors in the areas of rate analysis, pricing and rate design. My current responsibilities at Xcel Energy include Rate Design work conducted in support of the Company's rate cases and providing rate analysis and pricing support and other related analyses for the utility operating subsidiaries of Xcel Energy. I have served as a rate case witness in Iowa.

PROFESSIONAL EXPERIENCE

Principal Rate Analyst; Xcel Energy, NSPM	2013 – Present
Accountant; Christ Presbyterian Church	2012 – 2013
Program Coordinator; Prayer Ventures	2010 – 2012
Assistant Manager; Pathway Books/Music	2007 – 2010
Owner, Le Nantais French Delicatessen	1988 – 1993
Manager of Customer Accounting; Midwest Energy, Inc.	1986 – 1988
Rate Analyst; North Central Public Service Co.	1985 – 1986
Staff Accountant; North Central Public Service Co.	1983 – 1985

EDUCATIONAL BACKGROUND

University of Minnesota; BS Accounting	1983

CIP/ SEP/ GUIC TEST YEAR REVENUE ADJUSTMENT
Test Year Ending December 31, 2022

	(1) Therms	(2) Exempt Therm Sales	(3) Applicable Therm Sales	(4) CIP Base Revenues	(5) Adj to Test Year	(6) Test Year CIP Revenues
Residential Firm	389,299,108	0	389,299,108	$2,039,927	$7,265,100	$9,305,027
Small Commercial Firm	51,420,746	-11,000	51,409,747	$269,387	$959,409	$1,228,796
Large Commercial Firm	178,596,136	-77,167	178,518,969	$935,439	$3,331,521	$4,266,960
Small & Large Commercial Demand	29,905,854	-289,589	29,616,265	$155,189	$552,699	$707,888
Small Interruptible	16,409,131	0	16,409,131	$85,984	$306,227	$392,211
Medium & Large Interruptible	78,279,409	-531,035	77,748,374	$407,401	$1,450,940	$1,858,342
Transportation	133,818,194	-95,903,035	37,915,159	$198,675	$707,573	$906,248
Generation	233,390,970	-233,298,050	92,920	$487	$1,734	$2,221
Total	1,111,119,548	-330,109,876	781,009,672	$4,092,491	$14,575,202	$18,667,693

Test Year CIP Expense	$18,667,702
Test Year CIP Adjustment (CIP Test Year Expense - CIP Base Revenues)	$14,575,211
Per Therm Adjustment to adjust CIP Revenues (column 5/column 3)	$0.01866
Per Therm CCRC in Test Year Base Rates (column 6/column 3)	$0.02390
CCRC used to determine CIP Base Revenues	$0.00524

SEP	
Test Year SEP Expense	$1,036,675
Per Therm Adjustment for State Energy Policy Rate Rider	$0.00093

GUIC	GUIC Allocator	GUIC Allocation	Therms	GUIC	CIP	SEP	Total
Res	67.2244%	$18,474,290	389,299,108	0.0474553	0.018662	$0.00093	$0.06705
Comm Firm	21.2597%	$5,842,490	230,016,883	0.0254003	0.018662	$0.00093	$0.04500
Dmd Billed	2.1010%	$577,387	29,905,854	0.0193068	0.018662	$0.00093	$0.03890
Interruptible	5.6521%	$1,553,283	94,910,075	0.0163658	0.018662	$0.00093	$0.03596
Transportation	3.7628%	$1,034,075	366,987,629	0.0028177	0.018662	$0.00093	$0.02241
Test Year GUIC Expense		$27,481,525	1,111,119,548				

COMPARISON OF CURRENT REVENUES AND COSTS BY CLASS ($000)

Test Year Ending December 31, 2022

	Equal Return vs Present	1=2+15	2=3+11	3=4+5+8	4	5=6+7	6	7	8=9+10	11=12>>14	15=16+20	16=17>>19	20=21+22	21	22
	Operating Revenue Requirement	**Minn**	**Retail**	**Firm**	**Res**	**C&I Tot**	**Sm C&I**	**Lg C&I**	**Dmd Tot**	**Inter Tot**	**Non-Retail**	**Tran Tot**	**Gener Tot**	**Sys Gen**	**Tran Gen**
1	Return On Rate Base	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%	7.46%
2	Equalized Total Retail Rev	576,645	558,506	521,794	356,746	148,947	40,460	108,486	16,101	36,712	18,138	4,681	13,457	104	13,353
3	Present Total Retail Revenue	541,016	528,652	488,503	316,793	153,749	38,802	114,947	17,962	40,149	12,364	5,248	7,115	116	6,999
4	Revenue Deficiency	35,629	29,854	33,291	39,954	-4,802	1,659	-6,461	-1,861	-3,437	5,775	-567	6,342	-12	6,354
5	Deficiency / Pres Total Retail Rev	6.59%	5.65%	6.81%	12.61%	-3.12%	4.27%	-5.62%	-10.36%	-8.56%	46.71%	-10.80%	89.13%	-10.48%	90.79%
	Internal Retail Revenue Reqt														
6	Customer Retail Revenue Requirement	144,483	144,417	143,842	128,697	14,816	8,875	5,941	329	575	66	53	13	6	6
7	Average Monthly Customers	480,825	480,792	480,494	444,262	36,092	24,830	11,262	140	298	33	26	7	3	4
8	Revenue Requirement $ / Mo / Cust	25.04	25.03	24.95	24.14	34.21	29.79	43.96	196.08	160.57	166.73	171.01	150.80	175.78	132.06
9	Capacity Retail Revenue Requirement	86,922	71,282	69,083	41,637	24,827	6,962	17,865	2,619	2,199	15,640	3,193	12,447	13	12,434
10	Annual Dkt Sales	111,111,955	74,391,038	64,922,184	38,929,911	23,001,688	5,142,075	17,859,614	2,990,585	9,468,854	36,720,916	13,381,819	23,339,097	22,154	23,316,943
11	Revenue Requirement $ / Dkt	0.78	0.96	1.06	1.07	1.08	1.35	1.00	0.88	0.23	0.43	0.24	0.53	0.59	0.53
	Capacity - Sub Classification														
12	Capacity - Base Revenue Requirement	23,658	16,676	14,476	8,641	5,159	1,146	4,013	676	2,199	6,983	2,985	3,998	5	3,993
13	Capacity - Seasonal Revenue Requirement	44,640	38,441	38,441	23,254	13,851	4,168	9,682	1,336	0	6,199	132	6,067	6	6,061
14	Peak Shaving Revenue Requirement	18,624	16,166	16,166	9,741	5,818	1,648	4,170	606	0	2,458	76	2,382	2	2,380
15	Base Rev Requirement $ / Dkt	0.21	0.22	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.19	0.22	0.17	0.23	0.17
16	Seasonal Rev Requirement $ / Dkt	0.40	0.52	0.59	0.60	0.60	0.81	0.54	0.45	0.00	0.17	0.01	0.26	0.26	0.26
17	Peak Shave Rev Requirement $ / Dkt	0.17	0.22	0.25	0.25	0.25	0.32	0.23	0.20	0.00	0.07	0.01	0.10	0.10	0.10
18	Energy Retail Revenue Requirement	24,428	22,077	19,279	11,519	6,876	1,548	5,327	885	2,798	2,351	1,435	917	4	913
19	Revenue Requirement $ / Dkt	0.22	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.06	0.11	0.04	0.16	0.04
20	Total Internal Retail Revenue Requiremen	255,833	237,776	232,204	181,852	46,519	17,386	29,133	3,833	5,572	18,057	4,681	13,376	23	13,353
21	Revenue Requirement $ / Dkt	2.30	3.20	3.58	4.67	2.02	3.38	1.63	1.28	0.59	0.49	0.35	0.57	1.03	0.57
22	Revenue Requirement $ / Mo / Cust	44.34	41.21	40.27	34.11	107.41	58.35	215.57	2,281.42	1,557.17	45,598.87	15,003.68	159,238.14	635.32	278,190.25
	External Retail Revenue Reqt														
23	Capacity Revenue Requirement	66,581	66,573	66,573	40,418	23,692	5,448	18,244	2,464	0	9	0	9	9	0
24	Energy Revenue Requirement	253,474	253,401	222,261	133,777	78,680	17,589	61,091	9,804	31,140	73	0	73	73	0
25	Total External Revenue Requirement	320,055	319,974	288,834	174,195	102,371	23,037	79,334	12,268	31,140	81	0	81	81	0
26	Cap Revenue Requirement $ / Dkt	0.60	0.89	1.03	1.04	1.03	1.06	1.02	0.82	0.00	0.00	0.00	0.00	0.39	0.00
27	Ener Revenue Requirement $ / Dkt	2.28	3.41	3.42	3.44	3.42	3.42	3.42	3.28	3.29	0.00	0.00	0.00	3.27	0.00
28	Tot Revenue Requirement $ / Dkt	2.88	4.30	4.45	4.47	4.45	4.48	4.44	4.10	3.29	0.00	0.00	0.00	3.67	0.00
	Total Retail Revenue Reqt														
29	Customer Revenue Requirement	144,483	144,417	143,842	128,697	14,816	8,875	5,941	329	575	66	53	13	6	6
30	Capacity Revenue Requirement	153,503	137,855	135,655	82,054	48,519	12,410	36,109	5,082	2,199	15,648	3,193	12,455	22	12,434
31	Energy Revenue Requirement	277,902	275,478	241,540	145,296	85,556	19,137	66,418	10,689	33,938	2,424	1,435	989	76	913
32	Total Revenue Requirement	575,888	557,750	521,038	356,047	148,890	40,423	108,468	16,101	36,712	18,138	4,681	13,457	104	13,353
33	Customer Revenue Reqt $ / Dkt	1.30	1.94	2.22	3.31	0.64	1.73	0.33	0.11	0.06	0.00	0.00	0.00	0.29	0.00
34	Demand Revenue Reqt $ / Dkt	1.38	1.85	2.09	2.11	2.11	2.41	2.02	1.70	0.23	0.43	0.24	0.53	0.98	0.53
35	Energy Revenue Reqt $ / Dkt	2.50	3.70	3.72	3.73	3.72	3.72	3.72	3.57	3.58	0.07	0.11	0.04	3.43	0.04
36	Total Revenue Reqt $ / Dkt	5.18	7.50	8.03	9.15	6.47	7.86	6.07	5.38	3.88	0.49	0.35	0.58	4.70	0.57
	Proposed Return vs Present														
37	Proposed Total Retail Revenue	576,645	563,195	522,462	344,793	159,419	40,653	118,766	18,249	40,734	13,449	6,233	7,216	117	7,099
38	Revenue Deficiency	35,629	34,543	33,958	28,000	5,671	1,851	3,819	288	584	1,086	985	101	1	100
39	Deficiency / Pres Total Oper Revenue	6.59%	6.53%	6.95%	8.84%	3.69%	4.77%	3.32%	1.60%	1.46%	8.78%	18.77%	1.42%	0.97%	1.43%
	Proposed Return vs Equal														
40	Revenue Difference	0	4,689	668	-11,954	10,473	193	10,280	2,149	4,021	-4,689	1,552	-6,241	13	-6,254
41	Difference / Tot Equal Revenue"	0.00%	0.84%	0.13%	-3.35%	7.03%	0.48%	9.48%	13.34%	10.95%	-25.85%	33.15%	-46.38%	12.80%	-46.84%

REVENUE APPORTIONMENT (w/ fuel costs)
Test Year Ending December 31, 2022

	Present Revenue	CCOSS Responsibility	Increase without Design Change	Present Revenue as % of Cost	% Increase to Pay Cost	Proposed Revenue	Proposed $ Increase	Proposed % Increase
Residential	$316,792,737	$356,746,377	$337,655,180	88.8%	12.6%	$344,093,162	$27,300,425	8.6%
Small Commercial	$38,801,726	$40,460,488	$41,357,021	95.9%	4.3%	$40,615,357	$1,813,631	4.7%
Large Commercial	$114,946,993	$108,486,222	$122,516,848	106.0%	-5.6%	$118,747,868	$3,800,875	3.3%
Small & Large Commercial Demand Billed	$17,961,720	$16,100,836	$19,144,592	111.6%	-10.4%	$18,249,206	$287,486	1.6%
Small Interruptible	$7,975,156	$6,765,088	$8,500,361	117.9%	-15.2%	$8,265,725	$290,569	3.6%
Medium & Large Interruptible	$32,173,938	$29,947,266	$34,292,759	107.4%	-6.9%	$32,467,335	$293,397	0.9%
Transportation	$5,248,230	$4,681,184	$5,593,854	112.1%	-10.8%	$6,233,032	$984,802	18.8%
Generation - System	$116,320	$104,092	$123,980	111.7%	-10.5%	$117,447	$1,127	1.0%
Generation - Transportation	$6,999,032	$13,353,172	$7,459,955	52.4%	90.8%	$7,098,876	$99,844	1.4%
Total Retail	$541,015,852	$576,644,726	$576,644,550	93.8%	6.6%	$575,888,008	$34,872,156	6.4%
Other Revenues	$4,908,231					$5,664,773	$756,541	15.4%
Total Increase							$35,628,697	6.5%

SUMMARY OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED REVENUES
Test Year Ending December 31, 2022

	Average	Dkt	Revenue		Increase	
	Customers	Sales	Present	Proposed	Amount	Percent
Firm Service						
Residential Firm	444,262	38,929,911	$316,792,737	$344,093,162	$27,300,425	8.6%
Small Commercial Firm	24,830	5,142,075	$38,801,726	$40,615,357	$1,813,631	4.7%
Large Commercial Firm	11,262	17,859,614	$114,946,993	$118,747,868	$3,800,875	3.3%
Small & Large Commercial Demand Bille	140	2,990,585	$17,961,720	$18,249,206	$287,486	1.6%
Total Firm Service	**480,494**	**64,922,184**	**$488,503,176**	**$521,705,593**	**$33,202,417**	**6.8%**
Interruptible Service						
Small Interruptible	207	1,640,913	$7,975,156	$8,265,725	$290,569	3.6%
Medium & Large Interruptible	91	7,827,941	$32,173,938	$32,467,335	$293,397	0.9%
Total Interruptible Service	**298**	**9,468,854**	**$40,149,094**	**$40,733,060**	**$583,966**	**1.5%**
Total Gas Sales	**480,792**	**74,391,038**	**$528,652,270**	**$562,438,653**	**$33,786,383**	**6.4%**
Transportation Service						
Transportation	26	13,381,819	$5,248,230	$6,233,032	$984,802	18.8%
Total Transportation Service	**26**	**13,381,819**	**$5,248,230**	**$6,233,032**	**$984,802**	**18.8%**
Generation System	**3**	**22,154**	**$116,320**	**$117,447**	$1,127	1.0%
Generation Transportation	**4**	**23,316,943**	**$6,999,032**	**$7,098,876**	$99,844	1.4%
Total Retail*	**480,825**	**111,111,955**	**$541,015,852**	**$575,888,008**	**$34,872,156**	**6.4%**
Other Gas Revenues						
Limited Firm			$359,700	$359,700	$0	0.0%
Late Payment Charge			$1,020,612	$1,086,397	$65,785	6.4%
Connection Charges			$361,200	$1,051,956	$690,756	191.2%
Low Income Administrative Cost				$0	$0	0.0%
Miscellaneous			$3,166,720	$3,166,720	$0	0.0%
Return Check Charge			$41,988			
Gas Agreement			$436,548			
Balancing Service			$20,974			
Sales to Other - MN LP			$0			
Agency Service			$0			
Other Gas Revenue			$972,466			
Adjustments-New Area & Connect Smart			$1,694,744			
Subtotal Other Revenues			$4,908,231	$5,664,773	$756,541	15.4%
Total Sales and Other Gas Revenues			**$545,924,084**	**$581,552,781**	**$35,628,697**	**6.5%**

*February 2021 Gas Event surcharges are not included.

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES
Test Year Ending December 31, 2022
Revenue by Rate Schedule

Residential Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	5,331,144		$9.00	$47,980,296	$11.00	$58,642,584	$10,662,288	
Distribution Charge		389,299,108	$0.175996	$68,515,086	$0.285785	$111,255,845	$42,740,759	
CIP/SEP/GUIC TY Adj		389,299,108	$0.067050	$26,102,622	$0.000000	$0	-$26,102,622	
Margin Subtotal				$142,598,004		$169,898,429	$27,300,425	19.1%
Gas Supply Charge								
April through October		94,647,687	$0.397729	$37,644,130	$0.397729	$37,644,130	$0	
November through March		294,651,421	$0.463431	$136,550,603	$0.463431	$136,550,603	$0	
Gas Supply Subtotal		389,299,108		$174,194,733		$174,194,733	$0	0.0%
Average Customers	444,262		**Total**	$316,792,737		$344,093,162	$27,300,425	8.6%

Small Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	297,960		$25.00	$7,448,999	$30.00	$8,938,798	$1,489,799	
Distribution Charge		51,420,746	$0.116732	$6,002,447	$0.168025	$8,639,971	$2,637,524	
CIP/SEP/GUIC TY Adj		51,420,746	$0.044995	$2,313,692	$0.000000	$0	-$2,313,692	
CIP Neutrality exemption		11,000	-$0.018662	-$205	$0.000000	$0		
Cip base exemption		11,000	-$0.005240	-$58	-$0.023902	-$263		
Margin Subtotal				$15,764,875		$17,578,506	$1,813,631	11.5%
Gas Supply Charge								
April through October		10,838,776	$0.396154	$4,293,824	$0.396154	$4,293,824	$0	
November through March		40,581,971	$0.461856	$18,743,027	$0.461856	$18,743,027	$0	
Gas Supply Subtotal		51,420,746		$23,036,851		$23,036,851	$0	0.0%
Average Customers	24,830		**Total**	$38,801,726		$40,615,357	$1,813,631	4.7%

Large Commercial Firm

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	135,146		$50.00	$6,757,300	$70.00	$9,460,220	$2,702,920	
Distribution Charge		178,596,136	$0.116582	$20,821,095	$0.167725	$29,955,037	$9,133,942	
CIP/SEP/GUIC TY Adj		178,596,136	$0.044995	$8,035,987	$0.000000	$0	-$8,035,987	
CIP Neutrality exemption		77,167	-$0.018662	-$1,440	$0.000000	$0	$1,440	
Cip base exemption		77,167	-$0.005240	-$404	-$0.023902	-$1,844	-$1,440	
Margin Subtotal				$35,612,538		$39,413,413	$3,800,875	10.7%
Gas Supply Charge								
April through October		47,962,652	$0.396154	$19,000,597	$0.396154	$19,000,597	$0	
November through March		130,633,484	$0.461856	$60,333,858	$0.461856	$60,333,858	$0	
Gas Supply Subtotal		178,596,136		$79,334,455		$79,334,455	$0	0.0%
Average Customers	11,262		**Total**	$114,946,993		$118,747,868	$3,800,875	3.3%

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES
Test Year Ending December 31, 2022
Revenue by Rate Schedule

Small & Large Commercial Demand Billed

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,680		$275.00	$462,000	$275.00	$465,600	$3,600	
Discount				-$18,000		-$18,000		
Distribution Charges								
Distribution Demand Charge		3,395,255	$0.809470	$2,748,357	$0.882000	$2,994,615	$246,258	
Distribution Commodity Charge		29,905,854	$0.044978	$1,345,105	$0.085138	$2,546,125	$1,201,020	
CIP/SEP/GUIC TY Adj		29,905,854	$0.038902	$1,163,392	$0.000000	$0	-$1,163,392	
CIP Neutrality exemption		289,589	-$0.018662	-$5,404	$0.000000	$0	$5,404	
Cip base exemption		289,589	-$0.005240	-$1,517	-$0.023902	-$6,922	-$5,405	
Margin Subtotal				$5,693,933		$5,981,418	$287,485	5.0%
Gas Supply Charges								
Gas Supply Demand Charge		3,395,255	$0.725628	$2,463,692	$0.725628	$2,463,692	$0	
Gas Supply Commodity Charge		29,905,854	$0.327832	$9,804,096	$0.327832	$9,804,096	$0	
Gas Supply Subtotal				$12,267,788		$12,267,788	$0	0.0%
Average Customers	128		**Total**	$17,961,721		$18,249,206	$287,485	1.6%

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES
Test Year Ending December 31, 2022
Revenue by Rate Schedule

Small Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	2,486		$145.00	$360,470	$150.00	$372,900	$12,430	
Distribution Charge		16,409,131	$0.091214	$1,496,742	$0.144125	$2,364,966	$868,224	
CIP/SEP/GUIC TY Adj		16,409,131	$0.035961	$590,085	$0.000000	$0	-$590,085	
Margin Subtotal				$2,447,297		$2,737,866	$290,569	11.9%
Gas Supply Charge		16,409,131	$0.336877	$5,527,859	$0.336877	$5,527,859	$0	0.0%
Average Customers	207		**Total**	$7,975,156		$8,265,725	$290,569	3.6%

Medium & Large Interruptible

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	1,092		$300.00	$327,600	$300.00	$327,600	$0	
Discount				-89,279		9,000	$98,279	
Distribution Charge		78,279,409	$0.044978	$3,520,851	$0.083431	$6,530,959	$3,010,108	
CIP/SEP/GUIC TY Adj		78,279,409	$0.035961	$2,814,990	$0.000000	$0	-$2,814,990	
CIP Neutrality exemption		531,035	-$0.018662	-$9,910	$0.000000	$0	$9,910	
Cip base exemption		531,035	-$0.005240	-$2,783	-$0.023902	-$12,693	-$9,910	
Margin Subtotal				$6,561,469		$6,854,866	$293,397	4.5%
Gas Supply Charge		78,279,409	$0.327193	$25,612,469	$0.327193	$25,612,469	$0	0.0%
Average Customers	91		**Total**	$32,173,938		$32,467,335	$293,397	0.9%

DETAIL OF CUSTOMERS, SALES, AND PRESENT AND PROPOSED RATES AND REVENUES
Test Year Ending December 31, 2022
Revenue by Rate Schedule

Transportation

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	312		$325.00	$101,400	$325.00	$101,400	$0	
Discount				-3,300		-$3,300		
Distribution Charges								
Distribution Demand Charge		431,778	$0.809470	$349,511	$0.882000	$380,828	$31,317	
Distribution Commodity Charge		133,818,194	$0.027898	$3,733,196	$0.062239	$5,890,821	$2,157,625	
CIP/SEP/GUIC TY Adj		133,818,194	$0.022413	$1,715,432	$0.000000	$511,293	-$1,204,139	
CIP Neutrality exemption		(27,111,106)	$0.018662	-$505,948	$0.018662	-$505,947	$1	
Cip base exemption		(27,111,106)	$0.005240	-$142,062	$0.005240	-$142,062	$0	
Average Customers	26		**Total**	$5,248,229		$6,233,033	$984,804	18.8%

Generation (summary of 6 customers on 4 retail rates)

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Customer Charge	84			$24,300		$24,300	$0	0.0%
Distribution Charges		233,390,970		$6,129,687		$6,239,298	$109,611	1.8%
CIP/SEP/GUIC TY Adj		233,390,970	$0.015190	$880,115	$0.004890	$871,475	($8,640)	
Margin Subtotal				$7,034,102		$7,135,073		
Gas Supply Charge				$81,250		$81,250	$0	0.0%
Average Customers	7		**Total**	$7,115,352		$7,216,323	$100,971	1.4%

PRESENT & PROPOSED RATES
Test Year Ending December 31, 2022

PRESENT RATES	Res	Sm Com	Lg Com	Sm Dmd	Lg Dmd	Sm Int	Med Int	Lg Int	Lg Fm Tran	Sm Int Tran	Med Int Tran	Lg Int Tran
Customer Charge ($/Montl	$9.00	$25.00	$50.00	$150.00	$275.00	$145.00	$300.00	$450.00	$300.00	$170.00	$325.00	$475.00
Distribution Charges ($/Therm)												
Commodity	$0.175996	$0.116732	$0.116582	$0.044978	$0.044978	$0.091214	$0.044978	$0.041143	$0.044978	$0.091214	$0.044978	$0.041143
Demand	N/A	N/A	N/A	$0.80947	$0.80947	N/A	N/A	N/A	$0.80947	N/A	N/A	N/A
Proposed Cost of Gas ($/Therm)												
Summer	$0.397729	$0.396154	$0.396154	$0.327832	$0.327832	$0.336877	$0.327354	$0.326862				
Winter	$0.463431	$0.461856	$0.461856	$0.725628	$0.725628	$0.336877	$0.327354	$0.326862				
Total Commodity Rate ($/Therm)												
Summer	$0.573725	$0.512886	$0.512736	$0.372810	$0.372810	$0.428091	$0.372332	$0.368005				
Winter	$0.639427	$0.578588	$0.578438	$1.535098	$1.535098	$0.428091	$0.372332	$0.368005				

PROPOSED RATES	Res	Sm Com	Lg Com	Sm Dmd	Lg Dmd	Sm Int	Med Int	Lg Int	Lg Fm Tran	Sm Int Tran	Med Int Tran	Lg Int Tran
Customer Charge ($/Montl	$11.00	$30.00	$70.00	$175.00	$275.00	$150.00	$300.00	$450.00	$300.00	$175.00	$325.00	$475.00
Distribution Charges ($/Therm)												
Commodity	$0.285785	$0.168025	$0.167725	$0.085138	$0.085138	$0.144125	$0.085138	$0.079925	$0.085138	$0.144125	$0.085138	$0.079925
Demand	N/A	N/A	N/A	$0.882000	$0.882000	N/A	N/A	N/A	$0.882000	N/A	N/A	N/A
Proposed Cost of Gas ($/Therm)												
Summer	$0.397729	$0.396154	$0.396154	$0.327832	$0.327832	$0.336877	$0.327354	$0.326862				
Winter	$0.463431	$0.461856	$0.461856	$0.725628	$0.725628	$0.336877	$0.327354	$0.326862				
Total Commodity Rate ($/Therm)												
Summer	$0.683514	$0.564179	$0.563879	$0.412970	$0.412970	$0.481002	$0.412492	$0.406787				
Winter	$0.749216	$0.629881	$0.629581	$1.607628	$1.607628	$0.481002	$0.412492	$0.406787				

EFFECT OF PROPOSED RATES with Fuel Costs
Test Year Ending December 31, 2022

REVENUE DEFICIENCY VS. PROPOSED RATES (w/ fuel)

Customer Class	Total Present Revenues	Revenue Deficiency Indicated by CCOSS	Total Effect Of Proposed Rates	Difference Between Revenue Deficiency and Proposed Rates
Residential	$316,792,737	$39,953,641	$27,300,425	$12,653,216
		12.6%	8.6%	4.0%
Small Commercial	$38,801,726	$1,658,499	$1,813,631	($155,132)
		4.3%	4.7%	-0.4%
Large Commercial	$114,946,993	($6,460,508)	$3,800,875	($10,261,382)
		-5.6%	3.3%	-8.9%
Small & Large Commercial	$17,961,720	($1,860,884)	$287,486	($2,148,371)
Demand Billed		-10.4%	1.6%	-12.0%
Small Interruptible	$7,975,156	($1,210,068)	$290,569	($1,500,637)
		-15.2%	3.6%	-18.8%
Medium & Large Interruptible	$32,173,938	($2,226,672)	$293,397	($2,520,069)
		-6.9%	0.9%	-7.8%
Transportation	$5,248,230	($567,046)	$984,802	($1,551,848)
		-10.8%	18.8%	-29.6%
Generation - System	$116,320	($6,662)	$1,127	($7,789)
		-5.7%	1.0%	-6.7%
Generation - Transportation	$6,999,032	$6,348,574	$99,844	$6,248,730
		90.7%	1.4%	89.3%
Other Revenues			$756,541	($756,541)
			15.4%	15.4%
Total	$541,015,852	$35,628,875	$35,628,697	$177
		6.6%	6.6%	0.0%

COMPARISON OF MONTHLY BILLS UNDER PRESENT AND PROPOSED RATES
Test Year Ending December 31, 2022

RESIDENTIAL FIRM SERVICE

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
10	$15.91	$18.33	$2.42	15.2%
20	$22.81	$25.66	$2.85	12.5%
30	$29.72	$33.00	$3.28	11.0%
40	$36.62	$40.33	$3.71	10.1%
50	$43.53	$47.66	$4.13	9.5%
73	$59.42	$64.54	$5.12	8.6%
100	$78.05	$84.32	$6.27	8.0%
200	$147.10	$157.65	$10.55	7.2%
300	$216.15	$230.97	$14.82	6.9%
500	$354.25	$377.62	$23.37	6.6%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$9.00	$11.00
Distribution Charge	$0.175996	$0.285785
Average Cost of Gas	$0.447460	$0.447460
Commodity Total	$0.623456	$0.733245
GUIC/CIP/SEP	$0.067050	$0.000000

SMALL COMMERCIAL FIRM SERVICE

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
50	$55.49	$60.80	$5.31	9.6%
100	$85.97	$91.60	$5.63	6.5%
200	$146.95	$153.21	$6.26	4.3%
173	$130.23	$136.31	$6.08	4.7%
250	$177.43	$184.01	$6.58	3.7%
350	$238.41	$245.61	$7.20	3.0%
500	$329.87	$338.02	$8.15	2.5%
750	$482.30	$492.03	$9.73	2.0%
1,000	$634.74	$646.04	$11.30	1.8%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$25.00	$30.00
Distribution Charge	$0.116732	$0.168025
Average Cost of Gas	$0.448010	$0.448010
Commodity Total	$0.564742	$0.616035
GUIC/CIP/SEP	$0.044995	$0.000000

COMPARISON OF MONTHLY BILLS UNDER PRESENT AND PROPOSED RATES
Test Year Ending December 31, 2022

LARGE COMMERCIAL FIRM GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
100	$110.58	$131.19	$20.61	18.6%
250	$201.45	$222.98	$21.53	10.7%
500	$352.89	$375.97	$23.08	6.5%
750	$504.34	$528.95	$24.61	4.9%
1,000	$655.79	$681.94	$26.15	4.0%
1,322	$850.55	$878.68	$28.13	3.3%
3,000	$1,867.36	$1,905.81	$38.45	2.1%
5,000	$3,078.94	$3,129.68	$50.74	1.6%
7,500	$4,593.40	$4,659.51	$66.11	1.4%
10,000	$6,107.87	$6,189.35	$81.48	1.3%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$50.00	$70.00
Distribution Charge	$0.116582	$0.167725
Average Cost of Gas	$0.444210	$0.444210
Commodity Total	$0.560792	$0.611935
GUIC/CIP/SEP	$0.044995	$0.000000

SMALL INTERRUPTIBLE GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
2,500	$1,305.13	$1,352.51	$47.38	3.6%
5,000	$2,465.26	$2,555.01	$89.75	3.6%
6,601	$3,208.03	$3,324.91	$116.88	3.6%
10,000	$4,785.52	$4,960.02	$174.50	3.6%
15,000	$7,105.78	$7,365.03	$259.25	3.6%
20,000	$9,426.04	$9,770.04	$344.00	3.6%
25,000	$11,746.30	$12,175.05	$428.75	3.7%
30,000	$14,066.55	$14,580.06	$513.51	3.7%
40,000	$18,707.07	$19,390.08	$683.01	3.7%
50,000	$23,347.59	$24,200.10	$852.51	3.7%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$145.00	$150.00
Distribution Charge	$0.091214	$0.144125
Cost of Gas	$0.336877	$0.336877
Commodity Total	$0.428091	$0.481002
GUIC/CIP/SEP	$0.035961	$0.000000

COMPARISON OF MONTHLY BILLS UNDER PRESENT AND PROPOSED RATES
Test Year Ending December 31, 2022

MEDIUM INTERRUPTIBLE GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
5,000	$2,341.46	$2,362.46	$21.00	0.9%
10,000	$4,382.93	$4,424.92	$41.99	1.0%
20,000	$8,465.86	$8,549.84	$83.98	1.0%
30,000	$12,548.78	$12,674.76	$125.98	1.0%
40,000	$16,631.71	$16,799.68	$167.97	1.0%
51,020	$21,131.03	$21,345.28	$214.25	1.0%
60,000	$24,797.57	$25,049.52	$251.95	1.0%
70,000	$28,880.50	$29,174.44	$293.94	1.0%
80,000	$32,963.42	$33,299.36	$335.94	1.0%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$300.00	$300.00
Distribution Charge	$0.044978	$0.085138
Cost of Gas	$0.327354	$0.327354
Commodity Total	$0.372332	$0.412492
GUIC/CIP/SEP	$0.035961	$0.000000

LARGE INTERRUPTIBLE GAS SERVICE
SYSTEM SUPPLY

MONTHLY	BILLING		INCREASE	
THERM USE	PRESENT	PROPOSED	AMOUNT	PERCENT
50,000	$20,648.29	$20,789.35	$141.06	0.7%
100,000	$40,846.58	$41,128.70	$282.12	0.7%
200,000	$81,243.16	$81,807.40	$564.24	0.7%
300,000	$121,639.74	$122,486.10	$846.36	0.7%
400,000	$162,036.32	$163,164.80	$1,128.48	0.7%
427,116	$172,990.05	$174,195.03	$1,204.98	0.7%
500,000	$202,432.90	$203,843.50	$1,410.60	0.7%
600,000	$242,829.48	$244,522.20	$1,692.72	0.7%
700,000	$283,226.06	$285,200.90	$1,974.84	0.7%

	PRESENT RATE	PROPOSED RATE
Customer Charge	$450.00	$450.00
Distribution Charge	$0.041143	$0.079925
Cost of Gas	$0.326862	$0.326862
Commodity Total	$0.368005	$0.406787
GUIC/CIP/SEP	$0.035961	$0.000000

PROPOSED TARIFF SHEETS

Minnesota Gas Rate Book - MPUC No. 2

Sheet No. 1-1, revision 11
Sheet No. 1-2, revision 14
Sheet No. 2-1, revision 5
Sheet No. 3-3, revision 5
Sheet No. 5-TOC, revision 5
Sheet No. 5-1, revision 11
Sheet No. 5-1.1, revision 6
Sheet No. 5-2, revision 11
Sheet No. 5-2.1, revision 6
Sheet No. 5-3, revision 9
Sheet No. 5-3.1, revision 7*
Sheet No. 5-4, revision 9*
Sheet No. 5-4.1, revision 6
Sheet No. 5-5, revision 9
Sheet No. 5-6, revision 9*
Sheet No. 5-6.1, revision 8*
Sheet No. 5-6.2, revision 2
Sheet No. 5-7, revision 5*
Sheet No. 5-8, revision 7
Sheet No. 5-9, revision 3*
Sheet No. 5-10, revision 9*
Sheet No. 5-10.1, revision 2
Sheet No. 5-11, revision 8
Sheet No. 5-11.1, revision 3*
Sheet No. 5-12, revision 7
Sheet No. 5-13, original*
Sheet No. 5-16, revision 7
Sheet No. 5-17, revision 8
Sheet No. 5-17.1, revision 1*
Sheet No. 5-18, revision 8
Sheet No. 5-18.1, revision 3*
Sheet No. 5-60, revision 2*
Sheet No. 5-60.1, revision 2*
Sheet No. 5-61, revision 3*
Sheet No. 5-62, revision 3*
Sheet No. 5-63, revision 19
Sheet No. 5-64, revision 7*
Sheet No. 5-65, revision 2*
Sheet No. 5-19, revision 8
Sheet No. 5-20, original*
Sheet No. 5-23, revision 2*
Sheet No. 5-24, revision 2
Sheet No. 5-25, revision 1
Sheet No. 5-26, revision 8
Sheet No. 5-27, revision 2*
Sheet No. 5-29, revision 4*
Sheet No. 5-30, revision 1*
Sheet No. 5-31, revision 1
Sheet No. 5-32, original*
Sheet No. 5-33, revision 3
Sheet No. 5-40, revision 2*
Sheet No. 5-41, revision 9
Sheet No. 5-42, revision 4*
Sheet No. 5-42.1, original*
Sheet No. 5-43, revision 34*
Sheet No. 5-43.1, revision 1
Sheet No. 5-44, revision 9*
Sheet No. 5-44.1, revision 22 *
Sheet No. 5-44.2, revision 24 *
Sheet No. 5-44.3, revision 6*
Sheet No. 5-44.4, original*
Sheet No. 5-44.5, original*
Sheet No. 5-44.6, original*
Sheet No. 5-45, revision 2*
Sheet No. 5-46, revision 3*
Sheet No. 5-47, revision 5*
Sheet No. 5-48, revision 3*
Sheet No. 5-49, revision 2*
Sheet No. 5-50, revision 2*
Sheet No. 5-51, revision 2*
Sheet No. 5-53, revision 7*
Sheet No. 5-53.1, revision 8*
Sheet No. 5-54, revision 8
Sheet No. 5-54.1, revision 7*
Sheet No. 5-56, revision 3*
Sheet No. 5-57, revision 3*

* = No changes to sheet, but included to provide complete tariff.

PROPOSED TARIFF SHEETS

Sheet No. 5-66, revision 1*
Sheet No. 5-67, revision 1*
Sheet No. 5-68, revision 3*
Sheet No. 5-69, revision 4*
Sheet No. 5-70, revision 6*
Sheet No. 5-71, original
Sheet No. 5-72, original
Sheet No. 6-10, revision 5
Sheet No. 6-10.1, revision 1
Sheet No. 6-18.2, revision 1
Sheet No. 6-19, revision 3
Sheet No. 7-01-TOC, revision 5
Sheet No. 7-13, revision 5
Sheet No. 7-19, revision 6
Sheet No. 7-34, revision 3
Sheet No. 7-85, original
Sheet No. 7-86, original
Sheet No. 7-87, original
Sheet No. 7-88, original
Sheet No. 7-89, original
Sheet No. 7-90, original
Sheet No. 7-91, original
Sheet No. 7-92, original
Sheet No. 7-93, original
Sheet No. 7-94, original
Sheet No. 7-95, original
Sheet No. 7-96, original

* = No changes to sheet, but included to provide complete tariff.

Summary List of 2022 Tariff Changes

Tariff	Sheet No.	Rate Code	Changes
Table of Contents	1-1, 1-2		1. Added "Revenue Decoupling Mechanism Rider" 2. Added "Negotiated Transportation Service Agreement."
Index of Company's Service Area	3-3		Service area updates.
Tables of Contents	5-TOC		Added "Revenue Decoupling Mechanism Rider"
Residential Firm Service	5-1, 5-1.1	101	1. Rate changes. 2. Added "Revenue Decoupling Mechanism Rider"
Commercial Firm Service	5-2, 5-2.1	Small 102 & 108, Large 118 & 125	1. Rate changes. 2. Added "Revenue Decoupling Mechanism Rider"
Commercial Demand Billed Service	5-3, 5-4.1	Small 119, Large 103	1. Rate changes. 2. Added "in the gas year" as clarifying language.
Large Firm Transportation Service	5-5, 5-6.2, 5-8	104	1. Rate changes. 2. Updated daily gas volumes (nominations) schedule and instructions. 3. Added "in the gas year" as clarifying language.
Interruptible Service	5-10.1, 5-11, 5-12	Small 105 & 111, Medium 106, Large 120	1. Rate changes. 2. Added "in the gas year" as clarifying language.
Interruptible Transportation Service	5-16, 5-17, 5-18, 5-19	Small 123, Medium 107, Large 124	1. Rate changes. 2. Updated daily gas volumes (nominations) schedule and instructions. 3. Added "in the gas year" as clarifying language.
Negotiated Transportation Service	5-24, 5-25, 5-26	114	1. Rate changes. 2. Updated daily gas volumes (nominations) schedule and instructions. 3. Added "in the gas year" as clarifying language.
Small Volume Flex Interruptible Transportation of Customer Owned Gas	5-31, 5-33	157	1. Updated daily gas volumes (nominations) schedule and instructions. 2. Added "in the gas year" as clarifying language.
Purchased Gas Adjustment Clause	5-41		Rate changes.

Minnesota Gas Rate Book - MPUC No. 2

Summary List of 2022 Tariff Changes

Tariff	Sheet No.	Rate Code	Changes
Conservation Improvement Program Adjustment Rider	5-43.1		Rate changes.
Limited Firm Service	5-54		Added "in the gas year" as clarifying language.
State Energy Policy Rate Rider	5-63		Rate changes.
Revenue Decoupling Mechanism Rider	5-71, 5-72		New proposed rate rider.
General Rules and Regulations	6-10, 6-10.1		Clarified language.
General Rules and Regulations	6-18.2, 6-19		Rate changes.
Table of Contents-Contract and Agreement Forms	7-TOC		Added "Negotiated Transportation Service Agreement."
Firm Gas Transportation Agreement	7-13		Updated daily gas volumes (nominations) schedule and instructions.
Interruptible Gas Transportation Agreement	7-19		Updated daily gas volumes (nominations) schedule and instructions.
Underground Gas and/or Electric Distribution Agreement	7-34		Modified Xcel Energy signatory section.
Negotiated Transportation Service Agreement	7-85 through 7-96		Added customer agreement currently in use to the rate book.

Northern States Power Company
Gas Utility - Minnesota
END USER ALLOCATION SERVICE: COST STUDY
Number of EUAS Customers as of September 2021

(1)	(2)				(3)	(4)	(5) = (3)*(4)	(6)=(5)/12	(7)	(8)=(6)/(7)
Category	**Employee**	**Salary Midpoint**	**Labor Loading**	**Annual Work Hours**	**Loaded Hourly Rate**	**Annual EUAS Hours**	**Annual Labor**	**Monthly Labor**	**Customers**	**Monthly Cost / Customer**
Operational Labor	Principal Analyst	$108,900	166.36%	2,080	$87.10	**201**	$17,507.10	$1,458.93	**22**	$66.32
Regulatory Exp *	Associate Analyst	$82,400	166.36%	2,080	$65.90	**50**	$3,295.00	$274.58	**22**	$12.48
Regulatory Exp **	Managment / Legal	$143,400	166.36%	2,080	$114.69	**13**	$1,490.97	$124.25	**22**	$5.65
Total										**$84.45**

* Estimated staff hours required for development and monitoring of compliance filings.
** Estimated mgmt/legal hours required for compliance filing.