Direct Testimony and Schedules
Christopher J. Barthol

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 Gas Service in Minnesota

Docket No. G002/GR-25-356
Exhibit___(CJB-1)

Class Cost of Service Study

October 31, 2025

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Barthol. I am a Rate Consultant for Northern States Power Company – Minnesota (NSPM or the Company), d/b/a Xcel Energy.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Company.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include 14 years of regulatory experience in the areas of rate design and class cost of service. I have served as a witness before the Minnesota Public Utilities Commission (Commission), South Dakota Public Utilities Commission, and the North Dakota Public Service Commission. I have a Bachelor of Arts in Economics from Saint Cloud State University and a Master of Science in Agricultural Economics from Purdue University. A detailed statement of my qualifications and experience is provided in Exhibit___(CJB-1), Schedule 1.

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

A. The purpose of my testimony is to present the Company's Class Cost of Service Study (CCOSS).

Q. WHAT IS A CCOSS?

A. A CCOSS is an analytical tool used to determine the amount that different customer classes contribute to the overall cost of providing service. Once a CCOSS is prepared, it is used to guide decisions about revenue apportionment.

Q. HOW MANY CCOSSS ARE YOU PROVIDING FOR THIS RATE CASE?

A. I am providing three CCOSSs. The first is the Company's proposed CCOSS, which I believe is most reasonable and which I recommend be used as one factor in setting rates.

The other CCOSSs are required based on the Settlement Agreement that was reached in our previous rate case, in which the Company agreed to file one additional CCOSS based on recommendations from the Department, and one further CCOSS based on a recommendation from the Suburban Rate Authority (SRA).[1] As I explain below, I am providing these CCOSSs with my testimony but recommend that the Company's proposed CCOSS is more reasonable and should be used for this case.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CCOSS.

A. The CCOSS is done on a forecasted 2026 calendar year embedded cost basis, which, based on cost-causation principles, functionalizes, classifies, and allocates budgeted plant and expenses in the 2026 test year. Unlike previous rate cases, the Company is proposing several changes to the CCOSS methodology used in the Company's last natural gas rate case, Docket No. G002/GR-23-413. Below, I will describe the modifications to the class allocations and the rationale for the adjustments as compared to the initial filing in our last rate case, detail the class allocations indicated by the CCOSS, and discuss the results of the CCOSS.

[1] *In the Matter of the Application of Northern States Power Company, d/b/a Xcel Energy, for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. 23-413, Settlement Agreement at 16 (June 26, 2024).

II. CCOSS COMPLIANCE

Q. WHAT COMPLIANCE MATTERS WILL YOU ADDRESS?

A. In the Settlement Agreement[2] in the Company's last natural gas rate case, the Company agreed to provide a CCOSS in its next Minnesota natural gas rate case that incorporates the five following recommendations included in the Direct Testimony of Department witness Danielle D. Winner:

- Use the Premise allocator developed in response to Department Information Request (IR) No. 703 to allocate the customer component of distribution mains costs (Federal Energy Regulatory Commission (FERC) Account 376);
- Use the Service allocator developed in response to Department IR No. 702 to allocate service costs (FERC Account 380);
- Use the class weights developed for Department IR No. 706 to allocate costs for the Conservation Improvement Programs (CIP) Expenses sub-account of FERC account 908;
- Use the demand adjustment developed for the Company's response to Department IR No. 908 for the Minimum System Study demand adjustment; and
- Directly assign costs to the appropriate customer classes, as found in the Company's response to Department IR No. 711 in this proceeding.

The Company further agreed to prepare one CCOSS in its next Minnesota natural gas rate case that uses two-inch plastic mains in the minimum system

[2] *In the Application for Authority to Increase Rates for Natural Gas Service*, Docket No. G002/GR-23-413, SETTLEMENT AGREEMENT (June 26, 2024). The information requests referenced in the Settlement Agreement are from the Company's last gas rate case.

study following the recommendation in the Direct Testimony of SRA witness Jamie Tosches. The Settling Parties agreed, however, that none of the Settling Parties are obligated to support or endorse the methodologies in such study, and each Settling Party may take any positions it chooses with respect to the validity of those methodologies. We have incorporated all these suggestions except for the Premise allocator proposed by the Department and SRA's recommendation to only use two-inch pipe in calculating the cost of a minimum system. I will later explain in more detail which of these recommendations I have adopted and which ones I oppose.

III. CCOSS OVERVIEW

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I describe the purpose of the CCOSS that was conducted, and the Company's objectives in conducting the CCOSS. I will also summarize the results of the CCOSS.

A. CCOSS Purpose

Q. WHAT IS THE PURPOSE OF A CCOSS?

A. The CCOSS allocates the total cost of providing utility service (also referred to as the Company's revenue requirement) to our various customer classes in a way that reflects the engineering and operating characteristics of the natural gas utility system, and hence each class's contribution to the Company's costs of providing gas service as required by Minn. R. 7825.4300, Subp. C. The primary objective of the CCOSS is to determine the total cost of service for each customer class, which, given the characteristics of gas utility costs, includes the costs associated with investment in plant as well as operation and maintenance

(O&M) expenses. Another key objective of the CCOSS is to develop class cost allocation factors that accurately reflect cost causation. Results from the CCOSS serve as a guide for evaluating and developing the Company's rate design, as discussed in more detail by Company witness Michelle M. Terwilliger.

Q. WHAT ARE THE COMPANY'S OBJECTIVES WHEN DEVELOPING ITS CCOSS?

A. The Company's CCOSS objectives are:

1. Properly reflect all the costs and revenues that have been identified in the Company's Minnesota Jurisdictional Cost of Service Study (JCOSS);
2. Develop allocators that can be accurately determined and calculated with a reasonable amount of effort to properly assign those costs among the various customer classes and the three main billing classifications – customer, demand, and commodity; and
3. Use allocators that are consistent across the Company's jurisdictions.

B. Modifications to the Company's CCOSS

Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO THE CCOSS?

A. Yes. The Company is proposing to make several modifications to the CCOSS[3]:

- Use the Service allocator developed in response to Department IR No. 702 to allocate service costs (FERC Account 380);
- Use the class weights developed for Department IR No. 706 to allocate costs for the CIP Expenses sub-account of FERC account 908;
- Use the demand adjustment developed for the Company's response to Department IR No. 908 for the Minimum System Study demand adjustment; and

[3] The information requests referenced in the bulleted list above are from the Company's last gas rate case.

- Directly assign costs to the appropriate customer classes, as found in the Company's response to Department IR No. 711 in this proceeding.

Q. PLEASE EXPLAIN THE UPDATE YOU ARE PROPOSING TO THE SERVICE ALLOCATOR.

A. In the Company's last natural gas rate case, the Department recommended that the cost weightings derived from the Service Study[4] be calculated on a cost per service pipe instead of a cost per customer basis. I agreed with this recommendation in that this change would make the Service Study consistent with the Company's Meter Study, which calculates the meter cost weights on a cost per meter basis. I am incorporating this recommendation into the CCOSS.

Q. PLEASE EXPLAIN THE CHANGES YOU ARE MAKING TO THE ALLOCATION OF EXPENSES RELATED TO CIP.

A. The Department also proposed, in the Company's last natural gas rate case, that CIP-related expenses be classified as demand- and energy-related and allocate them with an allocator weighted by CIP expenses approved by the Department's Deputy Commissioner of Commerce. The Company previously classified these expenses as 100 percent energy-related and allocated them using a Sales w/o CIP Exempt allocator. We agreed to make this change because it recognizes the energy- and demand-related nature of different CIP programs.

Q. PLEASE EXPLAIN THE CHANGES YOU ARE MAKING TO THE DEMAND ADJUSTMENT.

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[4] The Service Study calculates weightings for each class. These weightings are applied to the number of customers in each class. The weighted number of customers in each class derives the allocator for assigning services costs to each class. The weightings recognize that a service pipe installed for a Large Commercial customer would likely cost more than a Residential customer.

A. The Company applies a demand adjustment to the Minimum System Study results that recognizes the capacity associated with a two-inch pipe. Since this two-inch pipe does have some capacity, it is reasonable to identify and classify the cost of this as demand-related. In order to calculate the demand adjustment, Company engineers looked at isolated segments of the distribution system that are made up of two-inch pipe and calculated the load carrying capacity of these pipes. I used the load carrying capacity from these isolated segments of the distribution system to calculate a demand adjustment. Please see Exhibit___(CJB-1), Schedule 2 for the calculation of the demand adjustment.

In the last rate case, the Company only used three isolated segments of the distribution to calculate the demand adjustment. The Department requested, via Information Request No. 708, that the Company add seven more segments of the distribution system in its calculation of the load carrying capacity that goes into calculating the demand adjustment. The Company is using these same segments of the distribution system except for one which is no longer on a single feed.

Q. PLEASE EXPLAIN THE CHANGES YOU ARE MAKING TO THE DIRECT ASSIGNMENTS

A. In the last natural gas rate case, the Department submitted Department IR No. 711 asking the Company why no other electricity-generation-related costs are directly assignable to the Generation class in the Company's proposed CCOSS when there are other generation plants that receive gas from the Company but do not have directly assignable costs in the Company's CCOSS. In responding to that information request, the Company determined that it was appropriate to directly assign additional costs to the Generation class and did so through a supplemental response to Department IR No. 711. The Company agreed to directly assign the costs associated with this electric generation plant to the Generation class in its CCOSS.

Q. DID THE DEPARTMENT MAKE ANY OTHER RECOMMENDATIONS REGARDING THE DIRECT ASSIGNMENT OF COST TO THE GENERATION CLASS?

A. No. However, the Department raised the fact that the Company only used the Modified Customer allocator to allocate the customer-related portion of distribution mains and did not apply this allocator to FERC Accounts 488, 495, 879, 880, 881, 901, 902, and 905.

Q. WHAT REVENUES AND COSTS ARE ASSOCIATED WITH FERC ACCOUNTS 488, 495, 879, 880, 881, 901, 902, AND 905?

A. Table 1 provides a brief description of what these FERC accounts pertain to.

Table 1
FERC Accounts

Number	Description
488 & 495	Miscellaneous Service & Other Gas Revenues
879	Customer Installations
880	Other Distribution
881	Rents
901	Supervision
902	Meter Reading Expenses
905	Miscellaneous Customer Accounts Expenses

Q. WHAT IS THE MODIFIED CUSTOMER ALLOCATOR?

A. The Modified Customer allocator is the same as the Customer allocator, except that the customer counts have been removed for those customers with direct assigned costs. Essentially, it is used to allocate distribution mains costs that have not been direct assigned to the Generation class.

Q. WOULD IT MAKE SENSE TO APPLY THE MODIFIED CUSTOMER ALLOCATOR TO FERC ACCOUNTS 488, 495, 879, 880, 881, 901, 902, and 905?

A. I have evaluated the Department's question but conclude that the customer allocator should still be used to allocate these costs to customer class since the costs associated with these FERC accounts are not directly assigned to the Generation class.

C. CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S PROPOSED CCOSS.

A. The classes in the CCOSS include:

- Residential (Res);
- Commercial (Com) – Small and Large Commercial customers;
- Demand – Small and Large Demand-Billed customers;
- Interruptible (Interrupt) – Small, Medium, and Large Interruptible customers;
- Transportation (Tran) – Firm, Interruptible, and Negotiated Transportation customers; and
- Generation (Gener) – Electric Generation customers who take service on our sales or transportation service tariffs noted above.

Table 2 below shows a summary of the CCOSS results at the major class level. A more detailed summary is provided in Exhibit___(CJB-1), Schedule 3. These results indicate the level of rate increase necessary for each class of service to produce equal rates of return from each class.

Table 2
Summary of Class Cost of Service Study ($000)

Item	Res	Com	Demand	Interrupt	Tran	Gener	Total
CCOSS Results	$503,676	$235,864	$22,982	$40,694	$7,753	$27,237	$838,205
Present Revenue	$452,991	$231,632	$24,367	$45,968	$8,010	$11,835	$774,803
Revenue Deficiency	$50,685	$4,232	-$1,386	-$5,274	-$257	$15,402	$63,401
Deficiency Pres	11.19%	1.83%	-5.69%	-11.47%	-3.21%	130.13%	8.18%

Q. PLEASE EXPLAIN THE CCOSS RESULTS SHOWN IN TABLE 2.

A. The CCOSS indicates a cost-of-service increase of 11.19 percent for Residential Firm service, 1.83 percent for Commercial customers, and 130.13 percent for Generation customers. The CCOSS indicates a decrease in the costs of service of 5.69 percent for Demand customers, 11.47 percent for Interruptible customers, and 3.21 percent for Transport customers. As I mentioned above, the CCOSS results serve as a guide for developing revenue apportionment and rate design, as discussed in more detail by Company witness Terwilliger.

Q. HOW DO THE CCOSS RESULTS COMPARE TO THOSE IN THE COMPANY'S LAST NATURAL GAS RATE CASE (DOCKET NO. G002/GR-23-413)?

A. The CCOSS results are similar to the results in the Company's last general rate case in that the Residential, Commercial, and Generation classes' rates are below cost while the Demand, Interruptible, and Transport classes are above cost. Since our class allocation methodology is similar to the last case, the approved revenue apportionment in the last case resulted in Residential rates recovering less than the cost of service, and other classes recovering more than the cost of service, this result is reasonable. It also should be noted that some customers in the Generation class take service under the flexible rate provisions of our tariffs. Their rates are designed to cover at least incremental costs and not the embedded costs included in the CCOSS. Embedded costs represent long-term investments and fixed system costs, while incremental costs reflect short-term, marginal expenses. In her Direct Testimony, Company witness Terwilliger explains in more detail how generation rates are designed.

Q. HOW DO THE CURRENT PRIMARY ALLOCATORS IN THE CCOSS FOR THIS CASE COMPARE WITH THE PRIMARY ALLOCATORS FROM THE CCOSS USED IN THE COMPANY'S LAST NATURAL GAS RATE CASE (DOCKET NO. G002/GR-23-413)?

A. The Company is using the same primary allocators as these allocators continue to be the most appropriate class allocators for assigning costs that vary by customer count, demand (design day), sales, or distribution investment. Table 3 provides a comparison of the primary allocators evaluating their current percentages versus those in the last natural gas rate case. While there are modest changes in these allocators, there are not material changes to the percentages themselves. I will explain later in my testimony how these allocators were developed for this CCOSS.

Table 3
Allocator Comparison (2026 TY vs. 2024 TY)

Allocator	Res	Com	Demand	Interrupt	Tran	Gener
Customers 2026	92.54%	7.38%	0.03%	0.05%	0.01%	0.00%
Customers 2024	92.52%	7.39%	0.03%	0.05%	0.01%	0.00%
Design Day 2026	51.29%	34.18%	2.75%	0.00%	0.80%	10.98%
Design Day 2024	53.13%	30.36%	3.21%	0.00%	0.64%	12.66%
Mains, Overall 2026	65.26%	22.25%	1.61%	1.43%	2.16%	7.29%
Mains, Overall 2024	66.77%	19.72%	1.80%	1.66%	2.63%	7.41%
Service Study 2026	86.20%	13.33%	0.15%	0.29%	0.03%	0.01%
Service Study 2024	86.69%	12.76%	0.14%	0.37%	0.03%	0.01%
Meter & Regul 2026	79.48%	18.52%	0.54%	1.10%	0.24%	0.12%
Meter & Regul 2024	80.16%	18.18%	0.57%	0.93%	0.14%	0.03%
Sales, w/o Trans 2026	53.03%	32.30%	3.87%	10.32%	0.00%	0.49%
Sales, w/o Trans 2024	53.23%	31.76%	3.98%	10.74%	0.00%	0.29%
Sales, w/ Trans 2026	32.11%	19.56%	2.34%	6.25%	8.30%	31.45%
Sales, w/ Trans 2024	33.40%	19.93%	2.50%	6.74%	10.34%	27.10%

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS WITH THE DEPARTMENT'S FIVE RECOMMENDATIONS IN THE LAST CASE?

A. Table 4 below shows a summary of the CCOSS results at the major class level. A more detailed summary is provided in Exhibit___(CJB-1), Schedule 4.

Table 4
Summary of Department Class Cost of Service Study ($000)

Item	Res	Com	Demand	Interrupt	Tran	Gener	Total
CCOSS Results	$504,001	$235,529	$22,984	$40,700	$7,754	$27,237	$838,205
Present Revenue	$452,991	$231,632	$24,367	$45,968	$8,010	$11,835	$774,803
Revenue Deficiency	$51,011	$3,897	-$1,384	-$5,268	-$257	$15,402	$63,401
Deficiency Pres	11.26%	1.68%	-5.68%	-11.46%	-3.20%	130.14%	8.18%

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS WITH THE SUBURBAN RATE AUTHORITY'S RECOMMENDATION FROM THE LAST NATURAL GAS RATE CASE?

A. Table 5 below shows a summary of the CCOSS results at the major class level. A more detailed summary is provided in Exhibit___(CJB-1), Schedule 5.

Table 5
Summary of SRA Class Cost of Service Study ($000)

Item	Res	Com	Demand	Interrupt	Tran	Gener	Total
CCOSS Results	$493,789	$241,343	$23,564	$41,203	$8,546	$29,759	$838,205
Present Revenue	$452,991	$231,632	$24,367	$45,968	$8,010	$11,835	$774,803
Revenue Deficiency	$40,799	$9,712	-$803	-$4,765	$536	$17,923	$63,401
Deficiency Pres	9.01%	4.19%	-3.30%	-10.37%	6.69%	151.44%	8.18%

Q. PLEASE DESCRIBE THE DEPARTMENT'S PROPOSAL TO USE CUSTOMER PREMISES INSTEAD OF CUSTOMER COUNTS TO ALLOCATE THE COSTS OF DISTRIBUTION MAINS TO CUSTOMER CLASS.

A. In the Company's last gas rate case, the Department proposed that the Company allocate the customer-related costs of distribution mains using a customer allocator calculated from customer premise counts instead of customer counts derived from the Company's sales and customer forecast.

Q. DO YOU FIND THE DEPARTMENT'S PROPOSAL TO BE REASONABLE?

A. No. The Department pointed out that there could be a scenario where there are multiple types of customers at a single premise. For example, a customer premise could be on both firm and interruptible rates. Under the Department's proposal, it is unclear as to which rate would be allocated the costs of distribution mains. Under the Company's proposal, the premise would be allocated costs under both rates because a customer count is made up of a unique combination of Premise, Service ID, and Rate Code (their applicable rate schedule).

Q. WHAT DOES SRA PROPOSE IN REGARD TO THE MINIMUM SYSTEM STUDY?

A. SRA proposed the Company only use the cost of plastic two-inch pipe in deriving the minimum system cost and that the circumstances that require steel in a minimum system should be omitted because the Minimum System Study is a hypothetical exercise; they believe that real world constraints should not be considered in deriving this "hypothetical" minimum system.

Q. WHAT TYPE OF PIPE DOES THE COMPANY USE IN ITS MINIMUM SYSTEM STUDY?

A. The Company applies the cost per foot of two-inch plastic pipe to the footage of all plastic pipes in its distribution system and applies the cost per foot of two-inch steel pipe to the footage of all steel pipe on its distribution system. The sum of the total cost of plastic and steel two-inch pipe derives the minimum system cost. Later in my testimony, I will explain the Minimum System Study in further detail.

Q. DO YOU AGREE WITH SRA THAT THE COST OF STEEL PIPE SHOULD BE OMITTED FROM THE MINIMUM SYSTEM COSTS?

A. No. Plastic pipe cannot be used in all areas of the distribution system because of a variety of factors such as:

- Proximity to a heat source that could affect the plastic (i.e., nearby steam pipe);
- Parts of the system where there is exposed pipe due to the negative ultraviolet (UV) effects on plastic;
- Systems with higher pressure classifications; the Company currently uses medium-density polyethylene (MDPE) plastic pipe for up to 66 pounds per square inch gauge (psig) but then uses steel pipe for higher pressures;
- Additional considerations and requirements for bridge, railroad, and other right-of-way crossings;
- Areas with contaminated soil are not suitable for plastic pipes;
- Systems with existing steel pipes where electrical isolation is desired; and
- Shape of a piece of pipe needs to be customized and this customization can only be done by welding steel.

Page 22 of the National Association of Regulatory Utility Commissioners (NARUC) Manual states the following regarding Minimum System Studies:

> One argument for the inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory." This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires.

The above statement from the NARUC Manual implies that the minimum size main consists of pipe "necessary" to connect customers. As I mentioned before, plastic pipe cannot be used under certain conditions, and therefore we have taken this into account by including both plastic and steel pipe in our Minimum System Study. Please see Exhibit___(CJB-1), Schedule 6 for an excerpted copy of pages 22-24 of the NARUC Manual.

Q. DO YOU RECOMMEND THE USE OF THE DEPARTMENT OR SRA CCOSS MODELS?

A. No, I do not. I believe that the Company's CCOSS is the most reasonable because it most accurately reflects cost causation for the reasons I described above.

IV. CCOSS PREPARATION

A. Preparation of a CCOSS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I provide an overview of the preparation of the CCOSS and describe the allocators used in the CCOSS.

Q. WHAT TYPE OF CCOSS WAS PREPARED?

A. The CCOSS presented in this case is a fully-distributed, embedded CCOSS. The CCOSS is "fully-distributed" in that it allocates plant and operating expenses based on the manner in which they are incurred. The CCOSS is considered "embedded" because it functionalizes, classifies, and allocates budgeted plant and expenses in the test year.

Q. WHAT ARE THE STEPS FOR PREPARING A CCOSS?

A. In general, preparing a CCOSS involves five major steps:

First, costs are identified by function, such as production, storage, transmission, and distribution. Costs are then separated by state jurisdiction – in this case, between the Minnesota and North Dakota retail gas jurisdictions. This step is supported in the Direct Testimony and Schedules of Company witness Benjamin C. Halama.

Second, costs that can be directly attributed to specific customer classes are directly assigned to their respective classes.

Third, the remaining unassigned costs are allocated among the customer classes by an appropriate allocation method. An external allocator is an allocator that takes information generated separate from the CCOSS, such as a class's sales or customer counts. Internal allocators are based on combinations of costs already allocated to the classes using external allocators. For example, the cost of distribution mains is allocated to a class using an internal allocator that performs calculations relying on a class's contribution to plant in service associated with distribution mains.

Fourth, the costs for each class are then classified as capacity (demand), customer, and commodity (gas) based on whether the costs are driven by Design Day demand, number of customers, or usage. This step guides rate design within a class, as opposed to between classes. For instance, customer-driven costs, like natural gas meters, are not impacted by variations in gas usage or contribution to overall demand on a Design Day. Rather, such costs are affected by changes in the number of customers; the more customers the Company has, the more natural gas meters are needed.

Finally, the cost of serving each class is compared to the test year revenues generated by each class at current rates to determine the adjustment in revenues that is necessary for each class to recover its costs of service.

A guide to the Company's CCOSS is provided in Exhibit___(CJB-1), Schedule 7. The guide provides information on individual studies conducted for the purpose of developing allocators within the CCOSS study, descriptions of how calculations within the CCOSS are performed, and an index of external and internal allocators and their definitions.

B. External and Internal Allocators

Q. WHAT ARE EXTERNAL ALLOCATORS?

A. External allocators are calculated with data outside the CCOSS model (e.g., Design Day demands, metering, and customer service-related cost ratios). There are three types of external allocators: Capacity (Demand), Commodity (Energy), and Customer-related allocators.

Q. WHAT DISTRIBUTION PLANT STUDIES WERE CONDUCTED TO DEVELOP EXTERNAL ALLOCATORS WITHIN THE CCOSS?

A. The following is a list of studies that were conducted to develop the external allocators:

- Minimum System;
- Meter and Regulator Study;
- Service Study;
- Record & Collections Study;
- Customer Information Study;
- Uncollectibles Study; and
- Late Fee Study.

A full description of all seven studies is provided in Schedule 7. I describe minor refinements to the Minimum System Study in my testimony below.

Q. WHAT IS A MINIMUM SYSTEM STUDY?

A. A Minimum System Study identifies the portion of distribution plant associated with basic connectivity between the utility and the customer. The Minimum System Study determines the breakdown of costs that are customer-related (and therefore allocated with a customer-related allocator), versus those costs associated with capacity (and allocated with a demand-related allocator). As in the Company's last gas rate case, the Company conducted a Minimum-Sized Plant Study that identifies the smallest and most common distribution mains in a utility's system, identifies the cost per foot of the smallest and most common main, and applies that cost per foot to every main in the distribution system to derive the cost of a "minimum system." The cost of the minimum system is divided by the total costs of actual distribution mains in the system to derive the portion of distribution costs that are customer related. The remaining costs are split into average and excess capacity costs, which I discuss later in my testimony.

Q. WHAT METHODOLOGY ARE YOU PROPOSING FOR THE MINIMUM SYSTEM STUDY?

A. I am proposing a minimum-sized plant study using the same methodology that was used in the Company's last natural gas rate case (Docket No. G002/GR-23-413). The Minimum System Study is provided in Exhibit___(CJB-1), Schedules 8.

Q. WHAT OTHER KEY ALLOCATORS ARE INCLUDED IN THE CCOSS?

A. The remaining external allocators include Design Day (Demand) and Sales allocators (Sales w/Transport and Sales w/o Transport). Key internal allocators include the Average and Peak, Mains-Overall, and Production-Storage-Transmission-Distribution. These allocators are derived from costs allocated within the CCOSS via external allocators. A full description of these allocators is provided in Schedule 7.

V. GENERAL RULES AND REGULATIONS

Q. WHAT REVISIONS ARE BEING PROPOSED IN THE COMPANY'S GENERAL RULES AND REGULATIONS TARIFFS?

A. The Company is proposing rate revisions to Section 6, Sheet No. 18.2, Residential Service Extension Policy and Section 6, Sheet No. 19, Winter Construction, of the General Rules and Regulations. These costs have not been revised since the Company's 2022 rate case, Docket No. G002/GR-21-678.

A. Excess Footage Charges – Section 6, Sheet No. 18.2

Q. WHAT IS AN EXCESS FOOTAGE CHARGE?

A The Excess Footage Charge is the charge customers must pay for service pipeline footage in excess of 75 feet or service footage that the customer requests.

Q. WHAT REVISIONS ARE PROPOSED IN THE EXCESS FOOTAGE CHARGES?

A. Based on current material, labor, and equipment costs, we are proposing an increase in the Excess Footage Charges in Tariff Sheet No. 6-18.2 of the General Rules and Regulations, as shown in Table 6 below.

Table 6
Residential Excess Footage Charges (per foot)

Type	Present Rate	Proposed Rate
Excess Footage	$9.10	$13.90

The cost analysis supporting the increase in this charge is based on increased material, labor, and equipment costs and is provided on page 2 of Exhibit___(CJB-1), Schedule 9.

B. Winter Construction Charges – Section 6, Sheet No. 19

Q. WHAT ARE WINTER CONSTRUCTION CHARGES?

A. When a service or main is installed between October 1 and April 15, customers are subject to a Winter Construction Charge if winter conditions of six inches or more of frost exists, snow removal or plowing is required to install service, or frost burners must be set at the main or underground facilities to install service for the entire length of service or gas main installed.

Q. WHEN INSTALLING A JOINT TRENCH FOR GAS AND ELECTRIC FACILITIES, DOES THE COMPANY CHARGE A CUSTOMER WINTER CONSTRUCTION CHARGES FOR BOTH ELECTRIC AND GAS?

A. No. If the Company's gas and electric facilities are installed in a joint trench for any portion, the Company will waive the lower of the gas and electric Winter Construction Charges on the joint portion.

Q. WHAT REVISIONS ARE PROPOSED IN THE WINTER CONSTRUCTION CHARGES?

A. There are two components to the Winter Construction Charges, as indicated on Tariff Sheet No. 6-19 of the General Rules and Regulations. The Company is proposing an increase in each as shown in Table 7 below.

Table 7
Winter Construction Charges

Type	Present Rate	Proposed Rate
Excavation (Per Excavation Unit)	$640	$870
Main & Service Extensions (Per Trench Foot)	$8.90	$18.00

The cost analysis supporting these proposed rate charges is based on current material, labor, and equipment costs, and is provided on page 3 of Schedule 9.

C. Other Revenue Impact

Q. HAVE YOU INCLUDED AN INCREASE TO OTHER REVENUES TO RECOGNIZE THESE PROPOSED RATE INCREASES?

A. Yes. Other revenues have increased $980,811 as shown on page 1 of Schedule 9. It is also shown on Schedule 5 to Company witness Terwilliger's testimony.

The proposed increase in these charges reduces the increase in retail revenues proposed by Company witness Terwilliger.

VI. CONCLUSION

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. The Company has prepared a fully-embedded CCOSS for this case, including background explanation on CCOSS concepts, as well as detailed documentation of the current CCOSS. This CCOSS meets all the objectives for proper CCOSS preparation, including identification of the revenues, costs, and profitability for each class of services, as required by Minn. R. 7825.4300, Subp. C. Other than some minor allocator updates, this version of the CCOSS adheres to the same methods employed by the Company in its previous rate cases. The results of this CCOSS have then been used by Company witness Terwilliger as the basis for rate design. We have also provided supporting cost schedules that justify our increases in excess footage and winter construction charges.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Christopher J. Barthol

OVERVIEW

My responsibilities at Xcel Energy include Class Cost of Service Studies conducted in support of the Company's rate cases and providing pricing function support and other related analyses for the utility operating subsidiaries of Xcel Energy.

PROFESSIONAL EXPERIENCE

Rate Consultant; Xcel Energy, NSPM	2022 – Present
Principal Pricing Analyst; Xcel Energy, NSPM	2017 – 2022
Senior Regulatory Analyst; Xcel Energy, Xcel Energy Services	2015 – 2017
Pricing and Cost-of-Service Analyst; PacifiCorp	2013 – 2015
Associate Pricing and Cost-of-Service Analyst; PacifiCorp	2011 – 2013

EDUCATIONAL BACKGROUND

Purdue University; MS Agricultural Economics	2010
Saint Cloud State University; BA Economics	2008

Xcel Energy Demand Adjustment

Class	Demand (Dth)	Customers	Demand Adjustment (Dth/day/customer)	Minimum
Residential	531,440	460,713	0.647	298,082
Small Commercial	145,953	25,000	0.647	16,175
Large Commercial	208,159	11,724	0.647	7,585
Small Demand	1,333	13	0.647	8
Large Demand	27,207	129	0.647	83
Firm Transport	8,241	11	0.647	7
Generation Demand	507,880	5	0.647	3
Total	**1,430,213**			**321,944**

Classification Adjustment
22.5%

Class Cost of Service Study ($000); Test Year 2026

SUMMARY

	Rate Base	**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
1	Production	131,882	67,643	45,072	3,633	0	1,049	14,485
2	Storage	133,956	68,707	45,781	3,690	0	1,065	14,713
3	Transmission	162,341	67,189	44,552	3,681	3,247	4,969	38,703
4	Distribution	1,819,128	1,304,674	359,502	20,956	20,538	26,382	87,075
5	General	320,811	215,303	70,650	4,562	3,395	4,777	22,123
6	Common	0	0	0	0	0	0	0
7	**Total Plant In Service**	**2,568,117**	**1,723,516**	**565,558**	**36,522**	**27,180**	**38,243**	**177,098**
8	Production	31,383	16,096	10,726	864	0	250	3,447
9	Storage	53,282	27,329	18,210	1,468	0	424	5,852
10	Transmission	37,298	14,875	9,864	815	719	1,100	9,926
11	Distribution	613,499	450,990	116,389	6,273	6,316	7,732	25,800
12	General	137,405	92,215	30,260	1,954	1,454	2,046	9,475
13	Common	0	0	0	0	0	0	0
14	**Total Depreciation Reserve**	**872,867**	**601,505**	**185,447**	**11,374**	**8,489**	**11,551**	**54,500**
15	**Net Plant**	**1,695,250**	**1,122,011**	**380,110**	**25,148**	**18,691**	**26,692**	**122,598**
16	**Deductions** (Accum Def Inc Tax)	**280,973**	**194,537**	**56,829**	**3,421**	**3,249**	**4,244**	**18,692**
17	**Additions**	**53,782**	**32,366**	**10,443**	**703**	**631**	**1,877**	**7,761**
18	**Rate Base**	**1,468,059**	**959,841**	**333,724**	**22,430**	**16,073**	**24,325**	**111,667**

	Income Statement	**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
19	**Present Retail Revenue**	**774,803**	**452,991**	**231,632**	**24,367**	**45,968**	**8,010**	**11,835**
20	**Present Other Oper Rev**	**3,457**	**2,717**	**503**	**30**	**20**	**25**	**162**
21	**Present Total Operating Rev**	**778,260**	**455,708**	**232,134**	**24,397**	**45,988**	**8,036**	**11,997**
	Operating & Maint Expenses							
22	Purchased Gas Expense	434,954	239,809	144,934	16,084	32,460	0	1,667
23	Other Purch Gas Exp	0	0	0	0	0	0	0
24	Other Production	7,822	3,801	2,479	222	184	143	992
25	Transmission	382	184	122	10	9	14	43
26	Distribution	50,427	38,507	7,920	465	433	662	2,440
27	Customer Accounting	12,256	10,942	963	124	198	22	8
28	Customer Service and Information	-4,232	-3,119	-951	-58	-92	-10	-4
29	Administrative and General	32,326	23,442	5,966	416	452	399	1,650
30	Amortizations; Sales Expense	44,641	23,042	13,412	1,570	4,182	2,119	316
31	**Total Operating & Maint Exp**	**578,575**	**336,608**	**174,845**	**18,834**	**37,826**	**3,350**	**7,113**
32	Book Depreciation	89,099	59,820	20,028	1,289	814	1,172	5,976
33	Taxes Other Than Income Taxes	33,123	16,919	10,001	812	636	991	3,765
34	Prov For Deferred Inc Taxes	8,407	5,792	1,898	102	80	68	467
35	Net Investment Tax Credit	-97	-63	-22	-2	-1	-2	-7
36	**Total Operating Expense**	**709,107**	**419,076**	**206,749**	**21,036**	**39,354**	**5,579**	**17,313**
37	State and Federal Income Taxes	2,812	-173	2,927	616	1,490	384	-2,431
38	**Total Expense**	**711,919**	**418,902**	**209,676**	**21,652**	**40,844**	**5,963**	**14,882**
39	AFUDC (Rev Credit)	2,842	1,799	693	49	31	49	221
40	**Total Operating Income**	**69,183**	**38,605**	**23,151**	**2,794**	**5,175**	**2,122**	**-2,664**
41	**Rate Base**	**1,468,059**	**959,841**	**333,724**	**22,430**	**16,073**	**24,325**	**111,667**
42	**Present Return on Rate Base**	**4.71%**	**4.02%**	**6.94%**	**12.46%**	**32.20%**	**8.72%**	**-2.39%**
43	**Present Return on Common Equity**	**4.79%**	**3.47%**	**9.02%**	**19.54%**	**57.14%**	**12.42%**	**-8.73%**
44	**Required Return on Rate Base**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**
45	**Required Operating Income**	**114,362**	**74,772**	**25,997**	**1,747**	**1,252**	**1,895**	**8,699**
46	**Income Deficiency**	**45,179**	**36,167**	**2,846**	**-1,047**	**-3,923**	**-227**	**11,363**
47	**Revenue Deficiency**	**63,401**	**50,685**	**4,232**	**-1,386**	**-5,274**	**-257**	**15,402**
48	**Deficiency / Pres Retail Revenue**	**8.18%**	**11.19%**	**1.83%**	**-5.69%**	**-11.47%**	**-3.21%**	**130.13%**

Class Cost of Service Study ($000); Test Year 2026 | SUMMARY | Page 2 of 11

Equal Return vs Present

	Operating Revenue Requirement	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Return On Rate Base	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
2	Equalized Total Retail Rev	838,205	503,676	235,864	22,982	40,694	7,753	27,237
3	Present Total Retail Revenue	774,803	452,991	231,632	24,367	45,968	8,010	11,835
4	Revenue Deficiency	63,401	50,685	4,232	-1,386	-5,274	-257	15,402
5	Deficiency / Pres Total Retail Rev	8.18%	11.19%	1.83%	-5.69%	-11.47%	-3.21%	130.13%
	Internal Retail Revenue Reqt							
6	Customer Retail Revenue Requirement	167,752	150,124	16,546	250	468	66	296
7	Average Monthly Customers	497,841	460,713	36,724	142	227	25	9
8	Revenue Requirement $ / Mo / Cust	28.08	27.15	37.55	146.91	171.62	220.29	2,745.03
9	Capacity Retail Revenue Requirement	193,882	93,567	62,288	5,216	3,932	5,534	23,346
10	Annual Dkt Sales	122,792,367	39,424,795	24,016,129	2,875,341	7,671,802	10,190,089	38,614,211
11	Revenue Requirement $ / Dkt	1.58	2.37	2.59	1.81	0.51	0.54	0.60
	Capacity - Sub Classification							
12	Capacity - Base Revenue Requirement	43,935	15,814	9,680	1,162	3,135	4,101	10,043
13	Capacity - Seasonal Revenue Requirement	91,238	47,865	32,719	2,352	0	625	7,676
14	Peak Shaving Revenue Requirement	58,710	29,887	19,889	1,702	796	808	5,627
15	Base Rev Requirement $ / Dkt	0.36	0.40	0.40	0.40	0.41	0.40	0.26
16	Seasonal Rev Requirement $ / Dkt	0.74	1.21	1.36	0.82	0.00	0.06	0.20
17	Peak Shave Rev Requirement $ / Dkt	0.48	0.76	0.83	0.59	0.10	0.08	0.15
18	Energy Retail Revenue Requirement	40,486	19,130	12,012	1,430	3,834	2,153	1,927
19	Revenue Requirement $ / Dkt	0.33	0.49	0.50	0.50	0.50	0.21	0.05
20	Total Internal Retail Revenue Requirement	402,120	262,821	90,846	6,897	8,233	7,753	25,570
21	Revenue Requirement $ / Dkt	3.27	6.67	3.78	2.40	1.07	0.76	0.66
22	Revenue Requirement $ / Mo / Cust	67.31	47.54	206.14	4,047.52	3,018.13	25,842.75	236,758.23
	External Retail Revenue Reqt							
23	Capacity Revenue Requirement	107,266	64,439	38,797	3,893	0	0	136
24	Energy Revenue Requirement	327,688	175,370	106,137	12,191	32,460	0	1,530
25	Total External Revenue Requirement	434,954	239,809	144,934	16,084	32,460	0	1,667
26	Cap Revenue Requirement $ / Dkt	0.87	1.63	1.62	1.35	0.00	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.67	4.45	4.42	4.24	4.23	0.00	0.04
28	Tot Revenue Requirement $ / Dkt	3.54	6.08	6.03	5.59	4.23	0.00	0.04
	Total Retail Revenue Reqt							
29	Customer Revenue Requirement	167,752	150,124	16,546	250	468	66	296
30	Capacity Revenue Requirement	301,148	158,005	101,085	9,110	3,932	5,534	23,483
31	Energy Revenue Requirement	368,174	194,500	118,149	13,621	36,293	2,153	3,457
32	Total Revenue Requirement	837,074	502,629	235,780	22,981	40,693	7,753	27,237
33	Customer Revenue Reqt $ / Dkt	1.37	3.81	0.69	0.09	0.06	0.01	0.01
34	Demand Revenue Reqt $ / Dkt	2.45	4.01	4.21	3.17	0.51	0.54	0.61
35	Energy Revenue Reqt $ / Dkt	3.00	4.93	4.92	4.74	4.73	0.21	0.09
36	Total Revenue Reqt $ / Dkt	6.82	12.75	9.82	7.99	5.30	0.76	0.71

Proposed Return vs Present

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
37	Proposed Total Retail Revenue	838,205	493,375	247,016	26,078	49,447	9,448	12,841
38	Revenue Deficiency	63,401	40,384	15,384	1,711	3,479	1,437	1,006
39	Deficiency / Pres Total Oper Revenue	8.18%	8.91%	6.64%	7.02%	7.57%	17.94%	8.50%

Proposed Return vs Equal

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
40	Revenue Difference	0.0	-10,301	11,152	3,097	8,753	1,695	-14,396
41	Difference / Tot Equal Revenue"	0.00%	-2.05%	4.73%	13.47%	21.51%	21.86%	-52.85%

Class Cost of Service Study ($000); Test Year 2026 | Page 3 of 11

RATE BASE

	Plant in Service	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	304, 305, 311	Design Day	131,882	67,643	45,072	3,633	0	1,049	14,485
2	**Storage Plant (LNG)**	360, 361, 362, 363	Design Day	133,956	68,707	45,781	3,690	0	1,065	14,713
3	Transmission - Average Capacity	365, 366, 367, 368, 369, 370, 371	Average and Peak	139,411	67,189	44,552	3,681	3,247	4,969	15,773
4	Transmission - Direct Assign	365, 366, 367, 368, 369, 370, 371	Direct Assign	22,929	0	0	0	0	0	22,929
5	**Transmission Plant**	Sub-total		162,341	67,189	44,552	3,681	3,247	4,969	38,703
	Distribution Plant									
6	Regulator Stations	374, 375, 378, 379	Average and Peak	605	292	193	16	14	22	68
7	Mains - Direct Assignment	376	Direct Assign	5,076	0	0	0	0	0	5,076
8	Mains - Minimum System	376	Modified Customers	463,760	429,175	34,210	132	212	23	7
9	Mains - Average Capacity	Split of 376	Modified Sales W/Transport	234,326	86,379	52,619	6,300	16,809	22,326	49,894
10	Mains - Excess Capacity	Split of 376	Excess Design Day	487,374	261,442	178,018	12,758	0	3,398	31,759
11	Mains - Total	376		1,190,536	776,996	264,847	19,190	17,020	25,747	86,736
12	Services	380	Service Study	420,612	362,567	56,054	626	1,226	109	30
13	Meters	381	Meter & Regul Study	167,599	133,207	31,041	909	1,841	408	194
14	House Regulators	383	Meter & Regul Study	39,775	31,613	7,367	216	437	97	46
15	Total Distribution Plant	Sub-total		1,819,128	1,304,674	359,502	20,956	20,538	26,382	87,075
16	**General Plant**	390-399	Prod-Stor-Tran-Dis	320,811	215,303	70,650	4,562	3,395	4,777	22,123
17	**Common Plant**	390-399	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
18	**Gas Plant in Service**	Total		**2,568,117**	**1,723,516**	**565,558**	**36,522**	**27,180**	**38,243**	**177,098**
	Accum Depr Reserve	**FERC Accounts**	**Allocator**							
19	**Production Plant (LPG)**	108(1)	Design Day	31,383	16,096	10,726	864	0	250	3,447
20	**Storage Plant (LNG)**	108(5)	Design Day	53,282	27,329	18,210	1,468	0	424	5,852
21	Transmission - Average Capacity	108(7)	Average and Peak	30,865	14,875	9,864	815	719	1,100	3,492
22	Transmission - Direct Assign	108(7)	Direct Assign	6,434	0	0	0	0	0	6,434
23	**Transmission Plant**	Sub-total		37,298	14,875	9,864	815	719	1,100	9,926
	Distribution Plant									
24	Regulator Stations	108(8)	Average and Peak	0	0	0	0	0	0	0
25	Mains Direct Assignment	108(8)	Direct Assign	415	0	0	0	0	0	415
26	Mains	108(8)	Mains, Overall	347,103	226,535	77,217	5,595	4,962	7,507	25,288
27	Services	108(8)	Service Study	194,255	167,447	25,888	289	566	51	14
28	Meters	108(8)	Meter & Regul Study	64,296	51,102	11,908	349	706	156	75
29	House Regulators	108(8)	Meter & Regul Study	7,430	5,905	1,376	40	82	18	9
30	Total Distribution Plant	Sub-total		613,499	450,990	116,389	6,273	6,316	7,732	25,800
31	**General Plant**	108(9)	Prod-Stor-Tran-Dis	137,405	92,215	30,260	1,954	1,454	2,046	9,475
32	**Common Plant**	108(9)	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
33	**Total Accum Depr**	Sub-total		**872,867**	**601,505**	**185,447**	**11,374**	**8,489**	**11,551**	**54,500**
34	**Net Plant**	Total		**1,695,250**	**1,122,011**	**380,110**	**25,148**	**18,691**	**26,692**	**122,598**
	Subtractions to Net Plant									
	Accum Deferred Inc Tax	**FERC Accounts**	**Allocator**							
35	**Production Plant (LPG)**	190, 281, 282, 283 Net	Design Day	-2,164	-1,110	-739	-60	0	-17	-238
36	**Storage Plant (LNG)**	190, 281, 282, 283 Net	Design Day	2,273	1,166	777	63	0	18	250
37	Transmission - Average Capacity	190, 281, 282, 283 Net	Average and Peak	18,056	8,702	5,770	477	421	644	2,043
38	Transmission - Direct Assign	190, 281, 282, 283 Net	Direct Assign	4,029	0	0	0	0	0	4,029
39	**Transmission Plant**	Sub-total		22,085	8,702	5,770	477	421	644	6,072
	Distribution Plant									
40	Regulator Stations	190, 281, 282, 283 Net	Average and Peak	14	7	5	0	0	1	2
41	Mains Direct Assignment	190, 281, 282, 283 Net	Direct Assign	246	0	0	0	0	0	246
42	Mains	190, 281, 282, 283 Net	Mains, Overall	144,562	94,348	32,159	2,330	2,067	3,126	10,532
43	Services	190, 281, 282, 283 Net	Service Study	59,108	50,951	7,877	88	172	15	4
44	Meters	190, 281, 282, 283 Net	Meter & Regul Study	23,745	18,873	4,398	129	261	58	28
45	House Regulators	190, 281, 282, 283 Net	Meter & Regul Study	4,662	3,705	863	25	51	11	5
46	Total Distribution Plant	Sub-total		232,339	167,884	45,303	2,573	2,551	3,211	10,817
47	**General Plant**	190, 281, 282, 283 Net	Prod-Stor-Tran-Dis	24,474	16,425	5,390	348	259	364	1,688
48	**Common Plant**	Sub-total	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
49	Net Operating Loss (NOL) Carry Forward	283	Net Plant	0	0	0	0	0	0	0
50	Non-Plant Related	190 & 282 Net	Labor	1,966	1,470	330	21	18	24	103
51	**Total Subtractions**	Total		**280,973**	**194,537**	**56,829**	**3,421**	**3,249**	**4,244**	**18,692**

Class Cost of Service Study ($000); Test Year 2026

RATE BASE

Additions to Net Plant

	CWIP	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production Plant (LPG)		Design Day	257	132	88	7	0	2	28
2	Storage Plant (LNG)		Design Day	3,786	1,942	1,294	104	0	30	416
3	Transmission - Average Capacity	107	Average and Peak	958	462	306	25	22	34	108
4	Transmission - Direct Assign	107	Direct Assignment	0	0	0	0	0	0	0
5	Transmission Plant			958	462	306	25	22	34	108
6	Regulator Stations	107	Average and Peak	0	0	0	0	0	0	0
7	Mains Direct Assignment	107	Direct Assign	0	0	0	0	0	0	0
8	Mains	107	Mains Overall	11,072	7,226	2,463	178	158	239	807
9	Services		Service Study	389	336	52	1	1	0	0
10	Meters		Meter & Regul Study	218	174	40	1	2	1	0
11	House Regulators		Meter & Regul Study	489	389	91	3	5	1	1
12	General & Common Plant	107	Prod-Stor-Tran-Dis	20,359	13,663	4,483	290	215	303	1,404
13	Total CWIP	Sub-total		37,529	24,323	8,817	609	405	611	2,764
14	**Materials & Supplies**	154, 155, 156	Tran & Distrib	1,545	1,070	315	19	19	24	98
	Gas In Storage									
15	Total Gas in Storage	Sub-total	Sales, W/ Transp	13,844	4,445	2,708	324	865	1,149	4,353
16	**Non-Plant Assets & Liab**	Total	Labor	11,037	8,253	1,851	117	103	134	579
	Miscellaneous	**FERC Accounts**	**Allocator**							
17	Prepay: Insurance	165	Tran & Distrib	0	0	0	0	0	0	0
18	Prepay: Miscellaneous	165	Tran & Distrib	1,736	1,202	354	22	21	27	110
19	Fuel	176	Sales, W/o Transp	0	0	0	0	0	0	0
20	Total Miscellaneous	Sub-total		1,736	1,202	354	22	21	27	110
	Working Cash									
21	Total Working Cash	Sub-total	Modified O&M Expense	-11,908	-6,925	-3,602	-388	-781	-68	-144
22	**Total Additions**	Sub-total		**53,782**	**32,366**	**10,443**	**703**	**631**	**1,877**	**7,761**
23	**Total Rate Base**	Sub-Total		**1,468,059**	**959,841**	**333,724**	**22,430**	**16,073**	**24,325**	**111,667**
24	**Common Rate Base (@ 52.50%)**			**770,731**	**503,916**	**175,205**	**11,776**	**8,438**	**12,771**	**58,625**
25	Customer Component			646,413	568,082	73,540	1,066	2,100	371	1,254
26	Demand Component			814,896	391,155	259,801	21,307	13,820	22,815	105,997
27	Energy Component			6,750	604	382	57	152	1,139	4,415

Class Cost of Service Study ($000); Test Year 2026 | Page 5 of 11

INCOME STATEMENT

Operating Revenue (Cal Month)

	Retail Revenue	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1a	**Present Retail Rev**	480, 481, 482, 484	Direct Assign	**774,803**	**452,991**	**231,632**	**24,367**	**45,968**	**8,010**	**11,835**
1b	**Proposed Retail Rev**	480, 481, 482, 484	Direct Assign	**837,074**	**492,329**	**246,932**	**26,078**	**49,446**	**9,448**	**12,841**
2	**Retail Rev Increase**			**62,270**	**39,338**	**15,301**	**1,711**	**3,478**	**1,437**	**1,006**
	Other Operating Revenue									
3	Late Pay Penalties	488, 495	Late Pay; Mod Pres Rev	1,868	1,724	137	2	6	0	0
4	Connection Charges	488, 495	Customers	433	401	32	0	0	0	0
5	Return Check Charges	488, 495	Customers	62	58	5	0	0	0	0
6	Connect Smart	488, 495	Customers	1	1	0	0	0	0	0
7	Interchange Gas	488, 495	Design Day	430	220	147	12	0	3	47
8	Damage Claim	488, 495	Design Day	0	0	0	0	0	0	0
9	Ltd Firm Sales - Rsrvs & Vols	488, 495	Design Day	168	86	57	5	0	1	18
10	Distribution Other	488, 495	Customers	42	39	3	0	0	0	0
11	Miscellaneous Other	488, 495	1/2 Dsgn Day, 1/2 Ener	452	189	122	12	14	21	96
12	**Tot Other Oper Rev - Pres**	**Sub-total**		**3,457**	**2,717**	**503**	**30**	**20**	**25**	**162**
13	Incr Late Pay - Proposed		Late Pay; Mod Pres Rev	150	139	11	0	0	0	0
14	Incr Connection Charge Revenue - Proposed		Customers	981	908	72	0	0	0	0
15	**Tot Other Oper Rev - Prop**			**4,588**	**3,764**	**586**	**30**	**21**	**25**	**162**
16a	**Total Oper Rev - Present**	Total		**778,260**	**455,708**	**232,134**	**24,397**	**45,988**	**8,036**	**11,997**
16b	**Total Oper Rev - Proposed**	Total		**841,662**	**496,092**	**247,518**	**26,108**	**49,467**	**9,473**	**13,003**
17	**Operating Rev Increase**			**63,401**	**40,384**	**15,384**	**1,711**	**3,479**	**1,437**	**1,006**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
18	Commodity	728, 804, 805, 808, 858	Direct Assign	327,688	175,370	106,137	12,191	32,460	0	1,530
19	Demand	804, 808, 858	Direct Assign	107,266	64,439	38,797	3,893	0	0	136
20	Propane		Design Day	0	0	0	0	0	0	0
21	Limited Firm	728	Design Day	0	0	0	0	0	0	0
22	Total Purchases	Sub-total		434,954	239,809	144,934	16,084	32,460	0	1,667
	Other Production Expense									
23	Other Purchased Gas		Design Day	813	417	278	22	0	6	89
24	MN Gas MGP Clean Up		Sales, W/o Transp	1,061	563	343	41	109	0	5
25	Misc. LPG Op Exp	710, 733, 735, 736, 742, 759	Design Day	3,559	1,826	1,216	98	0	28	391
26	Misc. LNG Op Exp	840, 841, 842, 843	1/2 Dsgn Day, 1/2 Ener	2,388	996	642	61	75	109	507
27	Total Other Production Expense	Sub-total		7,822	3,801	2,479	222	184	143	992
28	Transmission - Average Capacity	850-865	Average and Peak	382	184	122	10	9	14	43
29	Transmission - Other	850-865	Other	0	0	0	0	0	0	0
30	**Transmission Expense**			382	184	122	10	9	14	43
	Distribution Expense									
31	Regulator Stations	875, 877, 889, 891	Average and Peak	654	315	209	17	15	23	74
32	Mains Direct Assignment	874, 887	Direct Assign	0	0	0	0	0	0	0
33	Mains	874, 887	Mains, Overall	18,496	12,071	4,115	298	264	400	1,348
34	Services	892	Service Study	6,024	5,192	803	9	18	2	0
35	Meters	878, 893	Meter & Regul Study	-5,444	-4,327	-1,008	-30	-60	-13	-6
36	House Regulators	878, 893	Meter & Regul Study	2,234	1,775	414	12	25	5	3
37	Rents	881	Customers	1,612	1,491	119	0	1	0	0
38	Dispatching	871	1/2 Dsgn Day, 1/2 Ener	2,763	1,152	742	70	86	126	586
39	Customer Installations	879	Customers	961	889	71	0	0	0	0
40	Other Distribution	880	Customers	14,127	13,073	1,042	4	6	1	0
41	Supervision & Engineering	870, 885	Dist Exp, w/o Sup & Eng	9,002	6,874	1,414	83	77	118	436
42	Total Distribution Expense	Sub-total		50,427	38,507	7,920	465	433	662	2,440

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Operation & Maintenance (Pg 2 of 2)

	Cust Acctg & Inform	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Acct Superv	901	Customers	30	28	2	0	0	0	0
2	Acct Meter Read	902	Customers	761	704	56	0	0	0	0
3	Acct Recrds & Coll	903	Record & Coll Study	7,511	6,674	487	123	198	22	8
4	Acct Uncollect	904	Uncollectibles Study	3,877	3,465	412	0	0	0	0
5	Acct Misc	905	Customers	76	71	6	0	0	0	0
6	Asst Expense (w/o CIP)	908	Cust Inform Study	-4,232	-3,119	-951	-58	-92	-10	-4
7	Tot Cust Acctg & Inform	Sub-total		8,023	7,823	12	66	106	12	4
	Admin & General									
8	Property Insurance	924	Net Plant	784	519	176	12	9	12	57
9	Pension & Benefit-Direct	926	Labor	9,653	7,218	1,619	102	90	117	507
10	Salaries	920	Labor	8,661	6,476	1,453	92	81	105	455
11	Office & Supplies	921	Labor	11,938	8,926	2,002	126	111	145	627
12	Admin Transfer Credit	922	Labor	-5,682	-4,249	-953	-60	-53	-69	-298
13	Outside Services	923	Labor	2,071	1,549	347	22	19	25	109
14	Incentive Compensation	920 + other	Labor	0	0	0	0	0	0	0
15	Injuries and Claims	925	1/2 Rt Base, 1/2 Pres Rev;	2,989	1,851	786	70	105	40	136
16	Regulatory Comm Exp	928	Pres Rev; Mod Pres Rev	936	547	280	29	56	10	14
17	Contributions	929	Pres Rev; Mod Pres Rev	0	0	0	0	0	0	0
18	General Advertising	930	1/2 Rt Base, 1/2 Pres Rev;	28	17	7	1	1	0	1
19	Misc General Exp	930	1/2 Rt Base, 1/2 Pres Rev;	191	118	50	4	7	3	9
20	Rents	931	1/2 Rt Base, 1/2 Pres Rev;	693	429	182	16	24	9	32
21	Maint of Gen Plt	935	1/2 Rt Base, 1/2 Pres Rev;	65	40	17	2	2	1	3
22	Total A & G Expense	Sub-total		32,326	23,442	5,966	416	452	399	1,650
	Amortizations									
23	CIP/DSM	CIP	Sales, W/o CIP Exempt	42,183	21,278	12,958	1,537	4,140	2,086	183
24	Amortizations		Labor	2,098	1,568	352	22	20	26	110
25	Instructional Advertising	407	Pres Rev; Mod Pres Rev	302	177	90	10	18	3	5
26	Total Amortizations	Sub-total		44,583	23,023	13,400	1,569	4,178	2,115	297
	Sales Expense									
27	Sales, Econ Dvlp & Other	912, 913	Sales, W/ Transp	58	19	11	1	4	5	18
28	Total Sales Econ Dvlp & Other	Sub-total		58	19	11	1	4	5	18
29	**Total O&M Expense**			**578,575**	**336,608**	**174,845**	**18,834**	**37,826**	**3,350**	**7,113**
	Book Depreciation	**FERC Accounts**	**Allocator**							
30	**Production Plant (LPG)**	403	Design Day	7,849	4,026	2,682	216	0	62	862
31	**Storage Plant (LNG)**	403	Design Day	6,154	3,157	2,103	170	0	49	676
32	Transmission - Average Capacity	403	Average and Peak	2,520	1,214	805	67	59	90	285
33	Transmission - Direct Assign	403	Direct Assign	389	0	0	0	0	0	389
34	**Transmission Plant**	Sub-total		2,909	1,214	805	67	59	90	674
	Distribution Plant									
35	Regulator Stations	403	Average and Peak	0	0	0	0	0	0	0
36	Mains Direct Assignment	403	Direct Assign	112	0	0	0	0	0	112
37	Mains	403	Mains, Overall	28,077	18,324	6,246	453	401	607	2,046
38	Services	403	Service Study	14,820	12,774	1,975	22	43	4	1
39	Meters	403	Meter & Regul Study	4,933	3,920	914	27	54	12	6
40	House Regulators	403	Meter & Regul Study	1,070	851	198	6	12	3	1
41	Total Distribution Plant	Sub-total		49,011	35,870	9,333	507	511	626	2,165
42	**General & Common Plant**	403	Prod-Stor-Tran-Dis	23,175	15,553	5,104	330	245	345	1,598
43	**Common Plant**	403, 404	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
44	**Total Book Deprec**	Sub-total		**89,099**	**59,820**	**20,028**	**1,289**	**814**	**1,172**	**5,976**

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	Real Estate & Prop Taxes	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	408	Design Day	3,308	1,697	1,131	91	0	26	363
2	**Storage Plant (LNG)**	408	Design Day	0.0	0	0	0	0	0	0
3	Transmission - Average Capacity	408	Average and Peak	1,743	840	557	46	41	62	197
4	Transmission - Direct Assign	408	Direct Assignment	287	0	0	0	0	0	287
5	**Transmission Plant**	408		2,029	840	557	46	41	62	484
	Distribution Plant									
6	Regulator Stations	408	Average and Peak	24,058	11,594	7,688	635	560	857	2,722
7	Mains Direct Assignment	408	Direct Assign	0	0	0	0	0	0	0
8	Mains	408	Mains, Overall	0	0	0	0	0	0	0
9	Services	408	Service Study	0	0	0	0	0	0	0
10	Meters	408	Meter & Regul Study	0	0	0	0	0	0	0
11	House Regulators	408	Meter & Regul Study	0	0	0	0	0	0	0
12	Total Distribution Plant	Sub-total		24,058	11,594	7,688	635	560	857	2,722
13	**General and Common Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Common Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
15	**Total Rl Est & Prop Tax**	Sub-total		**29,395**	**14,131**	**9,376**	**772**	**601**	**946**	**3,569**
16	Payroll Taxes	408	Labor	3,728	2,788	625	39	35	45	196
17	**Tot Non-Income Taxes**			**33,123**	**16,919**	**10,001**	**812**	**636**	**991**	**3,765**
	Provision-Defer Inc Tax	**FERC Accounts**	**Allocator**							
18	**Production Plant (LPG)**	410.1, 411.1	Design Day	14	7	5	0	0	0	2
19	**Storage Plant (LNG)**	410.1, 411.1	Design Day	1,375	705	470	38	0	11	151
20	Transmission - Average Capacity	410.1, 411.1	Average and Peak	1,354	653	433	36	32	48	153
21	Transmission - Direct Assign	410.1, 411.1	Direct Assign	76	0	0	0	0	0	76
22	**Transmission Plant**	Sub-total		1,430	653	433	36	32	48	229
	Distribution Plant									
23	Regulator Stations	410.1, 411.1	Average and Peak	1	1	0	0	0	0	0
24	Mains Direct Assignment	410.1, 411.1	Direct Assign	51	0	0	0	0	0	51
25	Mains	410.1, 411.1	Mains, Overall	-1,366	-892	-304	-22	-20	-30	-100
26	Services	410.1, 411.1	Service Study	843	726	112	1	2	0	0
27	Meters	410.1, 411.1	Meter & Regul Study	3,250	2,583	602	18	36	8	4
28	House Regulators	410.1, 411.1	Meter & Regul Study	902	717	167	5	10	2	1
29	Total Distribution Plant	Sub-total		3,680	3,135	578	2	29	-19	-44
30	**General and Common Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	1,763	1,183	388	25	19	26	122
31	**Common Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
32	Net Operating Loss (NOL) Carry Forward	410.1, 411.1	Net Plant	0	0	0	0	0	0	0
33	Non-Plant Related	410.1, 411.1	Labor	145	108	24	2	1	2	8
34	**Tot Prov Defer Inc Tax**	Total		**8,407**	**5,792**	**1,898**	**102**	**80**	**68**	**467**
	Investment Tax Credit	**FERC Accounts**	**Allocator**							
35	**Production Plant (LPG)**	420	Design Day	0	0	0	0	0	0	0
36	**Storage Plant (LNG)**	420	Design Day	0	0	0	0	0	0	0
37	Transmission - Average Capacity	420	Average and Peak	-5	-2	-1	0	0	0	-1
38	Transmission - Direct Assign	420	Direct Assign	0	0	0	0	0	0	0
39	**Transmission Plant**			-5	-2	-1	0	0	0	-1
	Distribution Plant									
40	Regulator Stations	420	Average and Peak	0	0	0	0	0	0	0
41	Mains Direct Assignment	420	Direct Assign	0	0	0	0	0	0	0
42	Mains	420	Mains, Overall	-92	-60	-21	-1	-1	-2	-7
43	Services	420	Service Study	0	0	0	0	0	0	0
44	Meters	420	Meter & Regul Study	0	0	0	0	0	0	0
45	House Regulators	420	Meter & Regul Study	0	0	0	0	0	0	0
46	Total Distribution Plant	Sub-total		-92	-60	-21	-1	-1	-2	-7
47	**General and Common Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
48	**Common Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
49	**Net Invest Tax Credit**	Sub-total		**-97**	**-63**	**-22**	**-2**	**-1**	**-2**	**-7**
50	**Total Operating Exp**	Sub-total		**709,107**	**419,076**	**206,749**	**21,036**	**39,354**	**5,579**	**17,313**
42a	**Pres Op Inc Before Inc Tax**	Total		**69,153**	**36,632**	**25,385**	**3,361**	**6,634**	**2,457**	**-5,316**
42b	**Prop Op Inc Before Inc Tax**	Total		**132,554**	**77,017**	**40,769**	**5,072**	**10,113**	**3,894**	**-4,310**

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INCOME STATEMENT

	Tax Deprec & Removal	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Not Applicable	Design Day	7,785	3,993	2,661	214	0	62	855
2	**Storage Plant (LNG)**	Not Applicable	Design Day	10,700	5,488	3,657	295	0	85	1,175
3	Transmission - Average Capacity	Not Applicable	Average and Peak	7,626	3,675	2,437	201	178	272	863
4	Transmission - Direct Assign	Not Applicable	Direct Assign	682	0	0	0	0	0	682
5	**Transmission Plant**	Not Applicable		8,308	3,675	2,437	201	178	272	1,544
	Distribution Plant									
6	Regulator Stations	Not Applicable	Average and Peak	0	0	0	0	0	0	0
7	Mains Direct Assignment	Not Applicable	Direct Assign	290	0	0	0	0	0	290
8	Mains	Not Applicable	Mains, Overall	31,875	20,803	7,091	514	456	689	2,322
9	Services	Not Applicable	Service Study	14,309	12,334	1,907	21	42	4	1
10	Meters	Not Applicable	Meter & Regul Study	16,526	13,135	3,061	90	182	40	19
11	House Regulators	Not Applicable	Meter & Regul Study	4,388	3,487	813	24	48	11	5
12	Total Distribution Plant	Sub-total		67,388	49,760	12,871	648	727	744	2,638
13	**General and Common Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Common Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
15	Net Operating Loss (NOL) Carry Forward	Not Applicable	Net Plant	33,126	21,924	7,427	491	365	522	2,396
16	**Total Tax Depreciation**	Total		**127,307**	**84,841**	**29,054**	**1,850**	**1,270**	**1,684**	**8,608**
	Present Return									
	Inc Tax Additions	**FERC Accounts**	**Allocator**							
17	Total Book Depr Exp	from another page		89,099	59,820	20,028	1,289	814	1,172	5,976
18	Provision for Deferred	from another page		8,407	5,792	1,898	102	80	68	467
19	Net Inv Tax Credit	from another page		-97	-63	-22	-2	-1	-2	-7
20	Avoided Tax Interest	Not Applicable	CWIP	1,044	677	245	17	11	17	77
21	Total Tax Additions	Sub-total		98,453	66,226	22,149	1,407	904	1,255	6,512
	Inc Tax Deductions									
22	Tax Depr & Removal Exp	from another page		127,307	84,841	29,054	1,850	1,270	1,684	8,608
23	Debt Interest Expense	Calculation	; Mod Rate Base	32,297	21,116	7,342	493	354	535	2,457
24	Other Timing Differences	Not Applicable	Labor	-3,396	-2,539	-569	-36	-32	-41	-178
25	Meals		Labor	177	132	30	2	2	2	9
26	Total Tax Deductions	Sub-total		156,385	103,550	35,856	2,310	1,594	2,180	10,896
26a	**Pres Taxable Net Income**	Calculation		**11,221**	**-692**	**11,678**	**2,458**	**5,945**	**1,531**	**-9,699**
26b	**Prop Taxable Net Income**			**74,622**	**39,692**	**27,062**	**4,169**	**9,424**	**2,969**	**-8,693**
27a	**Pres Inc Tax, @25.06%**	Calculation		**2,812**	**-173**	**2,927**	**616**	**1,490**	**384**	**-2,431**
27b	**Prop Inc Tax, @28.19%**			**21,035**	**11,189**	**7,628**	**1,175**	**2,656**	**837**	**-2,451**
28a	**Pres Preliminary Return**			66,341	36,806	22,459	2,745	5,144	2,073	-2,885
28b	**Prop Preliminary Return**			111,519	65,828	33,141	3,897	7,456	3,057	-1,860
29	**Total AFUDC**	Not Applicable	CWIP	**2,842**	**1,799**	**693**	**49**	**31**	**49**	**221**
30a	**Pres Total Return**	Total	; Mod Rate Base	**69,183**	**38,605**	**23,151**	**2,794**	**5,175**	**2,122**	**-2,664**
30b	**Prop Total Return**		; Mod Rate Base	**114,362**	**67,627**	**33,834**	**3,946**	**7,488**	**3,106**	**-1,638**
31a	**Pres % Return on Rate Base**	Calculation		**4.71%**	**4.02%**	**6.94%**	**12.46%**	**32.20%**	**8.72%**	**-2.39%**
31b	**Prop % Return on Rate Base**			**7.79%**	**7.05%**	**10.14%**	**17.59%**	**46.59%**	**12.77%**	**-1.47%**
32a	**Pres Common Return**			**36,886**	**17,489**	**15,809**	**2,301**	**4,822**	**1,586**	**(5,121)**
32b	**Prop Common Return**			**82,064**	**46,511**	**26,492**	**3,453**	**7,134**	**2,571**	**(4,095)**
33a	**Pres % Ret on Common Rt Bs**			**4.79%**	**3.47%**	**9.02%**	**19.54%**	**57.14%**	**12.42%**	**-8.73%**
33b	**Prop % Ret on Common Rt Bs**			**10.65%**	**9.23%**	**15.12%**	**29.32%**	**84.55%**	**20.13%**	**-6.99%**
	AFUDC									
34	Production Plant (LPG)		Design Day	39	20	13	1	0	0	4
35	Storage Plant (LNG)		Design Day	361	185	123	10	0	3	40
36	Transmission - Average Capacity	Not Applicable	Average and Peak	175	85	56	5	4	6	20
37	Transmission - Direct Assign	Not Applicable	Direct Assign	0	0	0	0	0	0	0
38	Transmission Plant		Average and Peak	175	85	56	5	4	6	20
	Distribution:									
39	Regulator Stations		Average and Peak	0	0	0	0	0	0	0
40	Mains Direct Assignment		Direct Assign	0	0	0	0	0	0	0
41	Mains		Mains Overall	857	559	191	14	12	19	62
42	Services		Service Study	2	2	0	0	0	0	0
43	Meters		Meter & Regul Study	0	0	0	0	0	0	0
44	House Regulators		Meter & Regul Study	30	23	5	0	0	0	0
45	Total Distribution			889	585	196	14	13	19	62
46	General Plant		Prod-Stor-Tran-Dis	1,378	925	303	20	15	21	95
47	Gas Common		Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
48	Total AFUDC			2,842	1,799	693	49	31	49	221
	Labor Allocator	**FERC Accounts**	**Allocator**							
49	Customer Accounting	Labor Portion of O&M Accounts	Customers	3,750	3,471	277	1	2	0	0
50	Cust Serv & Inform	Labor Portion of O&M Accounts	Customers	746	690	55	0	0	0	0
51	Distribution	Labor Portion of O&M Accounts	Dist Exp, w/o Sup & Eng	28,995	22,141	4,554	267	249	380	1,403
52	Admin & General	Labor Portion of O&M Accounts	Labor w/o A&G	18,557	13,876	3,112	197	173	226	974
53	Production	Labor Portion of O&M Accounts	Other Production Exp	4,521	2,197	1,433	129	106	83	573
54	Sales	Labor Portion of O&M Accounts	Sales, W/ Transp	0	0	0	0	0	0	0
55	Transmission	Labor Portion of O&M Accounts	Design Day	324	166	111	9	0	3	36
56	Total			56,894	42,542	9,541	603	531	692	2,986

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ALLOCATORS

	Internal Allocators	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**41.70%**	**26.87%**	**2.55%**	**3.12%**	**4.55%**	**21.21%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**61.92%**	**26.31%**	**2.34%**	**3.51%**	**1.35%**	**4.57%**
3	Average and Peak (Mains)	721,700	347,820	230,637	19,057	16,809	25,724	81,653
4	Average and Peak	**100.00%**	**48.19%**	**31.96%**	**2.64%**	**2.33%**	**3.56%**	**11.31%**
5	CWIP	**100.00%**	**64.81%**	**23.50%**	**1.62%**	**1.08%**	**1.63%**	**7.36%**
6	Dist Exp, w/o Sup & Eng	41,426	31,633	6,506	382	356	544	2,005
7	Dist Exp, w/o Sup & Eng	**100.00%**	**76.36%**	**15.71%**	**0.92%**	**0.86%**	**1.31%**	**4.84%**
8	Distribution Plant	**100.00%**	**71.72%**	**19.76%**	**1.15%**	**1.13%**	**1.45%**	**4.79%**
9	Gas Plant In Service	**100.00%**	**67.11%**	**22.02%**	**1.42%**	**1.06%**	**1.49%**	**6.90%**
10	Labor	**100.00%**	**74.77%**	**16.77%**	**1.06%**	**0.93%**	**1.22%**	**5.25%**
11	Mains, Overall	**100.00%**	**65.26%**	**22.25%**	**1.61%**	**1.43%**	**2.16%**	**7.29%**
12	Modified O&M Expense	573,372	333,429	173,431	18,703	37,613	3,284	6,913
13	Modified O&M Expense	**100.00%**	**58.15%**	**30.25%**	**3.26%**	**6.56%**	**0.57%**	**1.21%**
14	Net Plant	**100.00%**	**66.19%**	**22.42%**	**1.48%**	**1.10%**	**1.57%**	**7.23%**
15	Other Production Exp	**100.00%**	**48.60%**	**31.69%**	**2.84%**	**2.35%**	**1.83%**	**12.68%**
16	Prod-Stor-Tran-Dis	2,247,306	1,508,213	494,908	31,960	23,785	33,466	154,975
17	Prod-Stor-Tran-Dis	**100.00%**	**67.11%**	**22.02%**	**1.42%**	**1.06%**	**1.49%**	**6.90%**
18	Rate Base	**100.00%**	**65.38%**	**22.73%**	**1.53%**	**1.09%**	**1.66%**	**7.61%**
19	Rt Base, w/o Work Cash	1,479,967	966,766	337,326	22,818	16,854	24,393	111,810
20	Rt Base, w/o Work Cash	**100.00%**	**65.32%**	**22.79%**	**1.54%**	**1.14%**	**1.65%**	**7.55%**
21	Transmission & Distribution	1,981,469	1,371,863	404,054	24,638	23,785	31,351	125,777
22	Tran & Distrib	**100.00%**	**69.23%**	**20.39%**	**1.24%**	**1.20%**	**1.58%**	**6.35%**
23	Labor w/o A&G	38,337	28,666	6,429	406	358	466	2,012
24	Labor w/o A&G	**100.00%**	**74.77%**	**16.77%**	**1.06%**	**0.93%**	**1.22%**	**5.25%**
	Component Allocators							
25	Mod Present Rev	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
26	Mod Rate Base	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
27	1/2 Mod Rt Bs, 1/2 Mod Pres Rv	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**

Class Cost of Service Study ($000); Test Year 2026 | ALLOCATORS | Page 10 of 11

External Allocators

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
	Customer-Related							
1	Bills	5,974,093	5,528,561	440,692	1,704	2,728	300	108
2	Modified Bills	5,974,069	5,528,561	440,692	1,704	2,728	300	84
3	Meter & Regul Weightings		1.00					
4	Meter (Wtd Bills)	6,955,962	5,528,561	1,288,305	37,711	76,401	16,914	8,070
5	Service Weightings		1.00					
6	Service (Wtd Bills)	6,413,659	5,528,561	854,734	9,551	18,689	1,668	456
7	Records & Collect Weightings		1.00					
8	Records & Collect (Wtd Bills)	6,222,041	5,528,561	403,080	102,240	163,680	18,000	6,480
9	Cust Information Weightings		1.00					
10	Cust Information (Wtd Bills)	7,502,193	5,528,561	1,685,392	102,240	162,600	16,920	6,480
11	Customers	100.00%	92.54%	7.38%	0.03%	0.05%	0.01%	0.00%
12	Modified Customers	100.00%	92.54%	7.38%	0.03%	0.05%	0.01%	0.00%
13	Meter & Regul Study	100.00%	79.48%	18.52%	0.54%	1.10%	0.24%	0.12%
14	Service Study	100.00%	86.20%	13.33%	0.15%	0.29%	0.03%	0.01%
15	Record & Coll Study	100.00%	88.85%	6.48%	1.64%	2.63%	0.29%	0.10%
16	Cust Inform Study	100.00%	73.69%	22.47%	1.36%	2.17%	0.23%	0.09%
	Energy-Related							
17	Cal Yr Sales Dkt, W/o Trans	74,351,221	39,424,795	24,016,129	2,875,341	7,671,802	0	363,155
18	Transportation Dkt	48,441,146	0	0	0	0	10,190,089	38,251,057
19	Cal Yr Sales Dkt, W/ Trans	122,792,367	39,424,795	24,016,129	2,875,341	7,671,802	10,190,089	38,614,211
20	CIP Exempt Dkt	44,633,482	0	6,040	26,741	0	6,324,935	38,275,766
21	Sales Dkt, W/o CIP Exempt	78,158,885	39,424,795	24,010,089	2,848,600	7,671,802	3,865,154	338,446
22	Sales, W/o Transp	100.00%	53.03%	32.30%	3.87%	10.32%	0.00%	0.49%
23	Sales, W/ Transp	100.00%	32.11%	19.56%	2.34%	6.25%	8.30%	31.45%
24	Sales, W/o CIP Exempt	100.00%	50.44%	30.72%	3.64%	9.82%	4.95%	0.43%
25	Modified Sales W/Transport	100.00%	36.86%	22.46%	2.69%	7.17%	9.53%	21.29%
	Demand-Related							
26	Design Day Demand (Retail)	1,036,133	531,440	354,112	28,540	0	8,241	113,800
27	Avg Daily Firm Dkt, W/ Trans	289,311	108,013	65,798	7,878	0	2,738	104,884
28	Design Day	100.00%	51.29%	34.18%	2.75%	0.00%	0.80%	10.98%
29	Excess Design Day	100.00%	53.64%	36.53%	2.62%	0.00%	0.70%	6.52%
	Miscellaneous (only alloc to class, not component)							
30	Present Retail Revenue	774,803	452,991	231,632	24,367	45,968	8,010	11,835
31	Uncollectibles Study	100.00%	89.38%	10.62%	0.00%	0.00%	0.00%	0.00%
32	Present Retail Revenue	100.00%	58.47%	29.90%	3.14%	5.93%	1.03%	1.53%
33	Late Payment Penalty	100.00%	92.27%	7.34%	0.09%	0.30%	0.00%	0.00%

Class Cost of Service Study ($000); Test Year 2026

Capital Structure		**Rate**	**Ratio**	**Wtd Cost**
37	Long Term Debt	4.64%	47.08%	2.18%
38	Short Term Debt	4.56%	0.42%	0.02%
39	Debt Total	4.63%	47.50%	2.20%
40	Preferred Stock	0.00%	0.00%	0.00%
41	Common Equity	10.65%	52.50%	5.59%
42	Required Rate of Return		100.00%	7.79%

Class Cost of Service Study ($000); Test Year 2026

SUMMARY

	Rate Base	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production	131,882	67,643	45,072	3,633	0	1,049	14,485
2	Storage	133,956	68,707	45,781	3,690	0	1,065	14,713
3	Transmission	162,341	67,189	44,552	3,681	3,247	4,969	38,703
4	Distribution	1,819,128	1,307,255	356,846	20,971	20,590	26,388	87,078
5	General	320,811	215,671	70,271	4,565	3,403	4,778	22,124
6	Common	0	0	0	0	0	0	0
7	**Total Plant In Service**	**2,568,117**	**1,726,465**	**562,522**	**36,540**	**27,239**	**38,250**	**177,101**
8	Production	31,383	16,096	10,726	864	0	250	3,447
9	Storage	53,282	27,329	18,210	1,468	0	424	5,852
10	Transmission	37,298	14,875	9,864	815	719	1,100	9,926
11	Distribution	613,499	451,742	115,614	6,277	6,331	7,733	25,801
12	General	137,405	92,373	30,097	1,955	1,457	2,047	9,476
13	Common	0	0	0	0	0	0	0
14	**Total Depreciation Reserve**	**872,867**	**602,415**	**184,511**	**11,379**	**8,508**	**11,553**	**54,501**
15	**Net Plant**	**1,695,250**	**1,124,050**	**378,012**	**25,160**	**18,732**	**26,696**	**122,600**
16	**Deductions** (Accum Def Inc Tax)	**280,973**	**194,880**	**56,476**	**3,423**	**3,256**	**4,245**	**18,692**
17	**Additions**	**53,782**	**32,425**	**10,383**	**703**	**632**	**1,878**	**7,761**
18	**Rate Base**	**1,468,059**	**961,595**	**331,918**	**22,440**	**16,108**	**24,329**	**111,669**

	Income Statement	Minn	Res	Com	Demand	Interrupt	Tran	Gener
19	**Present Retail Revenue**	**774,803**	**452,991**	**231,632**	**24,367**	**45,968**	**8,010**	**11,835**
20	**Present Other Oper Rev**	**3,457**	**2,717**	**503**	**30**	**20**	**25**	**162**
21	**Present Total Operating Rev**	**778,260**	**455,708**	**232,134**	**24,397**	**45,988**	**8,036**	**11,997**
	Operating & Maint Expenses							
22	Purchased Gas Expense	434,954	239,809	144,934	16,084	32,460	0	1,667
23	Other Purch Gas Exp	0	0	0	0	0	0	0
24	Other Production	7,822	3,801	2,479	222	184	143	992
25	Transmission	382	184	122	10	9	14	43
26	Distribution	50,427	38,556	7,870	465	434	662	2,440
27	Customer Accounting	12,256	10,942	963	124	198	22	8
28	Customer Service and Information	-4,232	-3,119	-951	-58	-92	-10	-4
29	Administrative and General	32,326	23,464	5,943	416	452	399	1,650
30	Amortizations; Sales Expense	44,641	23,043	13,410	1,571	4,182	2,119	316
31	**Total Operating & Maint Exp**	**578,575**	**336,681**	**174,769**	**18,835**	**37,827**	**3,350**	**7,113**
32	Book Depreciation	89,099	59,908	19,938	1,290	816	1,172	5,976
33	Taxes Other Than Income Taxes	33,123	16,922	9,998	812	636	991	3,765
34	Prov For Deferred Inc Taxes	8,407	5,791	1,899	102	80	68	467
35	Net Investment Tax Credit	-97	-63	-22	-2	-1	-2	-7
36	**Total Operating Expense**	**709,107**	**419,238**	**206,582**	**21,037**	**39,358**	**5,579**	**17,313**
37	State and Federal Income Taxes	2,812	-228	2,983	616	1,489	384	-2,431
38	**Total Expense**	**711,919**	**419,010**	**209,565**	**21,653**	**40,846**	**5,963**	**14,882**
39	AFUDC (Rev Credit)	2,842	1,803	689	49	31	49	221
40	**Total Operating Income**	**69,183**	**38,501**	**23,258**	**2,794**	**5,173**	**2,121**	**-2,664**
41	**Rate Base**	**1,468,059**	**961,595**	**331,918**	**22,440**	**16,108**	**24,329**	**111,669**
42	**Present Return on Rate Base**	**4.71%**	**4.00%**	**7.01%**	**12.45%**	**32.12%**	**8.72%**	**-2.39%**
43	**Present Return on Common Equity**	**4.79%**	**3.44%**	**9.16%**	**19.52%**	**56.98%**	**12.42%**	**-8.73%**
44	**Required Return on Rate Base**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**
45	**Required Operating Income**	**114,362**	**74,908**	**25,856**	**1,748**	**1,255**	**1,895**	**8,699**
46	**Income Deficiency**	**45,179**	**36,407**	**2,598**	**-1,045**	**-3,918**	**-226**	**11,363**
47	**Revenue Deficiency**	**63,401**	**51,011**	**3,897**	**-1,384**	**-5,268**	**-257**	**15,402**
48	**Deficiency / Pres Retail Revenue**	**8.18%**	**11.26%**	**1.68%**	**-5.68%**	**-11.46%**	**-3.20%**	**130.14%**

Class Cost of Service Study ($000); Test Year 2026

SUMMARY

Equal Return vs Present

	Operating Revenue Requirement	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Return On Rate Base	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
2	Equalized Total Retail Rev	838,205	504,001	235,529	22,984	40,700	7,754	27,237
3	Present Total Retail Revenue	774,803	452,991	231,632	24,367	45,968	8,010	11,835
4	Revenue Deficiency	63,401	51,011	3,897	-1,384	-5,268	-257	15,402
5	Deficiency / Pres Total Retail Rev	8.18%	11.26%	1.68%	-5.68%	-11.46%	-3.20%	130.14%
	Internal Retail Revenue Reqt							
6	Customer Retail Revenue Requirement	167,752	150,449	16,212	252	475	67	297
7	Average Monthly Customers	497,841	460,713	36,724	142	227	25	9
8	Revenue Requirement $ / Mo / Cust	28.08	27.21	36.79	148.04	174.05	222.81	2,748.40
9	Capacity Retail Revenue Requirement	193,883	93,567	62,288	5,216	3,932	5,534	23,346
10	Annual Dkt Sales	122,792,367	39,424,795	24,016,129	2,875,341	7,671,802	10,190,089	38,614,211
11	Revenue Requirement $ / Dkt	1.58	2.37	2.59	1.81	0.51	0.54	0.60
	Capacity - Sub Classification							
12	Capacity - Base Revenue Requirement	43,935	15,814	9,680	1,162	3,135	4,101	10,043
13	Capacity - Seasonal Revenue Requirement	91,238	47,865	32,719	2,352	0	625	7,676
14	Peak Shaving Revenue Requirement	58,710	29,887	19,889	1,702	796	808	5,627
15	Base Rev Requirement $ / Dkt	0.36	0.40	0.40	0.40	0.41	0.40	0.26
16	Seasonal Rev Requirement $ / Dkt	0.74	1.21	1.36	0.82	0.00	0.06	0.20
17	Peak Shave Rev Requirement $ / Dkt	0.48	0.76	0.83	0.59	0.10	0.08	0.15
18	Energy Retail Revenue Requirement	40,486	19,130	12,012	1,430	3,834	2,153	1,927
19	Revenue Requirement $ / Dkt	0.33	0.49	0.50	0.50	0.50	0.21	0.05
20	Total Internal Retail Revenue Requirement	402,120	263,146	90,511	6,899	8,240	7,754	25,570
21	Revenue Requirement $ / Dkt	3.27	6.67	3.77	2.40	1.07	0.76	0.66
22	Revenue Requirement $ / Mo / Cust	67.31	47.60	205.38	4,048.64	3,020.52	25,845.27	236,761.60
	External Retail Revenue Reqt							
23	Capacity Revenue Requirement	107,266	64,439	38,797	3,893	0	0	136
24	Energy Revenue Requirement	327,688	175,370	106,137	12,191	32,460	0	1,530
25	Total External Revenue Requirement	434,954	239,809	144,934	16,084	32,460	0	1,667
26	Cap Revenue Requirement $ / Dkt	0.87	1.63	1.62	1.35	0.00	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.67	4.45	4.42	4.24	4.23	0.00	0.04
28	Tot Revenue Requirement $ / Dkt	3.54	6.08	6.03	5.59	4.23	0.00	0.04
	Total Retail Revenue Reqt							
29	Customer Revenue Requirement	167,752	150,449	16,212	252	475	67	297
30	Capacity Revenue Requirement	301,148	158,006	101,085	9,110	3,932	5,534	23,483
31	Energy Revenue Requirement	368,174	194,500	118,148	13,621	36,293	2,153	3,457
32	Total Revenue Requirement	837,074	502,955	235,445	22,983	40,700	7,754	27,237
33	Customer Revenue Reqt $ / Dkt	1.37	3.82	0.68	0.09	0.06	0.01	0.01
34	Demand Revenue Reqt $ / Dkt	2.45	4.01	4.21	3.17	0.51	0.54	0.61
35	Energy Revenue Reqt $ / Dkt	3.00	4.93	4.92	4.74	4.73	0.21	0.09
36	Total Revenue Reqt $ / Dkt	6.82	12.76	9.80	7.99	5.31	0.76	0.71

Proposed Return vs Present

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
37	Proposed Total Retail Revenue	838,205	493,375	247,016	26,078	49,447	9,448	12,841
38	Revenue Deficiency	63,401	40,384	15,384	1,711	3,479	1,437	1,006
39	Deficiency / Pres Total Oper Revenue	8.18%	8.91%	6.64%	7.02%	7.57%	17.94%	8.50%

Proposed Return vs Equal

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
40	Revenue Difference	0.0	-10,626	11,487	3,095	8,747	1,694	-14,396
41	Difference / Tot Equal Revenue"	0.00%	-2.11%	4.88%	13.46%	21.49%	21.85%	-52.85%

Class Cost of Service Study ($000); Test Year 2026 | Page 3 of 11

RATE BASE

	Plant in Service	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	304, 305, 311	Design Day	131,882	67,643	45,072	3,633	0	1,049	14,485
2	**Storage Plant (LNG)**	360, 361, 362, 363	Design Day	133,956	68,707	45,781	3,690	0	1,065	14,713
3	Transmission - Average Capacity	365, 366, 367, 368, 369, 370, 371	Average and Peak	139,411	67,189	44,552	3,681	3,247	4,969	15,773
4	Transmission - Direct Assign	365, 366, 367, 368, 369, 370, 371	Direct Assign	22,929	0	0	0	0	0	22,929
5	**Transmission Plant**	Sub-total		162,341	67,189	44,552	3,681	3,247	4,969	38,703
	Distribution Plant									
6	Regulator Stations	374, 375, 378, 379	Average and Peak	605	292	193	16	14	22	68
7	Mains - Direct Assignment	376	Direct Assign	5,076	0	0	0	0	0	5,076
8	Mains - Minimum System	376	Modified Customers	463,760	431,756	31,554	147	263	29	9
9	Mains - Average Capacity	Split of 376	Modified Sales W/Transport	234,326	86,379	52,619	6,300	16,809	22,326	49,894
10	Mains - Excess Capacity	Split of 376	Excess Design Day	487,374	261,442	178,018	12,758	0	3,398	31,759
11	Mains - Total	376		1,190,536	779,576	262,191	19,205	17,072	25,753	86,739
12	Services	380	Service Study	420,612	362,567	56,054	626	1,226	109	30
13	Meters	381	Meter & Regul Study	167,599	133,207	31,041	909	1,841	408	194
14	House Regulators	383	Meter & Regul Study	39,775	31,613	7,367	216	437	97	46
15	Total Distribution Plant	Sub-total		1,819,128	1,307,255	356,846	20,971	20,590	26,388	87,078
16	**General Plant**	390-399	Prod-Stor-Tran-Dis	320,811	215,671	70,271	4,565	3,403	4,778	22,124
17	**Common Plant**	390-399	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
18	**Gas Plant in Service**	Total		**2,568,117**	**1,726,465**	**562,522**	**36,540**	**27,239**	**38,250**	**177,101**
	Accum Depr Reserve	**FERC Accounts**	**Allocator**							
19	**Production Plant (LPG)**	108(1)	Design Day	31,383	16,096	10,726	864	0	250	3,447
20	**Storage Plant (LNG)**	108(5)	Design Day	53,282	27,329	18,210	1,468	0	424	5,852
21	Transmission - Average Capacity	108(7)	Average and Peak	30,865	14,875	9,864	815	719	1,100	3,492
22	Transmission - Direct Assign	108(7)	Direct Assign	6,434	0	0	0	0	0	6,434
23	**Transmission Plant**	Sub-total		37,298	14,875	9,864	815	719	1,100	9,926
	Distribution Plant									
24	Regulator Stations	108(8)	Average and Peak	0	0	0	0	0	0	0
25	Mains Direct Assignment	108(8)	Direct Assign	415	0	0	0	0	0	415
26	Mains	108(8)	Mains, Overall	347,103	227,287	76,442	5,599	4,977	7,508	25,289
27	Services	108(8)	Service Study	194,255	167,447	25,888	289	566	51	14
28	Meters	108(8)	Meter & Regul Study	64,296	51,102	11,908	349	706	156	75
29	House Regulators	108(8)	Meter & Regul Study	7,430	5,905	1,376	40	82	18	9
30	Total Distribution Plant	Sub-total		613,499	451,742	115,614	6,277	6,331	7,733	25,801
31	**General Plant**	108(9)	Prod-Stor-Tran-Dis	137,405	92,373	30,097	1,955	1,457	2,047	9,476
32	**Common Plant**	108(9)	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
33	**Total Accum Depr**	Sub-total		**872,867**	**602,415**	**184,511**	**11,379**	**8,508**	**11,553**	**54,501**
34	**Net Plant**	Total		**1,695,250**	**1,124,050**	**378,012**	**25,160**	**18,732**	**26,696**	**122,600**
	Subtractions to Net Plant									
	Accum Deferred Inc Tax	**FERC Accounts**	**Allocator**							
35	**Production Plant (LPG)**	190, 281, 282, 283 Net	Design Day	-2,164	-1,110	-739	-60	0	-17	-238
36	**Storage Plant (LNG)**	190, 281, 282, 283 Net	Design Day	2,273	1,166	777	63	0	18	250
37	Transmission - Average Capacity	190, 281, 282, 283 Net	Average and Peak	18,056	8,702	5,770	477	421	644	2,043
38	Transmission - Direct Assign	190, 281, 282, 283 Net	Direct Assign	4,029	0	0	0	0	0	4,029
39	**Transmission Plant**	Sub-total		22,085	8,702	5,770	477	421	644	6,072
	Distribution Plant									
40	Regulator Stations	190, 281, 282, 283 Net	Average and Peak	14	7	5	0	0	1	2
41	Mains Direct Assignment	190, 281, 282, 283 Net	Direct Assign	246	0	0	0	0	0	246
42	Mains	190, 281, 282, 283 Net	Mains, Overall	144,562	94,661	31,837	2,332	2,073	3,127	10,532
43	Services	190, 281, 282, 283 Net	Service Study	59,108	50,951	7,877	88	172	15	4
44	Meters	190, 281, 282, 283 Net	Meter & Regul Study	23,745	18,873	4,398	129	261	58	28
45	House Regulators	190, 281, 282, 283 Net	Meter & Regul Study	4,662	3,705	863	25	51	11	5
46	Total Distribution Plant	Sub-total		232,339	168,197	44,980	2,574	2,558	3,212	10,817
47	**General Plant**	190, 281, 282, 283 Net	Prod-Stor-Tran-Dis	24,474	16,453	5,361	348	260	365	1,688
48	**Common Plant**	Sub-total	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
49	Net Operating Loss (NOL) Carry Forward	283	Net Plant	0	0	0	0	0	0	0
50	Non-Plant Related	190 & 282 Net	Labor	1,966	1,471	328	21	18	24	103
51	**Total Subtractions**	Total		**280,973**	**194,880**	**56,476**	**3,423**	**3,256**	**4,245**	**18,692**

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RATE BASE

Additions to Net Plant

	CWIP	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production Plant (LPG)		Design Day	257	132	88	7	0	2	28
2	Storage Plant (LNG)		Design Day	3,786	1,942	1,294	104	0	30	416
3	Transmission - Average Capacity	107	Average and Peak	958	462	306	25	22	34	108
4	Transmission - Direct Assign	107	Direct Assignment	0	0	0	0	0	0	0
5	Transmission Plant			958	462	306	25	22	34	108
6	Regulator Stations	107	Average and Peak	0	0	0	0	0	0	0
7	Mains Direct Assignment	107	Direct Assign	0	0	0	0	0	0	0
8	Mains	107	Mains Overall	11,072	7,250	2,438	179	159	240	807
9	Services		Service Study	389	336	52	1	1	0	0
10	Meters		Meter & Regul Study	218	174	40	1	2	1	0
11	House Regulators		Meter & Regul Study	489	389	91	3	5	1	1
12	General & Common Plant	107	Prod-Stor-Tran-Dis	20,359	13,686	4,459	290	216	303	1,404
13	Total CWIP	Sub-total		37,529	24,370	8,769	609	406	611	2,764
14	**Materials & Supplies**	154, 155, 156	Tran & Distrib	1,545	1,072	313	19	19	24	98
	Gas In Storage									
15	Total Gas in Storage	Sub-total	Sales, W/ Transp	13,844	4,445	2,708	324	865	1,149	4,353
16	**Non-Plant Assets & Liab**	Total	Labor	11,037	8,261	1,843	117	103	134	579
	Miscellaneous	**FERC Accounts**	**Allocator**							
17	Prepay: Insurance	165	Tran & Distrib	0	0	0	0	0	0	0
18	Prepay: Miscellaneous	165	Tran & Distrib	1,736	1,204	352	22	21	27	110
19	Fuel	176	Sales, W/o Transp	0	0	0	0	0	0	0
20	Total Miscellaneous	Sub-total		1,736	1,204	352	22	21	27	110
	Working Cash									
21	Total Working Cash	Sub-total	Modified O&M Expense	-11,908	-6,926	-3,600	-388	-781	-68	-144
22	**Total Additions**	Sub-total		**53,782**	**32,425**	**10,383**	**703**	**632**	**1,878**	**7,761**
23	**Total Rate Base**	Sub-Total		**1,468,059**	**961,595**	**331,918**	**22,440**	**16,108**	**24,329**	**111,669**
24	**Common Rate Base (@ 52.50%)**			**770,731**	**504,837**	**174,257**	**11,781**	**8,457**	**12,773**	**58,626**
25	Customer Component			646,413	569,836	71,734	1,076	2,135	375	1,256
26	Demand Component			814,896	391,155	259,801	21,307	13,820	22,815	105,997
27	Energy Component			6,750	604	382	57	152	1,139	4,415

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Operating Revenue (Cal Month)

	Retail Revenue	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1a	**Present Retail Rev**	480, 481, 482, 484	Direct Assign	**774,803**	**452,991**	**231,632**	**24,367**	**45,968**	**8,010**	**11,835**
1b	**Proposed Retail Rev**	480, 481, 482, 484	Direct Assign	**837,074**	**492,329**	**246,932**	**26,078**	**49,446**	**9,448**	**12,841**
2	**Retail Rev Increase**			**62,270**	**39,338**	**15,301**	**1,711**	**3,478**	**1,437**	**1,006**
	Other Operating Revenue									
3	Late Pay Penalties	488, 495	Late Pay; Mod Pres Rev	1,868	1,724	137	2	6	0	0
4	Connection Charges	488, 495	Customers	433	401	32	0	0	0	0
5	Return Check Charges	488, 495	Customers	62	58	5	0	0	0	0
6	Connect Smart	488, 495	Customers	1	1	0	0	0	0	0
7	Interchange Gas	488, 495	Design Day	430	220	147	12	0	3	47
8	Damage Claim	488, 495	Design Day	0	0	0	0	0	0	0
9	Ltd Firm Sales - Rsrvs & Vols	488, 495	Design Day	168	86	57	5	0	1	18
10	Distribution Other	488, 495	Customers	42	39	3	0	0	0	0
11	Miscellaneous Other	488, 495	1/2 Dsgn Day, 1/2 Ener	452	189	122	12	14	21	96
12	**Tot Other Oper Rev - Pres**	**Sub-total**		**3,457**	**2,717**	**503**	**30**	**20**	**25**	**162**
13	Incr Late Pay - Proposed		Late Pay; Mod Pres Rev	150	139	11	0	0	0	0
14	Incr Connection Charge Revenue - Proposed		Customers	981	908	72	0	0	0	0
15	**Tot Other Oper Rev - Prop**			**4,588**	**3,764**	**586**	**30**	**21**	**25**	**162**
16a	**Total Oper Rev - Present**	Total		**778,260**	**455,708**	**232,134**	**24,397**	**45,988**	**8,036**	**11,997**
16b	**Total Oper Rev - Proposed**	Total		**841,662**	**496,092**	**247,518**	**26,108**	**49,467**	**9,473**	**13,003**
17	**Operating Rev Increase**			**63,401**	**40,384**	**15,384**	**1,711**	**3,479**	**1,437**	**1,006**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
18	Commodity	728, 804, 805, 808, 858	Direct Assign	327,688	175,370	106,137	12,191	32,460	0	1,530
19	Demand	804, 808, 858	Direct Assign	107,266	64,439	38,797	3,893	0	0	136
20	Propane		Design Day	0	0	0	0	0	0	0
21	Limited Firm	728	Design Day	0	0	0	0	0	0	0
22	Total Purchases	Sub-total		434,954	239,809	144,934	16,084	32,460	0	1,667
	Other Production Expense									
23	Other Purchased Gas		Design Day	813	417	278	22	0	6	89
24	MN Gas MGP Clean Up		Sales, W/o Transp	1,061	563	343	41	109	0	5
25	Misc. LPG Op Exp	710, 733, 735, 736, 742, 759	Design Day	3,559	1,826	1,216	98	0	28	391
26	Misc. LNG Op Exp	840, 841, 842, 843	1/2 Dsgn Day, 1/2 Ener	2,388	996	642	61	75	109	507
27	Total Other Production Expense	Sub-total		7,822	3,801	2,479	222	184	143	992
28	Transmission - Average Capacity	850-865	Average and Peak	382	184	122	10	9	14	43
29	Transmission - Other	850-865	Other	0	0	0	0	0	0	0
30	**Transmission Expense**			382	184	122	10	9	14	43
	Distribution Expense									
31	Regulator Stations	875, 877, 889, 891	Average and Peak	654	315	209	17	15	23	74
32	Mains Direct Assignment	874, 887	Direct Assign	0	0	0	0	0	0	0
33	Mains	874, 887	Mains, Overall	18,496	12,112	4,073	298	265	400	1,348
34	Services	892	Service Study	6,024	5,192	803	9	18	2	0
35	Meters	878, 893	Meter & Regul Study	-5,444	-4,327	-1,008	-30	-60	-13	-6
36	House Regulators	878, 893	Meter & Regul Study	2,234	1,775	414	12	25	5	3
37	Rents	881	Customers	1,612	1,491	119	0	1	0	0
38	Dispatching	871	1/2 Dsgn Day, 1/2 Ener	2,763	1,152	742	70	86	126	586
39	Customer Installations	879	Customers	961	889	71	0	0	0	0
40	Other Distribution	880	Customers	14,127	13,073	1,042	4	6	1	0
41	Supervision & Engineering	870, 885	Dist Exp, w/o Sup & Eng	9,002	6,883	1,405	83	78	118	436
42	Total Distribution Expense	Sub-total		50,427	38,556	7,870	465	434	662	2,440

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Operation & Maintenance (Pg 2 of 2)

	Cust Acctg & Inform	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Acct Superv	901	Customers	30	28	2	0	0	0	0
2	Acct Meter Read	902	Customers	761	704	56	0	0	0	0
3	Acct Recrds & Coll	903	Record & Coll Study	7,511	6,674	487	123	198	22	8
4	Acct Uncollect	904	Uncollectibles Study	3,877	3,465	412	0	0	0	0
5	Acct Misc	905	Customers	76	71	6	0	0	0	0
6	Asst Expense (w/o CIP)	908	Cust Inform Study	-4,232	-3,119	-951	-58	-92	-10	-4
7	Tot Cust Acctg & Inform	Sub-total		8,023	7,823	12	66	106	12	4
	Admin & General									
8	Property Insurance	924	Net Plant	784	520	175	12	9	12	57
9	Pension & Benefit-Direct	926	Labor	9,653	7,225	1,612	102	90	117	507
10	Salaries	920	Labor	8,661	6,483	1,446	92	81	105	455
11	Office & Supplies	921	Labor	11,938	8,935	1,993	127	112	145	627
12	Admin Transfer Credit	922	Labor	-5,682	-4,253	-949	-60	-53	-69	-298
13	Outside Services	923	Labor	2,071	1,550	346	22	19	25	109
14	Incentive Compensation	920 + other	Labor	0	0	0	0	0	0	0
15	Injuries and Claims	925	1/2 Rt Base, 1/2 Pres Rev;	2,989	1,852	785	70	105	40	136
16	Regulatory Comm Exp	928	Pres Rev; Mod Pres Rev	936	547	280	29	56	10	14
17	Contributions	929	Pres Rev; Mod Pres Rev	0	0	0	0	0	0	0
18	General Advertising	930	1/2 Rt Base, 1/2 Pres Rev;	28	17	7	1	1	0	1
19	Misc General Exp	930	1/2 Rt Base, 1/2 Pres Rev;	191	118	50	4	7	3	9
20	Rents	931	1/2 Rt Base, 1/2 Pres Rev;	693	430	182	16	24	9	32
21	Maint of Gen Plt	935	1/2 Rt Base, 1/2 Pres Rev;	65	40	17	2	2	1	3
22	Total A & G Expense	Sub-total		32,326	23,464	5,943	416	452	399	1,650
	Amortizations									
23	CIP/DSM	CIP	Sales, W/o CIP Exempt	42,183	21,278	12,958	1,537	4,140	2,086	183
24	Amortizations		Labor	2,098	1,570	350	22	20	26	110
25	Instructional Advertising	407	Pres Rev; Mod Pres Rev	302	177	90	10	18	3	5
26	Total Amortizations	Sub-total		44,583	23,024	13,399	1,569	4,178	2,115	297
	Sales Expense									
27	Sales, Econ Dvlp & Other	912, 913	Sales, W/ Transp	58	19	11	1	4	5	18
28	Total Sales Econ Dvlp & Other	Sub-total		58	19	11	1	4	5	18
29	**Total O&M Expense**			**578,575**	**336,681**	**174,769**	**18,835**	**37,827**	**3,350**	**7,113**

Book Depreciation

		FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
30	**Production Plant (LPG)**	403	Design Day	7,849	4,026	2,682	216	0	62	862
31	**Storage Plant (LNG)**	403	Design Day	6,154	3,157	2,103	170	0	49	676
32	Transmission - Average Capacity	403	Average and Peak	2,520	1,214	805	67	59	90	285
33	Transmission - Direct Assign	403	Direct Assign	389	0	0	0	0	0	389
34	**Transmission Plant**	Sub-total		2,909	1,214	805	67	59	90	674
	Distribution Plant									
35	Regulator Stations	403	Average and Peak	0	0	0	0	0	0	0
36	Mains Direct Assignment	403	Direct Assign	112	0	0	0	0	0	112
37	Mains	403	Mains, Overall	28,077	18,385	6,183	453	403	607	2,046
38	Services	403	Service Study	14,820	12,774	1,975	22	43	4	1
39	Meters	403	Meter & Regul Study	4,933	3,920	914	27	54	12	6
40	House Regulators	403	Meter & Regul Study	1,070	851	198	6	12	3	1
41	Total Distribution Plant	Sub-total		49,011	35,931	9,270	508	512	626	2,165
42	**General & Common Plant**	403	Prod-Stor-Tran-Dis	23,175	15,580	5,076	330	246	345	1,598
43	**Common Plant**	403, 404	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
44	**Total Book Deprec**	Sub-total		**89,099**	**59,908**	**19,938**	**1,290**	**816**	**1,172**	**5,976**

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INCOME STATEMENT

	Real Estate & Prop Taxes	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	408	Design Day	3,308	1,697	1,131	91	0	26	363
2	**Storage Plant (LNG)**	408	Design Day	0.0	0	0	0	0	0	0
3	Transmission - Average Capacity	408	Average and Peak	1,743	840	557	46	41	62	197
4	Transmission - Direct Assign	408	Direct Assignment	287	0	0	0	0	0	287
5	**Transmission Plant**	408		2,029	840	557	46	41	62	484
	Distribution Plant									
6	Regulator Stations	408	Average and Peak	24,058	11,594	7,688	635	560	857	2,722
7	Mains Direct Assignment	408	Direct Assign	0	0	0	0	0	0	0
8	Mains	408	Mains, Overall	0	0	0	0	0	0	0
9	Services	408	Service Study	0	0	0	0	0	0	0
10	Meters	408	Meter & Regul Study	0	0	0	0	0	0	0
11	House Regulators	408	Meter & Regul Study	0	0	0	0	0	0	0
12	Total Distribution Plant	Sub-total		24,058	11,594	7,688	635	560	857	2,722
13	**General and Common Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Common Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
15	**Total Rl Est & Prop Tax**	Sub-total		**29,395**	**14,131**	**9,376**	**772**	**601**	**946**	**3,569**
16	Payroll Taxes	408	Labor	3,728	2,790	622	40	35	45	196
17	**Tot Non-Income Taxes**			**33,123**	**16,922**	**9,998**	**812**	**636**	**991**	**3,765**
	Provision-Defer Inc Tax	**FERC Accounts**	**Allocator**							
18	**Production Plant (LPG)**	410.1, 411.1	Design Day	14	7	5	0	0	0	2
19	**Storage Plant (LNG)**	410.1, 411.1	Design Day	1,375	705	470	38	0	11	151
20	Transmission - Average Capacity	410.1, 411.1	Average and Peak	1,354	653	433	36	32	48	153
21	Transmission - Direct Assign	410.1, 411.1	Direct Assign	76	0	0	0	0	0	76
22	**Transmission Plant**	Sub-total		1,430	653	433	36	32	48	229
	Distribution Plant									
23	Regulator Stations	410.1, 411.1	Average and Peak	1	1	0	0	0	0	0
24	Mains Direct Assignment	410.1, 411.1	Direct Assign	51	0	0	0	0	0	51
25	Mains	410.1, 411.1	Mains, Overall	-1,366	-895	-301	-22	-20	-30	-100
26	Services	410.1, 411.1	Service Study	843	726	112	1	2	0	0
27	Meters	410.1, 411.1	Meter & Regul Study	3,250	2,583	602	18	36	8	4
28	House Regulators	410.1, 411.1	Meter & Regul Study	902	717	167	5	10	2	1
29	Total Distribution Plant	Sub-total		3,680	3,132	581	2	28	-19	-44
30	**General and Common Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	1,763	1,185	386	25	19	26	122
31	**Common Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
32	Net Operating Loss (NOL) Carry Forward	410.1, 411.1	Net Plant	0	0	0	0	0	0	0
33	Non-Plant Related	410.1, 411.1	Labor	145	108	24	2	1	2	8
34	**Tot Prov Defer Inc Tax**	Total		**8,407**	**5,791**	**1,899**	**102**	**80**	**68**	**467**
	Investment Tax Credit	**FERC Accounts**	**Allocator**							
35	**Production Plant (LPG)**	420	Design Day	0	0	0	0	0	0	0
36	**Storage Plant (LNG)**	420	Design Day	0	0	0	0	0	0	0
37	Transmission - Average Capacity	420	Average and Peak	-5	-2	-1	0	0	0	-1
38	Transmission - Direct Assign	420	Direct Assign	0	0	0	0	0	0	0
39	**Transmission Plant**			-5	-2	-1	0	0	0	-1
	Distribution Plant									
40	Regulator Stations	420	Average and Peak	0	0	0	0	0	0	0
41	Mains Direct Assignment	420	Direct Assign	0	0	0	0	0	0	0
42	Mains	420	Mains, Overall	-92	-60	-20	-1	-1	-2	-7
43	Services	420	Service Study	0	0	0	0	0	0	0
44	Meters	420	Meter & Regul Study	0	0	0	0	0	0	0
45	House Regulators	420	Meter & Regul Study	0	0	0	0	0	0	0
46	Total Distribution Plant	Sub-total		-92	-60	-20	-1	-1	-2	-7
47	**General and Common Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
48	**Common Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
49	**Net Invest Tax Credit**	Sub-total		**-97**	**-63**	**-22**	**-2**	**-1**	**-2**	**-7**
50	**Total Operating Exp**	Sub-total		**709,107**	**419,238**	**206,582**	**21,037**	**39,358**	**5,579**	**17,313**
42a	**Pres Op Inc Before Inc Tax**	Total		**69,153**	**36,470**	**25,552**	**3,360**	**6,630**	**2,456**	**-5,316**
42b	**Prop Op Inc Before Inc Tax**	Total		**132,554**	**76,854**	**40,936**	**5,071**	**10,110**	**3,894**	**-4,310**

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INCOME STATEMENT

	Tax Deprec & Removal	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Not Applicable	Design Day	7,785	3,993	2,661	214	0	62	855
2	**Storage Plant (LNG)**	Not Applicable	Design Day	10,700	5,488	3,657	295	0	85	1,175
3	Transmission - Average Capacity	Not Applicable	Average and Peak	7,626	3,675	2,437	201	178	272	863
4	Transmission - Direct Assign	Not Applicable	Direct Assign	682	0	0	0	0	0	682
5	**Transmission Plant**	Not Applicable		8,308	3,675	2,437	201	178	272	1,544
	Distribution Plant									
6	Regulator Stations	Not Applicable	Average and Peak	0	0	0	0	0	0	0
7	Mains Direct Assignment	Not Applicable	Direct Assign	290	0	0	0	0	0	290
8	Mains	Not Applicable	Mains, Overall	31,875	20,872	7,020	514	457	690	2,322
9	Services	Not Applicable	Service Study	14,309	12,334	1,907	21	42	4	1
10	Meters	Not Applicable	Meter & Regul Study	16,526	13,135	3,061	90	182	40	19
11	House Regulators	Not Applicable	Meter & Regul Study	4,388	3,487	813	24	48	11	5
12	Total Distribution Plant	Sub-total		67,388	49,829	12,800	649	728	744	2,638
13	**General and Common Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Common Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
15	Net Operating Loss (NOL) Carry Forward	Not Applicable	Net Plant	33,126	21,964	7,386	492	366	522	2,396
16	**Total Tax Depreciation**	Total		**127,307**	**84,950**	**28,941**	**1,851**	**1,272**	**1,685**	**8,608**
	Present Return									
	Inc Tax Additions	**FERC Accounts**	**Allocator**							
17	Total Book Depr Exp	from another page		89,099	59,908	19,938	1,290	816	1,172	5,976
18	Provision for Deferred	from another page		8,407	5,791	1,899	102	80	68	467
19	Net Inv Tax Credit	from another page		-97	-63	-22	-2	-1	-2	-7
20	Avoided Tax Interest	Not Applicable	CWIP	1,044	678	244	17	11	17	77
21	Total Tax Additions	Sub-total		98,453	66,314	22,058	1,407	906	1,255	6,513
	Inc Tax Deductions									
22	Tax Depr & Removal Exp	from another page		127,307	84,950	28,941	1,851	1,272	1,685	8,608
23	Debt Interest Expense	Calculation	; Mod Rate Base	32,297	21,155	7,302	494	354	535	2,457
24	Other Timing Differences	Not Applicable	Labor	-3,396	-2,542	-567	-36	-32	-41	-178
25	Meals		Labor	177	132	29	2	2	2	9
26	Total Tax Deductions	Sub-total		156,385	103,695	35,706	2,311	1,596	2,181	10,896
26a	**Pres Taxable Net Income**	Calculation		**11,221**	**-912**	**11,904**	**2,457**	**5,940**	**1,531**	**-9,700**
26b	**Prop Taxable Net Income**			**74,622**	**39,473**	**27,288**	**4,168**	**9,419**	**2,968**	**-8,694**
27a	**Pres Inc Tax, @25.06%**	Calculation		**2,812**	**-228**	**2,983**	**616**	**1,489**	**384**	**-2,431**
27b	**Prop Inc Tax, @28.19%**			**21,035**	**11,127**	**7,692**	**1,175**	**2,655**	**837**	**-2,451**
28a	**Pres Preliminary Return**			66,341	36,699	22,569	2,744	5,142	2,073	-2,886
28b	**Prop Preliminary Return**			111,519	65,728	33,244	3,896	7,454	3,057	-1,860
29	**Total AFUDC**	Not Applicable	CWIP	**2,842**	**1,803**	**689**	**49**	**31**	**49**	**221**
30a	**Pres Total Return**	Total	; Mod Rate Base	**69,183**	**38,501**	**23,258**	**2,794**	**5,173**	**2,121**	**-2,664**
30b	**Prop Total Return**		; Mod Rate Base	**114,362**	**67,530**	**33,933**	**3,945**	**7,486**	**3,106**	**-1,639**
31a	**Pres % Return on Rate Base**	Calculation		**4.71%**	**4.00%**	**7.01%**	**12.45%**	**32.12%**	**8.72%**	**-2.39%**
31b	**Prop % Return on Rate Base**			**7.79%**	**7.02%**	**10.22%**	**17.58%**	**46.47%**	**12.76%**	**-1.47%**
32a	**Pres Common Return**			**36,886**	**17,346**	**15,956**	**2,300**	**4,819**	**1,586**	**(5,121)**
32b	**Prop Common Return**			**82,064**	**46,375**	**26,631**	**3,452**	**7,131**	**2,570**	**(4,095)**
33a	**Pres % Ret on Common Rt Bs**			**4.79%**	**3.44%**	**9.16%**	**19.52%**	**56.98%**	**12.42%**	**-8.73%**
33b	**Prop % Ret on Common Rt Bs**			**10.65%**	**9.19%**	**15.28%**	**29.30%**	**84.33%**	**20.12%**	**-6.99%**
	AFUDC									
34	Production Plant (LPG)		Design Day	39	20	13	1	0	0	4
35	Storage Plant (LNG)		Design Day	361	185	123	10	0	3	40
36	Transmission - Average Capacity	Not Applicable	Average and Peak	175	85	56	5	4	6	20
37	Transmission - Direct Assign	Not Applicable	Direct Assign	0	0	0	0	0	0	0
38	Transmission Plant		Average and Peak	175	85	56	5	4	6	20
	Distribution:									
39	Regulator Stations		Average and Peak	0	0	0	0	0	0	0
40	Mains Direct Assignment		Direct Assign	0	0	0	0	0	0	0
41	Mains		Mains Overall	857	561	189	14	12	19	62
42	Services		Service Study	2	2	0	0	0	0	0
43	Meters		Meter & Regul Study	0	0	0	0	0	0	0
44	House Regulators		Meter & Regul Study	30	23	5	0	0	0	0
45	Total Distribution			889	587	195	14	13	19	62
46	General Plant		Prod-Stor-Tran-Dis	1,378	926	302	20	15	21	95
47	Gas Common		Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
48	Total AFUDC			2,842	1,803	689	49	31	49	221
	Labor Allocator	**FERC Accounts**	**Allocator**							
49	Customer Accounting	Labor Portion of O&M Accounts	Customers	3,750	3,471	277	1	2	0	0
50	Cust Serv & Inform	Labor Portion of O&M Accounts	Customers	746	690	55	0	0	0	0
51	Distribution	Labor Portion of O&M Accounts	Dist Exp, w/o Sup & Eng	28,995	22,169	4,525	268	250	381	1,403
52	Admin & General	Labor Portion of O&M Accounts	Labor w/o A&G	18,557	13,889	3,098	197	173	226	974
53	Production	Labor Portion of O&M Accounts	Other Production Exp	4,521	2,197	1,433	129	106	83	573
54	Sales	Labor Portion of O&M Accounts	Sales, W/ Transp	0	0	0	0	0	0	0
55	Transmission	Labor Portion of O&M Accounts	Design Day	324	166	111	9	0	3	36
56	Total			56,894	42,583	9,498	603	532	692	2,986

Class Cost of Service Study ($000); Test Year 2026

ALLOCATORS

	Internal Allocators	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**41.70%**	**26.87%**	**2.55%**	**3.12%**	**4.55%**	**21.21%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**61.98%**	**26.25%**	**2.34%**	**3.52%**	**1.35%**	**4.57%**
3	Average and Peak (Mains)	721,700	347,820	230,637	19,057	16,809	25,724	81,653
4	Average and Peak	**100.00%**	**48.19%**	**31.96%**	**2.64%**	**2.33%**	**3.56%**	**11.31%**
5	CWIP	**100.00%**	**64.94%**	**23.37%**	**1.62%**	**1.08%**	**1.63%**	**7.36%**
6	Dist Exp, w/o Sup & Eng	41,426	31,673	6,465	382	357	544	2,005
7	Dist Exp, w/o Sup & Eng	**100.00%**	**76.46%**	**15.61%**	**0.92%**	**0.86%**	**1.31%**	**4.84%**
8	Distribution Plant	**100.00%**	**71.86%**	**19.62%**	**1.15%**	**1.13%**	**1.45%**	**4.79%**
9	Gas Plant In Service	**100.00%**	**67.23%**	**21.90%**	**1.42%**	**1.06%**	**1.49%**	**6.90%**
10	Labor	**100.00%**	**74.85%**	**16.69%**	**1.06%**	**0.93%**	**1.22%**	**5.25%**
11	Mains, Overall	**100.00%**	**65.48%**	**22.02%**	**1.61%**	**1.43%**	**2.16%**	**7.29%**
12	Modified O&M Expense	573,372	333,500	173,359	18,703	37,614	3,284	6,913
13	Modified O&M Expense	**100.00%**	**58.16%**	**30.23%**	**3.26%**	**6.56%**	**0.57%**	**1.21%**
14	Net Plant	**100.00%**	**66.31%**	**22.30%**	**1.48%**	**1.10%**	**1.57%**	**7.23%**
15	Other Production Exp	**100.00%**	**48.60%**	**31.69%**	**2.84%**	**2.35%**	**1.83%**	**12.68%**
16	Prod-Stor-Tran-Dis	2,247,306	1,510,794	492,252	31,975	23,837	33,472	154,978
17	Prod-Stor-Tran-Dis	**100.00%**	**67.23%**	**21.90%**	**1.42%**	**1.06%**	**1.49%**	**6.90%**
18	Rate Base	**100.00%**	**65.50%**	**22.61%**	**1.53%**	**1.10%**	**1.66%**	**7.61%**
19	Rt Base, w/o Work Cash	1,479,967	968,521	335,519	22,828	16,889	24,397	111,812
20	Rt Base, w/o Work Cash	**100.00%**	**65.44%**	**22.67%**	**1.54%**	**1.14%**	**1.65%**	**7.56%**
21	Transmission & Distribution	1,981,469	1,374,444	401,398	24,653	23,837	31,357	125,780
22	Tran & Distrib	**100.00%**	**69.36%**	**20.26%**	**1.24%**	**1.20%**	**1.58%**	**6.35%**
23	Labor w/o A&G	38,337	28,694	6,400	406	358	466	2,012
24	Labor w/o A&G	**100.00%**	**74.85%**	**16.69%**	**1.06%**	**0.93%**	**1.22%**	**5.25%**
	Component Allocators							
25	Mod Present Rev	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
26	Mod Rate Base	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
27	1/2 Mod Rt Bs, 1/2 Mod Pres Rv	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**

Class Cost of Service Study ($000); Test Year 2026

External Allocators

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
	Customer-Related							
1	Bills	5,974,093	5,528,561	440,692	1,704	2,728	300	108
2	Modified Bills	5,974,069	5,528,561	440,692	1,704	2,728	300	84
3	Meter & Regul Weightings		1.00					
4	Meter (Wtd Bills)	6,955,962	5,528,561	1,288,305	37,711	76,401	16,914	8,070
5	Service Weightings		1.00					
6	Service (Wtd Bills)	6,413,659	5,528,561	854,734	9,551	18,689	1,668	456
7	Records & Collect Weightings		1.00					
8	Records & Collect (Wtd Bills)	6,222,041	5,528,561	403,080	102,240	163,680	18,000	6,480
9	Cust Information Weightings		1.00					
10	Cust Information (Wtd Bills)	7,502,193	5,528,561	1,685,392	102,240	162,600	16,920	6,480
11								
12	Premises	443,608	412,995	30,183	141	252	28	9
13	Customers	100.00%	92.54%	7.38%	0.03%	0.05%	0.01%	0.00%
14	Modified Customers	100.00%	92.54%	7.38%	0.03%	0.05%	0.01%	0.00%
15	Meter & Regul Study	100.00%	79.48%	18.52%	0.54%	1.10%	0.24%	0.12%
16	Service Study	100.00%	86.20%	13.33%	0.15%	0.29%	0.03%	0.01%
17	Record & Coll Study	100.00%	88.85%	6.48%	1.64%	2.63%	0.29%	0.10%
18	Cust Inform Study	100.00%	73.69%	22.47%	1.36%	2.17%	0.23%	0.09%
19	Premise Count	100.00%	93.10%	6.80%	0.03%	0.06%	0.01%	0.00%
	Energy-Related							
20	Cal Yr Sales Dkt, W/o Trans	74,351,221	39,424,795	24,016,129	2,875,341	7,671,802	0	363,155
21	Transportation Dkt	48,441,146	0	0	0	0	10,190,089	38,251,057
22	Cal Yr Sales Dkt, W/ Trans	122,792,367	39,424,795	24,016,129	2,875,341	7,671,802	10,190,089	38,614,211
23	CIP Exempt Dkt	44,633,482	0	6,040	26,741	0	6,324,935	38,275,766
24	Sales Dkt, W/o CIP Exempt	78,158,885	39,424,795	24,010,089	2,848,600	7,671,802	3,865,154	338,446
25	Sales, W/o Transp	100.00%	53.03%	32.30%	3.87%	10.32%	0.00%	0.49%
26	Sales, W/ Transp	100.00%	32.11%	19.56%	2.34%	6.25%	8.30%	31.45%
27	Sales, W/o CIP Exempt	100.00%	50.44%	30.72%	3.64%	9.82%	4.95%	0.43%
28	Modified Sales W/Transport	100.00%	36.86%	22.46%	2.69%	7.17%	9.53%	21.29%
	Demand-Related							
29	Design Day Demand (Retail)	1,036,133	531,440	354,112	28,540	0	8,241	113,800
30	Avg Daily Firm Dkt, W/ Trans	289,311	108,013	65,798	7,878	0	2,738	104,884
31	Design Day	100.00%	51.29%	34.18%	2.75%	0.00%	0.80%	10.98%
32	Excess Design Day	100.00%	53.64%	36.53%	2.62%	0.00%	0.70%	6.52%
	Miscellaneous (only alloc to class, not component)							
33	Present Retail Revenue	774,803	452,991	231,632	24,367	45,968	8,010	11,835
34	Uncollectibles Study	100.00%	89.38%	10.62%	0.00%	0.00%	0.00%	0.00%
35	Present Retail Revenue	100.00%	58.47%	29.90%	3.14%	5.93%	1.03%	1.53%
36	Late Payment Penalty	100.00%	92.27%	7.34%	0.09%	0.30%	0.00%	0.00%

Class Cost of Service Study ($000); Test Year 2026

Capital Structure		Rate	Ratio	Wtd Cost
37	Long Term Debt	4.64%	47.08%	2.18%
38	Short Term Debt	4.56%	0.42%	0.02%
39	Debt Total	4.63%	47.50%	2.20%
40	Preferred Stock	0.00%	0.00%	0.00%
41	Common Equity	10.65%	52.50%	5.59%
42	Required Rate of Return		100.00%	7.79%

Class Cost of Service Study ($000); Test Year 2026

SUMMARY

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
Rate Base								
1	Production	131,882	67,643	45,072	3,633	0	1,049	14,485
2	Storage	133,956	68,707	45,781	3,690	0	1,065	14,713
3	Transmission	162,341	67,189	44,552	3,681	3,247	4,969	38,703
4	Distribution	1,819,128	1,226,316	402,933	25,572	24,572	32,671	107,063
5	General	320,811	204,117	76,850	5,221	3,971	5,675	24,977
6	Common	0	0	0	0	0	0	0
7	**Total Plant In Service**	**2,568,117**	**1,633,972**	**615,189**	**41,797**	**31,791**	**45,429**	**199,939**
8	Production	31,383	16,096	10,726	864	0	250	3,447
9	Storage	53,282	27,329	18,210	1,468	0	424	5,852
10	Transmission	37,298	14,875	9,864	815	719	1,100	9,926
11	Distribution	613,499	428,144	129,051	7,619	7,492	9,565	31,628
12	General	137,405	87,424	32,915	2,236	1,701	2,431	10,698
13	Common	0	0	0	0	0	0	0
14	**Total Depreciation Reserve**	**872,867**	**573,869**	**200,765**	**13,002**	**9,912**	**13,769**	**61,550**
15	**Net Plant**	**1,695,250**	**1,060,104**	**414,424**	**28,795**	**21,878**	**31,660**	**138,389**
16	**Deductions** (Accum Def Inc Tax)	**280,973**	**184,125**	**62,600**	**4,034**	**3,785**	**5,080**	**21,348**
17	**Additions**	**53,782**	**30,597**	**11,423**	**807**	**722**	**2,019**	**8,213**
18	**Rate Base**	**1,468,059**	**906,576**	**363,247**	**25,567**	**18,815**	**28,600**	**125,254**
Income Statement		**Minn**	**Res**	**Com**	**Demand**	**Interrupt**	**Tran**	**Gener**
19	**Present Retail Revenue**	**774,803**	**452,991**	**231,632**	**24,367**	**45,968**	**8,010**	**11,835**
20	**Present Other Oper Rev**	**3,457**	**2,717**	**503**	**30**	**20**	**25**	**162**
21	**Present Total Operating Rev**	**778,260**	**455,708**	**232,134**	**24,397**	**45,988**	**8,036**	**11,997**
	Operating & Maint Expenses							
22	Purchased Gas Expense	434,954	239,809	144,934	16,084	32,460	0	1,667
23	Other Purch Gas Exp	0	0	0	0	0	0	0
24	Other Production	7,822	3,801	2,479	222	184	143	992
25	Transmission	382	184	122	10	9	14	43
26	Distribution	50,427	37,025	8,741	552	510	781	2,818
27	Customer Accounting	12,256	10,942	963	124	198	22	8
28	Customer Service and Information	-4,232	-3,119	-951	-58	-92	-10	-4
29	Administrative and General	32,326	22,749	6,350	457	488	455	1,827
30	Amortizations; Sales Expense	44,641	22,995	13,438	1,573	4,184	2,123	328
31	**Total Operating & Maint Exp**	**578,575**	**334,387**	**176,076**	**18,965**	**37,940**	**3,528**	**7,679**
32	Book Depreciation	89,099	57,164	21,500	1,445	951	1,385	6,653
33	Taxes Other Than Income Taxes	33,123	16,836	10,047	817	640	998	3,786
34	Prov For Deferred Inc Taxes	8,407	5,817	1,884	101	79	66	460
35	Net Investment Tax Credit	-97	-57	-25	-2	-2	-3	-9
36	**Total Operating Expense**	**709,107**	**414,147**	**209,481**	**21,326**	**39,608**	**5,974**	**18,570**
37	State and Federal Income Taxes	2,812	1,499	2,000	517	1,404	250	-2,857
38	**Total Expense**	**711,919**	**415,646**	**211,481**	**21,844**	**41,012**	**6,224**	**15,713**
39	AFUDC (Rev Credit)	2,842	1,695	751	55	37	57	248
40	**Total Operating Income**	**69,183**	**41,757**	**21,404**	**2,609**	**5,013**	**1,869**	**-3,468**
41	**Rate Base**	**1,468,059**	**906,576**	**363,247**	**25,567**	**18,815**	**28,600**	**125,254**
42	**Present Return on Rate Base**	**4.71%**	**4.61%**	**5.89%**	**10.20%**	**26.64%**	**6.53%**	**-2.77%**
43	**Present Return on Common Equity**	**4.79%**	**4.58%**	**7.03%**	**15.24%**	**46.56%**	**8.25%**	**-9.46%**
44	**Required Return on Rate Base**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**	**7.79%**
45	**Required Operating Income**	**114,362**	**70,622**	**28,297**	**1,992**	**1,466**	**2,228**	**9,757**
46	**Income Deficiency**	**45,179**	**28,865**	**6,893**	**-617**	**-3,547**	**359**	**13,226**
47	**Revenue Deficiency**	**63,401**	**40,799**	**9,712**	**-803**	**-4,765**	**536**	**17,923**
48	**Deficiency / Pres Retail Revenue**	**8.18%**	**9.01%**	**4.19%**	**-3.30%**	**-10.37%**	**6.69%**	**151.44%**

Class Cost of Service Study ($000); Test Year 2026

SUMMARY

Equal Return vs Present

	Operating Revenue Requirement	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Return On Rate Base	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
2	Equalized Total Retail Rev	838,205	493,789	241,343	23,564	41,203	8,546	29,759
3	Present Total Retail Revenue	774,803	452,991	231,632	24,367	45,968	8,010	11,835
4	Revenue Deficiency	63,401	40,799	9,712	-803	-4,765	536	17,923
5	Deficiency / Pres Total Retail Rev	8.18%	9.01%	4.19%	-3.30%	-10.37%	6.69%	151.44%
	Internal Retail Revenue Reqt							
6	Customer Retail Revenue Requirement	145,373	129,521	14,894	244	457	65	193
7	Average Monthly Customers	497,841	460,713	36,724	142	227	25	9
8	Revenue Requirement $ / Mo / Cust	24.33	23.43	33.80	143.03	167.40	216.34	1,788.42
9	Capacity Retail Revenue Requirement	216,263	104,299	69,410	5,804	4,451	6,328	25,971
10	Annual Dkt Sales	122,792,367	39,424,795	24,016,129	2,875,341	7,671,802	10,190,089	38,614,211
11	Revenue Requirement $ / Dkt	1.76	2.65	2.89	2.02	0.58	0.62	0.67
	Capacity - Sub Classification							
12	Capacity - Base Revenue Requirement	51,204	18,481	11,306	1,356	3,655	4,790	11,616
13	Capacity - Seasonal Revenue Requirement	106,356	55,936	38,218	2,747	0	730	8,726
14	Peak Shaving Revenue Requirement	58,703	29,882	19,886	1,701	797	808	5,628
15	Base Rev Requirement $ / Dkt	0.42	0.47	0.47	0.47	0.48	0.47	0.30
16	Seasonal Rev Requirement $ / Dkt	0.87	1.42	1.59	0.96	0.00	0.07	0.23
17	Peak Shave Rev Requirement $ / Dkt	0.48	0.76	0.83	0.59	0.10	0.08	0.15
18	Energy Retail Revenue Requirement	40,484	19,114	12,022	1,431	3,834	2,154	1,928
19	Revenue Requirement $ / Dkt	0.33	0.48	0.50	0.50	0.50	0.21	0.05
20	Total Internal Retail Revenue Requirement	402,120	252,934	96,326	7,479	8,742	8,546	28,092
21	Revenue Requirement $ / Dkt	3.27	6.42	4.01	2.60	1.14	0.84	0.73
22	Revenue Requirement $ / Mo / Cust	67.31	45.75	218.58	4,389.26	3,204.72	28,487.65	260,109.22
	External Retail Revenue Reqt							
23	Capacity Revenue Requirement	107,266	64,439	38,797	3,893	0	0	136
24	Energy Revenue Requirement	327,688	175,370	106,137	12,191	32,460	0	1,530
25	Total External Revenue Requirement	434,954	239,809	144,934	16,084	32,460	0	1,667
26	Cap Revenue Requirement $ / Dkt	0.87	1.63	1.62	1.35	0.00	0.00	0.00
27	Ener Revenue Requirement $ / Dkt	2.67	4.45	4.42	4.24	4.23	0.00	0.04
28	Tot Revenue Requirement $ / Dkt	3.54	6.08	6.03	5.59	4.23	0.00	0.04
	Total Retail Revenue Reqt							
29	Customer Revenue Requirement	145,373	129,521	14,894	244	457	65	193
30	Capacity Revenue Requirement	323,529	168,738	108,207	9,697	4,451	6,328	26,107
31	Energy Revenue Requirement	368,172	194,484	118,159	13,623	36,294	2,154	3,458
32	Total Revenue Requirement	837,074	492,743	241,260	23,564	41,202	8,546	29,759
33	Customer Revenue Reqt $ / Dkt	1.18	3.29	0.62	0.08	0.06	0.01	0.01
34	Demand Revenue Reqt $ / Dkt	2.63	4.28	4.51	3.37	0.58	0.62	0.68
35	Energy Revenue Reqt $ / Dkt	3.00	4.93	4.92	4.74	4.73	0.21	0.09
36	Total Revenue Reqt $ / Dkt	6.82	12.50	10.05	8.20	5.37	0.84	0.77

Proposed Return vs Present

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
37	Proposed Total Retail Revenue	838,205	493,375	247,016	26,078	49,447	9,448	12,841
38	Revenue Deficiency	63,401	40,384	15,384	1,711	3,479	1,437	1,006
39	Deficiency / Pres Total Oper Revenue	8.18%	8.91%	6.64%	7.02%	7.57%	17.94%	8.50%

Proposed Return vs Equal

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
40	Revenue Difference	0.0	-414	5,672	2,514	8,244	901	-16,918
41	Difference / Tot Equal Revenue"	0.00%	-0.08%	2.35%	10.67%	20.01%	10.55%	-56.85%

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	Plant in Service	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	304, 305, 311	Design Day	131,882	67,643	45,072	3,633	0	1,049	14,485
2	**Storage Plant (LNG)**	360, 361, 362, 363	Design Day	133,956	68,707	45,781	3,690	0	1,065	14,713
3	Transmission - Average Capacity	365, 366, 367, 368, 369, 370, 371	Average and Peak	139,411	67,189	44,552	3,681	3,247	4,969	15,773
4	Transmission - Direct Assign	365, 366, 367, 368, 369, 370, 371	Direct Assign	22,929	0	0	0	0	0	22,929
5	**Transmission Plant**	Sub-total		162,341	67,189	44,552	3,681	3,247	4,969	38,703
	Distribution Plant									
6	Regulator Stations	374, 375, 378, 379	Average and Peak	605	292	193	16	14	22	68
7	Mains - Direct Assignment	376	Direct Assign	5,076	0	0	0	0	0	5,076
8	Mains - Minimum System	376	Modified Customers	287,071	265,663	21,177	82	131	14	4
9	Mains - Average Capacity	Split of 376	Modified Sales W/Transport	291,694	107,526	65,501	7,842	20,924	27,792	62,109
10	Mains - Excess Capacity	Split of 376	Excess Design Day	606,695	325,449	221,601	15,881	0	4,229	39,535
11	Mains - Total	376		1,190,536	698,638	308,278	23,805	21,055	32,036	106,724
12	Services	380	Service Study	420,612	362,567	56,054	626	1,226	109	30
13	Meters	381	Meter & Regul Study	167,599	133,207	31,041	909	1,841	408	194
14	House Regulators	383	Meter & Regul Study	39,775	31,613	7,367	216	437	97	46
15	Total Distribution Plant	Sub-total		1,819,128	1,226,316	402,933	25,572	24,572	32,671	107,063
16	**General Plant**	390-399	Prod-Stor-Tran-Dis	320,811	204,117	76,850	5,221	3,971	5,675	24,977
17	**Common Plant**	390-399	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
18	**Gas Plant in Service**	Total		**2,568,117**	**1,633,972**	**615,189**	**41,797**	**31,791**	**45,429**	**199,939**
	Accum Depr Reserve	**FERC Accounts**	**Allocator**							
19	**Production Plant (LPG)**	108(1)	Design Day	31,383	16,096	10,726	864	0	250	3,447
20	**Storage Plant (LNG)**	108(5)	Design Day	53,282	27,329	18,210	1,468	0	424	5,852
21	Transmission - Average Capacity	108(7)	Average and Peak	30,865	14,875	9,864	815	719	1,100	3,492
22	Transmission - Direct Assign	108(7)	Direct Assign	6,434	0	0	0	0	0	6,434
23	**Transmission Plant**	Sub-total		37,298	14,875	9,864	815	719	1,100	9,926
	Distribution Plant									
24	Regulator Stations	108(8)	Average and Peak	0	0	0	0	0	0	0
25	Mains Direct Assignment	108(8)	Direct Assign	415	0	0	0	0	0	415
26	Mains	108(8)	Mains, Overall	347,103	203,689	89,879	6,940	6,139	9,340	31,116
27	Services	108(8)	Service Study	194,255	167,447	25,888	289	566	51	14
28	Meters	108(8)	Meter & Regul Study	64,296	51,102	11,908	349	706	156	75
29	House Regulators	108(8)	Meter & Regul Study	7,430	5,905	1,376	40	82	18	9
30	Total Distribution Plant	Sub-total		613,499	428,144	129,051	7,619	7,492	9,565	31,628
31	**General Plant**	108(9)	Prod-Stor-Tran-Dis	137,405	87,424	32,915	2,236	1,701	2,431	10,698
32	**Common Plant**	108(9)	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
33	**Total Accum Depr**	Sub-total		**872,867**	**573,869**	**200,765**	**13,002**	**9,912**	**13,769**	**61,550**
34	**Net Plant**	Total		**1,695,250**	**1,060,104**	**414,424**	**28,795**	**21,878**	**31,660**	**138,389**
	Subtractions to Net Plant									
	Accum Deferred Inc Tax	**FERC Accounts**	**Allocator**							
35	**Production Plant (LPG)**	190, 281, 282, 283 Net	Design Day	-2,164	-1,110	-739	-60	0	-17	-238
36	**Storage Plant (LNG)**	190, 281, 282, 283 Net	Design Day	2,273	1,166	777	63	0	18	250
37	Transmission - Average Capacity	190, 281, 282, 283 Net	Average and Peak	18,056	8,702	5,770	477	421	644	2,043
38	Transmission - Direct Assign	190, 281, 282, 283 Net	Direct Assign	4,029	0	0	0	0	0	4,029
39	**Transmission Plant**	Sub-total		22,085	8,702	5,770	477	421	644	6,072
	Distribution Plant									
40	Regulator Stations	190, 281, 282, 283 Net	Average and Peak	14	7	5	0	0	1	2
41	Mains Direct Assignment	190, 281, 282, 283 Net	Direct Assign	246	0	0	0	0	0	246
42	Mains	190, 281, 282, 283 Net	Mains, Overall	144,562	84,833	37,433	2,891	2,557	3,890	12,959
43	Services	190, 281, 282, 283 Net	Service Study	59,108	50,951	7,877	88	172	15	4
44	Meters	190, 281, 282, 283 Net	Meter & Regul Study	23,745	18,873	4,398	129	261	58	28
45	House Regulators	190, 281, 282, 283 Net	Meter & Regul Study	4,662	3,705	863	25	51	11	5
46	Total Distribution Plant	Sub-total		232,339	158,369	50,576	3,133	3,041	3,975	13,244
47	**General Plant**	190, 281, 282, 283 Net	Prod-Stor-Tran-Dis	24,474	15,572	5,863	398	303	433	1,905
48	**Common Plant**	Sub-total	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
49	Net Operating Loss (NOL) Carry Forward	283	Net Plant	0	0	0	0	0	0	0
50	Non-Plant Related	190 & 282 Net	Labor	1,966	1,426	354	23	21	27	114
51	**Total Subtractions**	Total		**280,973**	**184,125**	**62,600**	**4,034**	**3,785**	**5,080**	**21,348**

Class Cost of Service Study ($000); Test Year 2026

RATE BASE

Additions to Net Plant

	CWIP	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Production Plant (LPG)		Design Day	257	132	88	7	0	2	28
2	Storage Plant (LNG)		Design Day	3,786	1,942	1,294	104	0	30	416
3	Transmission - Average Capacity	107	Average and Peak	958	462	306	25	22	34	108
4	Transmission - Direct Assign	107	Direct Assignment	0	0	0	0	0	0	0
5	Transmission Plant			958	462	306	25	22	34	108
6	Regulator Stations	107	Average and Peak	0	0	0	0	0	0	0
7	Mains Direct Assignment	107	Direct Assign	0	0	0	0	0	0	0
8	Mains	107	Mains Overall	11,072	6,498	2,867	221	196	298	993
9	Services		Service Study	389	336	52	1	1	0	0
10	Meters		Meter & Regul Study	218	174	40	1	2	1	0
11	House Regulators		Meter & Regul Study	489	389	91	3	5	1	1
12	General & Common Plant	107	Prod-Stor-Tran-Dis	20,359	12,953	4,877	331	252	360	1,585
13	Total CWIP	Sub-total		37,529	22,884	9,615	694	479	726	3,131
14	**Materials & Supplies**	154, 155, 156	Tran & Distrib	1,545	1,008	349	23	22	29	114
	Gas In Storage									
15	Total Gas in Storage	Sub-total	Sales, W/ Transp	13,844	4,445	2,708	324	865	1,149	4,353
16	**Non-Plant Assets & Liab**	Total	Labor	11,037	8,007	1,987	131	116	154	642
	Miscellaneous	**FERC Accounts**	**Allocator**							
17	Prepay: Insurance	165	Tran & Distrib	0	0	0	0	0	0	0
18	Prepay: Miscellaneous	165	Tran & Distrib	1,736	1,133	392	26	24	33	128
19	Fuel	176	Sales, W/o Transp	0	0	0	0	0	0	0
20	Total Miscellaneous	Sub-total		1,736	1,133	392	26	24	33	128
	Working Cash									
21	Total Working Cash	Sub-total	Modified O&M Expense	-11,908	-6,880	-3,627	-391	-783	-72	-155
22	**Total Additions**	Sub-total		**53,782**	**30,597**	**11,423**	**807**	**722**	**2,019**	**8,213**
23	**Total Rate Base**	Sub-Total		**1,468,059**	**906,576**	**363,247**	**25,567**	**18,815**	**28,600**	**125,254**
24	**Common Rate Base (@ 52.50%)**			**770,731**	**475,952**	**190,704**	**13,423**	**9,878**	**15,015**	**65,758**
25	Customer Component			525,892	456,933	64,680	1,032	2,045	365	837
26	Demand Component			935,418	449,040	298,184	24,479	16,618	27,096	120,002
27	Energy Component			6,750	604	382	57	152	1,139	4,415

Class Cost of Service Study ($000); Test Year 2026

INCOME STATEMENT

Operating Revenue (Cal Month)

	Retail Revenue	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1a	**Present Retail Rev**	480, 481, 482, 484	Direct Assign	**774,803**	**452,991**	**231,632**	**24,367**	**45,968**	**8,010**	**11,835**
1b	**Proposed Retail Rev**	480, 481, 482, 484	Direct Assign	**837,074**	**492,329**	**246,932**	**26,078**	**49,446**	**9,448**	**12,841**
2	**Retail Rev Increase**			**62,270**	**39,338**	**15,301**	**1,711**	**3,478**	**1,437**	**1,006**
	Other Operating Revenue									
3	Late Pay Penalties	488, 495	Late Pay; Mod Pres Rev	1,868	1,724	137	2	6	0	0
4	Connection Charges	488, 495	Customers	433	401	32	0	0	0	0
5	Return Check Charges	488, 495	Customers	62	58	5	0	0	0	0
6	Connect Smart	488, 495	Customers	1	1	0	0	0	0	0
7	Interchange Gas	488, 495	Design Day	430	220	147	12	0	3	47
8	Damage Claim	488, 495	Design Day	0	0	0	0	0	0	0
9	Ltd Firm Sales - Rsrvs & Vols	488, 495	Design Day	168	86	57	5	0	1	18
10	Distribution Other	488, 495	Customers	42	39	3	0	0	0	0
11	Miscellaneous Other	488, 495	1/2 Dsgn Day, 1/2 Ener	452	189	122	12	14	21	96
12	**Tot Other Oper Rev - Pres**	**Sub-total**		**3,457**	**2,717**	**503**	**30**	**20**	**25**	**162**
13	Incr Late Pay - Proposed		Late Pay; Mod Pres Rev	150	139	11	0	0	0	0
14	Incr Connection Charge Revenue - Proposed		Customers	981	908	72	0	0	0	0
15	**Tot Other Oper Rev - Prop**			**4,588**	**3,764**	**586**	**30**	**21**	**25**	**162**
16a	**Total Oper Rev - Present**	Total		**778,260**	**455,708**	**232,134**	**24,397**	**45,988**	**8,036**	**11,997**
16b	**Total Oper Rev - Proposed**	Total		**841,662**	**496,092**	**247,518**	**26,108**	**49,467**	**9,473**	**13,003**
17	**Operating Rev Increase**			**63,401**	**40,384**	**15,384**	**1,711**	**3,479**	**1,437**	**1,006**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
18	Commodity	728, 804, 805, 808, 858	Direct Assign	327,688	175,370	106,137	12,191	32,460	0	1,530
19	Demand	804, 808, 858	Direct Assign	107,266	64,439	38,797	3,893	0	0	136
20	Propane		Design Day	0	0	0	0	0	0	0
21	Limited Firm	728	Design Day	0	0	0	0	0	0	0
22	Total Purchases	Sub-total		434,954	239,809	144,934	16,084	32,460	0	1,667
	Other Production Expense									
23	Other Purchased Gas		Design Day	813	417	278	22	0	6	89
24	MN Gas MGP Clean Up		Sales, W/o Transp	1,061	563	343	41	109	0	5
25	Misc. LPG Op Exp	710, 733, 735, 736, 742, 759	Design Day	3,559	1,826	1,216	98	0	28	391
26	Misc. LNG Op Exp	840, 841, 842, 843	1/2 Dsgn Day, 1/2 Ener	2,388	996	642	61	75	109	507
27	Total Other Production Expense	Sub-total		7,822	3,801	2,479	222	184	143	992
28	Transmission - Average Capacity	850-865	Average and Peak	382	184	122	10	9	14	43
29	Transmission - Other	850-865	Other	0	0	0	0	0	0	0
30	**Transmission Expense**			382	184	122	10	9	14	43
	Distribution Expense									
31	Regulator Stations	875, 877, 889, 891	Average and Peak	654	315	209	17	15	23	74
32	Mains Direct Assignment	874, 887	Direct Assign	0	0	0	0	0	0	0
33	Mains	874, 887	Mains, Overall	18,496	10,854	4,789	370	327	498	1,658
34	Services	892	Service Study	6,024	5,192	803	9	18	2	0
35	Meters	878, 893	Meter & Regul Study	-5,444	-4,327	-1,008	-30	-60	-13	-6
36	House Regulators	878, 893	Meter & Regul Study	2,234	1,775	414	12	25	5	3
37	Rents	881	Customers	1,612	1,491	119	0	1	0	0
38	Dispatching	871	1/2 Dsgn Day, 1/2 Ener	2,763	1,152	742	70	86	126	586
39	Customer Installations	879	Customers	961	889	71	0	0	0	0
40	Other Distribution	880	Customers	14,127	13,073	1,042	4	6	1	0
41	Supervision & Engineering	870, 885	Dist Exp, w/o Sup & Eng	9,002	6,609	1,560	99	91	139	503
42	Total Distribution Expense	Sub-total		50,427	37,025	8,741	552	510	781	2,818

Class Cost of Service Study ($000); Test Year 2026

INCOME STATEMENT

Operation & Maintenance (Pg 2 of 2)

	Cust Acctg & Inform	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	Acct Superv	901	Customers	30	28	2	0	0	0	0
2	Acct Meter Read	902	Customers	761	704	56	0	0	0	0
3	Acct Recrds & Coll	903	Record & Coll Study	7,511	6,674	487	123	198	22	8
4	Acct Uncollect	904	Uncollectibles Study	3,877	3,465	412	0	0	0	0
5	Acct Misc	905	Customers	76	71	6	0	0	0	0
6	Asst Expense (w/o CIP)	908	Cust Inform Study	-4,232	-3,119	-951	-58	-92	-10	-4
7	Tot Cust Acctg & Inform	Sub-total		8,023	7,823	12	66	106	12	4
	Admin & General									
8	Property Insurance	924	Net Plant	784	490	192	13	10	15	64
9	Pension & Benefit-Direct	926	Labor	9,653	7,003	1,738	115	101	135	561
10	Salaries	920	Labor	8,661	6,284	1,559	103	91	121	504
11	Office & Supplies	921	Labor	11,938	8,661	2,149	142	125	166	694
12	Admin Transfer Credit	922	Labor	-5,682	-4,122	-1,023	-68	-60	-79	-330
13	Outside Services	923	Labor	2,071	1,503	373	25	22	29	120
14	Incentive Compensation	920 + other	Labor	0	0	0	0	0	0	0
15	Injuries and Claims	925	1/2 Rt Base, 1/2 Pres Rev;	2,989	1,796	816	73	108	45	150
16	Regulatory Comm Exp	928	Pres Rev; Mod Pres Rev	936	547	280	29	56	10	14
17	Contributions	929	Pres Rev; Mod Pres Rev	0	0	0	0	0	0	0
18	General Advertising	930	1/2 Rt Base, 1/2 Pres Rev;	28	17	8	1	1	0	1
19	Misc General Exp	930	1/2 Rt Base, 1/2 Pres Rev;	191	115	52	5	7	3	10
20	Rents	931	1/2 Rt Base, 1/2 Pres Rev;	693	417	189	17	25	10	35
21	Maint of Gen Plt	935	1/2 Rt Base, 1/2 Pres Rev;	65	39	18	2	2	1	3
22	Total A & G Expense	Sub-total		32,326	22,749	6,350	457	488	455	1,827
	Amortizations									
23	CIP/DSM	CIP	Sales, W/o CIP Exempt	42,183	21,278	12,958	1,537	4,140	2,086	183
24	Amortizations		Labor	2,098	1,522	378	25	22	29	122
25	Instructional Advertising	407	Pres Rev; Mod Pres Rev	302	177	90	10	18	3	5
26	Total Amortizations	Sub-total		44,583	22,976	13,426	1,572	4,180	2,118	309
	Sales Expense									
27	Sales, Econ Dvlp & Other	912, 913	Sales, W/ Transp	58	19	11	1	4	5	18
28	Total Sales Econ Dvlp & Other	Sub-total		58	19	11	1	4	5	18
29	**Total O&M Expense**			**578,575**	**334,387**	**176,076**	**18,965**	**37,940**	**3,528**	**7,679**

Book Depreciation

		FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
30	**Production Plant (LPG)**	403	Design Day	7,849	4,026	2,682	216	0	62	862
31	**Storage Plant (LNG)**	403	Design Day	6,154	3,157	2,103	170	0	49	676
32	Transmission - Average Capacity	403	Average and Peak	2,520	1,214	805	67	59	90	285
33	Transmission - Direct Assign	403	Direct Assign	389	0	0	0	0	0	389
34	**Transmission Plant**	Sub-total		2,909	1,214	805	67	59	90	674
	Distribution Plant									
35	Regulator Stations	403	Average and Peak	0	0	0	0	0	0	0
36	Mains Direct Assignment	403	Direct Assign	112	0	0	0	0	0	112
37	Mains	403	Mains, Overall	28,077	16,477	7,270	561	497	756	2,517
38	Services	403	Service Study	14,820	12,774	1,975	22	43	4	1
39	Meters	403	Meter & Regul Study	4,933	3,920	914	27	54	12	6
40	House Regulators	403	Meter & Regul Study	1,070	851	198	6	12	3	1
41	Total Distribution Plant	Sub-total		49,011	34,022	10,357	616	606	774	2,637
42	**General & Common Plant**	403	Prod-Stor-Tran-Dis	23,175	14,745	5,552	377	287	410	1,804
43	**Common Plant**	403, 404	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
44	**Total Book Deprec**	Sub-total		**89,099**	**57,164**	**21,500**	**1,445**	**951**	**1,385**	**6,653**

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INCOME STATEMENT

	Real Estate & Prop Taxes	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	408	Design Day	3,308	1,697	1,131	91	0	26	363
2	**Storage Plant (LNG)**	408	Design Day	0.0	0	0	0	0	0	0
3	Transmission - Average Capacity	408	Average and Peak	1,743	840	557	46	41	62	197
4	Transmission - Direct Assign	408	Direct Assignment	287	0	0	0	0	0	287
5	**Transmission Plant**	408		2,029	840	557	46	41	62	484
	Distribution Plant									
6	Regulator Stations	408	Average and Peak	24,058	11,594	7,688	635	560	857	2,722
7	Mains Direct Assignment	408	Direct Assign	0	0	0	0	0	0	0
8	Mains	408	Mains, Overall	0	0	0	0	0	0	0
9	Services	408	Service Study	0	0	0	0	0	0	0
10	Meters	408	Meter & Regul Study	0	0	0	0	0	0	0
11	House Regulators	408	Meter & Regul Study	0	0	0	0	0	0	0
12	Total Distribution Plant	Sub-total		24,058	11,594	7,688	635	560	857	2,722
13	**General and Common Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Common Plant**	408	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
15	**Total Rl Est & Prop Tax**	Sub-total		**29,395**	**14,131**	**9,376**	**772**	**601**	**946**	**3,569**
16	Payroll Taxes	408	Labor	3,728	2,705	671	44	39	52	217
17	**Tot Non-Income Taxes**			**33,123**	**16,836**	**10,047**	**817**	**640**	**998**	**3,786**
	Provision-Defer Inc Tax	**FERC Accounts**	**Allocator**							
18	**Production Plant (LPG)**	410.1, 411.1	Design Day	14	7	5	0	0	0	2
19	**Storage Plant (LNG)**	410.1, 411.1	Design Day	1,375	705	470	38	0	11	151
20	Transmission - Average Capacity	410.1, 411.1	Average and Peak	1,354	653	433	36	32	48	153
21	Transmission - Direct Assign	410.1, 411.1	Direct Assign	76	0	0	0	0	0	76
22	**Transmission Plant**	Sub-total		1,430	653	433	36	32	48	229
	Distribution Plant									
23	Regulator Stations	410.1, 411.1	Average and Peak	1	1	0	0	0	0	0
24	Mains Direct Assignment	410.1, 411.1	Direct Assign	51	0	0	0	0	0	51
25	Mains	410.1, 411.1	Mains, Overall	-1,366	-802	-354	-27	-24	-37	-122
26	Services	410.1, 411.1	Service Study	843	726	112	1	2	0	0
27	Meters	410.1, 411.1	Meter & Regul Study	3,250	2,583	602	18	36	8	4
28	House Regulators	410.1, 411.1	Meter & Regul Study	902	717	167	5	10	2	1
29	Total Distribution Plant	Sub-total		3,680	3,225	528	-4	24	-26	-67
30	**General and Common Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	1,763	1,122	422	29	22	31	137
31	**Common Plant**	410.1, 411.1	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
32	Net Operating Loss (NOL) Carry Forward	410.1, 411.1	Net Plant	0	0	0	0	0	0	0
33	Non-Plant Related	410.1, 411.1	Labor	145	105	26	2	2	2	8
34	**Tot Prov Defer Inc Tax**	Total		**8,407**	**5,817**	**1,884**	**101**	**79**	**66**	**460**
	Investment Tax Credit	**FERC Accounts**	**Allocator**							
35	**Production Plant (LPG)**	420	Design Day	0	0	0	0	0	0	0
36	**Storage Plant (LNG)**	420	Design Day	0	0	0	0	0	0	0
37	Transmission - Average Capacity	420	Average and Peak	-5	-2	-1	0	0	0	-1
38	Transmission - Direct Assign	420	Direct Assign	0	0	0	0	0	0	0
39	**Transmission Plant**			-5	-2	-1	0	0	0	-1
	Distribution Plant									
40	Regulator Stations	420	Average and Peak	0	0	0	0	0	0	0
41	Mains Direct Assignment	420	Direct Assign	0	0	0	0	0	0	0
42	Mains	420	Mains, Overall	-92	-54	-24	-2	-2	-2	-8
43	Services	420	Service Study	0	0	0	0	0	0	0
44	Meters	420	Meter & Regul Study	0	0	0	0	0	0	0
45	House Regulators	420	Meter & Regul Study	0	0	0	0	0	0	0
46	Total Distribution Plant	Sub-total		-92	-54	-24	-2	-2	-2	-8
47	**General and Common Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
48	**Common Plant**	420	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
49	**Net Invest Tax Credit**	Sub-total		**-97**	**-57**	**-25**	**-2**	**-2**	**-3**	**-9**
50	**Total Operating Exp**	Sub-total		**709,107**	**414,147**	**209,481**	**21,326**	**39,608**	**5,974**	**18,570**
42a	**Pres Op Inc Before Inc Tax**	Total		**69,153**	**41,561**	**22,653**	**3,071**	**6,380**	**2,061**	**-6,573**
42b	**Prop Op Inc Before Inc Tax**	Total		**132,554**	**81,945**	**38,037**	**4,782**	**9,859**	**3,498**	**-5,568**

Class Cost of Service Study ($000); Test Year 2026

INCOME STATEMENT

Tax Deprec & Removal

	Tax Deprec & Removal	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	**Production Plant (LPG)**	Not Applicable	Design Day	7,785	3,993	2,661	214	0	62	855
2	**Storage Plant (LNG)**	Not Applicable	Design Day	10,700	5,488	3,657	295	0	85	1,175
3	Transmission - Average Capacity	Not Applicable	Average and Peak	7,626	3,675	2,437	201	178	272	863
4	Transmission - Direct Assign	Not Applicable	Direct Assign	682	0	0	0	0	0	682
5	**Transmission Plant**	Not Applicable		8,308	3,675	2,437	201	178	272	1,544
	Distribution Plant									
6	Regulator Stations	Not Applicable	Average and Peak	0	0	0	0	0	0	0
7	Mains Direct Assignment	Not Applicable	Direct Assign	290	0	0	0	0	0	290
8	Mains	Not Applicable	Mains, Overall	31,875	18,705	8,254	637	564	858	2,857
9	Services	Not Applicable	Service Study	14,309	12,334	1,907	21	42	4	1
10	Meters	Not Applicable	Meter & Regul Study	16,526	13,135	3,061	90	182	40	19
11	House Regulators	Not Applicable	Meter & Regul Study	4,388	3,487	813	24	48	11	5
12	Total Distribution Plant	Sub-total		67,388	47,662	14,034	772	835	912	3,173
13	**General and Common Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
14	**Common Plant**	Not Applicable	Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
15	Net Operating Loss (NOL) Carry Forward	Not Applicable	Net Plant	33,126	20,715	8,098	563	428	619	2,704
16	**Total Tax Depreciation**	Total		**127,307**	**81,533**	**30,887**	**2,045**	**1,440**	**1,950**	**9,452**

Present Return

	Inc Tax Additions	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
17	Total Book Depr Exp	from another page		89,099	57,164	21,500	1,445	951	1,385	6,653
18	Provision for Deferred	from another page		8,407	5,817	1,884	101	79	66	460
19	Net Inv Tax Credit	from another page		-97	-57	-25	-2	-2	-3	-9
20	Avoided Tax Interest	Not Applicable	CWIP	1,044	637	268	19	13	20	87
21	Total Tax Additions	Sub-total		98,453	63,561	23,626	1,564	1,042	1,469	7,192
	Inc Tax Deductions									
22	Tax Depr & Removal Exp	from another page		127,307	81,533	30,887	2,045	1,440	1,950	9,452
23	Debt Interest Expense	Calculation	; Mod Rate Base	32,297	19,945	7,991	562	414	629	2,756
24	Other Timing Differences	Not Applicable	Labor	-3,396	-2,464	-611	-40	-36	-47	-197
25	Meals		Labor	177	128	32	2	2	2	10
26	Total Tax Deductions	Sub-total		156,385	99,142	38,299	2,569	1,820	2,534	12,020
26a	**Pres Taxable Net Income**	Calculation		**11,221**	**5,980**	**7,980**	**2,065**	**5,601**	**996**	**-11,401**
26b	**Prop Taxable Net Income**			**74,622**	**46,364**	**23,364**	**3,776**	**9,080**	**2,433**	**-10,395**
27a	**Pres Inc Tax, @25.06%**	Calculation		**2,812**	**1,499**	**2,000**	**517**	**1,404**	**250**	**-2,857**
27b	**Prop Inc Tax, @28.19%**			**21,035**	**13,069**	**6,586**	**1,064**	**2,560**	**686**	**-2,930**
28a	**Pres Preliminary Return**			66,341	40,063	20,653	2,553	4,976	1,812	-3,716
28b	**Prop Preliminary Return**			111,519	68,876	31,451	3,717	7,299	2,813	-2,637
29	**Total AFUDC**	Not Applicable	CWIP	**2,842**	**1,695**	**751**	**55**	**37**	**57**	**248**
30a	**Pres Total Return**	Total	; Mod Rate Base	**69,183**	**41,757**	**21,404**	**2,609**	**5,013**	**1,869**	**-3,468**
30b	**Prop Total Return**		; Mod Rate Base	**114,362**	**70,571**	**32,202**	**3,773**	**7,336**	**2,870**	**-2,389**
31a	**Pres % Return on Rate Base**	Calculation		**4.71%**	**4.61%**	**5.89%**	**10.20%**	**26.64%**	**6.53%**	**-2.77%**
31b	**Prop % Return on Rate Base**			**7.79%**	**7.78%**	**8.87%**	**14.76%**	**38.99%**	**10.03%**	**-1.91%**
32a	**Pres Common Return**			**36,886**	**21,813**	**13,413**	**2,046**	**4,599**	**1,239**	**(6,224)**
32b	**Prop Common Return**			**82,064**	**50,626**	**24,211**	**3,210**	**6,922**	**2,240**	**(5,145)**
33a	**Pres % Ret on Common Rt Bs**			**4.79%**	**4.58%**	**7.03%**	**15.24%**	**46.56%**	**8.25%**	**-9.46%**
33b	**Prop % Ret on Common Rt Bs**			**10.65%**	**10.64%**	**12.70%**	**23.92%**	**70.08%**	**14.92%**	**-7.82%**

AFUDC

	AFUDC	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
34	Production Plant (LPG)		Design Day	39	20	13	1	0	0	4
35	Storage Plant (LNG)		Design Day	361	185	123	10	0	3	40
36	Transmission - Average Capacity	Not Applicable	Average and Peak	175	85	56	5	4	6	20
37	Transmission - Direct Assign	Not Applicable	Direct Assign	0	0	0	0	0	0	0
38	Transmission Plant		Average and Peak	175	85	56	5	4	6	20
	Distribution:									
39	Regulator Stations		Average and Peak	0	0	0	0	0	0	0
40	Mains Direct Assignment		Direct Assign	0	0	0	0	0	0	0
41	Mains		Mains Overall	857	503	222	17	15	23	77
42	Services		Service Study	2	2	0	0	0	0	0
43	Meters		Meter & Regul Study	0	0	0	0	0	0	0
44	House Regulators		Meter & Regul Study	30	23	5	0	0	0	0
45	Total Distribution			889	528	228	17	15	23	77
46	General Plant		Prod-Stor-Tran-Dis	1,378	877	330	22	17	24	107
47	Gas Common		Prod-Stor-Tran-Dis	0	0	0	0	0	0	0
48	Total AFUDC			2,842	1,695	751	55	37	57	248

Labor Allocator

	Labor Allocator	FERC Accounts	Allocator	Minn	Res	Com	Demand	Interrupt	Tran	Gener
49	Customer Accounting	Labor Portion of O&M Accounts	Customers	3,750	3,471	277	1	2	0	0
50	Cust Serv & Inform	Labor Portion of O&M Accounts	Customers	746	690	55	0	0	0	0
51	Distribution	Labor Portion of O&M Accounts	Dist Exp, w/o Sup & Eng	28,995	21,289	5,026	318	293	449	1,621
52	Admin & General	Labor Portion of O&M Accounts	Labor w/o A&G	18,557	13,463	3,341	221	194	259	1,079
53	Production	Labor Portion of O&M Accounts	Other Production Exp	4,521	2,197	1,433	129	106	83	573
54	Sales	Labor Portion of O&M Accounts	Sales, W/ Transp	0	0	0	0	0	0	0
55	Transmission	Labor Portion of O&M Accounts	Design Day	324	166	111	9	0	3	36
56	Total			56,894	41,277	10,242	677	596	793	3,309

Class Cost of Service Study ($000); Test Year 2026

ALLOCATORS

	Internal Allocators	Minn	Res	Com	Demand	Interrupt	Tran	Gener
1	1/2 Dsgn Day, 1/2 Ener	**100.00%**	**41.70%**	**26.87%**	**2.55%**	**3.12%**	**4.55%**	**21.21%**
2	1/2 Rt Base, 1/2 Pres Rev; (Only for Class allocations)	**100.00%**	**60.11%**	**27.32%**	**2.44%**	**3.61%**	**1.49%**	**5.03%**
3	Average and Peak (Mains)	898,388	432,975	287,102	23,723	20,924	32,021	101,644
4	Average and Peak	**100.00%**	**48.19%**	**31.96%**	**2.64%**	**2.33%**	**3.56%**	**11.31%**
5	CWIP	**100.00%**	**60.98%**	**25.62%**	**1.85%**	**1.28%**	**1.94%**	**8.34%**
6	Dist Exp, w/o Sup & Eng	41,426	30,416	7,181	454	419	641	2,315
7	Dist Exp, w/o Sup & Eng	**100.00%**	**73.42%**	**17.33%**	**1.10%**	**1.01%**	**1.55%**	**5.59%**
8	Distribution Plant	**100.00%**	**67.41%**	**22.15%**	**1.41%**	**1.35%**	**1.80%**	**5.89%**
9	Gas Plant In Service	**100.00%**	**63.63%**	**23.95%**	**1.63%**	**1.24%**	**1.77%**	**7.79%**
10	Labor	**100.00%**	**72.55%**	**18.00%**	**1.19%**	**1.05%**	**1.39%**	**5.82%**
11	Mains, Overall	**100.00%**	**58.68%**	**25.89%**	**2.00%**	**1.77%**	**2.69%**	**8.96%**
12	Modified O&M Expense	573,372	331,280	174,623	18,829	37,724	3,456	7,461
13	Modified O&M Expense	**100.00%**	**57.78%**	**30.46%**	**3.28%**	**6.58%**	**0.60%**	**1.30%**
14	Net Plant	**100.00%**	**62.53%**	**24.45%**	**1.70%**	**1.29%**	**1.87%**	**8.16%**
15	Other Production Exp	**100.00%**	**48.60%**	**31.69%**	**2.84%**	**2.35%**	**1.83%**	**12.68%**
16	Prod-Stor-Tran-Dis	2,247,306	1,429,855	538,339	36,575	27,819	39,754	174,963
17	Prod-Stor-Tran-Dis	**100.00%**	**63.63%**	**23.95%**	**1.63%**	**1.24%**	**1.77%**	**7.79%**
18	Rate Base	**100.00%**	**61.75%**	**24.74%**	**1.74%**	**1.28%**	**1.95%**	**8.53%**
19	Rt Base, w/o Work Cash	1,479,967	913,456	366,873	25,958	19,599	28,672	125,409
20	Rt Base, w/o Work Cash	**100.00%**	**61.72%**	**24.79%**	**1.75%**	**1.32%**	**1.94%**	**8.47%**
21	Transmission & Distribution	1,981,469	1,293,505	447,485	29,253	27,819	37,640	145,765
22	Tran & Distrib	**100.00%**	**65.28%**	**22.58%**	**1.48%**	**1.40%**	**1.90%**	**7.36%**
23	Labor w/o A&G	38,337	27,814	6,901	456	401	535	2,230
24	Labor w/o A&G	**100.00%**	**72.55%**	**18.00%**	**1.19%**	**1.05%**	**1.39%**	**5.82%**
	Component Allocators							
25	Mod Present Rev	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
26	Mod Rate Base	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**
27	1/2 Mod Rt Bs, 1/2 Mod Pres Rv	**1300.00%**	**100.00%**	**200.00%**	**200.00%**	**300.00%**	**300.00%**	**200.00%**

Class Cost of Service Study ($000); Test Year 2026

ALLOCATORS

External Allocators

		Minn	Res	Com	Demand	Interrupt	Tran	Gener
	Customer-Related							
1	Bills	5,974,093	5,528,561	440,692	1,704	2,728	300	108
2	Modified Bills	5,974,069	5,528,561	440,692	1,704	2,728	300	84
3	Meter & Regul Weightings		1.00					
4	Meter (Wtd Bills)	6,955,962	5,528,561	1,288,305	37,711	76,401	16,914	8,070
5	Service Weightings		1.00					
6	Service (Wtd Bills)	6,413,659	5,528,561	854,734	9,551	18,689	1,668	456
7	Records & Collect Weightings		1.00					
8	Records & Collect (Wtd Bills)	6,222,041	5,528,561	403,080	102,240	163,680	18,000	6,480
9	Cust Information Weightings		1.00					
10	Cust Information (Wtd Bills)	7,502,193	5,528,561	1,685,392	102,240	162,600	16,920	6,480
11	Customers	100.00%	92.54%	7.38%	0.03%	0.05%	0.01%	0.00%
12	Modified Customers	100.00%	92.54%	7.38%	0.03%	0.05%	0.01%	0.00%
13	Meter & Regul Study	100.00%	79.48%	18.52%	0.54%	1.10%	0.24%	0.12%
14	Service Study	100.00%	86.20%	13.33%	0.15%	0.29%	0.03%	0.01%
15	Record & Coll Study	100.00%	88.85%	6.48%	1.64%	2.63%	0.29%	0.10%
16	Cust Inform Study	100.00%	73.69%	22.47%	1.36%	2.17%	0.23%	0.09%
	Energy-Related							
17	Cal Yr Sales Dkt, W/o Trans	74,351,221	39,424,795	24,016,129	2,875,341	7,671,802	0	363,155
18	Transportation Dkt	48,441,146	0	0	0	0	10,190,089	38,251,057
19	Cal Yr Sales Dkt, W/ Trans	122,792,367	39,424,795	24,016,129	2,875,341	7,671,802	10,190,089	38,614,211
20	CIP Exempt Dkt	44,633,482	0	6,040	26,741	0	6,324,935	38,275,766
21	Sales Dkt, W/o CIP Exempt	78,158,885	39,424,795	24,010,089	2,848,600	7,671,802	3,865,154	338,446
22	Sales, W/o Transp	100.00%	53.03%	32.30%	3.87%	10.32%	0.00%	0.49%
23	Sales, W/ Transp	100.00%	32.11%	19.56%	2.34%	6.25%	8.30%	31.45%
24	Sales, W/o CIP Exempt	100.00%	50.44%	30.72%	3.64%	9.82%	4.95%	0.43%
25	Modified Sales W/Transport	100.00%	36.86%	22.46%	2.69%	7.17%	9.53%	21.29%
	Demand-Related							
26	Design Day Demand (Retail)	1,036,133	531,440	354,112	28,540	0	8,241	113,800
27	Avg Daily Firm Dkt, W/ Trans	289,311	108,013	65,798	7,878	0	2,738	104,884
28	Design Day	100.00%	51.29%	34.18%	2.75%	0.00%	0.80%	10.98%
29	Excess Design Day	100.00%	53.64%	36.53%	2.62%	0.00%	0.70%	6.52%
	Miscellaneous (only alloc to class, not component)							
30	Present Retail Revenue	774,803	452,991	231,632	24,367	45,968	8,010	11,835
31	Uncollectibles Study	100.00%	89.38%	10.62%	0.00%	0.00%	0.00%	0.00%
32	Present Retail Revenue	100.00%	58.47%	29.90%	3.14%	5.93%	1.03%	1.53%
33	Late Payment Penalty	100.00%	92.27%	7.34%	0.09%	0.30%	0.00%	0.00%

Class Cost of Service Study ($000); Test Year 2026

Capital Structure		Rate	Ratio	Wtd Cost
37	Long Term Debt	4.64%	47.08%	2.18%
38	Short Term Debt	4.56%	0.42%	0.02%
39	Debt Total	4.63%	47.50%	2.20%
40	Preferred Stock	0.00%	0.00%	0.00%
41	Common Equity	10.65%	52.50%	5.59%
42	Required Rate of Return		100.00%	7.79%

accordance with prescribed uniform accounting systems. These systems, such as the Uniform System of Accounts, classify costs according to primary operating functions. Thus, the functionalization of costs is already done for the cost of service analyst.

2. Classification of Costs

The functionalization of costs is of limited use in the allocation of costs. Therefore, it is necessary to further classify costs into customer, energy or commodity, and demand or capacity costs.

a. Customer Costs

Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections.

A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory." This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires.

Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand. The zero-inch main method would allocate the cost of a theoretical main of zero-inch diameter to the customer function, and allocate the remaining costs associated with mains to demand. A calculation of a minimum size main is shown in the illustrative cost allocation study. The contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function. Under this basic system theory, only those facilities, such as meters, regulators and service taps, are considered to be customer related, as they vary directly with the number of customers on the system.

Another controversial item is the inclusion of sales promotion expenses in the customer cost component. Analysts vary in their opinions as to the extent of the inclusion. Some would include all, some none, and some a portion of sales promotion expense in the customer category. With emphasis placed on conservation, many regulatory bodies have prohibited this type of activity, and in those cases, if cost were incurred, it should be deleted from the study based upon its being a "below the line" or a stockholder expense.

b. <u>Energy or Commodity Costs</u>

Energy or commodity costs are those which vary with the quantity of gas produced or purchased. They are largely made up of the commodity portion of purchased gas cost and the cost of feedstock, catalyst, fuel, and other variable expenses used in the production of gas from a manufactured or synthetic gas (SNG) plant. Energy or commodity costs increase or decrease as more or less gas is consumed.

c. <u>Demand or Capacity Costs</u>

Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

3. Allocation of Costs to Customer Classes

After the assignment of costs to the customer, energy, and demand categories, each category must be allocated to the various service classifications or to their subdivisions.

a. Customer Costs

Customer costs may be distributed in proportion to the number of customers in a class, or a more detailed study may be made whereby certain components of the customer costs may be distributed on a per-customer basis, directly assigned or distributed on a weighted per-customer basis. The latter method permits recognition of known or ascertainable customer cost differences such as the frequency of meter readings, complexity in obtaining readings or integrating meter reading charts, and the individiual attention which may be given to large customers, such as separate meter reading schedules.

As discussed earlier, while there may be differences on whether certain items of plant should be assigned to customer costs, there are clearly certain expenses which are independent of whether a customer consumes gas or not. Since these costs will not be recouped if little or no gas is consumed, they are generally included in a minimum bill or customer service charge. One of the

Guide to the Gas Class Cost of Service Study (CCOSS)
Northern States Power Company

I. Overview

The purpose of the Northern States Power Company (NSP) gas Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as residential, commercial, demand, interruptible, and transport. For example, distribution mains costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as production, storage, transmission, and distribution. The CCOSS also assigns ***direct*** costs (e.g., purchased gas expenses), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g., Dth commodity usage and design day requirements), which are the drivers of the costs.

The two basic types of costs are: (1) capital costs associated with investment in production, storage, transmission, and distribution facilities and (2) on-going expenses such as purchased gas, labor costs and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e., the revenue requirements) to customer classes according to each class's share of the capacity, commodity, and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A CCOSS begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three basic steps:

1. Functionalization – The identification of each cost element as one of the six basic utility service "functions." The four main categories are production, storage, transmission, and distribution. There are also two other categories for general and common plant/expenses.
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g., Dths of demand, Dths of commodity usage or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class's respective service requirements (e.g., Dths of demand, Dths of commodity usage, and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the gas utility system. Costs must first be functionalized because each class's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four main functions and the associated sub-functions are shown in the table below:

Function	FERC Accounts	Sub-Function	Description
Production	304, 305, 311, 108(1), 190, 281-283 Net, 710, 733, 735, 736, 742, 759, 840-843, 403, 408.1, 410.1, 411.1, 420	None	Includes capital and associated operations and maintenance expenses related to manufacturing, buying, or producing gas. These costs include pipeline or producer gas purchases and producing owned or peaking gas.
Storage	360-363, 108(5), 190, 281-283 Net, 403, 408, 410.1, 411.1, 420	None	Includes capital and associated operations and maintenance expenses related to storing off-peak gas for use during the winter-peaking months.
Transmission	365-371, 108(7), 190, 281-283 Net, 107, 850-865, 403, 408.1, 410.1, 411.1, 420	None	Includes costs associated with transporting gas from interstate pipelines to the Company's distribution system. These included capital costs associated with transmission mains as well as operations and maintenance expenses associated with town border stations.
Distribution	374-376, 378-381, 383, 108(8), 281-283 Net, 107, 871, 874, 875, 877-881, 885, 887, 889, 891, 892, 403, 408, 410.1, 411.1, 420	"Customer" portion of the Distribution Mains	Includes the customer-related capital and operating costs associated with delivering gas to customers (distribution mains and services, customer services, meters, regulators)
		"Demand" portion of Distribution Mains	Includes the demand-related capital and operating costs associated with delivering gas to customers (distribution mains and services, customer services, meters, regulators)

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The three principal service requirements or billing components are:

1. Demand – Costs that are driven by customers' maximum dekatherm ("Dth") demand.
2. Commodity – Costs that are driven by customers' energy or dekatherm ("Dth") requirements.

3. Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs were classified:

Function/Sub-Function	Cost Classification		
	Demand	Customer	Commodity
Production	X		X
Storage	X		
Transmission	X		
Distribution (Customer-Related)		X	
Distribution (Demand-Related)	X		

As shown in the table above, distribution costs are classified as both "demand" and "customer" related. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The Company utilizes a minimum system methodology for determining the portion of costs that are demand- and customer-related.

V. Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of two ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. An example of a directly assigned cost is purchased gas expenses or transmission mains.
- Allocation - Most gas utility costs are incurred common or jointly in providing service to all or most customers and classes. Therefore, allocation methods must be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100 percent.
  - There are two types of allocators:
    - External Allocators – These are allocators that are based on data from outside the CCOSS model (e.g., design day demands, metering and customer service-related cost ratios). In general, there are three types of external allocators:
    - Capacity – related (sometimes referred to as Demand) allocators such as:
      - Design Day Demands – each firm class's usage in extreme peaking conditions
      - Excess Design Day – the portion of design day demand in excess of average daily sales

- Commodity-related allocators such as:
    - Sales w/ Transp – Forecasted sales, including forecasted transportation sales
    - Sales w/o Transp – Forecasted sales without forecasted transportation sales
- Customer-related allocators
    - Number of customers
    - Weighted number of customers, where the weights are based on cost of meters, services, billing, etc.

Details on the external allocators used in the CCOSS model are shown in Volume 3, Required Information, Page 10.

- Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as Dths demand, Dths of energy or the number of customers. Examples of internal allocators include:
- Average and Peak – portion of mains costs that are not allocated on customers
- Mains, Overall – total effect of mains allocated on customers, sales with transport, and excess design day
- Prod-Stor-Trans-Distr – Total production, storage, transmission, and distribution from original plant investment

Details on the development of the internal allocators used in the CCOSS model are shown in Volume 3, Required Information, Page 9.

VI. Classification and Allocation of Production, Storage, Transmission, and Distribution Plant and Expenses

A. Production and Storage Plant

Production costs include production-related land and land rights, structures and improvements, liquefied petroleum, and other expenses. Storage costs also include storage-related land and land rights, structures and improvements, gas holders, and purification equipment. These costs are classified as demand-related and allocated with a Design Day allocator. Production-related expenses such as the Minnesota Manufactured Gas Plant (MGP) are classified as energy-related and allocated with a Sales Without Transport allocator.

B. Transmission Plant

Transmission costs include transmission pipe-related land and land rights, rights-of-way used in connection with transmission operations, structures and improvements, and transmission mains. Transmission main costs that can be segregated to a specific class are directly assigned to that class. Those costs that are not directly assigned are classified as demand-related and allocated with an average and peak allocator.

C. Distribution Plant

Distribution Plant includes the pipelines, meters, and other infrastructure needed to deliver natural gas from the transmission system to customers' premises. The categories of Distribution Plant are: 1) distribution mains, 2) services (i.e., the pipe going to homes and businesses), 3) meters and regulators, and 4) regulator stations. The Table below shows the amount of distribution plant by category and how they are classified:

Distribution Plant Category	2026 TY Plant in Service (000)	Demand Component	Customer Component
Distribution Mains	$1,190,536	X	X
Services	$420,612		X
Meters & Regulators	$167,599		X
Regulator Stations	$39,775	X	

VII. Distribution Plant Cost Studies within CCOSS

There are three distribution cost studies within the CCOSS:

- Minimum System Study
- Meter and Regulator Study
- Service Study

Minimum System Study

The National Association of Regulatory Utilities Commissioners (NARUC) Gas Distribution Rate Design manual states that a portion of distribution mains may be classified as customer-related (with the remainder of costs classified as demand related) and that Minimum System studies may be utilized to derive the customer- and demand-related components of distribution mains. Consistent with this guidance, I utilized a Minimum System Study to establish the classification percentages of distribution mains.

The Minimum System method involves comparing the cost of the minimum size of distribution mains used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost. The table below shows the classification of distribution main costs.

Cost	Customer	Demand
Distribution Costs	61.6%	38.4%

The total cost of mains is split among Minimum System, Average Capacity, and Excess Capacity components. The Minimum System component identifies the cost to establish basic connectivity between the utility and the customer, using pipes with a diameter of two inches or less, which is the minimum-sized pipe for mains on our system. If all the mains in the Company's entire distribution system in Minnesota consisted of two-inch pipe, the initial plant investment would have been 61.6 percent of actual investment. These Minimum System costs are allocated to class based on the number of customers in each class and are also assigned to the Customer Charge billing component. However, it is reasonable to make a demand adjustment that accounts for capacity associated with the two-inch pipe that makes up the Minimum System. The Company calculated a demand adjustment of 22.5 percent. The following table illustrates the adjusted customer- and demand-related classification of distribution main costs.

Cost	Customer	Demand
Distribution Costs	39.1%	60.9%

Average Capacity costs are determined by taking the remaining 60.9 percent of the total cost of mains and multiplying by the test year 2026 system load factor. The system load factor is calculated by taking the Company's forecasted total sales (2026 Test Year Sales forecast of 122,792,367 Dth) and dividing that by the Company's peak demand (2025-2026 Design Day Demand of 1,036,133 Dth) and multiplying that by 365 days in the year. The test year 2026 forecasted system load factor is 32.5 percent. Multiplying the 60.9 percent of the remaining total cost of mains by the system load factor leads to an Average Capacity of 19.8 percent. These Average Capacity costs are allocated to class based on sales (including transportation sales). Then the results are credited to the Demand billing component and Base sub-component. The Base sub-component is comprised of non-seasonal and non-peak demand.

The Excess Capacity component is the remaining 41.1 percent of total cost of mains not ascribed to the Minimum System and Average Capacity components. The Excess Capacity costs are allocated to class using an Excess Design Day allocator. The Excess Design Day allocator is calculated by taking the difference between each class's Design Day demand and Average Daily Sales. Then, each class amount is credited to the Demand cost component and Seasonal sub-component.

Meter and Regulatory Study

A Meter and Regulator Study assigns meter costs and costs for pressure-regulating equipment to each class. Information is gathered on meter and regulator equipment and installation costs, the premises identification numbers associated with different meters, and the premises identification numbers associated with each rate code/class. From this list, total meter costs are developed for each class and divided by the number of meters in each class to develop a cost per meter weighting. Since the residential class had the lowest cost per meter and regulator, they received a customer weighting of 1.00. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 1.74, Large Commercial – 5.45, Small Demand – 13.25, Large Demand – 23.03, Small Interruptible – 15.74, Medium Interruptible – 43.95, Large Interruptible – 224.27, Firm Transport – 23.03, Interruptible Transport – 43.95, Negotiated Transport – 224.27, System Generation – 35.58, and Transport Generation – 123.65. The meter cost weighting for each class is applied to the number of customers in each respective class in order to calculate the Meters and Regulators Study allocator.

Service Study

A Services Study assigns gas services costs to each class. Services costs are the costs of service pipelines used to connect distribution mains to customers' premises. Information is gathered on premise identification numbers, service pipe type, service pipe length, and class associated with each premise. The cost per foot of each service pipe type is applied to each class based on the service pipe types and footage used in each class. This calculation allows us to determine the total cost of service pipes for each class. The total cost by class is divided by the number of customers in each class. Since the cost per customer for the residential class was lowest, that class received a weight of 1.00. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 1.63, Large Commercial – 2.60, Small Demand – 7.69, Large Demand – 5.39, Small Interruptible – 7.18, Medium Interruptible – 6.35, Large Interruptible – 3.28, Firm Transport – 5.39, Interruptible Transport – 6.35, Negotiated Transport – 3.28, System Generation – 5.87, and Transport Generation – 4.34. The service weightings are applied to the number of customers in each class. The weighted customers are then utilized to derive the Service Study allocator.

VIII. Other Cost Studies within CCOSS

Customer Care Studies

Two Customer Care studies were conducted within the CCOSS: 1) a Customer Records and Collections Study and 2) a Customer Information Study. The Customer Records and Collections Study, and the Customer Information Study were developed to allocate costs associated with Federal Energy Regulatory Commission (FERC) Accounts 903 and 908, respectively. FERC Account 903 costs include materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections, and complaints. FERC Account 908 costs include materials used, and expenses incurred in providing instructions or assistance to customers, the object of which is to promote safe, efficient, and economical use of the utility's service.

The Customer Records and Collections Study first determines the costs associated with billing and call centers for each class on a cost per customer basis. To make this determination, I first directly assign those FERC Account 903 costs that can be directly assigned to a specific class. Those FERC Account 903 costs that cannot be directly assigned are allocated based on the number of customers in each class. The weightings for each class are as follows: Residential – 1.00, Small Commercial – 0.95, Large Commercial – 0.84, Small Demand – 60.00, Large Demand – 60.00, Small Interruptible – 60.00, Medium Interruptible – 60.00, Large Interruptible – 60.00, Firm Transport – 60.00, Interruptible Transport – 60.00, Negotiated Transport – 60.00, System Generation – 60.00, and Transport Generation – 60.00. The weightings are derived for all other classes by dividing their cost per customer by that of the residential class. The weightings are then applied to the number of customers in each class. The weighted customers are used to derive the allocator for customer records and collections expenses.

In the same manner as the Customer Records and Collections Study, the Customer Information Study determines the costs associated with customer account management, expenses associated with low-income customers, and business development by directly assigning the FERC Account 908 costs that can be directly assigned to a specific class. Costs that cannot be directly assigned to a class are allocated based on the number of customers in each class.

The weightings for each class are as follows: Residential – 1.00, Small Commercial – 0.93, Large Commercial – 10.00, Small Demand – 60.00, Large Demand – 60.00, Small Interruptible – 60.00, Medium Interruptible – 60.00, Large Interruptible – 30.00, Firm Transport – 60.00, Interruptible Transport – 60.00, Negotiated Transport – 30.00, System Generation – 60.00, and Transport Generation – 60.00. The weightings are derived for all other classes by dividing their cost per customer by that of the residential class. The weightings are then applied to the number of customers in each class. The weighted customers are used to derive the allocator for costs associated with customer account management, expenses associated with low-income customers, and business development.

Uncollectibles Study
The Uncollectibles Study consists of gathering information on customer debtor numbers, net uncollectibles (bad debt less recoveries) for each debtor number, and classes associated with each debtor number to determine the net uncollectibles for each class. The net uncollectibles are then calculated for each class and used to derive the allocation of uncollectibles.

Late Fee Study
The Late Payment Study follows the same process as the Uncollectibles Study as it determines customer late fees by class. The late fees by class are used to derive the late fee revenue allocator and assign late payment revenues to each customer class.

IX. Direct Assignment of Transmission Plant and Related Expenses

Plant and related expenses associated with transmission mains that only serve two of our Transport Generation customers and one of our System Generation customers was isolated and directly assigned to those classes. Production, storage, and distribution plant and related expenses related to these three customers were not allocated to the Transport and System Generation classes by removing their respective sales from the Modified Sales w/ Transport allocator, customer counts from the Modified Customer Counts allocator, and Design Day demands from the Design Day and Excess Design Day allocators. For transmission plant and related expenses, the remaining costs that are not directly assigned are allocated to the classes via the Average and Peak allocator. For distribution plant and related expenses, the remaining costs that are not directly assigned are allocated the classes via the Sales w/ Transport and Excess Design Day allocators.

X. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential
2. Small Commercial
3. Large Commercial
4. Small Demand
5. Large Demand
6. Small Interruptible
7. Medium Interruptible
8. Large Interruptible
9. Firm Transport
10. Interruptible Transport
11. Negotiated Transport
12. System Generation
13. Transport Generation

XI. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "Tot") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below (the label of the worksheet tab is shown in parenthesis below):

1. Billing Unit:
   a. Demand (Dem)
   b. Customer (Cus)
   c. Commodity (Com)

2. Function and Associated Sub-Function
   a. Demand (Dem)
      a) Base (Base)
      b) Seasonal (Seas)
      c) Peak Shaving (Peak)

In the CCOSS spreadsheet there is a separate worksheet tab for each of the above billing units, functions and sub-functions. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

XII. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accumulated Depreciation Reserve – Accumulated Deferred Income Tax + Additions to Net Plant

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "cost" responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "cost" responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function, and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function, and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (less off-setting credits from Other Operating Revenues)

+

(((% Return on Invest x Rate Base) - AFUDC - Fed Credits) x 1 / (1 - Fed T) - Fed Section 199 Deduc x Fed T/(1-Fed T) - State Credits) x 1 / (1 - State T)

+

(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)

Where:

Tax Rate = 1 – (1- State T) x (1-Fed T)

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax
+ Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit
+ Other Misc Expenses.

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class's "revenue" responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes – Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "revenue" responsibility differs from class **"cost"** responsibility.

XIII. Allocator Descriptions

In the table below, the Name column briefly describes what the allocator is, and the Derivation column describes how the allocator was created. The E/I column tells whether an allocator is external or internal. (An external allocator is one that was prepared outside of the CCOSS. An internal allocator is created within the CCOSS by combining the results of external allocators and / or other internal allocators.) The Components column indicates to which billing component(s) the allocator applies, including possibly the two demand subcomponents. (C=Customer, D=Demand, E=Energy, B=Base Demand, S=Seasonal Demand and P=Peak

Shaving Demand). Most lines of this table show normal allocators that first spread dollars to class and then spread each class amount to billing and subcomponents. But some allocators, such as Present Retail Revenue, only spread dollars to class. And a few other allocators, such as Mod Present Revenue, only spread dollars to billing component. (These latter allocators are only used after dollars have already been spread to class-by-class allocators.) Such two-stage allocations are indicated in the Alloc column of the CCOSS with a semi-colon (e.g., "Pres Rev; Mod Pres Rev").

Name	Derivation	E/I	Components
1/2 Dsgn Day, 1/2 Ener	Average class percents from the Design Day and Sales, w/ Transp allocators	Int	DE-P
1/2 Mod Rt Bs, 1/2 Mod Pres Rv (Component only)	Average class percents from Mod Pres Rev and Mod Rate Base column allocators	Int	CDE-BSP
1/2 Rt Base, 1/2 Pres Rev; (Class only)	Average class percents from the Rate Base and Present Retail Revenue allocators	Int	---
Average and Peak	Total effect of mains allocated on excess design day and average sales	Int	D-BS
Cust Inform Study	Forecasted customers, weighted by the typical cost to serve each class	Ext	C-
Customers	Forecasted customers	Ext	C-
CWIP	Construction Work In Process	Int	CD-BSP
Design Day	Each firm class's participation in extreme peak conditions	Ext	D-P
Dist Exp, w/o Sup & Eng	Distribution O&M expenses, excluding Supervision & Engineering	Int	CDE-BSP
Distribution Plant	Total original investment in mains, services, meters and regulators	Int	CD-BS
Excess Design Day	The portion of Design Day in excess of average daily sales	Ext	D-P
Gas Plant In Service	Total original capital investments	Int	CD-BSP
Labor	Total of various labor-related expenses	Int	CDE-BSP
Labor w/o A&G	All labor expenses except A&G	Int	CDE-BSP
Late Pay Penalties (Class only)	Late pay penalties	Ext	---
Mains, Overall	Total effect of mains allocated on customers, sales with transport & excess design day	Int	CD-BS
Meter & Regul Study	Customer count, weighted by relative cost of each class's average meter and regulator	Ext	C-
Mod Present Reven (Component only)	Present Retail Revenue, w/o Gross Earnings, Late Pay, etc.	Int	CDE-BSP
Mod Rate Base (Component only)	Column version of Rate Base excluding Working Cash	Int	CDE-BSP
Modified O&M Expense	Total O&M expense, less rate case expense and various Admin & General expenses	Int	CDE-BSP
Net Plant	Plant In Service, minus Accumulated Depreciation	Int	CD-BSP
Other Production Expense	Miscellaneous production expenses for LPG, LNG, etc.	Int	DE-
Present Retail Rev (Class only)	Forecasted present revenue	Ext	---
Prod-Stor-Tran-Dis	Total Production, Storage, Transmission and Distribution, from original plant investment	Int	CD-BSP
Rate Base	Rate Base (Plant in Svc, less Accumulated Deprec, plus and minus other adjustments)	Int	CDE-BSP
Record & Coll Study	Forecasted customers, weighted by typical cost to provide billing records and collections	Ext	C-

Name	Derivation	E/I	Components
Rt Base, w/o Work Cash	Rate base, excluding working cash	Int	CDE-BSP
Sales, w/ Transp	Forecasted sales, including forecasted transportation	Ext	E-
Sales, w/o CIP Exempt	Forecasted sales, w/o forecasted CIP-exempt sales	Ext	E-
Sales, w/o Transp	Forecasted sales, w/o forecasted transportation	Ext	E-
Service Study	Customer count, weighted by relative cost of each class's average service	Ext	C-
Tran & Distrib	Transmission and Distribution plant (original investment)	Int	CD-BS
Uncollectibles Study	Forecasted customers, weighted by the typical cost of each class's uncollectibles	Ext	C-

XIV. Allocator Index

The following table lists all the CCOSS allocators, in alphabetical order. If a given allocator is used multiple times within the CCOSS, those occurrences are further sorted by page and line number. Most allocators are used to spread dollars both to class and then billing component. But as indicated parenthetically, some allocators are used only for class allocations or only for billing component allocations.

Allocator	Category	Item	Page	Line
1/2 Dsgn Day, 1/2 Ener	Pres Other Oper Rev	Other - Miscellaneous	5	11
	Other Production Exp	Misc. LNG Op Exp	5	26
	Distribution O&M Exp	Dispatching	5	38
1/2 Rt Base, 1/2 Pres Rev (Class only)	Admin & General	Injuries and Claims	6	15
		General Advertising	6	18
		Misc General Exp	6	19
		Rents	6	20
		Maint of Gen Plt	6	21
Average and Peak	Plant in Service	Transmission Plant	3	3
		Regulator Stations	3	6
	Accum Depr Rsv	Transmission Plant	3	21
		Regulator Stations	3	24
	Accum Defer IT	Transmission Plant	3	37
		Regulator Stations	3	40
	CWIP	Transmission Plant	4	3
		Regulator Stations	4	6
	Transmiss O&M Exp	Transmission Expense	5	28
	Distribution O&M Exp	Regulator Stations	5	31
	Book Deprec	Transmission Plant	6	32
		Regulator Stations	6	35
	Rl Estate & Prop Tax	Transmission Plant	7	3
		Regulator Stations	7	6
	Provis-Defer Inc Tax	Transmission Plant	7	20
		Regulator Stations	7	23

Allocator	Category	Item	Page	Line
Average and Peak	Investment Tax Credit	Transmission Plant	7	37
		Regulator Stations	7	40
	Tax Depr & Removal	Transmission Plant	8	3
		Regulator Stations	8	6
	AFUDC	Transmission Plant	8	36
		Regulator Stations	8	39
Cust Inform Study	Cust Acctg & Inform	Asst Expense (w/o CIP)	6	6
Customers (Also Modified Customers)	Plant in Service	Mains - Minimum System	3	8
	Pres Other Oper Rev	Connection Charges	5	4
		Return Check Charges	5	5
		Connect Smart	5	6
		Distribution Other	5	10
		Incr Misc Serv	5	14
	Distribution O&M Exp	Other Property & Equipment	5	37
		Customer Installations	5	39
		Other Distribution	5	40
	Cust Acctg & Inform	Acct Superv	6	1
		Acct Meter Read	6	2
		Acct Misc	6	5
	Labor Allocator	Customer Accounting	8	49
		Cust Serv & Inform	8	50
CWIP	Income Tax Additions	Avoided Tax Interest	8	20
	AFUDC	Total AFUDC	8	29

Allocator	Category	Item	Page	Line
Design Day	Plant in Service	Production Plant (LPG)	3	1
		Storage Plant (LNG)	3	2
	Accum Depr Rsv	Production Plant (LPG)	3	19
		Storage Plant (LNG)	3	20
	Accum Defer IT	Production Plant (LPG)	3	35
		Storage Plant (LNG)	3	36
	CWIP	Production Plant (LPG)	4	1
		Storage Plant (LNG)	4	2
	Pres Other Oper Rev	Interchange Gas	5	7
		Damage Claim	5	8
		Ltd Firm Sales - Rsrvs & Vols	5	9
	Purchased Gas Exp	Propane	5	20
		Limited Firm	5	21
	Other Production Exp	Other Purchased Gas	5	23
		Misc. LPG Op Exp	5	25
	Book Deprec	Production Plant (LPG)	6	30
		Storage Plant (LNG)	6	31
	Rl Estate & Prop Tax	Production Plant (LPG)	7	1
		Storage Plant (LNG)	7	2
	Provis-Defer Inc Tax	Production Plant (LPG)	7	18
		Storage Plant (LNG)	7	19
	Investment Tax Credit	Production Plant (LPG)	7	35
		Storage Plant (LNG)	7	36
	Tax Depr & Removal	Production Plant (LPG)	8	1
		Storage Plant (LNG)	8	2
	AFUDC	Production Plant (LPG)	8	34
		Storage Plant (LNG)	8	35
	Labor Allocator	Transmission	8	55
Direct Assign	Plant in Service	Transmission	3	4
	Accum Depr Rsv	Transmission	3	22
	Accum Defer IT	Transmission	3	38
	CWIP	Transmission	4	4

Allocator	Category	Item	Page	Line
Direct Assign	Purchased Gas Exp	Commodity	5	18
		Demand	5	19
	Book Deprec	Transmission	6	33
	Real Estate & Prop Taxes	Transmission	7	4
	Provis-Defer Inc Tax	Transmission	7	21
	Investment Tax Credit	Transmission	7	38
	Tax Depr & Removal	Transmission	8	4
	AFUDC	Transmission	8	37
	Pres Retail Revenue	Present Retail Rev	5	1a
	Prop Retail Revenue	Proposed Retail Rev	5	1b
	Plant in Service	Distribution	3	7
	Accum Depr Rsv	Distribution	3	25
	Accum Defer IT	Distribution	3	41
	CWIP	Distribution	4	7
	Operations & Maintenance	Distribution	5	32
	Book Depreciation	Distribution	6	33
	Real Estate & Prop Taxes	Distribution	6	7
	Provision-Defer Inc Tax	Distribution	7	24
	Investment Tax Credit	Distribution	7	41
	Tax Deprec & Removal	Distribution	8	7
	AFUDC	Distribution	8	40
Dist Exp, w/o Sup & Eng	Distribution O&M Exp	Supervision & Engineering	5	41
	Labor Allocator	Distribution	8	51
Excess Design Day	Plant in Service	Mains - Excess Capacity	3	10
Labor	Accum Defer IT	Non-Plant Related	3	50
	Non-Plt Asset-Liab	Non-Plant Assets & Liab	4	16
	Admin & General	Pension & Benefit-Direct	6	9
		Salaries	6	10
		Office & Supplies	6	11
		Admin Transfer Credit	6	12
		Outside Services	6	13
		Incentive Compensation	6	14
	Cust Service & Info	Amortizations	6	24
	Tot Rl Est & Prop Tax	Payroll Taxes	7	16
	Provis-Defer Inc Tax	Non-Plant Related	7	33
	Inc Tax Deductions	Other Timing Differences	8	24
		Meals	8	25
Labor w/o A&G	Labor Allocator	Admin & General	8	52
Late Payment Study	Pres Other Oper Rev	Late Pay Penalties	5	3
	Prop Other Oper Rev	Incr Late Pay - Proposed	5	13

Allocator	Category	Item	Page	Line
Mains, Overall	Accum Depr Rsv	Mains	3	26
	Accum Defer IT		3	42
	CWIP		4	8
	Distribution O&M Exp		5	33
	Book Deprec		6	37
	Rl Estate & Prop Tax		7	8
	Provis-Defer Inc Tax		7	25
	Investment Tax Credit		7	42
	Tax Depr & Removal		8	8
Meter & Regul Study	Plant in Service	Meters	3	13
		House Regulators	3	14
	Accum Depr Rsv	Meters	3	28
		House Regulators	3	29
	Accum Defer IT	Meters	3	44
		House Regulators	3	45
	CWIP	Meters	4	10
		House Regulators	4	11
	Distribution O&M Exp	Meters	5	35
		House Regulators	5	36
	Book Deprec	Meters	6	39
		House Regulators	6	40
	Rl Estate & Prop Tax	Meters	7	10
		House Regulators	7	11
	Provis-Defer Inc Tax	Meters	7	27
		House Regulators	7	28
	Investment Tax Credit	Meters	7	44
		House Regulators	7	45
	Tax Depr & Removal	Meters	8	10
		House Regulators	8	11
	AFUDC	Meters	8	43
		House Regulators	8	44
Modified O&M Expense	Working Cash	Total Working Cash	4	21
Net Plant	Accum Defer IT	Accumulated Deferred Tax	3	49
	Admin & General	Property Insurance	6	8
	Provis-Defer Inc Tax	Tax Benefit Transfers	7	32
	Tax Depr & Removal	Tax Benefit Transfers	8	15
Other Production Exp	Labor Allocator	Production	8	53
Present Rev; Mod Pres Rev (Class only)	Admin & General	Regulatory Comm Exp	6	16
		Duplicate Charge Credit	6	17
	Amortizations	Rate Case Exp Amort	6	25

Allocator	Category	Item	Page	Line
Prod-Stor-Tran-Dis	Plant in Service	General Plant	3	16
		Common Plant	3	17
	Accum Depr Rsv	General Plant	3	31
		Common Plant	3	32
	Accum Defer IT	General Plant	3	47
		Common Plant	3	48
	CWIP	General & Common Plant	4	12
	Book Deprec	General Plant	6	42
		Common Plant	6	43
	Rl Estate & Prop Tax	General Plant	7	13
		Common Plant	7	14
	Provis-Defer Inc Tax	General Plant	7	30
		Common Plant	7	31
	Investment Tax Credit	General Plant	7	47
		Common Plant	7	48
	Tax Depr & Removal	General Plant	8	13
		Common Plant	8	14
	AFUDC	General Plant	8	46
		Common Plant	8	47
Record & Coll Study	Cust Acctg & Inform	Acct Recrds & Coll	6	3
Sales, w/ Transp & Modified Sales w/ Transp	Plant in Service	Mains - Average Capacity	3	9
	Gas In Storage	Total Gas in Storage	4	15
	Sales Expense	Sales, Econ Dvlp & Other	6	27
	Labor Allocator	Sales	8	54
Sales, w/o CIP Exempt	Amortizations	CIP / DSM Amortization	6	23
Sales, w/o Transp	Miscellaneous	Fuel	4	19
	Other Prod Expense	MGP	5	24
Service Study	Plant in Service	Services	3	12
	Accum Depr Rsv		3	27
	Accum Defer IT		3	43
	CWIP		4	9
	Distribution O&M Exp		5	34
	Book Deprec		6	38
	Rl Estate & Prop Tax		7	9
	Provis-Defer Inc Tax		7	26
	Investment Tax Credit		7	43
	Tax Depr & Removal		8	9
	AFUDC		8	42
Tran & Distrib	Material & Supply	Materials & Supplies	4	14
	Miscellaneous	Prepay: Insurance	4	17
		Prepay: Miscellaneous	4	18
Uncollectibles Study	Cust Acctg & Inform	Acct Uncollect	6	4

XV. Class Cost of Service Table of Contents

Page 1 contains a summary of the allocated rate base and income statement.

Page 2 contains the revenue deficiency/excess by class assuming each class has an equal return on rate base. It also shows the classification components (e.g., customer related, capacity related). This can be used to design cost-based intra-class rates for customers. For example, the CCOSS shows the total revenue deficiency for the residential customer class as $50,684,978 and the cost-based customer charge for residential of $27.15 per month. The cost classifications (e.g., customer related) are only shown as a total class revenue deficiency. However, the Company does have the same data as below for each cost classification category.

Pages 3 through 8 contain in more detail the components of the rate base and income statement along with the method used to allocate the various cost components. Each item contains a line number along with a description of the item. For those items that use an allocator to split the costs between classes, the next column ("Alloc") shows the name of the allocation method. A value that is not allocated but directly assigned to each class will contain the designation "Direct." Calculated lines such as subtotals do not have a designation in this column. The remaining columns contain the Minnesota jurisdictional total and the class cost allocations for each item.

Pages 9 and 10 contain external allocators and certain internal allocation percentages.

Page 11 contains certain cost of capital items and tax rates used in the CCOSS.

Pipe Material	Diameter	Pipe Type	Footage	Total Cost Normalized 2025	2025 Normalized Cost per Foot	Total Cost Assuming Cost of 2 inch Plastic or Steel Pipe
Plastic	<=2"	Main Gas Plastic <=2"	38,961,533	$682,517,788	**$17.52**	$682,517,788
	> 2" to 4"	Main Gas Plastic > 2" to 4"	10,300,010	$325,841,809	$31.64	$180,432,840
	> 4" to 8"	Main Gas Plastic > 4" to 8"	2,732,230	$129,630,002	$47.44	$47,862,480
	> 8" to 10"	Main Gas Plastic >8" to 10"	50	$0	$0.00	$876
	>12" to 20"	Main Gas Plastic >12" to 20"	1,880	$271,535	$144.43	$32,933
Steel	<=2"	Main Gas Steel <=2"	1,321,445	$100,153,186	**$75.79**	$100,153,186
	> 2" to 4"	Main Gas Steel > 2" to 4"	1,882,124	$200,376,835	$106.46	$142,647,417
	> 4" to 8"	Main Gas Steel > 4" to 8"	1,425,647	$318,088,387	$223.12	$108,050,724
	> 8" to 10"	Main Gas Steel > 8" to 10"	227,336	$44,475,247	$195.64	$17,229,945
	>10" to 12"	Main Gas Steel >10" to 12"	439,092	$171,102,309	$389.67	$33,279,072
	>12" to 20"	Main Gas Steel >12" to 20"	218,999	$183,612,577	$838.42	$16,598,078
Total			**57,510,346**	**$2,156,069,676**	**$37.49**	**$1,328,805,338**

Type	Footage	Share
Plastic	51,995,703	90.41%
Steel	5,514,643	9.59%
Total	**57,510,346**	**100%**

Minimum System % Assuming 2 Inch Plastic or Steel >>>	**61.6%**
Demand Adjustment >>>	**22.5%**
Adjusted Minimum System % Assuming 2 Inch Plastic or Steel >>>	**39.1%**

Increase to Other Revenues

Other Revenue Impact

Tariff	Type	Present Charge	Proposed Charge	Unit	Present Revenue	Proposed Revenue	Difference
5.4	Excess Footage	$9.10	$13.90	77,282	$703,262	$1,074,213	$370,951
5.5	Excavation	$640	$870	401	$256,320	$348,435	$92,115
5.5	Service Ext.	$8.90	$18.00	56,895	$506,366	$1,024,110	$517,745
				Revenue Impact	**$1,465,947**	**$2,446,758**	**$980,811**

Residential New Services < or = 75 feet
Cost Per Service

		Residential
Total Number of Work Orders (1 Work Order = 1 Service)		3,574
Total Actual Cost With Overheads	$	7,412,216
Base Cost per Service	**$**	**2,073.93**
Total Cost Per Service including Material & Meter Costs	**$**	**2,683.37**
Labor for removal		
Percentage of Setup Charge Labor to remove		42%
Total Labor Dollars for Removal	**$**	**871.05**
Other Items for Removal*	**$**	**766.90**
Incremental Cost Per Service	**$**	**1,045.42**
Incremental Cost Per Foot	**$**	**13.94**
Proposed Continuation of Excess Footage Charge	**$**	**13.90**

*These other items include meter credit capitalized at receipt, excess flow valves, service tees, meter brackets, straight risers, and meter assemblies.

Winter Construction Charges

2024 Winter Construction Thaw Unit Costs

Before January 1st (typically burns for 2 days)
A thaw unit requires 3 - 20 lb propane tanks to run for 2 days (20 lb tank = 5 gallons)

Process	Crew or Vehicles	Time to Do	Cost per Hour	Cost	Cost per Gallon	Gallons Used	Propane Cost	Totals
Set thaw unit	Two man crew	1	$100.00	$100.00				
Re-tank thaw unit	Two man crew	0	$100.00	$0.00				
Remove thaw unit	Two man crew	1	$100.00	$100.00				
Total Labor				**$200.00**				
Labor Loading @ 78.604%				$157.21				
Labor w/ Loading				**$357.21**				**$357.21**
Vehicle & Equipment	2 Trucks (stafford truck and the leads truck	2	55	$110.00				$110.00
Propane Cost					2.72	15	$40.80	$40.80
Costs (before E&S)				**$508.01**				**$508.01**
E&S Cost @ 25.00%				$127.00				$127.00
Total Cost				**$635.01**				**$635.01**

After January 1st (typically burns for 3 days)

Process	Crew or Vehicles	Time to Do	Cost per Hour	Cost	Cost per Gallon	Gallons Used	Propane Cost	Totals
Set thaw unit	Two man crew	1	$100.00	$100.00				
Re-tank thaw unit	Two man crew	1	$100.00	$100.00				
Remove thaw unit	Two man crew	1	$100.00	$100.00				
Total Labor				**$300.00**				
Labor Loading @ 78.604%				$235.81				
Labor w/ Loading				**$535.81**				**$535.81**
Vehicle & Equipment	2 Trucks (stafford truck and the leads truck	2	55	$110.00				$110.00
Propane Cost					2.72	22.5	$61.20	$61.20
Costs (before E&S)				**$707.01**				**$707.01**
E&S Cost @ 25.00%				$176.75				$176.75
Total Cost				**$883.77**				**$883.77**

* Please note, 90% of all thaw units are set after January 1st.

Before and after January Costs	Percentage	
$635.01	10%	$63.50
$883.77	90%	$795.39
		$858.89

Billing Labor	$10.00
Producing Bill	$0.53
Postage	$0.73
Total Cost of a Thaw Unit	**$870.15**

2024 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 2024

Average Cost per Foot Winter 2024 Services =	$48.78
Average Cost per Foot Non-Winter Months Services =	$30.61
Difference for Winter Construction	**$18.17**

2024 Updates to Charges

Tariff							
Current Electric Charges			Updated Costs		Proposed Tarif Charge		
Winter Construction Service primary or secondary distribution	$640.00	per thaw unit	$870.15	per thaw unit	Thawing	$870.00	per thaw unit
	$8.90	plus per trench foot	$18.17	plus per trench foot	Service, Primary, or Secondary distribution extension	$18.00	per foot