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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 Electric Service in Minnesota

Docket No. E002/GR-24-320
Exhibit___(CJB-1)

Class Cost of Service Study
and
Selected Rate Design

November 1, 2024

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Barthol. I am a Rate Consultant employed by Northern States Power Company (NSPM or the Company). My responsibilities include preparing testimony on Class Cost of Service Studies for rate cases.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include 13 years of regulatory experience in the areas of rate design and class cost of service. I have a Bachelor of Arts in Economics from St. Cloud State University and a Master of Science in Agricultural Economics from Purdue University. A detailed statement of my qualifications and experience is provided as Exhibit___(CJB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the proposed 2025 and 2026 Class Cost of Service Studies (CCOSSs) for the Company, as required by Minn. Rule 7825.4300(C); and Order Point 17(e) of the Minnesota Public Utilities Commission's (Commission) June 17, 2013 Order in Docket No. E,G999/M-12-587.[1] Copies of these CCOSSs are included in Volume 3, Required Information of this filing (Volume 3). Additionally, I support certain rate design proposals and address several compliance matters.

[1] *In the Matter of the Minnesota Office of Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. 216B.16, subd. 19*, Docket No. E,G999/M-12-587, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTIYEAR RATE PLANS (June 17, 2013).

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following Sections:

- Section II discusses the compliance items related to the CCOSS and where these compliance items are addressed;
- Section III presents the Company's proposed 2025 and 2026 CCOSS and examines the methodology used in developing the CCOSSs;
- Section IV presents the Company's proposed revisions to the Conservation Improvement Program (CIP) Riders;
- Section V presents proposed changes to the excess footage and winter construction charges listed in Section 6 – Rules and Regulations of the Minnesota Electric Rate Book;
- Section VI is my conclusion.

II. COMPLIANCE ITEMS

Q. WHAT COMPLIANCE MATTERS WILL YOU ADDRESS?

A. In compliance with previous Commission Orders, I will address the following topics:

- Basing the D10S capacity allocator on Xcel Energy's system peak coincident with MISO's system peak;
- Classifying joint transmission costs as 70 percent demand-related and 30 percent energy-related;
- Allocating demand-related joint transmission costs with a 12 Coincident Peak (CP) Allocator;

- Providing multiple CCOSSs, for classifying and allocating distribution costs using the Minimum System, Basic Customer, and Peak & Average methods;
- Excluding the loads of customers who are direct assigned the costs of specific distribution substations from calculation of the D60Sub allocator;
- Identifying other production Operation and Maintenance (O&M) costs that vary directly with energy output and allocating the remaining costs using the stratification method;
- Providing a description of each allocation method and reasons why each method is appropriate;
- Providing data linkages in the CCOSS model and more data transparency in the model; and
- Providing CCOSS results in compliance with the Commission's multi-year rate plan Order.

Q. PLEASE SPECIFY THE COMPLIANCE ITEMS FROM PREVIOUS COMMISSION ORDERS THAT ARE ADDRESSED IN YOUR TESTIMONY.

A. Table 1 lists the specific order points that I address in my Direct Testimony.

Table 1
Compliance Items from Prior Commission Decisions

Docket No.	Commission Order	Description of Compliance Item	Testimony Section
E002/GR-15-826	June 12, 2017 Order at 47	Exclude the loads of customers who are directly assigned the costs of specific distribution substations from the calculation of the D60Sub allocator.	Section II (C)(3)
E002/GR-15-826	June 12, 2017 Order at 45	Provide the Commission with the results of multiple methods for functionalizing distribution costs.	Section II (C)(7)(c)
E002/GR-21-630	July 17, 2023 Order at 99	The D10S allocator based on its system peak coincident with the MISO system peak using historical data.	Section III
E002/GR-21-630	July 17, 2023 Order at 101	Classify transmission assets as 70% demand-related and 30% energy-related.	Section III
E002/GR-21-630	July 17, 2023 Order at 102	Allocate demand-related transmission costs using a 12 coincident peak allocator.	Section III
E002/GR-21-630	July 17, 2023 Order at 105	File multiple CCOSSs classifying and allocating distribution system costs.	Section III

III. CCOSS

A. Overview of CCOSS

Q. WHAT IS A CCOSS AND HOW IS IT USED IN SETTING RATES?

A. The purpose of a CCOSS is to evaluate the extent to which different customer classes are responsible for the costs of providing service. This information can be used as a tool when setting rates. Described more technically, the CCOSS allocates jurisdictional costs (in this case, costs of the Company's State of Minnesota electric jurisdiction) to customer classes using class cost allocation factors. The CCOSS measures the contribution each class makes to the Company's overall cost of service, including calculating inter-class and intra-class cost responsibilities. One of the primary goals of the CCOSS is to develop class cost allocation factors that most accurately reflect cost causation. The CCOSS therefore serves as a tool for evaluating and refining the Company's rate structure, as discussed in more detail by Company witness Nicholas N. Paluck.

Q. ARE THE COMPANY'S CCOSSS THE APPROPRIATE TOOLS FOR EVALUATING THE RATE DESIGN IN THIS CASE?

A. Yes. As discussed by Company witness Paluck, a CCOSS is the appropriate starting point for making revenue apportionment and rate design decisions. The Company's proposed CCOSSs are appropriate because they:

- Properly recognize that our investments in generation facilities provide value to all customers, particularly our energy-intensive users;
- Accurately reflect the value of our investments in peaking capacity, transmission, and distribution facilities used to meet system peak requirements;

- Recognize the differing impact that seasonal and time usage patterns can have on the cost of service; and
- Recognize that a portion of distribution costs are incurred to simply connect customers to the system and therefore should be allocated to customer class based on the number of customers.

Q. DOES THE COMPANY PROVIDE ANY DOCUMENTATION TO EXPLAIN HOW ITS CCOSS IS DEVELOPED?

A. Yes. Exhibit___(CJB-1), Schedule 2 includes a document titled, "Guide to Class Cost of Service Study" or "CCOSS Guide." It is a primer on how the CCOSS was conducted, including the processes of cost functionalization, classification, and allocation. This CCOSS Guide also describes how each of the cost allocation factors were developed and identifies the cost items to which each allocator is applied. As ordered by the Commission in Docket No. E002/GR-13-868,[2] the CCOSS Guide has been enhanced to detail each allocation method used in the study. We also provide information on why each allocation method is appropriate compared to other allocation methods and the manual of the National Association of Regulatory Utility Commissioners (NARUC Manual).[3] We note that our CCOSS model has been refined in past years, both by Company proposals and Commission Order. We are now in a position to enhance the structure of our model for increased transparency and ease of review, and we discuss those structural enhancements below.

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[2] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at Order Point No. 37 (May 8, 2015).

[3] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners (January 1992).

Appendix 1 of Schedule 2 explains how the CCOSS customer classes were defined. It also identifies the specific costs that are not assigned to each customer class and the reasons why a given cost is not assigned or allocated to that class. This appendix is responsive to the Minnesota Department of Commerce, Division of Energy Resources (Department) Information Request (IR) Nos. 705 and 707 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

Appendix 2 of Schedule 2 provides detail on the derivation and application of the "External" class cost allocation factors (those allocators that are calculated and developed outside of the CCOSS model), while Appendix 3 to Schedule 2 provides more detail on the "Internal" class cost allocation factors (those allocators based on combinations of costs already allocated to the classes using external allocators). Each appendix includes a rationale supporting each allocator. These appendices along with additional details included in Exhibit___(CJB-1), Schedules 4 and 6 are responsive to Department IR Nos. 709 through 729 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

Finally, Appendix 4 of Schedule 2 provides detail on the other analyses that were conducted to provide inputs to the CCOSS study, including a description of the analysis, the data used in the analysis, and the vintage of the data. This appendix is responsive to Department IR No. 706 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

Q. WHAT ARE THE MAIN CHANGES IN THE CCOSS MODEL COMPARED TO THE MOST RECENT CASE?

A. The Company is proposing two changes to the allocation methodology as compared to the Commission's Order in the Company's last rate case (Docket No. E002/GR-21-630). The Company is proposing to allocate economic development discounts with a base revenue allocator, instead of a total revenue allocator, and to remove the demand adjustment associated with the Zero Intercept Study. In addition to these two changes, we also updated the allocators using more recent system data and updated the Minimum System/Zero Intercept Study for the classification and allocation of distribution costs.

B. CCOSS Results

1. 2025 CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2025 CCOSS.

A. Table 2 below provides a summary of the Company's 2025 test year CCOSS (the 2025 CCOSS) results at the class level, showing the resulting class cost responsibilities (as opposed to revenue apportionment that is addressed by Company witness Paluck). Table 2 replicates Exhibit___(CJB-1), Schedule 3. However, for comparison purposes, Schedule 3 also provides the class revenue apportionment proposed by Company witness Paluck. The detailed 2025 CCOSS output is included in Schedule 4.

These CCOSS results indicate the changes from present rates that would be necessary to result in equal rates of return on investment for each class (*i.e.*, the increase in rates necessary to produce equalized rates of return). In particular, line 18 indicates the revenue increases that would be needed for rates to be based entirely on cost.

Table 2
Summary of 2025 Class Cost of Service Study
State of Minnesota Electric Jurisdiction
($ Thousands)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	4,016,627	1,631,353	124,967	2,220,924	39,383
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[3]	Unadjusted Operating Revenues (line 1 + line 2)	4,018,734	1,633,237	125,031	2,221,062	39,404
[4]	Present Rates (CCOSS page 2, line 2)	3,665,482	1,451,117	115,793	2,066,616	31,956
[5]	Unadjusted Deficiency (line 3 - line 4)	353,252	182,120	9,238	154,446	7,447
[6]	Defic / Pres (line 5 / line 4)	9.6%	12.6%	8.0%	7.5%	23.3%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.30**	**0.83**	**0.78**	**2.42**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL DATA BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
						HIGHLY CONFIDENTIAL DATA ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	6,616	602	(7,290)	72

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	4,016,627	1,637,969	125,569	2,213,633	39,455
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[15]	Adjusted Operating Revenues (line 13 + line 14)	4,018,734	1,639,853	125,634	2,213,771	39,476
[16]	Present Rates (line 4)	3,665,482	1,451,117	115,793	2,066,616	31,956
[17]	Adjusted Deficiency (line 15 - line 16)	353,252	188,736	9,840	147,156	7,520
[18]	**Defic / Pres Rates (line 17 / line 16)**	**9.6%**	**13.0%**	**8.5%**	**7.1%**	**23.5%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.35**	**0.88**	**0.74**	**2.44**

Q. IN TABLE 2, YOU SHOW "ADJUSTED" AND "UNADJUSTED" COST RESPONSIBILITIES. PLEASE EXPLAIN THIS DISTINCTION.

A. The distinction between "adjusted" and "unadjusted" cost responsibilities relates to how the cost of interruptible rate discounts and economic development discounts are reflected in the CCOSS. The method used to reflect the cost of the interruptible rate discounts is the same as that used in the Company's last seven rate cases.

Q. HOW DOES THE COMPANY TREAT INTERRUPTIBLE SERVICE IN THE CCOSS?

A. The Company's CCOSS process treats interruptible discounts as a cost of peaking capacity and allocates that cost to classes based on firm loads. As explained in previous rate cases, the Company views interruptible service as firm service with an attached, after-the-fact, purchased-power contract provision. Through this provision, the Company has the option to buy back all or part of a customer's regulatory entitlement to firm service. The resulting capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity; this helps the Company obtain a reliable power supply portfolio at the lowest cost. This means interruptible rate discounts are really power supply costs and they need to be recognized as such in the CCOSS.

Q. HOW DOES THE COMPANY TREAT ECONOMIC DEVELOPMENT DISCOUNTS IN THE CCOSS?

A. Economic development discounts are treated as a reduction in revenues from the Commercial and Industrial (C&I) Demand class. In the past, as ordered by the Commission in the Company's 2013 rate case (Docket No. E002/GR-13-868), the Company used to allocate these costs with a total revenue allocator. As discussed in more detail below, however, that is not the most reasonable way to allocate economic development discounts and the 2025 CCOSS instead allocates the costs based on 2025 test year base revenues.

Q. HOW ARE INTERRUPTIBLE RATE DISCOUNTS AND ECONOMIC DEVELOPMENT DISCOUNTS REFLECTED IN THE CCOSS?

A. The Company has specific highly confidential trade secret line items in the CCOSS model to address the allocation of interruptible rate discounts and economic development discounts:

1. Line 8 on Table 2 above and Schedule 3, labeled "Interruptible Rate Discounts" shows the amount of the total interruptible rate discounts originating from each class. Line 9 on Table 2 above shows the amount of economic development discounts originating from each class. The amounts shown for each class are lost revenues from that class. These discounts reduce the revenue received from the classes and thus have the effect of increasing the revenue requirement for the classes that receive the discounts.
2. Lines 10 and 11 on Table 2 above and Schedule 3, labeled "Interruptible Rate Disc. Cost Allocation" and "Economic Development Disc. Cost Allocation" shows how the cost of interruptible rate discounts and economic development discounts are allocated to the classes. Interruptible rate discounts are allocated using the applicable generation capacity cost allocation factor, while economic development discounts are allocated based on 2025 test year present revenues.
3. Line 12 on Table 2 above and Schedule 3, labeled "Revenue Requirement Change" shows the net change in the revenue requirement for each customer class.
4. The resulting Line 13 on Table 2 above and Schedule 3, labeled "Adjusted Rate Revenue Requirement" shows the appropriate cost of service for determining class revenue responsibilities. Finally, the adjusted revenue deficiency and percent deficiency are shown on lines 17 and 18, respectively.

Q. HAS THE COMPANY PROVIDED A DOCUMENT THAT SHOWS HOW INDIVIDUAL ITEMS ARE ALLOCATED TO EACH CUSTOMER CLASS AND THE RESULTS OF THAT CLASS ALLOCATION?

A. Yes, Schedule 4 shows the detailed CCOSS results. Pages one through three provide a more detailed summary of the CCOSS results. Page one is a summary of the Company's rate base by function and a summary of the Company's income statement. Page two shows the proposed "Cost" responsibility at equal rates of return in total, by cost classification and function. Page three shows the proposed cost of service compared to the proposed rate revenue responsibility. The listing of the detailed cost allocations begins on page four. The column labeled "Alloc" lists the class cost allocator that is used to allocate costs.[4] The column labeled "FERC Accounts" specifies the FERC codes that are being allocated.[5] Pages four through six show the allocation of costs and calculations needed to determine rate base by class. Pages seven through 12 show the allocation of costs and calculations needed for the income statement. Finally, page 13 shows the cost allocators that are generated internally in the CCOSS model, while page 14 shows the data used to calculate the external allocators.

2. 2026 CCOSS Results

Q. IN ADDITION TO THE 2025 CCOSS, THE COMPANY HAS ALSO INCLUDED A 2026 CCOSS IN THIS FILING. COULD YOU EXPLAIN HOW THE 2025 CCOSS COMPARES TO THE 2026 CCOSS?

A. The 2026 CCOSS uses the same approach as the 2025 CCOSS, but is based upon the cost of service for 2026. Table 3 below provides a summary of the 2026 CCOSS results at the class level, showing the resulting class cost responsibilities. Table 3 replicates a portion of Exhibit___(CJB-1), Schedule 5. For comparison purposes, Schedule 5 includes the full 2026 CCOSS summary

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[4] More detail on each allocator is provided in Appendices 2 and 3 of Schedule 2 (Guide to the Class Cost of Service Study).

[5] The inclusion of the "FERC Accounts" column is in response to Department IR Nos. 709-729 from the Company's 2012 rate case (Docket No. E002/GR-12-961).

and the class revenue allocations proposed by Company witness Paluck. The detailed 2026 CCOSS output is included in Schedule 6.

Table 3
Summary of 2026 Class Cost of Service Study
State of Minnesota Electric Jurisdiction
($ Thousands)

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	4,212,844	1,738,180	127,423	2,305,044	42,197
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,351	2,069	72	181	28
[15]	Adjusted Operating Revenues (line 13 + line 14)	4,215,195	1,740,249	127,496	2,305,225	42,225
[16]	Present Rates (line 4)	3,724,454	1,447,977	114,442	2,130,075	31,961
[17]	Adjusted Deficiency (line 15 - line 16)	490,741	292,272	13,054	175,150	10,264
[18]	**Defic / Pres Rates (line 17 / line 16)**	**13.2%**	**20.2%**	**11.4%**	**8.2%**	**32.1%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.53**	**0.87**	**0.62**	**2.44**

Q. WHAT IS THE PURPOSE OF THE 2026 CCOSS?

A. First, Company witness Paluck uses the 2026 CCOSS to help design 2026 rates. Second, as mentioned above, we are required to provide a 2026 CCOSS pursuant to Order Point 17(e) of the Commission's June 17, 2013 Order in Docket No. E,G999/M-12-587.

C. CCOSS Methodology

1. *Transparency of the CCOSS Model*

Q. HAS THE COMPANY MODIFIED ITS CCOSS METHODOLOGY SINCE THE 2013, 2015, AND 2021 RATE CASES?

A. No. The proposed CCOSSs incorporate the allocator methodology approved in the Company's three most recent cases. Table 4 summarizes the major allocation decisions approved in those cases.

Table 4
CCOSS Methodology Summary

CCOSS Methodology Elements Approved in Docket Nos. E002/GR-13-868, E002/GR-15-826, and E002/GR-21-630
• Allocation of Other Production O&M using the "Location" method; • Classification and Allocation of All Company-Owned Wind Generation using the Plant Stratification method; • Allocation of CIP CCRC using per kWh method; • Allocation of Economic Development Costs to all Customers Based on Present Revenues; and • Calculation of the D10S Capacity Allocator Using Class Peaks that are Coincident with MISO's Peak for the Test Year; • Classification of transmission costs as 70 percent demand-related and 30 percent energy-related and allocate the demand-related costs using a 12 CP allocator.

Q. OVER THE PAST SEVERAL RATE CASES HAS THE COMPANY MADE ITS CCOSS MODEL TRANSPARENT AND EASIER TO REVIEW?

A. Yes. Since the Company's 2013 rate case (Docket No. E002/GR-13-868), the Company has taken several actions to enhance the transparency and ease of review of our CCOSS. These steps were discussed in detail in Company witness Michael A. Peppin's Direct Testimony from our 2015 rate case (Docket No. E002/GR-15-826) and 2021 rate case (Docket No. E002/GR-21-630). For example, worksheet tabs clearly identify all financial and non-financial inputs, with direct linkages for all calculations in the CCOSS model. Exhibit___(CJB-1), Schedule 7 is the "CCOSS Worksheet Tab Index" which provides a description of the contents of each of the 61 tabs to the CCOSS.

Q. DID THE COMPANY ALTER THE DEFINITION OF ITS CUSTOMER CLASSES?

A. No. The Company has used the same class definitions in its last seven rate cases. More detail on the customer class definitions is provided on Appendix 1 of Schedule 2.

2. Plant Stratification

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIED FIXED PRODUCTION PLANT COSTS IN THE PROPOSED CCOSSS.

A. The Company classifies fixed production plant into capacity versus energy-related sub-functions using a process called "Plant Stratification." Though refined over the years, this is the same process the Company has used with Commission approval since the late 1970s. In the NARUC Manual, this process has also been referred to as the Equivalent Peaker Method.

Q. HOW DOES THE COMPANY CLASSIFY FIXED PRODUCTION PLANT INTO CAPACITY-RELATED AND ENERGY-RELATED PORTIONS?

A. The capacity-related portion of the fixed costs of owned-generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost and the highest operating cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant is sub-functionalized as energy-related. These costs are in excess of the capacity-related portion, and as such, were not incurred to obtain capacity, but rather to obtain the lower-cost energy that such plants can produce.

Q. DOES THE COMPANY PROPOSE TO CHANGE THE PLANT STRATIFICATION METHODOLOGY FOR THIS CASE?

A. No, we propose to use the same underlying methodology that was approved in our most recent rate case.

Q. HAS THE COMPANY UPDATED ITS PLANT STRATIFICATION CALCULATIONS FOR THIS CASE?

A. Yes, the underlying methodology has not changed but we have recalculated plant stratification using updated figures. As shown in Table 5 below, the Company has updated plant replacement costs and the resulting capacity-energy splits.

Q. WHAT ARE THE APPLICABLE STRATIFICATION PERCENTAGES IN THIS CASE?

A. The Plant Stratification analysis used in this case is shown in Table 5 below. Table 5 compares the 2023 current-dollar replacement costs of each plant type towards developing stratification percentages.

Table 5
Stratification Allocation by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$1,414	$1,414 / $1,414	100.0%	0.0%
Nuclear	$1,414	$1,414 / $6,972	20.3%	79.7%
Fossil	$1,414	$1,414 / $4,051	34.9%	65.1%
Combined Cycle	$1,414	$1,414 / $2,148	65.9%	34.1%
Hydro	$1,414	$1,414 / $7,584	18.7%	81.3%
Wind	$1,414	$1,414 / $11,419	12.4%	87.6%
Solar	$1,414	$1,414 / $3,736	37.9%	62.1%

Q. ARE THE STRATIFICATION PERCENTAGES APPLIED TO EACH COMPONENT OF THE REVENUE REQUIREMENT RELATED TO FIXED PRODUCTION PLANT?

A. Yes. The process of "stratifying" the revenue requirements of fixed production plant is accomplished by applying these stratification percentages to each component of the revenue requirements (*e.g.*, book investment, accumulated depreciation, accumulated deferred income taxes, Construction Work in Progress), for each generation plant type.

Q. WHAT IS THE MAIN ADVANTAGE OF THE STRATIFICATION METHODOLOGY?

A. This method appropriately reflects cost causation because it recognizes that a significant portion of the fixed generation costs are incurred to obtain fuel savings that more than offset the higher fixed costs, thereby minimizing total costs.

a. Allocation of Demand-Related Portion of Fixed Production Plant – the D10S Allocator

Q. WHAT IS THE D10S ALLOCATOR?

A. The D10S allocator is used to allocate demand-related costs after the plant stratification method is applied. It identifies the percentage of overall demand that is caused by each customer class for a specific time period. For example, it might identify that at five o'clock on August 15, the demand for energy is caused 40 percent by residential customers, 30 percent by commercial customers, and 30 percent by industrial customers. The demand-related fixed production plant costs are then allocated to classes based on these percentages.

Q. WHAT WAS THE COMMISSION'S ORDER IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-21-630) REGARDING THE D10S DEMAND ALLOCATOR?

A. The Commission's Order on the D10S allocator was as follows:

"[F]or Xcel's next general rate case, consistent with the suggestions of the utility and the OAG, the Commission will direct Xcel to calculate the D10S allocator based on its system peak coincident with the MISO system peak using historical data."[6]

Q. PRIOR TO THIS COMMISSION ORDER, HOW WAS THE D10S ALLOCATOR CALCULATED?

A. In the last rate case, the Company also calculated the D10S allocator based on our system peak coincident with the MISO Local Resource Zone 1 (LRZ-1) peak. As we explained in previous cases, however, MISO does not provide forecasts of the peak hour for future years, such as a future test year. Because it was not possible to identify the specific MISO peak hour for the test year in that case, we used historical data for the prior 12 years of the MISO Local Resource Zone-1 peak. In its Order, the Commission directed the Company to continue to use historical data to calculate the D10S allocator, but to use the overall MISO system peak rather than the LRZ-1 peak.

Q. FOR THE 2025 TEST YEAR, DOES MISO FORECAST THE HOUR AND PROJECTED PEAK FOR ITS SYSTEM?

[6] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at Order Point 9(e)(ii) (July 17, 2023).

A. No. As in the last rate case, MISO does not provide forecast estimates of the day and hour that their peak will occur. As a result, the Company is not able to determine forecasted class loads that would be coincident with MISO's forecasted system peak hour for the 2025-2026 test years. For that reason, the calculation of the D10S allocator is based on historical data as ordered by the Commission.

Q. WHAT DOES IT MEAN TO BASE THE D10S ALLOCATOR ON THE NSPM SYSTEM PEAK COINCIDENT WITH THE MISO SYSTEM PEAK?

A. Xcel Energy's system peak occurs at the specific hour of the year that has the highest customer demand for electricity. The overall MISO system also has a system peak, which represents the specific hour of the year that has the highest customer demand for electricity for the entire MISO system. While the Xcel Energy system peak and the MISO system peak are often similar, it is unlikely that they will occur at exactly the same hour over the course of an entire year.

Identifying Xcel Energy's system peak coincident with the MISO system peak first requires identification of the specific hour of the MISO system peak, and then measuring Xcel Energy's corresponding hourly loads at that specific hour.

Q. WITHOUT A MISO PUBLISHED PEAK HOUR FOR THE 2025 TEST YEAR, HOW DOES THE COMPANY PROPOSE TO DETERMINE CLASS LOADS TO COMPLY WITH THE COMMISSION'S ORDER?

A. In order to comply with the Commission's Order, the Company looked at the hour that MISO's system peaked in 2023, the most recent year that has complete annual data. The hour that MISO's system peaked was then compared to the corresponding hourly loads for the NSP system. In 2023, MISO's system peaked on August 23, 2023 at 4 p.m. central time.

Q. WHAT ARE THE CORRESPONDING FORECASTED CLASS LOADS FOR THE MISO HISTORICAL PEAK IN 2023 AND THE RESULTING D10S ALLOCATOR?

A. The forecasted coincident loads by class for the MISO system peak hour is shown in Table 6 below along with the resulting D10S allocator.

Table 6
Minnesota MW Class Loads Coincident with MISO System Peak Hours
Test Year 2025 Forecast

Date & Hour	Residential	Commercial Non-Demand	C&I Demand	Lighting	Total
08/23/2025 04:00 PM	1,585	97	2,240	0	3,922
D10S Allocator	40.41%	2.48%	57.11%	0.00%	100.00%

Q. HOW DOES THIS RESULT COMPARE TO THE D10S ALLOCATOR CALCULATED FOR THE PREVIOUS RATE CASE?

A. Table 7 provides a comparison of the D10S allocator from the Company's last rate case with this one.

Table 7
2022 vs. 2025 D10S Allocator

Year	Residential	Commercial Non-Demand	C&I Demand	Lighting	Total
2022	39.78%	2.83%	57.39%	0.00%	100.00%
2025	40.41%	2.48%	57.11%	0.00%	100.00%

b. Allocation of the Energy-Related Portion of Fixed Production Plant and Variable Production O&M Costs – the E8760 Allocator

Q. WHAT IS THE E8760 ALLOCATOR?

A. The E8760 allocator is calculated by taking each class's hourly load for all 8,760 hours of the test year and weighting it by the corresponding hourly marginal energy costs. It is a reasonable allocator to use for fixed-production energy costs because it weights each hourly load by the hourly marginal energy cost which takes into account the on- and off-peak nature of these costs.

Q. WHAT COSTS ARE ALLOCATED USING THE E8760 ALLOCATOR?

A. The E8760 allocator has been used to allocate fixed production costs that have been classified as being energy-related using the plant stratification classification method. It also allocates all fuel cost items, including purchased energy and energy-related transmission costs.

Q. HOW IS THE E8760 ALLOCATOR CALCULATED?

A. In order to calculate an E8760 for the future test years, the Company's Load Research team established test year load shapes. The test year load shapes are calculated by adjusting historical load shapes to reflect test year weather values. Initially, we used historical load shapes from 2018 through 2022 to create the preliminary 2025 load shape. We then forecasted 2025 weather values, including Cooling Degree Days (CDD), and Heating Degree Days (HDD), to develop the 2025 typical meteorological year (TMY) weather normalized (WN) class load shape templates. Specialized software is used to convert the WN load shape into a WN percentage scalar by removing the magnitude of loads. This software then applies the monthly WN energy kWh forecast to the WN percentage scalar load shape, resulting in the final 2025 WN load shape. This analysis is repeated for the 2026 plan year, following the same methodology used in the Company's past seven rate cases. Table 8 provides the E8760 allocators for 2025 and 2026.

Table 8
2025 and 2026 E8760 Allocators

Year	Residential	Commercial Non-Demand	C&I Demand	Lighting	Total
2025	32.61%	2.77%	64.27%	0.34%	100.00%
2026	31.84%	2.66%	65.17%	0.32%	100.00%

3. *Classification and Allocation of Transmission Costs*

Q. WHAT WAS THE COMMISSION'S ORDER IN THE COMPANY'S LAST RATE CASE (DOCKET NO. E002/GR-21-630) REGARDING THE CLASSIFICATION AND ALLOCATION OF TRANSMISSION COSTS?

A. The Commission ordered the Company to classify transmission costs as 70 percent demand-related and 30 percent energy-related and to allocate the demand-related costs using a 12CP allocator.

Q. DOES IT MAKE SENSE TO CLASSIFY THESE COSTS AS BOTH ENERGY- AND DEMAND-RELATED AND ALLOCATE THE DEMAND-RELATED PORTION OF THESE COSTS WITH A 12 CP ALLOCATOR?

A. Yes, in part. It is reasonable to classify transmission assets as both energy- and demand-related because transmission assets permit the Company to gain access to low-cost energy for its customers. As discussed below, I disagree with the continued use of the 12 CP allocator for the demand-related portion of transmission assets.

Q. WHAT IS A 12 CP ALLOCATOR?

A. The "CP" in 12 CP stands for coincident peak, and the 12 indicates the use of a coincident peak for each of the 12 months. A 12 CP allocation factor is based on the average of 12 monthly coincident peaks.

Q. WHY DID THE COMMISSION DIRECT XCEL ENERGY TO ALLOCATE COSTS USING THE 12 CP ALLOCATOR?

A. The Office of the Attorney General originally recommended the use of the 12 CP allocator for demand-related transmission costs, based on the argument that Xcel Energy collects revenues from transmission assets based on demand charges that are calculated based on the entity's peak load during each month. The Commission adopted this recommendation, explaining that the CCOSS should be calculated by relying on a broader concept of peak demand.

Q. IS IT REASONABLE TO USE THE 12 CP ALLOCATOR FOR DEMAND-RELATED TRANSMISSION COSTS?

A. No. The purpose of the CCOSS is to identify cost causation principles, and classify and allocate costs based on those principles. The arguments from the previous rate case mix up transmission revenues with transmission costs. While transmission revenues are generated, in part, based on demand charges that are calculated monthly, the transmission costs are based on the need to meet customer demands at the single highest peak of the year, not an average peak across twelve months. The transmission system serves multiple functions that are driven by peak demand which include:

- Linking utility system to allow for power exchanges;
- Delivering power to load using markets; and
- Connection to specific generators.

Put another way, if the transmission system were planned to meet an average peak across 12 months, the system would be inadequate to meet customer demand on the actual highest peak.

For this reason, it does not reflect cost causation to allocate demand-related transmission costs using a method that gives equal weight to all 12 months of the year because that is not how the system is planned. Instead, our system is planned to meet maximum customer demand, which occurs during the summer.

Q. WHAT DATA INDICATES THAT THE NSP SYSTEM PEAKS IN THE SUMMER?

A. Table 9 below illustrates the NSP peak for the past eleven years.

Table 9
NSP System Peak

Year	NSP System Peak Day
2013	August 26
2014	July 21
2015	Aug 14
2016	July 20
2017	July 17
2018	June 29
2019	July 19
2020	July 8
2021	July 27
2022	June 20
2023	Aug 23

Q. WHAT ALLOCATOR SHOULD BE USED TO ALLOCATE DEMAND-RELATED TRANSMISSION COSTS GIVEN THAT THE COSTS ARE DRIVEN BY THE NEED TO PLAN FOR THE SUMMER PEAK?

A. Rather than a 12 CP allocator, the demand-related transmission costs should be allocated using the D10S allocator. The D10S allocator appropriately identifies the extent to which customer classes contribute to demand at the time of the NSP load at the MISO peak, to ensure that the cost responsibility is shared fairly across classes.

The NARUC Manual states that demand-related transmission costs should be allocated using the same method that are used for demand-related production costs, on page 75:

> In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs, it is argued, tend to drive transmission costs as well.

As discussed above, demand-related production costs are allocated using the D10S allocator, not the 12 CP method. According to the NARUC manual, demand-related transmission costs should be allocated using the D10S allocator because that is how we allocate demand-related production costs. In fact, the Company does not use a 12 CP allocator to allocate *any* other costs in the CCOSS.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF DEMAND-RELATED TRANSMISSION COSTS?

A. While we have filed the 2025 and 2026 test year CCOSSs using the 12 CP allocator as directed by the Commission in the last rate case, it would be more reasonable to use the D10S allocator. For that reason, I recommend that the D10S allocator be used to allocate demand-related transmission costs in our future rate cases.

Q. PLEASE SUMMARIZE THE RESULTS OF USING THE D10S ALLOCATOR TO ASSIGN DEMAND-RELATED TRANSMISSION COSTS?

A. Table 10 below illustrates the results of the 2025 CCOSS using a D10S allocator to allocate demand-related transmission costs.

Table 10
2025 CCOSS Results – D10S Allocation of Demand-Related Transmission Costs

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	4,016,627	1,653,897	124,606	2,200,162	37,962
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[15]	Adjusted Operating Revenues (line 13 + line 14)	4,018,734	1,655,782	124,670	2,200,300	37,983
[16]	Present Rates (line 4)	3,665,482	1,451,117	115,793	2,066,616	31,956
[17]	Adjusted Deficiency (line 15 - line 16)	353,252	204,664	8,877	133,684	6,026
[18]	**Defic / Pres Rates (line 17 / line 16)**	**9.6%**	**14.1%**	**7.7%**	**6.5%**	**18.9%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.46**	**0.80**	**0.67**	**1.96**

4. *Allocation of Distribution Substation Costs – The D60Sub Allocator*

Q. WHAT COSTS ARE ALLOCATED USING THE D60SUB ALLOCATOR?

A. The D60Sub allocator allocates the costs of distribution substations that individually serve multiple classes of customers.

Q. HOW IS THE D60SUB ALLOCATOR CALCULATED?

A. The D60Sub allocator is based on each class's maximum class coincident load levels forecast for the test year.

Q. ARE THERE OTHER DISTRIBUTION SUBSTATION COSTS THAT ARE INCLUDED IN THE RATE CASE?

A. Yes, there are several substations that are dedicated to serving specific large industrial customers. The costs for these substations are directly assigned to those specific customer classes.

Q. HAS THE COMPANY EXCLUDED THE PEAK LOADS FOR THESE DEDICATED SUBSTATIONS FROM THE D60SUB ALLOCATOR?

A. Yes. In the Company's 2015 rate case (Docket No. E002/GR-15-826), the Commission ordered that loads from customers who are served by distribution substations whose costs are directly assigned should be excluded from the calculation of the D60Sub allocator. The Company agrees that excluding the peak loads of these customers more accurately reflects cost causation. The MW loads for these customers as shown in Table 11 below have been excluded from the D60Sub allocator.

Table 11
Customer Loads Excluded from the D60Sub Allocator (MW)

Customer Class and Voltage	2025 MW Loads Excluded from D60Sub Allocator	2026 MW Loads Excluded from D60Sub Allocator
C&I Demand Secondary Voltage	1.342	1.342
C&I Demand Primary Voltage	3.133	3.133
C&I Demand Transmission Transformed Voltage	182.160	182.199
C&I Demand Transmission Voltage	19.171	19.171
Total	205.807	205.846

Table 12 provides the D60Sub allocators for 2025 and 2026.

Table 12
2025 and 2026 D60Sub Allocator

Year	Residential	Commercial Non-Demand	C&I Demand	Lighting	Total
2025	41.64%	3.11%	54.71%	0.54%	100.00%
2026	42.73%	3.02%	53.71%	0.55%	100.00%

5. Allocation of CIP Conservation Cost Recovery Charge (CCRC)

Q. IS THE COMPANY PROPOSING TO CHANGE HOW IT ALLOCATES CIP COSTS IN THIS CASE?

A. No. Consistent with the Commission's Order in the Company's 2015 rate case (Docket No. E002/GR-15-826), we allocated both the CCRC and the CIP Adjustment Factor (CAF) using the per kWh method. In the proposed

CCOSSs, CCRC costs are allocated to class using the test year sales forecast after subtracting sales to CIP exempt customers.

6. Classification and Allocation of Other Production O&M

Q. DID THE COMPANY ANALYZE THE NATURE OF OTHER PRODUCTION O&M COSTS AS PART OF THIS CASE?

A. Yes. In the Company's 2013 rate case, the Commission required the Company to analyze Other Production O&M costs in order to identify those costs that vary directly with the amount of energy produced.[7]

Based on our analysis, the only Other Production O&M costs that vary directly with energy output (*i.e.,* increase or decrease based on energy output) are chemicals and water use costs. In the case of chemicals, which are used for pollution control purposes, as generator energy output increases, chemical use increases in direct proportion. Similarly, with water usage, which is used to control both boiler water quality and replace lost steam, such as for soot blowing, usage changes proportionally to energy output. Total chemical and water use costs for the 2025 test year are $4.8 million and make up only 1.1 percent of total Other Production O&M costs. The remaining $451.2 million of Other Production O&M does not vary directly with energy output.

Q. DOES THE COMPANY'S CCOSS ALLOCATE THE DIRECTLY-VARIABLE OTHER PRODUCTION O&M COSTS BASED UPON ENERGY?

A. Yes. Consistent with Order Point 37 from the Company's 2013 rate case

[7] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at Order Point 37 (May 8, 2015).

(Docket No. E002/GR-13-868), the CCOSS has classified the Other Production O&M costs that vary directly with energy usage as energy-related and classified the remaining Other Production O&M that originate from a specific generator based on the type of production plant associated with the costs. I note that there are $11.7 million in costs that are not specific to a generator type and $9.9 million of Regional Markets expense that is split into demand and energy components based on how total plant-specific expense is split. Table 13 shows the resulting classification of the 2025 test year Other Production O&M costs.

Table 13
2025 Classification of Other Production O&M Costs
State of Minnesota Electric Jurisdiction
($ Thousands)

Expense Category	2025 Other Production O&M ($000)	Percent Energy	Percent Demand	Energy-Related Portion	Demand-Related Portion
Variable (Chemicals & Water Use)	$4,849.4	100.0%	0.0%	$4,849.4	$0.0
Fossil	$33,902.3	65.08%	34.92%	$22,063.8	$11,838.5
Combustion Turbine	$2,047.4	0.0%	100.0%	$0.0	$2,047.4
Nuclear	$295,860.7	79.71%	20.29%	$235,839.4	$60,021.4
Combined Cycle	$12,633.4	34.15%	65.85%	$4,313.8	$8,319.6
Hydro	$758.9	81.35%	18.65%	$617.4	$141.5
Wind	$84,373.3	87.61%	12.39%	$73,921.5	$10,451.8
Total Generation-Specific Other Production O&M	$434,425.4	78.63%	21.37%	$341,605.3	$92,820.1
Corporate Other Production O&M not Assigned to Generation Type	$11,746.0	78.63%	21.37%	$9,236.3	$2,509.7
Regional Market Expense (FERC Codes 575.1 – 575.8)	$9,862.2	78.63%	21.37%	$7,755.1	$2,107.2
Total Other Production O&M	$456,033.6	78.63%	21.37%	$358,596.6	$97,437.0

7. Direct Assignment of Distribution Costs to the Street Lighting Class

Q. WHAT DISTRIBUTION COSTS DID THE COMPANY DIRECTLY ASSIGN TO THE STREET LIGHTING CLASS?

A. Consistent with finding 693 from the ALJ's report in the 2012 rate case,[8] the Company has directly assigned all costs in FERC Account 373 to the Street Lighting class and a portion of the costs of FERC Account 364. FERC Account 373 includes all street lighting costs except for the cost of wood poles used solely by lighting in overhead distribution areas. The specific cost items included in FERC Account 373 are:

- Overhead and underground lines that only serve street lighting;
- Metal and fiberglass street lighting poles in underground areas;
- Lamps and fixtures; and
- Automatic control equipment.

As shown on page 4, line 45 of Schedule 4, we directly assigned $92.7 million in 2025 test year FERC Account 373 costs to the Street Lighting class in the 2025 CCOSS. This direct assignment is appropriate because the costs included in FERC Account 373 are directly attributable to street lighting.

Q. WHAT COSTS ARE INCLUDED IN FERC ACCOUNT 364?

A. FERC Account 364 includes the cost of installed poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

[8] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION (July 3, 2013).

Q. DOES FERC ACCOUNT 364 INCLUDE MORE THAN JUST STREET LIGHTING COSTS?

A. Yes. The 2025 CCOSS includes $786.5 million Plant in Service for FERC Account 364. Analysis of the FERC account detail shows that 79.6 percent of this account is the cost of the 521,015 wooden poles. Company-owned street lights are attached to 88,531 of these poles, meaning 16.99 percent of the FERC Account 364 costs are attributable to street lighting. Through consultation with our Street Lighting staff, we determined that 60 percent of the lighting poles serve only Street Lighting customers (*i.e.,* they do not have other facilities attached that serve other customer classes).

Q. BASED ON THESE CHARACTERISTICS, HOW MUCH OF THE FERC ACCOUNT 364 COST SHOULD BE DIRECTLY ASSIGNED TO THE STREET LIGHTING CLASS?

A. We directly assigned $63.8 million in 2025 test year FERC Account 364 costs to the Street Lighting class in the 2025 CCOSS. The calculation of the direct assignment is shown in Table 14 and the direct assignment is included on page 4, line 27 of Schedule 4.

Table 14
2025 Calculation of FERC Account 364 Direct Assignment
State of Minnesota Electric Jurisdiction
($ Thousands)

Line No.		
1	FERC Acct 364	$786,530
2	Wood Pole Cost as a Percent of FERC 364	79.6%
3	FERC Acct 364 Pole Cost (line 1 x line 2)	$625,717
4	MN Company-Owned Street Lights on Wooden Poles	88,531
5	Total MN Wood Poles	521,015
6	Lighting Poles as % of Total Poles (line 4 / line 5)	16.99%
7	Lighting % x FERC 364 Pole Cost (line 1 x line 6)	$106,322
8	Percent of Lighting Poles that only Serve Lighting	60%
9	FERC Acct 364 Direct Assignment to Lighting (line 7 x line 8)	$63,793

Q. IN TOTAL, HOW MUCH PLANT INVESTMENT IS DIRECTLY ASSIGNED TO THE STREET LIGHTING CLASS IN THE 2025 CCOSS?

A. In total, $156.5 million of distribution plant investment is directly assigned to the Street Lighting class in the 2025 CCOSS.

8. Classification of Distribution System Costs

Q. WHAT ARE DISTRIBUTION SYSTEM COSTS?

A. The distribution system includes the local distribution conductors, transformers, service drops, and meters.

Q. HOW ARE THE COSTS OF THE DISTRIBUTION SYSTEM CLASSIFIED AND ALLOCATED?

A. As directed by the Commission in the last rate case, we have provided three CCOSS models using different methods to classify and allocate the costs of the distribution system: a Minimum System Study, a Basic Customer Method, and a method that identifies customer-related costs using the Basic Customer Method and identified demand- and energy-related costs using the Peak-and-Average Method. I refer to this third method as the Peak & Average CCOSS.

Q. WHAT IS THE OVERALL PURPOSE OF CLASSIFYING AND ALLOCATING THE COSTS OF THE DISTRIBUTION SYSTEM?

A. The purpose of this analysis is to determine what percentage of distribution system costs should be classified as customer-, demand-, or energy-related, and then determine how those costs should be allocated. As with other types of costs, the classification and allocation should be based on cost causation principles. The costs should be classified and then allocated based on which classes are contributing to the costs.

Q. HOW HAVE THE COSTS OF THE DISTRIBUTION SYSTEM BEEN CLASSIFIED AND ALLOCATED HISTORICALLY?

A. For many years it has been accepted that the costs of the distribution system grow in response to the number of customers served. As the number of customers grows, the size and scale of the distribution system must also increase. In this way, the costs of the distribution system are caused by the number of customers on our system and have traditionally been classified as customer-related costs.[9]

[9] The NARUC Manual states that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system," and thus should be classified as customer-related costs. NARUC Manual at 90.

Not all of the costs are related to the number of customers, however. Some portion of the distribution system costs are incurred to meet peak demand. Because those costs vary based on peak demand, they are classified as demand-related costs.

This understanding of the distribution system is consistent with the guidance in the NARUC Manual, which explains that the distribution system should be classified into demand- and customer-related costs:

> To ensure that (distribution) costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both…
>
> As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.[10]

The Company classifies the distribution system costs in this way using a Minimum System Study.

a. Minimum System Study

Q. WHAT IS A MINIMUM SYSTEM STUDY?

A. A Minimum System Study is used to estimate the percentage of the distribution system that is needed to connect customers but serve no demand. This hypothetical system would carry no capacity (*e.g.*, demand), and so represents the minimum cost that would be needed to connect customers.

[10] *Id.*

Q. IS THE MINIMUM SYSTEM STUDY RELIED UPON IN XCEL ENERGY'S OTHER JURISDICTIONS?

A. Yes. With respect to the regional and state prevalence of the classification, all Commissions in the four-state region (Minnesota, North Dakota, South Dakota, and Wisconsin) accept the customer- and demand-related components of distribution costs. Additionally, the Minnesota Public Utilities Commission has accepted the Minimum System method as a means to separate distribution facilities into demand and customer components since the 1980s.

Q. HOW IS THE MINIMUM SYSTEM STUDY CONDUCTED?

A. There are several ways to perform a Minimum System Study. The NARUC Manual specifically identifies two: the Minimum Size Method and the Zero-Intercept Study.

Q. WHAT IS THE MINIMUM SIZE METHOD?

A. The Minimum Size Method identifies the smallest-sized piece of relevant equipment that is used in the distribution system and assumes that any larger equipment must be selected to serve demand.

To calculate the classification percentages, the Minimum Size Method identifies the cost of the minimum sized equipment, if it were used for all installations, and compares it to the overall cost of the cost item.

Q. WHAT IS THE ZERO-INTERCEPT STUDY?

A. The Zero-Intercept Study is a more technical method used to estimate the same information as the Minimum Size Method. Instead of assuming that the minimum distribution equipment is the smallest equipment that is actually installed, as for the Minimum Size Method, the Zero-Intercept Study calculates the cost of equipment that actually has zero capacity. This calculation is performed using statistical analysis to estimate a cost curve for all currently installed equipment at different capacity amounts, and then estimating the cost of a piece of equipment that had, statistically, zero capacity. This estimated cost is then compared to the overall cost for that equipment to calculate a percentage that is classified as customer-related and demand-related.

Q. WHICH METHOD DID YOU USE TO CALCULATE THE MINIMUM SYSTEM STUDY?

A. Consistent with the Company's practice in past cases, I used both methods and combined their results. I refer to this as the Hybrid Minimum System Study. I selected the results which provided the lower customer-related percentage in order to ensure that we are not overstating the customer classification.

Q. HOW DID YOU CONDUCT THE MINIMUM SIZE METHOD ANALYSIS?

A. There are four steps in the Minimum Size Method analysis.

Step 1: Determine the minimum sized conductor, transformer, and service installed on the distribution system.

Step 2: Determine the installed cost per unit for the minimum sized distribution plant. Installed costs include material costs, labor costs, and equipment costs.

Step 3: Multiply the cost per unit of the minimum sized distribution plant by the total inventory of each plant type.

Step 4: The total cost of the minimum sized distribution plant is divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the customer-related portion of distribution plant investment, with the balance being the capacity-related portion.

Steps one and two are described in more detail by Company witness Marty D. Mensen.

Q. WHAT WERE THE RESULTS OF THE MINIMUM SIZE METHOD ANALYSIS?

A. The Minimum Size Method resulted in the following customer- and demand-related percentages as illustrated in Table 15.

Table 15
Minimum Size Method Classification

Equipment Type	Customer	Demand
Overhead Primary	63.1%	36.9%
Overhead Secondary	96.0%	4.0%
Underground Primary	63.8%	36.2%
Underground Secondary	100.0%	0.0%
Transformers	71.4%	28.6%

Q. HOW DID YOU CONDUCT THE ZERO-INTERCEPT METHOD?

A. The steps for completing a Zero-Intercept Study are described on pages 92 to 94 of the NARUC Manual (the manual refers to it as a "Minimum-Intercept Method"). A Zero Intercept Study requires the following data:

- A listing of all the configurations of equipment installed for the following distribution property units:
  - Overhead Primary Conductor;
  - Overhead Secondary Conductor;

  - Overhead Transformers;
  - Underground Primary Conductor;
  - Underground Secondary Conductor;
  - Underground Transformers; and
  - Primary Voltage Stepdown Transformers.
- For each of the above property units, the equipment inventory is obtained for each property unit configuration.
- The maximum capacity rating for each property unit configuration.
  - Ampacity for conductors
  - kVa for transformers
- The installed cost per unit for the most common property unit configurations.

After the above data is acquired, the following analysis steps are taken to complete a Zero-Intercept Study:

Step 1: The statistical analysis technique called linear regression is applied to the data acquired for each property unit. Specifically, the variable "cost per unit" as the dependent variable (Y axis) is regressed on the variable "maximum capacity" as the independent variable (X axis). The point where the regression line crosses the Y intercept is the theoretical "zero load" cost per unit.

Step 2: The zero load cost per unit is multiplied by the total inventory of the distribution property unit.

Step 3: The installed cost per unit for the most common property configurations is multiplied by the inventory of each configuration. The resulting product is then summed for each property unit.

Step 4: The result from step 2 is divided by the result from step 3. This ratio is classified as the customer component for each property unit.

As with the Minimum Size Method, Company witness Mensen provides more explanation of how the data to complete the Zero-Intercept Study was obtained.

Q. ARE YOU PROPOSING ANY CHANGES TO THE ZERO-INTERCEPT STUDY?

A. Yes. I am proposing one change to the Zero-Intercept Study to remove the demand adjustment. A Zero-Intercept Study estimates the costs of a minimum system that has no load or capacity which means the load carrying capacity of this minimum system would be zero. Therefore, it makes sense to remove the demand adjustment for allocating costs based on the Zero-Intercept Study. This change was proposed by the Xcel Large Industrial party in our last rate case,[11] and I conclude that it is reasonable to make for this case.

Q. WHAT WERE THE RESULTS OF THE ZERO-INTERCEPT STUDY?

A. The Zero-Intercept Study resulted in the following customer- and demand-related percentages as illustrated in Table 16.

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[11] *In the Matter of the Application of Northern States Power Company, d/b/a Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Direct Testimony of Jeffry Pollock at 22–23, Docket No. E002/GR-21-630 (Oct. 3, 2022).

Table 16
Zero-Intercept Study Classification

Equipment Type	Customer	Demand
Overhead Primary	24.0%	76.0%
Overhead Secondary	79.9%	20.1%
Underground Primary	34.7%	65.3%
Underground Secondary	58.5%	41.5%
Transformers	68.1%	31.9%

Q. HOW DID YOU COMBINE THE RESULTS OF THE MINIMUM SIZE METHOD AND THE ZERO-INTERCEPT STUDY TO PRODUCE THE HYBRID RESULTS?

A. As I explained above, I selected the results which provided the lower customer-related percentage in order to ensure that we are not overstating the customer classification. The Zero-Intercept Study resulted in lower customer-related percentages than the Minimum Size Method for all equipment types. Therefore, the results of the Zero-Intercept Study are used to classify all distribution conductor and transformer costs into their customer- and demand-related components. Please see Exhibit___(CJB-1), Schedule 8 for the calculations and results of the Minimum Size Method and Zero-Intercept Study.

Q. WHAT ARE THE RESULTS OF THE HYBRID MINIMUM SYSTEM METHOD?

A. As mentioned above, the Zero-Intercept Study resulted in lower customer-related percentages than the Minimum Size Method. Once distribution costs are classified as customer- and demand-related using the Zero-Intercept method, they are allocated with a customer allocator and a variety of demand-related allocators such as the D61PS1Ph, D61PS, and D62SecL. Please see Appendix 2 of Schedule 2 for definitions of these demand-related allocators.

Q. DID YOU USE ANY OTHER METHODS TO CLASSIFY AND ALLOCATE THE COSTS OF THE DISTRIBUTION SYSTEM?

A. Yes. As ordered by the Commission in our last rate case, I have provided additional CCOSSs in which the costs of the distribution system are classified and allocated using two other methods. The first is a Basic Customer Method. The second uses the Basic Customer Method to identify customer-related costs, and the Peak & Average Method to identify demand- and energy-related costs.

b. Basic Customer Method

Q. WHAT IS THE BASIC CUSTOMER METHOD?

A. The Basic Customer Method classifies distribution plant that serves a single customer as 100 percent customer-related, and all other costs as demand-related. The customer-related costs are allocated with customer counts and the demand-related costs are allocated using the D61PS1Ph, D61PS, and D62SecL allocators.

Q. HOW ARE DISTRIBUTION SYSTEM COSTS CLASSIFIED IN YOUR BASIC CUSTOMER METHOD CCOSS?

A. The Basic Customer Method is very simple. The first step is to identify which costs are installed to serve a single customer. All of those costs are classified as 100 percent customer-related, and all remaining costs are classified as demand-related. For purposes of the Basic Customer Method only, Table 17 indicates how equipment was classified.

Table 17
2025 Basic Customer Method Classification

Equipment Type	Customer	Demand
Conductors	0.0%	100.0%
Transformers	0.0%	100.0%
Service Drops	100.0%	0.0%
Meters	100.0%	0.0%

Table 18 indicates the results for how the Basic Customer Method assigns cost responsibility among the various customer classes.

Table 18
2025 CCOSS Results of Basic Customer Method

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	4,016,627	1,569,395	120,683	2,286,878	39,671
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[15]	Adjusted Operating Revenues (line 13 + line 14)	4,018,734	1,571,279	120,747	2,287,016	39,692
[16]	Present Rates (line 4)	3,665,482	1,451,117	115,793	2,066,616	31,956
[17]	Adjusted Deficiency (line 15 - line 16)	353,252	120,162	4,954	220,400	7,736
[18]	**Defic / Pres Rates (line 17 / line 16)**	**9.6%**	**8.3%**	**4.3%**	**10.7%**	**24.2%**
[19]	**Ratio: Class % / Total %**	**1.00**	**0.86**	**0.44**	**1.11**	**2.51**

Q. ARE THESE RESULTS OF THE BASIC CUSTOMER METHOD ANALYSIS CONSISTENT WITH THE RESULTS OF THE SAME METHOD FROM THE LAST RATE CASE?

A. I determined that in the Company's last rate case, the Basic Customer Method classified service drops as demand related. While I do not agree with the Basic Customer Method overall for the reasons discussed below, it appears to me that applying its underlying theory would cause service drops to be classified as customer-related. I have incorporated this update for this case, which has a small change in the results of the Basic Customer CCOSS.

Table 19
2025 CCOSS Results – Basic Customer CCOSS Class Increases: Service Drops Classified as 100 Percent Demand-Related vs. 100 Percent Customer-Related

Service Drop Classification	Residential	Commercial Non-Demand	C&I Demand	Lighting
100% Customer	8.28%	4.28%	10.66%	24.21%
100% Demand	7.73%	3.95%	11.07%	24.21%

Q. IS THE BASIC CUSTOMER METHOD A REASONABLE WAY TO CLASSIFY THE COSTS OF THE DISTRIBUTION SYSTEM?

A. No. The Basic Customer Method is not reasonable because its core assumption is not supported. The Basic Customer Method assumes, without any technical analysis, that all primary conductor, secondary conductor, and transformers are 100 percent demand-related with no recognition that these costs are driven by the addition of customers. This classification is inappropriate because it ignores the well-established tenet that the addition of customers is a significant determinant of distribution system costs, which is supported by the NARUC manual.[12] While I do not find the Basic Customer Method to be reasonable, I have included the results of a Basic Customer Method CCOSS in compliance with Commission Order.

c. Peak & Average Method

Q. WHAT IS THE PEAK & AVERAGE METHOD?

A. The Peak & Average Method was proposed by the Office of the Attorney General (OAG) in our last rate case. OAG witness Twite explained it in this

[12] Chapter 6, Page 87 of the National Association of Regulatory Utility Commissioners Cost Allocation Manual.

way:

> The Peak & Average method is founded upon the belief that a portion of the shared distribution system is needed to serve a regular amount of energy usage at all times, while additional costs are incurred to ensure the system can meet the cumulative local peak demand. The Peak & Average method classifies a portion of shared distribution system costs as energy-related (to reflect the baseline energy needs of the system) and the remainder as demand-related (to reflect the 'upsizing' of the system to meet peak demand). Typically, the Company's load factor is used to determine the energy-related portion.[13]

Q. HOW IS THE PEAK & AVERAGE METHOD CALCULATED?

A. The Peak & Average Method recommended by the OAG in our last rate case is performed in several steps.

Step 1: the Basic Customer Method is used to identify the portion of customer-related costs.

Step 2: the remaining costs are classified as either energy- or demand-related. The OAG indicated in the last rate case that this calculation should be done using the Company's load factor.

Step 3: the costs are allocated to customer classes using different allocators for each of the customer-, demand-, and energy-related costs.

Q. DID THE COMPANY CREATE ANY NEW ALLOCATORS TO CALCULATE THE PEAK & AVERAGE METHOD?

A. Yes. In order to accurately develop a Peak & Average CCOSS, we needed to

[13] Twite Direct Testimony at 4, 2021 Rate Case, Docket No. E002/GR-21-630.

create new energy allocators that do not allocate distribution costs to customers who take service at transmission voltages and also do not allocate secondary-related distribution costs to customers who take service at primary voltages. Table 20 below provides the new allocators and their definitions.

Table 20
Peak & Average Study New Allocators

Allocator	Definition
E61PS	Based off the E8760 allocator. This allocator allocates the energy-related portion of multi-phase primary distribution line costs to all customers except those who take service at transmission voltages.
E61PS1Ph	Based off the E8760 allocator. This allocator allocates the energy-related portion of single-phase primary distribution line costs to all customers except multiphase customers and those who take service at transmission voltages.
E62Sec	Based off the E8760 allocator. This allocator allocates the energy-related portion of secondary distribution line costs.

Q. WHAT ARE THE RESULTS OF THE PEAK & AVERAGE METHOD?

A. Applying the Peak & Average Method described by the OAG results in the following classification percentages for customer-, demand- and energy-related costs as illustrated in Tables 21 and 22 below.

Table 21
2025 Peak & Average Method Classification

Equipment Type	Customer	Demand	Energy
Conductors	0.0%	45.2%	54.8%
Transformers	0.0%	45.2%	54.8%
Service Drops	100.0%	0.0%	0.0%
Meters	100.0%	0.0%	0.0%

As mentioned above, the energy portion of distribution conductors and transformer costs are determined by the Company's load factor while the remaining costs are allocated with the same demand allocators used under the Minimum System and Basic Customer methods.

The overall results of cost responsibility under the Peak & Average Method are described in Table 22.

Table 22
2025 CCOSS Results of Peak & Average Method

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	4,016,627	1,543,687	120,109	2,313,819	39,012
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[15]	Adjusted Operating Revenues (line 13 + line 14)	4,018,734	1,545,571	120,173	2,313,957	39,033
[16]	Present Rates (line 4)	3,665,482	1,451,117	115,793	2,066,616	31,956
[17]	Adjusted Deficiency (line 15 - line 16)	353,252	94,454	4,380	247,342	7,076
[18]	**Defic / Pres Rates (line 17 / line 16)**	**9.6%**	**6.5%**	**3.8%**	**12.0%**	**22.1%**
[19]	**Ratio: Class % / Total %**	**1.00**	**0.68**	**0.39**	**1.24**	**2.30**

Q. IS THE PEAK & AVERAGE METHOD A REASONABLE WAY TO CLASSIFY AND ALLOCATE THE COSTS OF THE DISTRIBUTION SYSTEM?

A. No. The Peak & Average Method is not reasonable because it ignores that distribution conductors and transformers are driven by the addition of customers. Also, the NARUC Manual does not recognize that distribution costs are classified as energy related.

d. Conclusion regarding Distribution System Classification and Allocation

Q. PLEASE PROVIDE THE COMPARATIVE RESULTS OF THE DISTRIBUTION CLASSIFICATION METHODS.

A. In addition to the Company's proposed CCOSSs, we have provided CCOSSs using different methods to classify and allocate the costs of the distribution system as ordered by the Commission. The results of these three CCOSS methods are compared in Table 23.

Table 23
2025 and 2026 CCOSS Results Comparison:
Class Revenue Percentage Increases and
Residential Monthly Customer-Related Cost per Customer
under Hybrid (Zero-Intercept), Basic Customer, and Peak & Average

2025						
Method	Residential	Commercial Non Demand	C&I Demand	Lighting	Total	Residential Monthly Customer-Related Cost per Customer
Hybrid (Zero-Intercept)	13.0%	8.5%	7.1%	23.5%	9.6%	$21.14
Basic Customer	8.3%	4.3%	10.7%	24.2%	9.6%	$10.04
Peak & Average	6.5%	3.8%	12.0%	22.1%	9.6%	$10.04
2026						
Method	Residential	Commercial Non Demand	C&I Demand	Lighting	Total	Residential Monthly Customer-Related Cost per Customer
Hybrid (Zero-Intercept)	20.2%	11.4%	8.2%	32.1%	13.2%	$23.80
Basic Customer	14.8%	6.3%	12.2%	32.9%	13.2%	$10.75
Peak & Average	12.5%	5.9%	13.8%	30.4%	13.2%	$10.75

Q. WHICH OF THE DISTRIBUTION CLASSIFICATION METHODS DO YOU BELIEVE IS THE MOST REASONABLE?

A. As I mentioned above, I believe the Hybrid (Zero-Intercept) Method is the most reasonable because it follows cost causation and the well-established tenet that the addition of customers is a significant determinant of distribution system costs, which is supported by the NARUC manual

Q. HOW DOES THE COMPANY USE THESE CCOSS RESULTS TO SET RATES?

A. Company witness Paluck explains how the different CCOSS methodologies are used to guide revenue apportionment and rate design.

9. Percent of Customers Served by Three-Phase Primary versus Single-Phase Primary Distribution Lines

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN SINGLE-PHASE AND MULTI-PHASE CONFIGURATIONS.

A. Feeders originate at distribution substations in a three-phase configuration and then often split into three, single-phase lines that serve lower usage customers (in less common instances the system may split into a two-phase configuration).

Q. WAS THE COMPANY ABLE TO QUANTIFY THE PERCENTAGE OF CUSTOMERS IN EACH CUSTOMER CLASS THAT RECEIVE SERVICE OFF THE SINGLE-PHASE PRIMARY DISTRIBUTION SYSTEM AS OPPOSED TO THE MULTI-PHASE PRIMARY DISTRIBUTION SYSTEM?

A. Yes. Based on the data in the Company's Geographic Information System, the Company's Distribution staff determined 71.6 percent of Residential customers receive service off the single-phase primary distribution system. Table 24 also shows that significantly fewer C&I customers receive service from the single-phase primary distribution system.

Table 24
Percent of Customers Served by Single-Phase and Multi-Phase Primary Distribution Lines
State of Minnesota Electric Jurisdiction

Primary Distribution Line Serving the Customer Premise	Customer Class			
	Residential Customers	Commercial Non-Demand	C&I Demand	Lighting Customers
Single-Phase	71.6%	39.3%	17.8%	57.4%
Multi-Phase	28.4%	60.7%	82.2%	42.6%
Total	100.0%	100.0%	100.0%	100.0%

Q. HAS THE COMPANY BASED ITS CLASS ALLOCATION OF PRIMARY DISTRIBUTION LINES COSTS ON THE ABOVE UPDATED ANALYSIS?

A. Yes. We continue to separate distribution lines into capacity and customer components using the Company's Minimum System and Zero Intercept Studies, as described in the CCOSS Guide. As we did in previous rate cases, we then split the classified costs for primary distribution lines into single-phase and multi-phase components. We based the split on miles of single-phase and multi-phase distribution plant and their associated replacement cost (in dollars per mile). The resulting separation of costs is shown on page four of Schedule 4, lines 19-22 (overhead primary distribution lines) and lines 29-32 (underground primary distribution lines). We also created distribution line cost allocators to account for the differing usage of the single-phase portions of the system by different customer classes. Exhibit___(CJB-1), Schedule 9 shows how these allocators were developed.

IV. RATE RIDER REVISIONS

Q. PLEASE EXPLAIN HOW CONSERVATION IMPROVEMENT PROGRAM (CIP) EXPENSES ARE RECOVERED.

A. The total CIP expenses are recovered through two rate components. The first (and usually the largest) component is the Conservation Cost Recovery Charge (CCRC), which is bundled into base rates. The CCRC is reset in general rate case proceedings at the test year CIP expense level. The second component is the Conservation Improvement Program Adjustment Factor (CAF). The CAF is calculated annually to reflect the difference between total CIP program costs (as they change over time) and the most recent test year CCRC.

Q. WHAT ARE THE CURRENT CCRC AND CAF LEVELS?

A. The current CCRC is 0.4955¢ per kWh and was established in the Company's most recent case based on the 2022 test year level of CIP expenses. The current CAF is 0.2225¢ per kWh, which became effective with Commission approval on July 21, 2023 in Docket No. E002/M-23-145.

Q. IS THE COMPANY PROPOSING TO UPDATE THE CCRC IN THIS CASE?

A. Yes. The Company is proposing an increase in the CCRC from the current 0.4955¢ per kWh to 0.6204¢ per kWh to reflect 2025 test year CIP costs of $166,570,277. The calculation of these revised CCRC is shown in Exhibit___(CJB-1), Schedule 10.

V. GENERAL RULES AND REGULATIONS

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

A. The following are the areas in the General Rules and Regulations portion of the tariff where the Company is proposing revisions.

- Excess Footage Charges Section 6.5.1.A.1
  (cost updated in rate case September 1, 2012)
- Winter Construction Charges Section 6.5.1.A.2
  (cost updated in rate case January 1, 2024)
- Dedicated Switching Section 6.5.1.8-7
  (cost updated in rate case 2010)

A. Excess Footage Charges—Section 6.5.1.A.1

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

A. There are three excess footage charges specified on Northern States Power Company's Minnesota Electric Rate Book, Tariff Sheet No. 6-23 of the General Rules and Regulations. Based on increases in material, labor, and equipment costs, the Company is proposing increases in each charge to reflect current costs, as shown in Table 25 below.

Table 25
Excess Footage Charges (Per Foot)

Type	Present Rate	Proposed Rate
Service Line	$7.90	$10.00
Single Phase Sec or Prim	$8.00	$10.50
Three Phase Sec or Prim	$13.90	$17.00

The cost analysis supporting these increases in charges is provided on page 2 of Exhibit___(CJB-1), Schedule 11.

B. Winter Construction Charges—Section 6.5.1.A.2

Q. WHAT REVISIONS ARE PROPOSED FOR WINTER CONSTRUCTION CHARGES?

A. There are two components to the Winter Construction Charges, as indicated on Tariff Sheet No. 6-24 of the General Rules and Regulations. Based on increases in material, labor, and equipment costs, the Company is proposing increases in both Winter Construction Charges to reflect current costs. The Company is proposing an increase in each as shown in Table 26 below.

Table 26
Winter Construction Charges

Type	Present Rate	Proposed Rate
Thawing (Per Frost Burner)	$640.00	$870.00
Trenching (Per 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 11.

C. Dedicated Switching – Section 6.5.1.8-7

Q. WHAT IS DEDICATED SWITCHING?

A. Dedicated Switching is a service requested by a few large C&I customers. It typically occurs when a customer needs to perform work on their own facilities and where doing so requires that the electric service be de-energized. This service takes place at a customer-specified date and time, which is often outside of normal business hours. Providing this service requires taking a service crew off of normal work activities and dispatching them to de-energize the service so the customer can do their internal work. The Company's crew then restores the customer's service as soon as the customer completes their work.

Q. WHAT IS THE PROPOSED CHANGE TO THE DEDICATED SWITCHING SERVICE TARIFF?

A. The Dedicated Switching tariff provides two hourly rates for this service. Based on increases in labor and equipment costs, the Company is proposing to revise these rates to reflect current costs. For Dedicated Switching Service provided on Monday through Saturday, the current rate is $300.00 per hour and the proposed rate is $800.00 per hour. The current rate for this service provided on

Sundays or Holidays is $400.00 per hour and the proposed rate is $1,000.00 per hour. The cost analysis supporting these increases in charges is provided on Page 4 of Schedule 11.

D. Revenue Impact of the Proposed Excess Footage and Winter Construction Rate Increases

Q. WHAT IS THE NET REVENUE IMPACT DUE TO THE PROPOSED INCREASES IN EXCESS FOOTAGE, WINTER CONSTRUCTION, AND DEDICATED SWITCHING CHARGES?

A. The net annual revenue impact from the increase in these rates is $1,337,580 as shown on page 1 of Schedule 11. This increase in revenues is shown with the increase in late payment charges on lines 2 and 14 of Schedules 3 and 5 attached to my testimony. It is also shown on page 7, row 21 of Schedules 4 and 6 attached to my testimony. The proposed increase in these charges reduces the proposed increase in retail revenues by Company witness Paluck.

VI. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE THE CONCLUSIONS FROM YOUR TESTIMONY.

A. The purpose of a CCOSS is to provide a reasonable measure of the contribution each class makes to the Company's overall cost of service, with the ultimate goal of generating a basis from which rates can be evaluated and refined. We have modified our CCOSS methodology since the Company's most recent case based on several new or renewed studies and Commission Order. These modifications result in CCOSSs that:

- Properly recognize that our investments in baseload generation facilities provide value to all customers, particularly our energy-intensive users;

- Accurately reflect the value of our investments in peaking capacity, transmission and distribution facilities used to meet system peak requirements;
- Recognize the differing impact that seasonal and time usage patterns can have on the cost of service; and
- Recognize that a portion of distribution costs are incurred to simply connect customers to the system and therefore should be allocated to customer class based on the number of customers.

Given the refinements to the CCOSS over time, resulting in appropriate and improved allocations to previous years, the Company has turned to structural enhancements in this case. Our CCOSS model is now more robust and transparent. Therefore, the Company's CCOSSs are appropriate rate making tools in this case.

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
United States Marine Corps Machine Gunner	2000 – 2004

EDUCATIONAL BACKGROUND

Purdue University; MS Agricultural Economics	2010
St. Cloud State University; BA Economics	2008

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

I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as Residential, Non-Demand C&I, and Demand C&I. For example, generation capacity costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as distribution, transmission, and generation. The CCOSS also assigns ***direct*** costs (e.g. a dedicated service extensions or dedicated substations), 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. kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are; (1) capital costs associated with investment in generation, transmission, and distribution facilities and (2) on-going expenses such as fuel used to produce the energy, 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' share of the capacity, energy, and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study 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 (3) basic steps:

1. Functionalization – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution, and customer).
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy, or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g. kWs of capacity, kWhs of energy, 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 electric utility system. Costs must be first functionalized because each class' 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 (4) basic functions and the associated sub-functions are shown in the table below:

Function	FERC Accounts	Sub-Function	Description
Generation	120, 310-346, 500-557	"Energy-related"	Includes the fixed costs of generation plant investment and purchase capacity costs, which have been stratified as "energy-related."
		Summer "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system summer peak load requirements.
		Winter "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system winter peak load requirements.
		On-Peak Energy	Includes costs for fuel and purchases of energy for on-peak hours.
		Off-Peak Energy	Includes costs for the fuel and purchases of energy for off-peak hours.
Transmission	350-359, 560-579	None	Includes costs of transmission lines used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
Distribution	360-368, 580-598	Distribution Substations	Includes costs of the facilities (e.g. transformers and switch gear) between the transmission and distribution systems.
		Primary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of primary voltage conductors, transformers and related facilities.
		Secondary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of secondary voltage conductors, transformers, customer services and related facilities.
Customer	360-369, 580-598, 901-916	"Customer" portion of the Primary and Secondary Systems	Includes costs for the "customer" portion of primary and secondary conductors, transformers, customer service drops, related facilities and the costs of metering.
		Energy Services	Includes costs for meter reading, billing, customer service and information, and back office support.

A. Generation Cost Stratification

Stratification is the term used to identify the part of the CCOSS process used to separate or "stratify" fixed generation costs into the necessary "capacity-related" and "energy-related" sub-functions. The "capacity-related" portion of the fixed costs of owned generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant are sub-functionalized as "energy-related." This second portion of the fixed generation costs is "energy-related" because these costs are in excess of the "capacity-related" portion and as such were not incurred to obtain capacity but rather were incurred to obtain the lower cost energy that such plants can produce.

For example, the plant stratification analysis used in the current rate case is shown in the table below. It compares the current dollar replacement costs of each plant type, to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$1,414	$1,414 / $1,414	100.0%	0.0%
Nuclear	$6,972	$1,414 / $6,972	20.3%	79.7%
Fossil	$4,051	$1,414 / $4,051	34.9%	65.1%
Combined Cycle	$2,148	$1,414 / $2,148	65.9%	34.1%
Hydro	$7,584	$1,414 / $7,584	18.7%	81.3%
Wind	$11,419	$1,414 / $11,419	12.4%	87.6%
Solar	$3,736	$1,414 / $3,736	37.9%	62.1%

This process of "stratifying" the revenue requirements of the generation plant is accomplished by applying these stratification percentages to each component of the revenue requirements (e.g. plant investment, accumulated depreciation, deferred income taxes, construction work in progress (CWIP), etc.), for each generation plant type.

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 (3) principle service requirements or billing components are:

1. Demand – Costs that are driven by customers' maximum kilowatt (kW) demand.
2. Energy – Costs that are driven by customers' energy or kilowatt-hours (kWh) 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 was classified:

Function/Sub-Function	**Cost Classification**		
	Demand	**Energy**	**Customer**
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation		X	
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X	X	
Distribution Substations	X		
Primary Transformers	X		
Primary Lines	X		X
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X
Customer Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers, and service drops are classified as both "demand" and "customer" related costs. 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. Two methods that are mentioned in the NARUC manual for performing this cost separation are the Minimum Distribution System method and the Minimum/Zero Intercept method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility 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 Minimum/Zero Intercept method requires significantly more data and analysis than the Minimum Distribution System method. The Minimum/Zero Intercept method requires the analyst to develop installed per unit costs for the most common property unit configurations. Next, the maximum capacity rating (Ampacity for conductors and kVa for transformers) must be determined. Once the above data has been acquired, the statistical analysis technique called linear regression is applied to each property unit. Specifically, the variable "cost per unit" as the dependent variable (Y axis) is regressed on the variable "maximum capacity" as the independent variable (X axis). The point where the regression line crosses the Y intercept is the theoretical "zero load" cost per unit. The zero intercept cost for a given property unit determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the zero intercept cost.

The Company completed both minimum system and zero intercept studies for all property units except distribution services. Detailed property records on the configuration or footage of distribution service drops are not available. As a result, the Company was not able to conduct a detailed minimum system or zero intercept study for classifying the cost of service drops. As a substitute, a simplified minimum system analysis was conducted.

For each property unit, the table below shows the percent of costs that were classified as customer-related using the Minimum/Zero Intercept method compared to the Minimum Distribution System method. As shown below, for all 6 property units the Zero-Intercept method provides a lower customer component.

	% of Costs Classified as "Customer" Related	
Equipment Type	**Minimum/Zero Intercept Method**	**Minimum Distribution System Method**
Overhead Lines Primary	24.0%	63.2%
Overhead Lines Secondary	79.9%	96.0%
Overhead Transformers	69.1%	78.0%
Underground Lines Primary	34.7%	63.8%
Underground Lines Secondary	58.6%	100%
Underground Transformers	70.2%	66.7%

In applying the results of the zero intercept and minimum system studies to the proposed CCOSS, the Company used a hybrid of the two methods, such that the Company used the method that provided the lower customer component as shown in the table below.

Property Unit	**% Customer Related**	**% Capacity Related**
Overhead Lines Primary (used Zero Intercept Result)	24.0%	76.0%
Overhead Lines Secondary (used Zero Intercept Result)	79.9%	20.1%
Underground Lines Primary (used Zero Intercept Result)	34.7%	65.3%
Underground Lines Secondary (used Zero Intercept Result)	58.6%	41.4%
Weighted Average for Overhead & Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	68.1%	31.9%

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. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations; and
  - Street lighting facility costs.
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to 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%.
  - There are 2 types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, 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:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP);
        - Class peak or non-coincident peak; and
        - Individual customer maximum demands.
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales);
        - kWh at the generator (kWh sales plus losses); and
        - kWh energy, weighted by the variable cost of the energy in the hour it is used.
      - Customer-related allocators
        - Number of customers; and
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

      Details on the external allocators used in the CCOSS model are shown in Appendix 2.

    - 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 kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:

- Production, transmission and distribution plant investment – Labeled "PTD" in the CCOSS model.
- Distribution O&M expenses without supervision and miscellaneous expenses – Labeled "OXDTS" in the CCOSS model.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 3.

VI. 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. Non-Demand Metered Commercial;
3. Demand Metered Commercial & Industrial; and
4. Street & Outdoor Lighting.

Also, because of the significantly different distribution-functional requirements of customers within the Demand Metered C&I class, the Company's CCOSS also identifies the cost differences associated with the following distribution-function requirements within this class based on the voltage they are served at:

1. Secondary;
2. Primary;
3. Transmission Transformed; and
4. Transmission.

More detail on customer class definitions is shown in Appendix 1.

VII. 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 "RR-TOT") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below (the label of the worksheet tab in shown in parenthesis below):

1. Billing Unit:

   a. Customer (RR-Cus)
   b. Demand (RR-Dmd)
   c. Energy (RR-Ene)

2. Function and Associated Sub-Function:

   a. Energy (RR-Ene)
      a) On-Peak Energy (RR-On)
      b) Off-Peak Energy (RR-Off)

   b. Generation (RR-Gen_Dmd): Sub-functions include:
      a) Summer Capacity-Related Plant (RR-Summ)
      b) Winter Capacity-Related Plant (RR-Wint)
      c) Energy-Related Plant (RR-Base)

   c. Transmission (RR-Transco)

   d. Distribution (RR-Disco): Sub-functions include:
      a) Distribution Substations (RR-Psub)
      b) Primary Voltage (RR-Prim)
      c) Secondary Voltage (RR-Sec)

   e. Customer (RR-Cus): Sub-functions include:
      a) Service Drops (RR-Svc_Drop)
      b) Energy Services (RR-En_Svc)

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.

VIII. 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, as well as other analyses such as the development of voltage discounts.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accum Depr – Accum Defer Inc Tax+ CWIP + Other Additions

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' "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.

XI. CCOSS Output

The filed output of the CCOSS model includes the "TOT" worksheet layer of the much larger model. The important output from the functional, sub-functional and billing component layers is presented on pages 2 and 3 of this "TOT" layer. The following table lists what is shown on each CCOSS page when printed.

Final CCOSS Printout "TOT" Worksheet			
CCOSS Section	**Page Number**	**Results Detail**	**Line Numbers**
Results Summary	1	Rate Base Summary	1-21
		Income Statement Summary	22-31
	2	**Proposed Cost** Responsibility at <u>Equal ROR</u> (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-51
	3	**Proposed Cost** Responsibility at <u>Equal ROR</u> (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-54
Rate Base Detail	4	Original Plant in Service	1-50
	5	MINUS Accumulated Depreciation	1-29
		MINUS Accumulated Deferred Income Tax	30-57
	6	PLUS Construction Work in Progress & Other Additions	1-36
		EQUALS Total Rate Base & Common Rate Base	37-38
Income Statement Detail	7	Present and Proposed Revenues	1-26
		MINUS O&M Expenses part 1	27-41
	8	MINUS O&M Expenses part 2	1-34
	9	MINUS Book Depreciation	1-24
		MINUS Real Estate & Property Taxes, Other Taxes	25-51
	10	MINUS Provision for Deferred Income Tax	1-27
		MINUS Investment Tax Credit; Total Operating Expense	28-52
		EQUALS Present and Proposed Operating Income Before Income Taxes	53A 53B
	11 (Income Tax Calcs.)	Tax Additions	1-36
		MINUS Tax Deductions	1-30
		EQUALS Total Income Tax Adjustments	37
		Present and Proposed Taxable Net Income	38A 38B
		Present and Proposed State and Federal Income Taxes	39A 39B
		Present and Proposed Preliminary Return	40A 40B
		AFUDC (from page 12)	41
		Present and Proposed Total Return	42A 42B
Misc Calcs	12	AFUDC	1-25
		Labor Allocator	26-47
Allocator Data	13	Internal Allocators and Associated Data	1-31
	14	External Allocators and Associated Data	1-50

	Customer Class	Rate Codes	kW Size	Voltage Specifications	Costs Not Assigned	Why Costs Not Assigned
1	Residential	A00, A01, A02, A03, A04, A05 (if residential), A06 (if residential), A08, A72, A74, A80, A81, A82, A83			• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.
2	C&I Non Demand Metered	A05 (if C&I), A06 (if C&I), A09, A10, A11, A12, A13, A16, A18, A22, A40, A42,	< 25 kW		• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.
3	C&I Secondary Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63, A87, A88, A89, A90	> 25 kW	Secondary	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Underground (UG) services. C&I customers pay for their own UG services.	The listed facilities and their associated costs are not used to provide service to these customers.
4	C&I Primary Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63	> 25 kW	Primary	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers.

	Customer Class	Rate Codes	kW Size	Voltage Specifications	Costs Not Assigned	Why Costs Not Assigned
5	C&I Transmission Transformed Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63	> 25 kW	Transmission Transformed	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes. • Costs of Primary Voltage Transformers. • Costs of Primary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers.
6	C&I Transmission Voltage	A14, A15, A17, A19, A23, A24, A27, A29, A41, A62, A63	> 25 kW	Transmission	• Costs directly attributed to and directly assigned to Street Lighting customers. • Directly assigned costs of specific Transmission Radial Lines. • Costs of Distribution Substations. • Costs of Primary Voltage Transformers. • Costs of Primary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Overhead and Underground Lines that have been classified as either “Customer” or “Capacity” related. • Costs of Secondary Voltage Transformers that have been classified as either “Customer” or “Capacity” related. • Costs of Service Lines that have been classified as either “Customer” or “Capacity” related.	The listed facilities and their associated costs are not used to provide service to these customers.
7	Outdoor Lighting	A07, A30, A32, A34, A35, A37			• Directly assigned costs of specific Transmission Radial Lines and Distribution Substations that solely serve other customer classes.	The listed facilities and their associated costs are not used to provide service to these customers.

Code	Allocator for:	Description	Data Source(s)	Derivation	Allocator Rationale
C11	Connection charge revenues	Average monthly customers	- 2024 Customer forecast for TY2025	Forecasted annual bills / 12	Connection charge revenue isn't specifically included in the NARUC Manual. New customer connections, by class, follow the pattern of existing customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C11WA	Customer accounting costs	Weighted customer accounting costs	- 2024 Customer forecast for TY2025 and - 2025 customer accounting weighting factors	C11 X C11WAF	On page 103, the NARUC Manual says customer accounting costs are classified as customer-related, which matches Xcel Energy's approach. As for allocating costs to class, the chosen allocator recognizes that classes with larger customers require more complicated tracking per customer. Thus, such classes should get heavier weights. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C12WM	Meter costs	Weighted meter investment	- 2024 meter, CT and VT model inventory by customer class - 2024 meter, CT and VT replacement costs	C12 X C12WMF	On page 96, the NARUC Manual notes that meters are normally classified as customer-related. And on page 98, the Manual supports the idea of weighting classes differently to reflect differences in capital investment levels. Xcel Energy's allocator follows both suggestions. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C61PS	The "customer" (minimum system) portion of multi-phase primary distribution line costs	Average monthly customers served at primary or secondary voltage	- Customer 2024 forecast for TY2025 - 2024 Minimum System and Zero Intercept studies	C11 less transmission transformed and transmission voltage customers	On page 87, the NARUC Manual only discusses overhead and underground lines in general, rather than primary, multi-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a Minimum System Study. Xcel Energy follows that approach. This allocator only addresses customer-based costs. It reflects both secondary and primary voltage customers, since both make use of primary lines. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C61PS1Ph	The "customer" (minimum system) portion of single phase <u>primary</u> distribution line costs	Average monthly customers that are served by single phase primary distribution facilities	- Customer forecast for TY2024 and 2025 - Minimum System and Zero Intercept studies - GIS data that shows the percent of customers in each class that receive service from the single phase primary distribution system	C61PS multiplied by the percent of customers in each class that receive service from the single phase primary distribution system	On page 87, the NARUC Manual only discusses overhead and underground lines in general, rather than primary, single-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel Energy follows that approach. This allocator only addresses customer-based costs. It reflects both secondary and primary voltage customers, since both make use of primary lines. But it only applies to those served by a single phase. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Code	Allocator for:	Description	Data Source(s)	Derivation	Allocator Rationale
C62NL	The customer portion of Company owned service costs.	Adjusted average monthly secondary voltage customers	- Customer forecast for TY2025 - 2024 Minimum System and Zero Intercept studies	C62Sec less street lighting and C&I underground customers	On page 87, the NARUC Manual discusses services, suggesting just a customer-related classification. Xcel Energy chose instead to extend the minimum system approach to service lines, thus recognizing that a service wire has a capacity aspect, as well as the ability to deliver a minimum electrical connectivity. This allocator only addresses customer-based costs. It excludes lighting customers, since they don't have service wires. And it excludes C&I underground customers, since they own their service wire. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
C62Sec	The customer portion of secondary distribution line costs	Average monthly customers served at secondary voltage	- Customer forecast for TY2025 - 2024 Minimum System and Zero Intercept studies	C61PS less primary voltage customers	On page 87, the NARUC Manual only discusses overhead and underground lines in general, rather than secondary lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel Energy follows that approach. This allocator only addresses customer-based costs. It reflects all secondary voltage customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
D10S	Capacity-related generation costs and all transmission costs	Class contribution to System Peaks at MISO's peak hour for Local Resource Zone 1 (LRZ-1)	- 8760 load research data by class for the years 2018-2022 synched to the 2024 kWh Sales Forecast for TY2025	Since the MISO system peak hour for the test year is not available, used hourly class loads that are in the same hour as the 2023 MISO system peak hour.	Pages 39 through 63 of the NARUC Manual discuss numerous methods for allocating generation capital costs to class. And pages 75 through 83 of the Manual discuss many of the same methods for allocating transmission line costs. The Company employs a different approach that nonetheless reflects many of the underlying issues in the manual. This approach recognizes that a portion of a utility's generation assets, as well as all of their transmission assets, are built for the purpose of meeting peak load. And this allocator is applied to those costs. This allocator previously reflected the utility's own annual, coincident peak – i.e., a 1CP approach. But because the company has become so fully integrated with MISO, and because MISO basically dispatches the company's power plants, a MISO-coincident peak is now used. A significant portion of the utility's generation investments is made primarily to facilitate the consumption of lower-cost fuel (rather than to meet peak demand). Those costs are allocated to class based on an energy allocator, as discussed for E8760. Such costs are still classified as demand-related. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D60Sub	Distribution substation costs	Class-coincident peak less transmission-level demand	- 8760 load research data by class for the years 2018-2022 synched to the 2024 kWh Sales Forecast for TY2025		On pages 77 through 83, the NARUC Manual discusses several possible class allocation methods for transmission plant, all related to some form of peak demand (other than a direct assignment approach). If a single season (in Xcel Energy's case, summer) clearly has the largest peak, then a 1CP method seems to be the most appropriate. And the Company does use 1CP. In particular, this allocator represents the annual coincident peak demand of every customer class except those served at transmission voltage (since they don't make use of step-down substations).The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
D61PS	The capacity portion of multi-phase primary voltage distribution line costs.	Class-coincident peak for primary and secondary voltage customers	- 8760 load research data by class for the years 2018-2022 synched to the 2024 kWh Sales Forecast for TY2025 - 2024 Minimum System and Zero Intercept studies	D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect their summer peak is less than their winter peak	On page 87, the NARUC Manual only discusses overhead and underground lines in general, rather than primary, multi-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel Energy follows that approach. This allocator only addresses demand-based costs. It reflects the class-coincident peak for both secondary and primary voltage customers, since both make use of primary lines. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D61PS1Ph	The capacity portion of single phase primary distribution line costs	Class-coincident peak for primary and secondary voltage customers for customers that use the single phase primary distribution system	- 8760 load research data by class for the years 2018-2022 synched to the 2024 kWh Sales Forecast for TY2025 - 2024 Minimum System and Zero Intercept studies - GIS data that shows the percent of customers in each class that receive service from the single phase primary distribution system	D61PS multiplied by the percent of customers in each class that receive service from the single phase primary distribution system.	On page 87, the NARUC Manual only discusses overhead and underground lines in general, rather than primary, single-phase lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel Energy follows that approach. This allocator only addresses demand-based costs. It reflects the class-coincident peak for both secondary and primary voltage customers, since both make use of primary lines. But it only applies to those served by a single phase. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
D62NLL	The capacity portion of company owned service line costs	Secondary voltage demand less lighting	- Individual customer maximum demands from load research for non-demand billed customers and 2013 billing data for demand billed customers - 2024 Minimum system and Zero Intercept studies.	Non-coincident (or “customer peak”) demand for secondary voltage customers, less the following: street lighting, area lighting and C&I customers served underground	On page 87, the NARUC Manual discusses services, suggesting just a customer-related classification. Xcel Energy chose instead to extend the minimum system approach to service lines, thus recognizing that a service wire has a capacity aspect, as well as the ability to deliver a minimum electrical connectivity. This allocator only addresses demand-based costs. It excludes lighting customers, since they don’t have service wires. And it excludes C&I underground service customers, since they own their service wire. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Code	Allocator for	Description	Data Sources	Derivation	Allocator Rationale
D62SecL	The capacity portion of secondary distribution line costs	Average of class-coincident peak, secondary voltage percentages and non-coincident secondary voltage percentages	- TY2025 load research class coincident demands - 2024 Minimum system and Zero Intercept studies - Individual customer maximum demands from load research for non-demand billed customers and billing data for demand billed customers.	First define D62Sec as equal to D61PS, less primary customers. Then for each secondary class, D62SecL equals the average of D62Sec percent and non-coincident (or "customer peak"), secondary voltage percent.	On page 87, the NARUC Manual discusses only overhead and underground lines in general, rather than secondary lines in particular. It suggests a mixed classification of demand- and customer-related, based on a minimum system study. Xcel Energy follows that approach. This allocator only addresses demand-based costs. It reflects all secondary voltage customers. These capacity costs are driven by a 50/50 blend of class coincident peak demand and individual customer maximum (non-coincident) demand, less minimum system requirements. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
E8760	Fuel, purchased energy and energy-related fixed generation costs.	Class hourly energy (MWh) requirements weighted to reflect higher on-peak fuel costs	- 8760 load research data by class for the years 2018-2022 synched to the 2024 kWh Sales Forecast for TY2025 - Hourly marginal energy costs for the 2025 test year.	The hourly on-peak sales each class weighted by the hourly marginal energy cost.	On page 64, the NARUC Manual notes that fuel costs are almost always classified as energy-related. And some form of time differentiation, such as on-peak vs. off-peak, is most appropriate. Xcel Energy previously used such an on-peak / off-peak approach. Then the Company migrated to a more precise approach that properly weights the marginal energy cost for each of the 8,760 hours in a standard year, along with class consumption during each hour. This allocator is applied to all fuel cost items, including purchased energy. Those costs are classified as energy-related. And as is explained in more detail for the D10S allocator, this allocator is also applied to the fuel-related portions of generation equipment. Those costs are classified as demand-related. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.
E99XCIP	CIP O&M Expenses	TY2025 sales forecast by customer class Less the TY2025 sales forecast for CIP exempt customers	2024 kWh Sales Forecast for TY2025		Programs such as CIP were not anticipated by the NARUC Manual. This allocator is simply based on sales. But since it applies to CIP program costs, it excludes sales from CIP-exempt customers. The Company feels that this allocator most appropriately reflects cost and is superior to other possible methods.

Internal Allocators are those that are determined from data generated within the Class Cost of Service Study (CCOSS). Below is a list of internal allocators that are used within the CCOSS.

The Order in rate case Docket No. E002/GR-13-868 required the following CCOSS compliance item:

> In its next rate case the Company's class-cost-of-service study shall include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered by the Company, whether those methods are based on the Manual of the National Association of Regulatory Utility Commissioners or the Company's specific system requirements, its experience, and its engineering and operating characteristics. The Company shall also explain its reasoning in cases in which it did not consider alternative methods of allocation or classification.

To comply with this requirement, Schedule 2, Appendix 2, provided detailed comments about the appropriateness of all the external allocators. However, the internal allocators are simply derived by summing up multiple external allocators – in some cases, a few dozen. If the external allocators are fitting, then the internal allocators should also be fitting.

Code	Allocator for:	Description	Allocator Justification
C11P10	Expenses and labor related to customer assistance and instructional advertising	This allocator is the average of the Customer-related C11 allocator and the Production Plant investment P10 allocator.	Customer assistance and advertising expenses are driven by # of customers, and since most assistance pertains to helping customers reduce energy use it affects production plant investment.
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims	Total Labor costs on Page 12 line 48 less A&G Labor on Page 12 line 46. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance, Net Operating Loss Carryover, Misc Prepayments	Electric plant in service less accumulated provision for depreciation.	These costs are driven by net electric plant in service.
OXDTS	Distribution customer installation expenses and miscellaneous distribution expense	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision & engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expense are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8).	The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses.

Code	Allocator for:	Description	Allocator Justification
OXTS	Selected administrative and general expenses such as Office Supplies, General Advertising, Contributions and maintenance of “General” plant	All O&M costs except Regulatory Expense and any A&G costs, which are the costs to be allocated on OXTS (lines 16, 17 and 23-27 of page 8). These A&G expenses are excluded to avoid circular references.	The OXTS allocator includes all O&M expenses except regulatory expense and those A&G items that are allocated with OXTS. Representing most O&M expenses, the OXTS allocator is appropriate for allocating A&G expenses.
P10	Interchange Production Capacity (i.e. fixed) inter-company Revenues. Rate base addition production-related materials and supplies	Total Production Plant: Original Plant in Service (line 6 of page 4).	Total production plant investment is closely associated with Interchange Agreement Capacity related revenues and Miscellaneous Rate Base Production additions.
P10WoN	Interchange Production Capacity (i.e. fixed) inter-company Costs	Total Production Plant less Nuclear Fuel Original Plant in Service. Nuclear fuel is excluded since NSP Wisconsin does not have nuclear plants (Total Production Plant on line 6 of page 4 less Nuclear Fuel on line 5 of page 4).	Since Wisconsin does not have nuclear plants, Total production plant investment less nuclear fuel investment is a good indicator of Interchange Agreement Capacity related expenses.
P5161A	Used to allocate Step-up sub transmission costs in the Labor Allocator development	Total Generation Set-Up Transformer original plant in service: Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4).	Generation step-up plant investment drives step-up generation labor costs.
P61	Distribution Substation O&M expense and Distribution Substation labor	Distribution Plant: Substations Original Plant in Service (line 18, page 4).	Substation plant original investment drives Distribution Substation plant O&M costs and Distribution Substation Labor.
P68	All costs related to Distribution Plant “Line Transformers”	Distribution Plant: Line Transformers Original Plant in Service (line 42 of page 4).	Line transformer plant investment drives all line transformer costs.
P69	All costs related to Distribution Plant “Services”	Customer-Connection “Services” Original Plant in Service (line 45 of page 4).	Distribution “Services” plant investment drives all costs of “Services.”
P73	All costs related to Street Lighting	Street Lighting Original Plant in Service (line 47 of page 4).	Street Lighting plant investment drives all Street Lighting costs. The results of the direct assignment of Street Lighting costs were turned into an allocator, for use elsewhere in the CCOSS.

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Code	Allocator for:	Derivation	Allocator Justification
POL	All costs related to Overhead Distribution Lines including Rental costs and Distribution overhead line rent revenues.	Distribution Plant: Overhead Lines Original Plant in Service (line 28 of page 4)	Overhead distribution line plant investment drives all costs related to Overhead Distribution Lines.
PT0	Working Cash	Total Real Estate & Property Taxes (line 49 of page 9)	Working Cash is closely related to Real Estate Taxes.
PTD	All costs related to General Plant and Electric Common Plant	Original Plant Investment: Production + Transmission + Distribution (lines 6, 13 and 48 of page 4)	Total investment in production, transmission and distribution plant is the best allocator for general and common plant.
PUL	All costs related to Underground Distribution Lines	Distribution Plant: Underground Lines Original Plant in Service (line 38 of page 4)	Underground distribution line plant investment drives all costs related to Underground Distribution Lines.
R01	Sales	Present budgeted revenues for the test year	The intent of sales is to maintain or increase revenues to lessen the need for future rate increases.
R02	Economic Development	Base revenues for the test year	Allocates economic development discounts
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 36 of page 6)	Total rate base drives avoided tax interest.
STRATH	Step-up Transformers that are Dedicated to Hydro	Using the current Stratification for Hydro Plants, the allocator is an 81% weighting of the E8760 energy allocator and a 19% weighting of the D10S capacity allocator.	Energy vs. capacity weighting of Hydro plants drives Step-up Transformer investment. It applies to just the very small portion of generation step-up assets that are hydro-related and are located on the Distribution system, unlike all of the other generation step-up facilities that are located on the Transmission system.
TD	Transmission and Distribution Materials and Supplies that are Rate Base Additions	Total Transmission and Distribution Original Plant in Service (Lines 13 and 48 of page 4)	Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies.
ZDTS	Supervision & Engineering and Customer Installation Distribution Labor	All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (All of lines 33 thru 42 on page 12, except lines 33 and 40)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

Analysis	Analysis Description	Data Sources and Associated Vintage
E8760 Allocator Development	This allocator is developed by multiplying customer class loads by system marginal energy costs for each hour of the 2025-2026 Test Years. The allocation is the relationship of the annual class totals of these hourly results to the retail total.	1. Test Year 8760 load shapes for each customer class are developed from five years of load research data (2018-2022). The resulting load shapes for each class are synced up to the 2024 forecasts for the 2025-2026 Test Years. 2. Hourly system marginal energy costs are based on the 2025-2026 Test Year forecasts from the Commercial Operations area.
Generation Plant Stratification Analysis	Cost stratification is the term used to identify the capital substitution analysis that separates or “stratifies” fixed generation costs into “capacity-related” and “energy-related” categories. The information used for this analysis includes the 2024 replacement costs of NSPM power plants that were developed by the Capital Asset Accounting area, and the corresponding capacity ratings for those plants. This information is used to define the “capacity-related” component for each type of non-peaking generation plant. This capacity component by plant type is recognized by dividing the peaking plant cost per kW by the non-peaking cost per kW. The remaining “energy-related” component by plant type is the percent determined by subtracting the capacity-related percent from 100 percent. This component is sub-functionalized as “energy-related,” because it represents the additional investment above the cost of a peaking plant that is made to obtain lower energy (and total) costs as compared to a peaking plant.	Based on 2024 replacement costs of all NSP Minnesota Company Power Plants.
Customer Accounting Weights	The relative costs by customer class for meter reading, back-office support, customer service and billing were developed based on current budgets and the experience of management in the Billing and Customer Service area. Residential customers are assigned a weight of 1. Based on this analysis, the other customer classes are assigned weights based on the relative differences compared to the residential class.	Based on 2024 budgets with the relative weighting estimates provided by management from the Billing and Customer Service areas.

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
Minimum System and Zero Intercept Analyses	The Minimum System and Zero Intercept Analyses is used to separate FERC Accounts 364-369 into “Demand/Capacity-Related” and “Customer-Related” cost classifications. As ordered by the Commission in the Company’s 2013 rate case (Docket No. E002/GR-13-868) the Company conducted an updated Minimum System study. The Company was also able to obtain the data for a Zero Intercept study. A detailed description of these studies is provided Schedule 11 of Christopher J. Barthol’s Direct Testimony. The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the “customer” component of total costs. The “capacity” cost component is the difference between total installed cost and the minimum sized cost. The Zero Intercept method attempts to determine the portion of plant that relates to a hypothetical no load or zero intercept situation. By analyzing the actual costs of 14 years of construction work orders, installed costs per unit (e.g. cost per foot of overhead primary conductor) were obtained for equipment configurations that comprise at least 90% distribution plant in the field. The installed cost was regressed against the load carrying capacity of each equipment configuration. The zero intercept of the regression was used as the minimum system cost. The cost of the minimum size facilities determines the “customer” component of total costs.	Based on an analysis of distribution construction work orders in Minnesota that were completed from 2007 to 2020.
Customer Metering Cost per Customer	Customer metering weights are assigned to each class based on the actual replacement costs of meters, current transformers (CTs) and voltage transformers (VTs) for each customer in each class. An inventory of the meter model, CT model and VT model installed for each customer by customer class was obtained from the Company’s Meter Data Management System (MDMS). Metering staff provided current replacement costs for each meter model, CT model and VT model. Weighted customer metering costs including the cost of CTs and VTs were then calculated for each customer and rolled up for each customer class.	Based on a 2024 inventory of meter models, CT models and VT models for each customer. Meter, CT and VT replacement costs are for 2024.

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
Compliance Classification of Other Production O&M Costs	Based on the MPUC order in Docket Nos. E002/GR-12-961 and E002/GR-13-868, consulted with Xcel Generation Cost modeling staff to identify production Other Production O&M expenses that vary directly with energy consumption. Staff in the Generation Cost Modeling area considers Chemicals and Water as the only Other Production O&M costs that vary directly with energy output. These costs were classified as 100% energy related. The remaining cost items were split in groups based on the type of plant (i.e., Nuclear, Fossil, etc.) and classified as capacity or energy related based on the plant stratification for that plant type.	2025-2026 budget detail of Other Production O&M expenses and 2024 Plant Stratification Analysis.
Direct Assignment of Overhead Secondary Distribution Line Costs to the Lighting Class	In consultation with staff in the Company's Capital Asset Accounting area, identified specific lighting costs that are included in each FERC account code for distribution plant. Discovered that all lighting plant investment is included in FERC Account 373 except for the cost of wood poles that are solely used by lighting in overhead distribution areas. These costs are included in FERC Account 364. This analysis quantified the amount of overhead distribution pole investment that is attributed to lighting poles only. The costs for cross arms are excluded from the analysis since cross arms are used to carry conductors which means the pole has more than street lights attached.	• TY2025 plant investment in FERC Account 364 (overhead distribution poles). • The total number of overhead distribution poles based on 2024 data. • The number of street lights in overhead distribution area in 2024. • Estimated percent of distribution poles with lighting that only serve lighting load.
Customers Served by 3 Phase Vs 1 Phase Primary Distribution Lines	Customers who do not receive service off the single-phase primary distribution system should not pay the costs of this part of the distribution system. Based on data from the Company's GIS system determined the percent of customers in each class the receive service off the 3 phase or 1 phase primary distribution system. This analysis is described in Christopher J. Barthol's Direct Testimony.	2024 listing from the GIS system of all customer premises in MN and whether they receive service off the 3 phase of 1 phase distribution system.
Customers Served by Overhead Vs Underground Transformers	C&I secondary voltage customers with underground services own the service. This analysis determined the percent of customers that are served from an underground service. These customers are excluded from the allocation of distribution service costs.	2024 listing from the GIS system of all customer premises in MN and whether they are served from an overhead or underground transformer.
Comparison of MISO's system historical peak hour to historical NSP System hourly loads	Conduct a comparison of MISO's system historical peak hour to the historical hourly loads of the NSP System. This is done to determine which hours for the 2025-2026 test years should be used to calculate the D10S class Generation and Transmission capacity cost allocator.	• NSP System Operations area has historical hourly loads for the NSP System. • MISO's most recent Loss of Load Expectations Study lists historical peak days and hours for each LRZ.

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Northern States Power Company
State of Minnesota Electric Jurisdiction
Summary of 2025 Class Cost of Service Study ($000)

Highly Confidential data is shaded.

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	4,016,627	1,631,353	124,967	2,220,924	39,383
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[3]	Unadjusted Operating Revenues (line 1 + line 2)	4,018,734	1,633,237	125,031	2,221,062	39,404
[4]	Present Rates (CCOSS page 2, line 2)	3,665,482	1,451,117	115,793	2,066,616	31,956
[5]	Unadjusted Deficiency (line 3 - line 4)	353,252	182,120	9,238	154,446	7,447
[6]	Defic / Pres (line 5 / line 4)	9.6%	12.6%	8.0%	7.5%	23.3%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.30**	**0.83**	**0.78**	**2.42**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL DATA BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
				HIGHLY CONFIDENTIAL DATA ENDS]		
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	6,616	602	(7,290)	72

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	4,016,627	1,637,969	125,569	2,213,633	39,455
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[15]	Adjusted Operating Revenues (line 13 + line 14)	4,018,734	1,639,853	125,634	2,213,771	39,476
[16]	Present Rates (line 4)	3,665,482	1,451,117	115,793	2,066,616	31,956
[17]	Adjusted Deficiency (line 15 - line 16)	353,252	188,736	9,840	147,156	7,520
[18]	**Defic / Pres Rates (line 17 / line 16)**	**9.6%**	**13.0%**	**8.5%**	**7.1%**	**23.5%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.35**	**0.88**	**0.74**	**2.44**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	4,016,626	1,599,698	126,623	2,254,401	35,905
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,108	1,884	64	138	21
[22]	Proposed Operating Revenues (line 20 + line 21)	4,018,734	1,601,583	126,687	2,254,539	35,926
[23]	Proposed Increase (line 22 - line 16)	353,252	150,465	10,894	187,923	3,969
[24]	Difference / Pres (line 23 / line 16)	9.6%	10.4%	9.4%	9.1%	12.4%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.08**	**0.98**	**0.94**	**1.29**

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Northern States Power Company
State of Minnesota Electric Jurisdiction
2025 CCOSS

Highly Confidentail data is shaded.

Rate Base

	Plant In Service	Alloc	1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
1	Production		13,503,928	4,668,170	8,801,486	364,509	8,436,977	34,273
2	Transmission		4,258,347	1,483,674	2,758,108	117,032	2,641,076	16,565
3	Distribution		5,462,753	3,575,553	1,705,595	229,761	1,475,834	181,605
4	General		2,725,709	1,141,616	1,556,814	83,479	1,473,335	27,280
5	Common		0	0	0	0	0	0
6	Total Plant In Service		25,950,738	10,869,012	14,822,003	794,780	14,027,223	259,723
7	Production		7,707,909	2,643,194	5,044,225	208,864	4,835,362	20,490
8	Transmission		995,930	347,484	644,599	27,331	617,268	3,846
9	Distribution		1,832,665	1,215,048	556,325	73,594	482,731	61,292
10	General		1,277,823	535,194	729,841	39,135	690,705	12,789
11	Common		0	0	0	0	0	0
12	Total Depreciation Reserve		11,814,328	4,740,920	6,974,990	348,924	6,626,066	98,417
13	**Net Plant In Service**		14,136,410	6,128,091	7,847,013	445,857	7,401,156	161,306
14	Deducts: Accum Defer Inc Tax		2,262,282	901,484	1,341,700	67,061	1,274,639	19,097
15	Constr Work In Progress		982,733	413,580	563,464	28,117	535,347	5,690
16	Fuel Inventory		85,634	27,928	57,415	2,375	55,041	290
17	Materials & Supplies		185,838	70,257	114,495	5,315	109,180	1,086
18	Prepayments		99,179	42,994	55,054	3,128	51,926	1,132
19	Non-Plant & Work Cash		10,480	3,203	7,470	412	7,058	(193)
20	Total Additions		1,363,864	557,962	797,897	39,347	758,551	8,004
21	**Rate Base**		13,237,993	5,784,569	7,303,210	418,142	6,885,068	150,213

Income Statement

			1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
22A	**Tot Oper Rev - Pres**		4,529,137	1,750,215	2,743,935	139,480	2,604,455	34,988
22B	**Tot Oper Rev - Prop**		4,882,389	1,900,680	2,942,752	150,374	2,792,378	38,957
23	Oper & Maint		2,925,253	1,087,098	1,820,116	87,221	1,732,895	18,039
24	Book Depr + IRS Int		914,479	389,521	513,591	28,266	485,325	11,367
25	Payroll, Rl Est & Prop Tax		209,175	93,157	113,485	6,680	106,805	2,533
26	Deferred Inc Tax & Net ITC		(167,776)	(75,301)	(89,850)	(5,386)	(84,464)	(2,625)
27A	Present Income Tax		(19,505)	(17,781)	(1,764)	(21)	(1,743)	41
27B	Proposed Income Tax		82,027	25,466	55,380	3,110	52,269	1,182
28	Allow Funds Dur Const		81,561	34,017	47,127	2,308	44,819	416
29A	**Present Return**		749,072	307,538	435,485	25,029	410,456	6,049
29B	**Proposed Return**		1,000,792	414,757	577,157	32,791	544,366	8,878
30A	**Pres Ret on Rt Base**		5.66%	5.32%	5.96%	5.99%	5.96%	4.03%
30B	**Prop Ret on Rt Base**		**7.56%**	7.17%	7.90%	7.84%	7.91%	5.91%
31A	**Pres Ret on Common**		6.68%	6.03%	7.26%	7.31%	7.26%	3.58%
31B	**Prop Ret on Common**		**10.30%**	9.56%	10.96%	10.84%	10.96%	7.16%

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Northern States Power Company
State of Minnesota Electric Jurisdiction
2025 CCOSS

Highly Confidentail data is shaded.

Docket No. E002/GR-24-320
Exhibit___(CJB-1), Schedule 4

PRES vs Equal Rev Reqts

			1	2	3	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.56%**		**4,016,627**	**1,631,353**	**2,345,891**	**124,967**	**2,220,924**	**39,383**
2	**Present Revenue**		**3,665,482**	**1,451,117**	**2,182,409**	**115,793**	**2,066,616**	**31,956**
3	**UnAdj Revenue Deficiency**		**351,144**	**180,236**	**163,482**	**9,174**	**154,308**	**7,427**
4	**UnAdj Deficiency / Present**		**9.58%**	**12.42%**	**7.49%**	**7.92%**	**7.47%**	**23.24%**
			[HIGHLY CONFIDENTIAL DATA BEGINS					
5	**Pres Int Rate Discounts**							
6	**Pres Econ Dvlp Rate Discounts**							
7	**Pres Int Rate Disc Cost Alloc**	**D10S**						
8	**Pres Econ Dvlp Disc Cost Alloc**	**R02**						
								HIGHLY CONFIDENTIAL DATA ENDS]
9	**Revenue Requirement Shift**		**0**	**6,616**	**(6,688)**	**602**	**(7,290)**	**72**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**4,016,627**	**1,637,969**	**2,339,203**	**125,569**	**2,213,633**	**39,455**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**351,144**	**186,852**	**156,794**	**9,776**	**147,018**	**7,499**
12	**Adj Deficiency / Adj Present**		**9.58%**	**12.88%**	**7.18%**	**8.44%**	**7.11%**	**23.47%**
	Equal Customer Classification							
13	Min Sys & Service Drop		298,943	244,125	27,898	17,211	10,687	26,920
14	Energy Services		87,343	73,550	13,307	6,772	6,536	486
15	Total Customer **(Cusco)**		386,286	317,675	41,205	23,982	17,223	27,406
16	Ave Monthly Customers		1,420,649	1,252,372	140,049	89,349	50,699	28,229
17	Svc Drop Reqt	$ / Mo / Cust	$17.54	$16.24	$16.60	$16.05	$17.57	$79.47
18	Ener Svcs Reqt	$ / Mo / Cust	$5.12	$4.89	$7.92	$6.32	$10.74	$1.44
19	Total Reqt	$ / Mo / Cust	$22.66	$21.14	$24.52	$22.37	$28.31	$80.91
	Equal Energy Classification							
20	On Peak Rev Reqt		897,379	285,620	610,248	25,913	584,336	1,511
21	Off Peak Rev Reqt		926,332	309,863	611,636	24,884	586,752	4,834
22	Total Ener Rev Reqt		1,823,711	595,483	1,221,884	50,796	1,171,087	6,345
23	Annual MWh Sales		28,304,704	9,010,863	19,179,784	775,642	18,404,142	114,057
24	On Pk Reqt	Mills / kWh	31.704	31.697	31.817	33.408	31.750	13.245
25	Off Pk Reqt	Mills / kWh	32.727	34.388	31.890	32.082	31.882	42.381
26	Total Reqt	Mills / kWh	64.431	66.085	63.707	65.489	63.632	55.626
	Equal Demand Classification							
27	Energy-Related Prod		447,051	148,173	297,483	12,294	285,189	1,395
28	Capacity-Related Summer Peak Prod		349,626	140,971	208,655	8,666	199,989	0
29	Capacity-Related Winter Peak Prod		108,673	43,817	64,855	2,694	62,162	0
30	Total Capacity-Related Prod		458,298	184,788	273,510	11,360	262,150	0
31	Total Production		905,349	332,961	570,993	23,654	547,339	1,395
32	Transmission **(Transco)**		508,579	177,053	329,526	13,995	315,532	2,000
33	Primary Dist Subs		90,244	36,639	53,130	2,741	50,389	474
34	Prim Dist Lines		242,689	135,601	105,508	7,860	97,648	1,580
35	Second Dist, Trans		59,768	35,941	23,643	1,938	21,705	184
36	Total Distribution **(Disco)**		392,701	208,182	182,282	12,539	169,743	2,238
37	Total Demand Rev Reqt		1,806,629	718,196	1,082,801	50,188	1,032,613	5,632
38	Annual Billing kW		48,584,599	0	48,584,599	0	48,584,599	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$6.12	$0.00	$5.87	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.29	$0.00	$4.12	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.33	$0.00	$1.28	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$11.75	$0.00	$11.27	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$6.78	$0.00	$6.49	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.75	$0.00	$3.49	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$22.29	$0.00	$21.25	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	63.828	79.703	56.455	64.705	56.108	49.381
47	Summer Billing kW		18,135,939	0	18,135,939	0	18,135,939	0
48	Winter Billing kW		30,448,660	0	30,448,660	0	30,448,660	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$28.16	$0.00	$26.89	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$18.79	$0.00	$17.90	$0.00
51	Energy + Production **(Genco)**		2,729,060	928,443	1,792,877	74,451	1,718,426	7,740

Highly Confidentail data is shaded.

PROP vs Equal Rev Reqts

			1	2	3	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.56%**	**7.17%**	**7.90%**	**7.84%**	**7.91%**	**5.91%**
2	**UnAdj Equalized Rev Reqt**		**4,016,627**	**1,631,353**	**2,345,891**	**124,967**	**2,220,924**	**39,383**
3	**Proposed Revenue**		**4,016,626**	**1,599,698**	**2,381,023**	**126,623**	**2,254,401**	**35,905**
4	**UnAdj Revenue Deficiency**		**0**	**31,655**	**(35,133)**	**(1,656)**	**(33,477)**	**3,478**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**1.98%**	**-1.48%**	**-1.31%**	**-1.48%**	**9.69%**
			[HIGHLY CONFIDENTIAL DATA BEGINS					
6	**Prop Interrupt Rate Discounts**							
7	**Prop Econ Dev Rate Discounts**							
8	**Prop Int Rate Disc Cost Alloc**	**D10S**						
9	**Prop ED Discount Cost Alloc**	**R02**						
								HIGHLY CONFIDENTIAL DATA ENDS]
10	**Revenue Requirement Shift**		**0**	**6,803**	**(6,888)**	**621**	**(7,509)**	**85**
11	**Adj Equal Rev (Rows 2+10)**		**4,016,627**	**1,638,157**	**2,339,002**	**125,588**	**2,213,414**	**39,468**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**38,458**	**(42,021)**	**(1,035)**	**(40,986)**	**3,563**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**2.40%**	**-1.76%**	**-0.82%**	**-1.82%**	**9.92%**
	Prop Customer Component							
14	Min Sys & Service Drop		283,967	231,354	28,353	17,200	11,152	24,260
15	Energy Services		87,293	73,499	13,308	6,770	6,538	486
16	Total Customer **(Cusco)**		371,260	304,854	41,661	23,971	17,690	24,745
17	Ave Monthly Customers		1,420,649	1,252,372	140,049	89,349	50,699	28,229
18	Svc Drop Reqt	$ / Mo / Cust	$16.66	$15.39	$16.87	$16.04	$18.33	$71.62
19	Ener Svcs Reqt	$ / Mo / Cust	$5.12	$4.89	$7.92	$6.31	$10.75	$1.43
20	Total Reqt	$ / Mo / Cust	$21.78	$20.29	$24.79	$22.36	$29.08	$73.05
	Prop Energy Component							
21	On Peak Rev Reqt		896,923	285,353	610,062	25,906	584,156	1,508
22	Off Peak Rev Reqt		925,795	309,571	611,399	24,877	586,522	4,825
23	Total Ener Rev Reqt		1,822,718	594,924	1,221,461	50,783	1,170,677	6,333
24	Annual MWh Sales		28,304,704	9,010,863	19,179,784	775,642	18,404,142	114,057
25	On Pk Reqt	Mills / kWh	31.688	31.668	31.808	33.399	31.740	13.225
26	Off Pk Reqt	Mills / kWh	32.708	34.355	31.877	32.073	31.869	42.301
27	Total Reqt	Mills / kWh	64.396	66.023	63.685	65.473	63.609	55.526
	Prop Demand Component							
28	Energy-Related Prod		431,030	135,105	294,854	12,332	282,522	1,071
29	Capacity-Related Summer Peak Prod		376,691	148,532	228,159	9,547	218,612	0
30	Capacity-Related Winter Peak Prod		117,085	46,167	70,918	2,967	67,950	0
31	Total Capacity-Related Prod		493,776	194,699	299,077	12,515	286,562	0
32	Total Production		924,806	329,804	593,931	24,847	569,084	1,071
33	Transmission **(Transco)**		506,668	170,590	334,307	14,295	320,012	1,771
34	Primary Dist Subs		92,390	35,793	56,180	2,873	53,306	418
35	Prim Dist Lines		239,791	129,832	108,552	7,913	100,639	1,407
36	Second Dist, Trans		58,994	33,903	24,931	1,940	22,992	160
37	Total Distribution **(Disco)**		391,175	199,527	189,663	12,726	176,937	1,985
38	Total Demand Rev Reqt		1,822,649	699,921	1,117,902	51,868	1,066,033	4,827
39	Annual Billing kW		48,584,599	0	48,584,599	0	48,584,599	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.82	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.50	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.40	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$11.71	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$6.59	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.64	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$21.94	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	64.394	77.675	58.285	66.872	57.924	42.318
48	Summer Billing kW		18,135,939	0	18,135,939	0	18,135,939	0
49	Winter Billing kW		30,448,660	0	30,448,660	0	30,448,660	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$29.43	$0.00	$28.10	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$19.18	$0.00	$18.28	$0.00
52	Energy + Production **(Genco)**		2,747,524	924,728	1,815,392	75,630	1,739,761	7,404
53	Prop Rev - Pres Rev (Pg 2)		351,144	148,581	198,614	10,829	187,785	3,949
54	Difference / Present		9.58%	10.24%	9.10%	9.35%	9.09%	12.36%

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Original Plant in Service

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Summer Peak	D10S		2,582,454	1,043,661	1,538,793	64,012	1,474,781	0
2	WInter Peak	D10S		802,693	324,397	478,297	19,896	458,400	0
3	Total Peak	D10S		3,385,147	1,368,058	2,017,090	83,908	1,933,182	0
4	Base Load	E8760		7,182,645	2,342,528	4,815,789	199,180	4,616,609	24,328
5	Nuclear Fuel	E8760		2,936,136	957,583	1,968,608	81,421	1,887,187	9,945
6	Total	32.03%	120, 310-346	13,503,928	4,668,170	8,801,486	364,509	8,436,977	34,273
	Transmission								
7	Gen Step Up Base	E8760		136,691	44,580	91,648	3,791	87,857	463
8	Gen Step Up Peak	D10S		39,814	16,090	23,724	987	22,737	0
9	Total Gen Step Up			176,505	60,670	115,372	4,777	110,594	463
10	Bulk Transmission	D10T		4,072,296	1,423,004	2,633,190	112,254	2,520,936	16,102
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		9,546	0	9,546	0	9,546	0
13	Total		350-359	4,258,347	1,483,674	2,758,108	117,032	2,641,076	16,565
	Distribution:								
	Substations								
14	Generat Step Up	STRATH		2,812	958	1,846	76	1,770	8
15	Bulk Transmission	D10T		0	0	0	0	0	0
16	Distrib Function	D60Sub		877,932	365,608	507,586	27,298	480,288	4,738
17	Direct Assign	Dir Assign		20,356	0	20,356	0	20,356	0
18	Total		360-363	901,101	366,566	529,789	27,375	502,414	4,746
	Overhead Lines								
19	Primary Capacity 1 Phase	D61PS1Ph		246,875	203,922	40,835	8,363	32,472	2,118
20	Primary Capacity Multi Phase	D61PS		542,018	229,361	309,684	17,125	292,559	2,973
21	Primary Customer 1 Phase	C61PS1Ph		78,022	74,379	3,349	2,918	432	293
22	Primary Customer Multi Phase	C61PS		171,299	153,366	17,178	10,953	6,225	754
23	Total Primary			1,038,213	661,028	371,047	39,359	331,688	6,137
24	Second Capacity	D62SecL		84,131	45,066	38,704	3,071	35,633	361
25	Second Customer	C62Sec		334,236	299,353	33,411	21,379	12,032	1,472
26	Total Secondary			418,367	344,419	72,115	24,450	47,666	1,833
27	Street Lighting	DASL		63,793	0	0	0	0	63,793
28	Total		364,365	1,520,374	1,005,448	443,163	63,809	379,354	71,763
	Underground Lines								
29	Primary Capacity 1 Phase	D61PS1Ph		361,197	298,354	59,745	12,236	47,509	3,098
30	Primary Capacity Multi Phase	D61PS		521,301	220,594	297,848	16,471	281,377	2,859
31	Primary Customer 1 Phase	C61PS1Ph		191,736	182,784	8,231	7,170	1,061	720
32	Primary Customer Multi Phase	C61PS		276,725	247,756	27,751	17,694	10,057	1,218
33	Total Primary			1,350,958	949,488	393,575	53,570	340,004	7,896
34	Second Capacity	D62SecL		149,449	80,055	68,753	5,455	63,298	641
35	Second Customer	C62Sec		211,063	189,035	21,098	13,500	7,598	929
36	Total Secondary			360,512	269,090	89,852	18,955	70,896	1,570
37	Street Lighting	DASL		0	0	0	0	0	0
38	Total		366,367	1,711,471	1,218,578	483,426	72,526	410,901	9,466
	Line Transformers								
39	Primary	D61PS		94,136	39,835	53,785	2,974	50,811	516
40	Second Capacity	D62SecL		139,331	74,635	64,099	5,086	59,013	597
41	Second Customer	C62Sec		296,798	265,822	29,669	18,984	10,685	1,307
42	Total		368	530,265	380,292	147,552	27,044	120,508	2,421
	Services								
43	Second Capacity	D62NLL		161,633	124,724	36,909	3,547	33,362	0
44	Second Customer	C62NL		263,181	250,568	12,613	8,070	4,542	0
43	Total Services	C62NL	369	424,813	375,292	49,521	11,617	37,904	0
44	Meters	C12WM	370	282,066	229,377	52,144	27,390	24,753	545
45	Street Lighting	Dir Assign	373	92,664	0	0	0	0	92,664
46	**Total Distribution**			5,462,753	3,575,553	1,705,595	229,761	1,475,834	181,605
47	**General & Common Plant**	PTD	303, 389-399	2,725,709	1,141,616	1,556,814	83,479	1,473,335	27,280
48	Prelim Elec Plant			25,950,738	10,869,012	14,822,003	794,780	14,027,223	259,723
49	TBT Investment	NEPIS		0	0	0	0	0	0
50	**Elec Plant in Serv**			25,950,738	10,869,012	14,822,003	794,780	14,027,223	259,723

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Accum Deprec; Net Plant

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		1,658,469	670,246	988,223	41,109	947,114	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,749,967	896,867	1,843,786	76,258	1,767,527	9,314
5	Base Load	E8760		3,299,473	1,076,081	2,212,216	91,497	2,120,720	11,175
6	Total		108,111,115,120.5	7,707,909	2,643,194	5,044,225	208,864	4,835,362	20,490
	Transmission								
7	Gen Step Up Base	E8760		20,986	6,844	14,070	582	13,488	71
8	Gen Step Up Peak	D10S		17,325	7,002	10,323	429	9,894	0
9	Total Gen Step Up			38,311	13,846	24,394	1,011	23,383	71
10	Bulk Transmission	D10T		954,794	333,639	617,380	26,319	591,060	3,775
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,825	0	2,825	0	2,825	0
13	Total		108,111,115,120.5	995,930	347,484	644,599	27,331	617,268	3,846
	Distribution								
14	Generat Step Up	STRATH		1,855	632	1,218	50	1,167	5
15	Bulk Transmission	D10T		0	0	0	0	0	0
16	Distrib Function	D60Sub		259,294	107,981	149,914	8,062	141,851	1,399
17	Direct Assign	Dir Assign		6,340	0	6,340	0	6,340	0
18	Total Substations			267,489	108,613	157,472	8,113	149,359	1,405
19	Overhead Lines	POL		492,544	325,727	143,568	20,672	122,896	23,249
20	Underground	PUL		593,519	422,589	167,647	25,151	142,496	3,283
21	Line Transformers	P68		204,099	146,374	56,793	10,409	46,384	932
22	Services	P69		205,204	181,283	23,921	5,612	18,309	0
23	Meters	C12WM		37,459	30,461	6,925	3,637	3,287	72
24	Street Lighting	P73		32,352	0	0	0	0	32,352
25	Total		108,111,115,120.5	1,832,665	1,215,048	556,325	73,594	482,731	61,292
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,277,823	535,194	729,841	39,135	690,705	12,789
27	**Total Accum Depr**			11,814,328	4,740,920	6,974,990	348,924	6,626,066	98,417
28	**Net Elec Plant**			14,136,410	6,128,091	7,847,013	445,857	7,401,156	161,306
29	**Net Plant w/ TBT**			14,136,410	6,128,091	7,847,013	445,857	7,401,156	161,306
	Subtractions: Accum Defer Inc Tax								
	Production								
30	Peaking Plant	D10S		323,434	130,711	192,723	8,017	184,706	0
31	Base Load	E8760		1,067,322	348,094	715,613	29,598	686,016	3,615
32	Nuclear Fuel	E8760		(5,330)	(1,738)	(3,574)	(148)	(3,426)	(18)
33	Total		190,281,282,283	1,385,426	477,066	904,763	37,467	867,296	3,597
	Transmission								
34	Gen Step Up Base	E8760		22,200	7,240	14,885	616	14,269	75
35	Gen Step Up Peak	D10S		4,958	2,004	2,954	123	2,831	0
36	Total Gen Step Up			27,158	9,244	17,839	739	17,100	75
37	Bulk Transmission	D10T		757,687	264,762	489,928	20,886	469,042	2,996
38	Distrib Function	D60Sub		0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,701	0	1,701	0	1,701	0
40	Total		281,282,283	786,545	274,006	509,468	21,624	487,844	3,071
	Distribution								
41	Generat Step Up	STRATH		223	76	147	6	141	1
42	Bulk Transmission	D10T		0	0	0	0	0	0
43	Distrib Function	D60Sub		123,061	51,248	71,149	3,826	67,323	664
44	Direct Assign	Dir Assign		2,954	0	2,954	0	2,954	0
45	Total Substations			126,238	51,324	74,250	3,832	70,417	665
46	Overhead Lines	POL		162,932	107,750	47,492	6,838	40,654	7,691
47	Underground	PUL		187,741	133,673	53,030	7,956	45,074	1,038
48	Line Transformers	P68		56,728	40,684	15,785	2,893	12,892	259
49	Services	P69		22,265	19,670	2,596	609	1,987	0
50	Meters	C12WM		14,317	11,643	2,647	1,390	1,256	28
51	Street Lighting	P73		8,599	0	0	0	0	8,599
52	Total		281,282,283	578,821	364,743	195,799	23,519	172,280	18,280
53	**General & Common Plant**	PTD	281,282,283	173,382	72,618	99,029	5,310	93,719	1,735
54	**Total Deferred Tax**			2,924,175	1,188,433	1,709,058	87,920	1,621,138	26,683
55	Net Operating Loss (NOL) Carry Forward	NEPIS		(677,377)	(293,641)	(376,007)	(21,364)	(354,642)	(7,729)
56	Non-Plant Related	LABOR		15,483	6,692	8,649	505	8,144	143
57	**Accum Def W/ Adj**			2,262,282	901,484	1,341,700	67,061	1,274,639	19,097

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Additions: CWIP, Etc; Rate Base

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		402,216	162,550	239,667	9,970	229,697	0
2	Base Load	E8760		(163,082)	(53,187)	(109,343)	(4,522)	(104,820)	(552)
3	Nuclear Fuel	E8760		184,520	60,179	123,716	5,117	118,599	625
4	Total		107	423,654	169,541	254,040	10,564	243,476	73
	Transmission								
5	Gen Step Up Base	E8760		(6,343)	(2,069)	(4,253)	(176)	(4,077)	(21)
6	Gen Step Up Peak	D10S		9,877	3,991	5,885	245	5,640	0
7	Total Gen Step Up			3,533	1,923	1,632	69	1,563	(21)
8	Bulk Transmission	D10T		134,870	47,128	87,209	3,718	83,491	533
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		107	138,404	49,051	88,841	3,787	85,054	512
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		40,567	16,894	23,454	1,261	22,193	219
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			40,567	16,894	23,454	1,261	22,193	219
17	Overhead Lines	POL		28,092	18,578	8,188	1,179	7,009	1,326
18	Underground	PUL		36,117	25,715	10,202	1,530	8,671	200
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		1,721	1,521	201	47	154	0
21	Meters	C12WM		2,003	1,629	370	194	176	4
22	Street Lighting	P73		235	0	0	0	0	235
23	Total		107	108,735	64,337	42,415	4,212	38,203	1,984
24	**General & Common Plant**	PTD	107	311,940	130,651	178,168	9,554	168,614	3,122
25	**Total CWIP**			982,733	413,580	563,464	28,117	535,347	5,690
26	Fuel Inventory	E8760	151,152	85,634	27,928	57,415	2,375	55,041	290
	Materials & Supplies								
27	Production	P10		151,420	52,344	98,691	4,087	94,604	384
28	Trans & Distr	TD		34,419	17,913	15,804	1,228	14,576	702
29	Total		154	185,838	70,257	114,495	5,315	109,180	1,086
	Prepayments								
30	Miscellaneous	NEPIS		99,179	42,994	55,054	3,128	51,926	1,132
	LED Deferral	DASLED		0	0	0	0	0	0
31	Fuel	E8760		0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0
33	Total		235,252,165	99,179	42,994	55,054	3,128	51,926	1,132
34	Non-Plant Assets & Liab	LABOR	190,283,	97,601	42,181	54,519	3,185	51,334	901
35	Working Cash	PT0	calculated	(87,121)	(38,978)	(47,049)	(2,773)	(44,277)	(1,094)
36	**Total Additions**			1,363,864	557,962	797,897	39,347	758,551	8,004
37	**Total Rate Base**			13,237,993	5,784,569	7,303,210	418,142	6,885,068	150,213
38	**Common Rate Base (@ 52.50%)**			6,949,946.1	3,036,899	3,834,185	219,525	3,614,661	78,862

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Operating Rev (Cal Month)

				1	2	3	4	5	6
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,665,482	1,451,117	2,182,409	115,793	2,066,616	31,956
2	Proposed Rate Revenue	PROREV; (calc)		4,016,626	1,599,698	2,381,023	126,623	2,254,401	35,905
3	Equal Rate Revenue			4,016,627	1,631,353	2,345,891	124,967	2,220,924	39,383
	Other Retail Revenue								
4	Interdepartmental	R01; R02	448	667	264	397	21	376	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0
7	**Tot Other Retail Rev**			667	264	397	21	376	6
	Other Operating Revenue								
8	Interchg Prod Capacity	P10	456	443,316	153,250	288,941	11,966	276,974	1,125
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10T	456	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	454	4,748	3,140	1,384	199	1,185	224
13	Connection Charges	C11	451	0	0	0	0	0	0
14	Sales For Resale	E8760	447	261,017	85,127	175,006	7,238	167,768	884
15	Joint Op Agree-Other PSCo Rev	D10T	456	(1,464)	(512)	(947)	(40)	(906)	(6)
16	Misc Ancillary Trans Rev	D10T		245,156	85,666	158,520	6,758	151,762	969
17	MISO	D10T	456	(99,347)	(34,715)	(64,239)	(2,739)	(61,500)	(393)
18	Other	D10T	451,456,457	2,197	768	1,421	61	1,360	9
19	Late Pay Chg - Pres	R16C; R02		7,366	6,110	1,044	222	821	212
20	**Tot Other Op - Pres**		450	862,988	298,834	561,129	23,666	537,464	3,025
21	Incr Misc Serv - Prop	C62NL		1,338	1,273	64	41	23	0
22	Incr Inter-Dept'l - Prop	R01; R02		64	25	38	2	36	1
23	Incr Late Pay - Prop	(R16C); R02		706	585	100	21	79	20
	Tot Incr Other Op			2,108	1,884	202	64	138	21
24	**Tot Other Op - Prop**			865,096	300,718	561,331	23,730	537,602	3,046
25	**Tot Oper Rev - Pres**			4,529,137	1,750,215	2,743,935	139,480	2,604,455	34,988
26	**Tot Oper Rev - Prop**			4,882,389	1,900,680	2,942,752	150,374	2,792,378	38,957
	Tot Oper Rev - Eql			4,882,389	1,932,335	2,907,619	148,718	2,758,901	42,435

Operating & Maint (Pg 1 of 2)

	Production Expen		**FERC Accounts**						
27	**Fuel**	E8760	501,518,547	791,164	258,028	530,456	21,940	508,517	2,680
	Purchased Power								
28	Purchases: Cap Peak	D10S		90,075	36,402	53,673	2,233	51,440	0
29	Purchases: Cap Base	D10S		33,518	13,546	19,972	831	19,142	0
30	Purchases: Demand		555	123,593	49,948	73,645	3,064	70,581	0
31	Purchases: Other Energy	E8760	555	507,597	165,546	340,332	14,076	326,256	1,719
32	Tot Non-Assoc Purch			631,191	215,495	413,977	17,140	396,837	1,719
33	Interchg Agr Capacity	P10WoN	557	48,383	16,988	31,283	1,296	29,987	111
34	Interchg Agr Energy	E8760	557	16,827	5,488	11,282	467	10,815	57
35	Tot Wis Interchg Purch			65,210	22,476	42,566	1,763	40,803	168
36	**Tot Purchased Power**			696,401	237,971	456,542	18,902	437,640	1,888
	Other Production		500,502,505-507 509-514,517-519,520,						
37	Capacity Related	D10S	523-525,528-532,535,	97,437	39,378	58,059	2,415	55,644	0
38	Energy Related	E8760	539,543-546,548-550	358,597	116,952	240,430	9,944	230,486	1,215
39	Total Other Produc	21.37%	552-554,556,557 575.1-575.8	456,034	156,329	298,490	12,359	286,130	1,215
40	**Total Production**			1,943,598	652,329	1,285,488	53,201	1,232,287	5,782
41	**Transmission Exp**	D10T	560-563, 565-568 570-573	281,844	98,486	182,244	7,769	174,474	1,114

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Operating & Maint (Pg 2 of 2)

				1	2	3	4	5	6
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	17,462	11,490	5,292	780	4,512	679
2	Load Dispatching	T20D80	581	399	165	232	12	220	2
3	Substations	P61	582,591,592	4,295	1,747	2,525	130	2,395	23
4	Overhead Lines	POL	583,593	68,453	45,269	19,953	2,873	17,080	3,231
5	Underground Lines	PUL	584, 594	18,529	13,193	5,234	785	4,448	102
6	Line Transformers	P68	595	0	0	0	0	0	0
7	Meters	C12WM	586,597,598	1,541	1,253	285	150	135	3
8	Customer Install'n	OXDTS	587	(818)	(525)	(240)	(34)	(207)	(52)
9	Street Lighting	Dir Assign	585,596	2,806	0	0	0	0	2,806
10	Miscellaneous	OXDTS	588	976	627	287	40	247	62
11	Rents (Pole Attachmts)	POL	589	3,015	1,994	879	127	752	142
12	**Total Distribution**			116,658	75,213	34,446	4,864	29,583	6,998
13	**Customer Accounting**	C11WA	901-905	68,408	57,520	10,548	5,335	5,213	341
14	**Sales, Econ Dvlp & Other**	R01	912	10,409	4,121	6,197	329	5,868	91
	Admin & General								
15	Salaries	LABOR	920	105,038	45,395	58,673	3,427	55,246	969
16	Office Supplies	OXTS	921	63,613	23,636	39,585	1,896	37,689	392
17	Admin Transfer Credit	OXTS	922	(84,143)	(31,264)	(52,361)	(2,508)	(49,852)	(518)
18	Outside Services	LABOR	923	26,843	11,601	14,995	876	14,119	248
19	Property Insurance	NEPIS	924	8,562	3,711	4,752	270	4,482	98
20	Pensions & Benefits	LABOR	926	71,757	31,012	40,083	2,341	37,741	662
21	Injuries & Claims	LABOR	925	27,449	11,863	15,333	896	14,437	253
22	Regulatory Exp	R01; R02	928	8,343	3,303	4,967	264	4,704	73
23	General Advertising	OXTS	930.1	1,068	397	664	32	633	7
24	Contributions	OXTS		0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(124)	(46)	(77)	(4)	(74)	(1)
26	Rents	OXTS	931	61,613	22,893	38,341	1,837	36,504	380
27	Maint of General Plant	OXTS	935	485	180	302	14	287	3
28	Total			290,503	122,680	165,257	9,341	155,916	2,565
	Cust Service & Info								
29	Cust Assist Exp - Non-CIP	C11P10	908	1,578	968	592	71	521	18
30	CIP Total	E99XCIP	908	166,570	55,901	109,961	4,811	105,150	708
31	Instructional Advertising	C11P10	909	746	457	280	34	246	8
32	Total			168,894	57,327	110,833	4,916	105,917	734
33	Amortizations	LABOR		44,939	19,422	25,102	1,466	23,636	415
	Amortizations LED Deferral	DASLED		0	0	0	0	0	0
34	**Total O&M Expense**			2,925,253	1,087,098	1,820,116	87,221	1,732,895	18,039

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Book Depreciation

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		130,943	52,919	78,024	3,246	74,778	0
2	Base Load	E8760		314,162	102,460	210,638	8,712	201,926	1,064
3	Total		403,413	445,105	155,378	288,662	11,958	276,704	1,064
	Transmission								
4	Gen Step Up Base	E8760		2,452	800	1,644	68	1,576	8
5	Gen Step Up Peak	D10S		1,330	538	793	33	760	0
6	Total Gen Step Up			3,782	1,337	2,436	101	2,335	8
7	Bulk Transmission	D10T		90,123	31,492	58,274	2,484	55,790	356
8	Distrib Function	D60Sub		0	0	0	0	0	0
9	Direct Assign	Dir Assign		210	0	210	0	210	0
10	Total		403,413	94,114	32,829	60,920	2,585	58,335	365
	Distribution								
11	Generat Step Up	STRATH		73	25	48	2	46	0
12	Bulk Transmission	D10T		0	0	0	0	0	0
13	Distrib Function	D60Sub		22,648	9,431	13,094	704	12,390	122
14	Direct Assign	Dir Assign		514	0	514	0	514	0
15	Total Substations		403,413	23,235	9,456	13,656	706	12,950	122
16	Overhead Lines	POL		54,758	36,212	15,961	2,298	13,663	2,585
17	Underground	PUL		50,860	36,213	14,366	2,155	12,211	281
18	Line Transformers	P68		16,483	11,821	4,587	841	3,746	75
19	Services	P69		17,426	15,395	2,031	477	1,555	0
20	Meters	C12WM		13,360	10,864	2,470	1,297	1,172	26
21	Street Lighting	P73		4,905	0	0	0	0	4,905
22	Total		403,413	181,027	119,962	53,071	7,774	45,297	7,994
23	**General & Common Plant**	PTD	403,413	194,233	81,351	110,938	5,949	104,990	1,944
24	**Total Book Deprec**		403,404	914,479	389,521	513,591	28,266	485,325	11,367

Real Estate & Property Tax

				1	2	3	4	5	6
	Production								
25	Peaking Plant	D10S		25,931	10,480	15,452	643	14,809	0
26	Base Load	E8760		55,022	17,945	36,891	1,526	35,365	186
27	Total		408.1	80,953	28,424	52,342	2,169	50,174	186
	Transmission								
28	Gen Step Up Base	E8760		1,357	443	910	38	872	5
29	Gen Step Up Peak	D10S		395	160	236	10	226	0
30	Total Gen Step Up			1,753	602	1,146	47	1,098	5
31	Bulk Transmission	D10T		40,434	14,129	26,145	1,115	25,030	160
32	Distrib Function	D60Sub		0	0	0	0	0	0
33	Direct Assign	Dir Assign		95	0	95	0	95	0
34	Total		408.1	42,281	14,731	27,385	1,162	26,223	164
	Distribution								
35	Generat Step Up	STRATH		30	10	20	1	19	0
36	Bulk Transmission	D10T		0	0	0	0	0	0
37	Distrib Function	D60Sub		9,294	3,871	5,374	289	5,085	50
38	Direct Assign	Dir Assign		216	0	216	0	216	0
39	Total Substations			9,540	3,881	5,609	290	5,319	50
40	Overhead Lines	POL		16,095	10,644	4,692	676	4,016	760
41	Underground	PUL		18,119	12,901	5,118	768	4,350	100
42	Line Transformers	P68		5,614	4,026	1,562	286	1,276	26
43	Services	P69		4,497	3,973	524	123	401	0
44	Meters	C12WM		2,986	2,428	552	290	262	6
45	Street Lighting	P73		981	0	0	0	0	981
46	Total		408.1	57,832	37,853	18,056	2,432	15,624	1,923
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			181,066	81,009	97,784	5,763	92,021	2,273
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0
50	Payroll Taxes	LABOR		28,109	12,148	15,701	917	14,784	259
51	**Tot Non-Inc Taxes**			209,175	93,157	113,485	6,680	106,805	2,533

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Provision For Defer Inc Tax

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		33,461	13,523	19,938	829	19,109	0
2	Nuclear Fuel	E8760		(74)	(24)	(50)	(2)	(47)	(0)
3	Base Load	E8760		(19,460)	(6,347)	(13,047)	(540)	(12,508)	(66)
4	Total		410, 411	13,927	7,152	6,841	288	6,553	(66)
	Transmission								
5	Gen Step Up Base	E8760		650	212	436	18	418	2
6	Gen Step Up Peak	D10S		218	88	130	5	124	0
7	Total Gen Step Up			868	300	566	23	542	2
8	Bulk Transmission	D10T		12,966	4,531	8,384	357	8,027	51
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		28	0	28	0	28	0
11	Total		410, 411	13,862	4,831	8,978	381	8,597	53
	Distribution								
12	Generat Step Up	STRATH		(34)	(12)	(23)	(1)	(22)	(0)
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		(139)	(58)	(80)	(4)	(76)	(1)
15	Direct Assign	Dir Assign		(30)	0	(30)	0	(30)	0
16	Total Substations			(203)	(70)	(133)	(5)	(127)	(1)
17	Overhead Lines	POL		5,867	3,880	1,710	246	1,464	277
18	Underground	PUL		(8,647)	(6,157)	(2,443)	(366)	(2,076)	(48)
19	Line Transformers	P68		(1,560)	(1,119)	(434)	(80)	(354)	(7)
20	Services	P69		364	321	42	10	32	0
21	Meters	C12WM		4,092	3,328	757	397	359	8
22	Street Lighting	P73		(393)	0	0	0	0	(393)
23	Total		410, 411	(481)	184	(500)	202	(703)	(164)
24	**General & Common Plant**	PTD	410, 411	8,080	3,384	4,615	247	4,367	81
25	**Net Operating Loss (NOL) Carry Forwarc**	NEPIS		(228,552)	(99,077)	(126,867)	(7,208)	(119,659)	(2,608)
26	**Non - Plant Related**	LABOR	410, 411	491	212	274	16	258	5
27	**Tot Prov For Defer**			(192,673)	(83,313)	(106,660)	(6,074)	(100,586)	(2,700)

Inv Tax Credit; Total Oper Exp

	Production								
28	Peaking Plant	D10S		(255)	(103)	(152)	(6)	(145)	0
29	Base Load	E8760		25,554	8,334	17,134	709	16,425	87
30	Total		411	25,300	8,231	16,982	702	16,280	87
	Transmission								
31	Gen Step Up Base	E8760		0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0
34	Bulk Transmission	D10T		(150)	(52)	(97)	(4)	(93)	(1)
35	Distrib Function	D60Sub		0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0
37	Total		411	(150)	(52)	(97)	(4)	(93)	(1)
	Distribution								
38	Generat Step Up	STRATH		0	0	0	0	0	0
39	Bulk Transmission	D10T		0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0
43	Overhead Lines	POL		(248)	(164)	(72)	(10)	(62)	(12)
44	Underground	PUL		0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0
49	Total		411	(248)	(164)	(72)	(10)	(62)	(12)
50	**General & Common Plant**	PTD	411	(6)	(2)	(3)	(0)	(3)	(0)
51	**Net Inv Tax Credit**			24,896	8,013	16,809	688	16,122	74
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0
52	**Total Operating Exp**			**3,881,130**	**1,494,475**	**2,357,342**	**116,780**	**2,240,562**	**29,314**
53A	**Pres Op Inc Before Inc Tax**			**648,007**	**255,740**	**386,593**	**22,700**	**363,893**	**5,674**
53B	**Prop Op Inc Before Inc Tax**			**1,001,258**	**406,206**	**585,410**	**33,594**	**551,816**	**9,643**

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Docket No. E002/GR-24-320
Exhibit___(CJB-1), Schedule 4

Tax Deprec; Inc Tax & Return

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		282,088	114,002	168,086	6,992	161,094	0
2	Nuclear Fuel	E8760		99,572	32,474	66,761	2,761	63,999	337
3	Base Load	E8760		326,496	106,483	218,908	9,054	209,854	1,106
4	Total		tax books	708,156	252,959	453,755	18,807	434,947	1,443
	Transmission								
5	Gen Step Up Base	E8760		7,712	2,515	5,171	214	4,957	26
6	Gen Step Up Peak	D10S		1,938	783	1,155	48	1,107	0
7	Total Gen Step Up			9,650	3,298	6,325	262	6,063	26
8	Bulk Transmission	D10T		151,214	52,839	97,776	4,168	93,608	598
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		320	0	320	0	320	0
11	Total		tax books	161,183	56,138	104,421	4,430	99,991	624
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		25,690	10,699	14,853	799	14,054	139
15	Direct Assign	Dir Assign		329	0	329	0	329	0
16	Total Substations			26,019	10,699	15,182	799	14,383	139
17	Overhead Lines	POL		60,666	40,119	17,683	2,546	15,137	2,863
18	Underground	PUL		73,743	52,505	20,830	3,125	17,705	408
19	Line Transformers	P68		18,947	13,588	5,272	966	4,306	86
20	Services	P69		15,734	13,900	1,834	430	1,404	0
21	Meters	C12WM		28,311	23,023	5,234	2,749	2,485	55
22	Street Lighting	P73		3,839	0	0	0	0	3,839
23	Total		tax books	227,259	153,834	66,034	10,616	55,419	7,390
24	**General & Common Plant**	PTD	tax books	223,677	93,683	127,755	6,850	120,905	2,239
25	Net Operating Loss (NOL) Carry Forward	NEPIS		(2,579)	(1,118)	(1,432)	(81)	(1,350)	(29)
26	**Total Tax Deprec**			1,317,696	555,495	750,534	40,622	709,912	11,667
27	Interest Expense		427,431	284,616.84	124,368	157,019	8,990	148,029	3,230
28	Other Tax Timing Differ	LABOR		(15,846)	(6,848)	(8,852)	(517)	(8,335)	(146)
29	Meals & Enter	LABOR		1,582	684	883	52	832	15
30	Total Tax Deductions			1,588,048	673,698	899,585	49,147	850,438	14,765
	Inc Tax Additions								
31	Book Depreciation			914,479	389,521	513,591	28,266	485,325	11,367
32	Deferred Inc Tax & ITC			(167,776.36)	(75,301)	(89,850)	(5,386)	(84,464)	(2,625)
33	Nuclear Fuel Book Burn	E8760		108,172	35,279	72,527	3,000	69,527	366
34	Tax Capitalized Leases	PTD		53,341	22,341	30,466	1,634	28,833	534
35	Avoided Tax Interest	RTBASE		46,386	20,269	25,590	1,465	24,125	526
36	Total Tax Additions			954,602	392,109	552,324	28,978	523,347	10,168
37	**Total Inc Tax Adjustments**			(633,446)	(281,589)	(347,260)	(20,169)	(327,091)	(4,596)
38A	**Pres Taxable Net Income**			14,561	(25,849)	39,333	2,531	36,802	1,077
38B	**Prop Taxable Net Income**			367,813	124,616	238,149	13,425	224,725	5,047
39A	Pres Fed & State Inc Tax			(19,505)	(17,781)	(1,764)	(21)	(1,743)	41
38A	Exp Fed & State Inc Tax			82,027	22,716	58,385	3,186	55,199	927
39B	Prop Fed & State Inc Tax			82,027	25,466	55,380	3,110	52,269	1,182
38C	Equal Fed & State Inc Tax			82,027	34,564	45,282	2,634	42,647	2,181
40A	Pres Preliminary Return	(total); BASE		667,511	273,521	388,357	22,721	365,637	5,633
40B	Prop Preliminary Return	(total); BASE		919,231	380,740	530,030	30,483	499,547	8,461
41	Total AFUDC			81,561	34,017	47,127	2,308	44,819	416
42A	**Present Total Return**			749,072	307,538	435,485	25,029	410,456	6,049
42B	**Proposed Total Return**			1,000,792	414,757	577,157	32,791	544,366	8,878
42C	**Equal Total Return**			1,000,792	437,313	552,123	31,612	520,511	11,356
43A	**Pres % Return on Rate Base**			5.66%	5.32%	5.96%	5.99%	5.96%	4.03%
38A	**Exp % Return on Rate Base**			7.56%	7.05%	8.00%	7.89%	8.01%	5.49%
43B	**Prop % Return on Rate Base**			7.56%	7.17%	7.90%	7.84%	7.91%	5.91%
44A	**Present Common Return**			464,455	183,170	278,466	16,039	262,427	2,820
44B	**Proposed Common Return**			716,175	290,389	420,138	23,801	396,337	5,648
45A	**Pres % Ret on Common Rt Base**			6.68%	6.03%	7.26%	7.31%	7.26%	3.58%
45B	**Prop % Ret on Common Rt Base**			10.30%	9.56%	10.96%	10.84%	10.96%	7.16%

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Allow For Funds Used During Constr

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		35,076	14,175	20,901	869	20,031	0
2	Nuclear Fuel	E8760		13,334	4,349	8,940	370	8,571	45
3	Base Load	E8760		(11,066)	(3,609)	(7,420)	(307)	(7,113)	(37)
4	Total		419.1,432	37,344	14,915	22,421	932	21,489	8
	Transmission								
5	Gen Step Up Base	E8760		185	60	124	5	119	1
6	Gen Step Up Peak	D10S		836	338	498	21	478	0
7	Total Gen Step Up			1,021	398	622	26	597	1
8	Bulk Transmission	D10T		11,866	4,146	7,672	327	7,345	47
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		419.1,432	12,887	4,545	8,295	353	7,942	48
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		3,903	1,626	2,257	121	2,135	21
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			3,903	1,626	2,257	121	2,135	21
17	Overhead Lines	POL		2,147	1,420	626	90	536	101
18	Underground	PUL		3,144	2,238	888	133	755	17
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		5	5	1	0	0	0
21	Meters	C12WM		0	0	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0
23	Total		419.1,432	9,199	5,288	3,771	345	3,426	140
24	**General & Common Plant**	PTD	419.1,432	22,130	9,269	12,640	678	11,962	221
25	**Total AFUDC**			81,561	34,017	47,127	2,308	44,819	416

Labor Allocator

	Production								
26	Other Prod - Cap	D10S		66,684	26,949	39,734	1,653	38,081	0
27	Other Prod - Ene	E8760		141,490	46,145	94,866	3,924	90,942	479
28	Total		500 through 557	208,173	73,094	134,600	5,577	129,023	479
	Transmission								
29	Stepup Subtrans	P5161A		717	246	469	19	449	2
30	Bulk Power Subs	D10T		16,543	5,781	10,697	456	10,241	65
31	Total		560 through 571	17,260	6,027	11,166	475	10,690	67
	Distribution								
32	Superv & Eng	ZDTS	580, 590	11,829	7,784	3,585	529	3,057	460
33	Load Dispatch	D10T	581	180	63	117	5	112	1
34	Substation	P61	582, 592	2,504	1,019	1,472	76	1,396	13
35	Overhead Lines	POL	583, 593	15,914	10,524	4,639	668	3,971	751
36	Underground Lines	PUL	584, 594	7,561	5,383	2,136	320	1,815	42
37	Line Transformer	P68	595	0	0	0	0	0	0
38	Meter	C12WM	586, 597	2,714	2,207	502	264	238	5
39	Cust Installation	ZDTS	587	838	551	254	37	217	33
40	Street Lighting	P73	585, 596	19	0	0	0	0	19
41	Miscellaneous	OXDTS	588	11,789	7,573	3,465	485	2,980	751
42	Total			53,349	35,105	16,169	2,384	13,785	2,074
43	**Cust Accounting**	C11WA	901,902,903,904,905	13,373	11,244	2,062	1,043	1,019	67
44	**Sales Expense**	C11P10	912	3,381	2,075	1,269	152	1,117	38
45	**Admin & General**	LABOR	920,921,922,923,924,	176,493	76,277	98,588	5,759	92,829	1,629
46	**Service & Inform**	C11P10	908, 909	987	606	370	44	326	11
47	**Labor**			473,016	204,428	264,223	15,434	248,789	4,365

			1	2	3	4	5	6
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	61.36%	37.52%	4.49%	33.02%	1.12%
2	Peaking Plant Capacity	D10S	100.00%	40.41%	59.59%	2.48%	57.11%	0.00%
3	57% Dmd; 43% Energy: Sales & ED	D57E43	100.00%	32.61%	67.05%	2.77%	64.27%	0.34%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	32.61%	67.05%	2.77%	64.27%	0.34%
5	20%D10T; 80%D60Sub	T20D80	100.00%	41.40%	58.17%	2.98%	55.19%	0.43%
6	Labor w/o (or w/) A&G	LABOR	100.00%	43.22%	55.86%	3.26%	52.60%	0.92%
7	Net Plant In Service	NEPIS	100.00%	43.35%	55.51%	3.15%	52.36%	1.14%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	64.24%	29.39%	4.12%	25.27%	6.37%
9	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.00%	37.16%	62.23%	2.98%	59.25%	0.62%
10	Production Plant	P10	100.00%	34.57%	65.18%	2.70%	62.48%	0.25%
11	Production Plant Wo Nuclear	P10WoN	100.00%	35.11%	64.66%	2.68%	61.98%	0.23%
12	Total P51 & P61A	P5161A	100.00%	34.37%	65.37%	2.71%	62.66%	0.26%
13	Distribution Plant	P60	100.00%	65.45%	31.22%	4.21%	27.02%	3.32%
14	Distr Substn Plant	P61	100.00%	40.68%	58.79%	3.04%	55.76%	0.53%
15	Line Transformer Plant	P68	100.00%	71.72%	27.83%	5.10%	22.73%	0.46%
16	Services Plant	P69	100.00%	88.34%	11.66%	2.73%	8.92%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	66.13%	29.15%	4.20%	24.95%	4.72%
18	Real Est & Property Tax	PT0	100.00%	44.74%	54.00%	3.18%	50.82%	1.26%
19	Produc, Trans & Distrib	PTD	100.00%	41.88%	57.12%	3.06%	54.05%	1.00%
20	Dist Plt Undground Lines	PUL	100.00%	71.20%	28.25%	4.24%	24.01%	0.55%
21	Rate Base (Non-Column)	RTBASE	100.00%	43.70%	55.17%	3.16%	52.01%	1.13%
22	Stratified Hydro Baseload	STRATH	100.00%	34.07%	65.66%	2.72%	62.94%	0.28%
23	Transmission & Distrib	TD	100.00%	52.04%	45.92%	3.57%	42.35%	2.04%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	65.80%	30.31%	4.47%	25.84%	3.89%
			1	2	3	4	5	6
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	296,523	128,151	165,636	9,675	155,960	2,737
26	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	99,038	63,621	29,107	4,077	25,031	6,309
27	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	2,874,399	1,068,000	1,788,694	85,690	1,703,005	17,705
28	Total P51 & P61A	P5161A	179,316	61,628	117,218	4,854	112,364	471
29	Produc, Trans & Distrib	PTD	23,225,028	9,727,396	13,265,189	711,301	12,553,888	232,443
30	Transmission & Distrib	TD	9,721,100	5,059,227	4,463,703	346,792	4,116,910	198,170
31	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	40,681	26,770	12,330	1,818	10,512	1,582

Docket No. E002/GR-24-320
Exhibit___(CJB-1), Schedule 4

Northern States Power Company
State of Minnesota Electric Jurisdiction
2025 CCOSS

Highly Confidentail data is shaded.

			1	2	3	4	5	6
EXTERNAL ALLOCATORS		Extern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	88.15%	9.86%	6.29%	3.57%	1.99%
2	Cust Acctg Wtg Factor	C11WA	100.00%	84.08%	15.42%	7.80%	7.62%	0.50%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	81.32%	18.49%	9.71%	8.78%	0.19%
4	Sec & Pri Customers	C61PS	100.00%	89.53%	10.03%	6.39%	3.63%	0.44%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.33%	4.29%	3.74%	0.55%	0.38%
6	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	95.21%	4.79%	3.07%	1.73%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.56%	10.00%	6.40%	3.60%	0.44%
8	Summer Peak Resp KW	D10S	100.00%	40.41%	59.59%	2.48%	57.11%	0.00%
9	Transmission Demand %	D10T	100.00%	34.94%	64.66%	2.76%	61.90%	0.40%
10	Winter Peak Resp KW	D10W	100.00%	35.92%	63.42%	2.97%	60.45%	0.66%
11	Alternative Production Allocator	12CP	100.00%	35.94%	63.64%	2.75%	60.89%	0.42%
12	Sec, Pri & TT, Class Coin kW @ Substatior	D60Sub	100.00%	41.64%	57.82%	3.11%	54.71%	0.54%
13	Sec & Pri, Cl Coin kW (no Min Sys; adj Res	D61PS	100.00%	42.32%	57.14%	3.16%	53.98%	0.55%
14	Pri & Sec Coin kW Served w/ 1 Ph	D61PS1Ph	100.00%	82.60%	16.54%	3.39%	13.15%	0.86%
15	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	77.17%	22.83%	2.19%	20.64%	0.00%
16	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	53.57%	46.00%	3.65%	42.35%	0.43%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	Direct Assign LED Lighting Deferal	DASLED	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	32.61%	67.05%	2.77%	64.27%	0.34%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	33.56%	66.01%	2.89%	63.13%	0.42%
21	Present Rev	R01	100.00%	39.59%	59.54%	3.16%	56.38%	0.87%
22	Base Rev	R02	100.00%	42.21%	56.72%	3.28%	53.44%	1.07%
23	Late Fee Revenue Allocator	LateFee	100.00%	82.95%	14.17%	3.02%	11.15%	2.88%

			1	2	3	4	5	6
EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
23	Customers - B Basis	C10	1,394,386	1,248,393	139,855	89,156	50,699	6,138
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,420,649	1,252,372	140,049	89,349	50,699	28,229
25	Mo Cus Wtd By Cus Acct	C11WA	1,489,451	1,252,372	229,660	116,154	113,505	7,420
26	Cust Acctg Wtg Factor	C11WAF	24.62	1.00	23.62	1.30	22.32	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign St Ltg)	C12	1,395,698	1,252,372	140,049	89,349	50,699	3,277
28	Mo Cus Wtd By Mtr Invest	C12WM	293,893,522	238,994,793	54,330,372	28,538,939	25,791,433	568,358
29	Meter Invest / Cust Factor	C12WMF	25,034	191	24,670	319	24,350	173
30	Sec & Pri Customers	C61PS	1,394,361	1,248,393	139,830	89,156	50,674	6,138
31	% Served by Primary Single Phase		0.0%	71.59%	0.00%	39.32%	0.00%	57.36%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	937,493	893,725	40,247	35,058	5,189	3,521
33	C62Sec, w/o Ltg & C/I Underground	C62NL	1,311,232	1,248,393	62,839	40,209	22,630	0
34	Secondary Customers	C62Sec	1,393,866	1,248,393	139,335	89,156	50,179	6,138
35	Summer Peak Resp KW	D10S	3,922	1,585	2,337	97	2,240	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,853,758	6,118,611	268,392	5,850,219	27,631
37	Winter Peak Resp KW	D10W	4,047	1,454	2,567	120	2,446	27
38	Alternative Production Allocator	12CP	4,148	1,491	2,640	114	2,526	17
39	Sec, Pri & TT, Class Coin kW @ Substatior	D60Sub	6,166,193	2,567,861	3,565,051	191,730	3,373,321	33,281
40	Sec & Pri, Class Coin kW (w/o Min Sys; rec	D61PS	6,068,286	2,567,861	3,467,144	191,730	3,275,414	33,281
41	Pri & Sec Coin kW Served w/ 1 Ph	D61PS1Ph	2,225,548	1,838,334	368,124	75,392	292,732	19,090
42	D62Sec, w/o Ltg & C/I Underground	D62NLL	10,402,623	8,027,186	2,375,438	228,286	2,147,151	0
43	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	10,000,000	5,356,680	4,600,440	365,005	4,235,434	42,880
44	Annual Billing kW	D99	48,584.599	0	48,585	0	48,585	0
45	Summer Billing kW	D99S	18,135.939	0	18,136	0	18,136	0
46	Winter Billing kW	D99W	30,448.660	0	30,449	0	30,449	0
47	Non-Coinc Pk Second	DN-Sec	13,327,583	8,027,186	5,267,116	506,185	4,760,932	33,281
48	MWh Sales	E99	28,304,704	9,010,863	19,179,784	775,642	18,404,142	114,057
49	MWh Sales Excl CIP Exempt	E99XCIP	26,849,829	9,010,863	17,724,909	775,540	16,949,369	114,057
50	Late Fee Revenue Allocation	LateFee	100.00%	82.95%	14.17%	3.02%	11.15%	2.88%
	Base Revenues		$2,688,329	$1,134,656	$1,524,930	$88,264	$1,436,666	$28,743

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL DATA EXCISED

Northern States Power Company
State of Minnesota Electric Jurisdiction
Summary of 2026 Class Cost of Service Study ($000)

Highly Confidential data is shaded.

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	4,212,844	1,728,144	126,708	2,315,947	42,045
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,351	2,069	72	181	28
[3]	Unadjusted Operating Revenues (line 1 + line 2)	4,215,195	1,730,213	126,781	2,316,128	42,073
[4]	Present Rates (CCOSS page 2, line 2)	3,724,454	1,447,977	114,442	2,130,075	31,961
[5]	Unadjusted Deficiency (line 3 - line 4)	490,741	282,237	12,339	186,053	10,112
[6]	Defic / Pres (line 5 / line 4)	13.2%	19.5%	10.8%	8.7%	31.6%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.48**	**0.82**	**0.66**	**2.40**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
		[HIGHLY CONFIDENTIAL DATA BEGINS				
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)					
[9]	Economic Development Discount (CCOSS page 2, line 6)					
[10]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)					
[11]	Economic Development Disc Cost Allocation (CCOSS page 2, line 8)					
						HIGHLY CONFIDENTIAL DATA ENDS]
[12]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	10,036	715	(10,903)	152

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[13]	Adjusted Rate Revenue Reqt (line 1 + line 12)	4,212,844	1,738,180	127,423	2,305,044	42,197
[14]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,351	2,069	72	181	28
[15]	Adjusted Operating Revenues (line 13 + line 14)	4,215,195	1,740,249	127,496	2,305,225	42,225
[16]	Present Rates (line 4)	3,724,454	1,447,977	114,442	2,130,075	31,961
[17]	Adjusted Deficiency (line 15 - line 16)	490,741	292,272	13,054	175,150	10,264
[18]	**Defic / Pres Rates (line 17 / line 16)**	**13.2%**	**20.2%**	**11.4%**	**8.2%**	**32.1%**
[19]	**Ratio: Class % / Total %**	**1.00**	**1.53**	**0.87**	**0.62**	**2.44**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[20]	Proposed Rates (CCOSS page 3, line 3)	4,212,844	1,657,917	129,043	2,388,523	37,361
[21]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	2,351	2,069	72	181	28
[22]	Proposed Operating Revenues (line 20 + line 21)	4,215,195	1,659,986	129,116	2,388,704	37,389
[23]	Proposed Increase (line 22 - line 16)	490,741	212,009	14,674	258,629	5,428
[24]	Difference / Pres (line 23 / line 16)	13.2%	14.6%	12.8%	12.1%	17.0%
[25]	**Ratio: Class % / Total %**	**1.00**	**1.11**	**0.97**	**0.92**	**1.29**

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HIGHLY CONFIDENTIAL DATA EXCISED

Northern States Power Company
State of Minnesota Electric Jurisdiction
2026 CCOSS

Highly Confidential data is shaded.

Rate Base

	Plant In Service	Alloc	1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
1	Production		13,572,848	4,667,922	8,872,923	345,129	8,527,795	32,003
2	Transmission		4,515,407	1,537,075	2,961,152	118,565	2,842,587	17,180
3	Distribution		6,092,849	4,012,575	1,886,761	251,999	1,634,761	193,514
4	General		3,088,305	1,304,944	1,752,365	91,405	1,660,960	30,996
5	Common		0	0	0	0	0	0
6	Total Plant In Service		27,269,409	11,522,515	15,473,201	807,099	14,666,103	273,692
7	Production		7,830,094	2,648,286	5,161,793	201,212	4,960,581	20,015
8	Transmission		1,063,192	362,542	696,636	27,862	668,773	4,014
9	Distribution		1,950,982	1,306,838	577,936	77,714	500,221	66,208
10	General		1,496,150	632,189	848,945	44,282	804,663	15,016
11	Common		0	0	0	0	0	0
12	Total Depreciation Reserve		12,340,417	4,949,855	7,285,309	351,071	6,934,238	105,253
13	**Net Plant In Service**		14,928,992	6,572,660	8,187,892	456,028	7,731,864	168,439
14	Deducts: Accum Defer Inc Tax		2,346,466	928,823	1,398,219	66,726	1,331,493	19,424
15	Constr Work In Progress		1,088,222	447,111	634,277	30,019	604,258	6,834
16	Fuel Inventory		85,634	27,270	58,086	2,281	55,805	278
17	Materials & Supplies		185,838	70,082	114,716	5,053	109,664	1,041
18	Prepayments		88,520	38,972	48,549	2,704	45,845	999
19	Non-Plant & Work Cash		2,522	(921)	3,785	79	3,706	(342)
20	Total Additions		1,450,736	582,513	859,413	40,135	819,278	8,810
21	**Rate Base**		14,033,262	6,226,351	7,649,086	429,437	7,219,649	157,825

Income Statement

		1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
22A	**Tot Oper Rev - Pres**	4,581,300	1,740,895	2,805,554	136,792	2,668,762	34,851
22B	**Tot Oper Rev - Prop**	5,072,041	1,952,904	3,078,857	151,467	2,927,391	40,279
23	Oper & Maint	2,989,992	1,106,157	1,865,014	85,527	1,779,488	18,821
24	Book Depr + IRS Int	930,236	402,410	516,084	27,874	488,210	11,742
25	Payroll, Rl Est & Prop Tax	220,171	98,536	119,038	6,766	112,272	2,597
26	Deferred Inc Tax & Net ITC	(190,669)	(81,499)	(106,559)	(5,918)	(100,642)	(2,610)
27A	Present Income Tax	7,187	(18,316)	25,433	1,244	24,189	70
27B	Proposed Income Tax	148,236	42,620	103,986	5,462	98,524	1,630
28	Allow Funds Dur Const	85,437	35,366	49,593	2,332	47,261	478
29A	**Present Return**	709,819	268,973	436,136	23,630	412,506	4,710
29B	**Proposed Return**	1,059,511	420,047	630,886	34,086	596,800	8,578
30A	**Pres Ret on Rt Base**	5.06%	4.32%	5.70%	5.50%	5.71%	2.98%
30B	**Prop Ret on Rt Base**	**7.55%**	6.75%	8.25%	7.94%	8.27%	5.44%
31A	**Pres Ret on Common**	5.56%	4.15%	6.78%	6.40%	6.81%	1.61%
31B	**Prop Ret on Common**	**10.30%**	8.77%	11.63%	11.04%	11.67%	6.28%

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL DATA EXCISED

Northern States Power Company
State of Minnesota Electric Jurisdiction
2026 CCOSS

Highly Confidential data is shaded.

Docket No. E002/GR-24-320
Exhibit___(CJB-1), Schedule 6

PRES vs Equal Rev Reqts

			1	2	3	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.55%**		**4,212,844**	**1,728,144**	**2,442,655**	**126,708**	**2,315,947**	**42,045**
2	**Present Revenue**		**3,724,454**	**1,447,977**	**2,244,516**	**114,442**	**2,130,075**	**31,961**
3	**UnAdj Revenue Deficiency**		**488,390**	**280,167**	**198,139**	**12,267**	**185,872**	**10,084**
4	**UnAdj Deficiency / Present**		**13.11%**	**19.35%**	**8.83%**	**10.72%**	**8.73%**	**31.55%**
			[HIGHLY CONFIDENTIAL DATA BEGINS					
5	**Pres Int Rate Discounts**							
6	**Pres Econ Dvlp Rate Discounts**							
7	**Pres Int Rate Disc Cost Alloc**	**D10S**						
8	**Pres Econ Dvlp Disc Cost Alloc**	**R02**						
								HIGHLY CONFIDENTIAL DATA ENDS]
9	**Revenue Requirement Shift**		**0**	**10,036**	**(10,187)**	**715**	**(10,903)**	**152**
10	**Adj Equal Rev Reqt (Rows 1+9)**		**4,212,844**	**1,738,180**	**2,432,468**	**127,423**	**2,305,044**	**42,197**
11	**Adj Rev Defic vs Pres Rev (Row 2)**		**488,390**	**290,203**	**187,951**	**12,982**	**174,970**	**10,235**
12	**Adj Deficiency / Adj Present**		**13.11%**	**20.04%**	**8.37%**	**11.34%**	**8.21%**	**32.02%**
	Equal Customer Classification							
13	Min Sys & Service Drop		340,004	279,271	31,437	19,481	11,956	29,295
14	Energy Services		98,216	82,930	14,708	7,021	7,688	578
15	Total Customer **(Cusco)**		438,220	362,201	46,146	26,502	19,644	29,873
16	Ave Monthly Customers		1,437,828	1,268,459	141,043	89,982	51,061	28,326
17	Svc Drop Reqt	$ / Mo / Cust	$19.71	$18.35	$18.57	$18.04	$19.51	$86.19
18	Ener Svcs Reqt	$ / Mo / Cust	$5.69	$5.45	$8.69	$6.50	$12.55	$1.70
19	Total Reqt	$ / Mo / Cust	$25.40	$23.80	$27.26	$24.54	$32.06	$87.89
	Equal Energy Classification							
20	On Peak Rev Reqt		913,573	284,286	627,804	25,322	602,482	1,483
21	Off Peak Rev Reqt		916,255	298,591	613,047	23,597	589,450	4,617
22	Total Ener Rev Reqt		1,829,828	582,877	1,240,850	48,919	1,191,931	6,100
23	Annual MWh Sales		29,392,644	9,082,285	20,195,239	771,624	19,423,615	115,120
24	On Pk Reqt	Mills / kWh	31.082	31.301	31.087	32.817	31.018	12.878
25	Off Pk Reqt	Mills / kWh	31.173	32.876	30.356	30.581	30.347	40.108
26	Total Reqt	Mills / kWh	62.255	64.177	61.443	63.398	61.365	52.986
	Equal Demand Classification							
27	Energy-Related Prod		422,862	137,228	284,363	11,125	273,238	1,271
28	Capacity-Related Summer Peak Prod		384,724	158,056	226,668	8,549	218,119	0
29	Capacity-Related Winter Peak Prod		121,693	49,995	71,698	2,704	68,994	0
30	Total Capacity-Related Prod		506,417	208,051	298,366	11,253	287,113	0
31	Total Production		929,279	345,279	582,729	22,379	560,350	1,271
32	Transmission **(Transco)**		553,906	188,323	363,452	14,565	348,888	2,131
33	Primary Dist Subs		105,392	43,854	60,978	3,107	57,871	560
34	Prim Dist Lines		289,800	165,085	122,817	9,072	113,745	1,899
35	Second Dist, Trans		66,419	40,525	25,683	2,165	23,518	211
36	Total Distribution **(Disco)**		461,611	249,463	209,478	14,344	195,134	2,670
37	Total Demand Rev Reqt		1,944,797	783,066	1,155,659	51,287	1,104,372	6,072
38	Annual Billing kW		50,438,651	0	50,438,651	0	50,438,651	0
39	Base Rev Reqt	$ / kW	$0.00	$0.00	$5.64	$0.00	$5.42	$0.00
40	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.49	$0.00	$4.32	$0.00
41	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.42	$0.00	$1.37	$0.00
42	Prod Rev Reqt	$ / kW	$0.00	$0.00	$11.55	$0.00	$11.11	$0.00
43	Tran Rev Reqt	$ / kW	$0.00	$0.00	$7.21	$0.00	$6.92	$0.00
44	Dist Rev Reqt	$ / kW	$0.00	$0.00	$4.15	$0.00	$3.87	$0.00
45	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$22.91	$0.00	$21.90	$0.00
46	Tot Dmd Rev Reqt	Mills / kWh	66.166	86.219	57.224	66.466	56.857	52.745
47	Summer Billing kW		18,795,390	0	18,795,390	0	18,795,390	0
48	Winter Billing kW		31,643,261	0	31,643,261	0	31,643,261	0
49	Tot Summer Reqt	$ / kW	$0.00	$0.00	$29.06	$0.00	$27.81	$0.00
50	Tot Winter Reqt	$ / kW	$0.00	$0.00	$19.26	$0.00	$18.38	$0.00
51	Energy + Production **(Genco)**		2,759,107	928,156	1,823,580	71,298	1,752,282	7,371

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Exhibit___(CJB-1), Schedule 6

PROP vs Equal Rev Reqts

			1	2	3	4	5	6
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.55%**	**6.75%**	**8.25%**	**7.94%**	**8.27%**	**5.44%**
2	**UnAdj Equalized Rev Reqt**		**4,212,844**	**1,728,144**	**2,442,655**	**126,708**	**2,315,947**	**42,045**
3	**Proposed Revenue**		**4,212,844**	**1,657,917**	**2,517,566**	**129,043**	**2,388,523**	**37,361**
4	**UnAdj Revenue Deficiency**		**0**	**70,227**	**(74,911)**	**(2,335)**	**(72,576)**	**4,684**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**4.24%**	**-2.98%**	**-1.81%**	**-3.04%**	**12.54%**
			[HIGHLY CONFIDENTIAL DATA BEGINS					
6	**Prop Interrupt Rate Discounts**							
7	**Prop Econ Dev Rate Discounts**							
8	**Prop Int Rate Disc Cost Alloc**	**D10S**						
9	**Prop ED Discount Cost Alloc**	**R02**						
								HIGHLY CONFIDENTIAL DATA ENDS]
10	**Revenue Requirement Shift**		**0**	**10,804**	**(10,988)**	**791**	**(11,779)**	**184**
11	**Adj Equal Rev (Rows 2+10)**		**4,212,844**	**1,738,948**	**2,431,667**	**127,499**	**2,304,168**	**42,229**
12	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**81,032**	**(85,899)**	**(1,545)**	**(84,355)**	**4,868**
13	**Adj Deficiency / Adj Prop**		**0.00%**	**4.89%**	**-3.41%**	**-1.20%**	**-3.53%**	**13.03%**
	Prop Customer Component							
14	Min Sys & Service Drop		315,103	256,715	32,694	19,628	13,066	25,694
15	Energy Services		98,142	82,852	14,713	7,020	7,693	577
16	Total Customer **(Cusco)**		413,245	339,567	47,407	26,648	20,759	26,271
17	Ave Monthly Customers		1,437,828	1,268,459	141,043	89,982	51,061	28,326
18	Svc Drop Reqt	$ / Mo / Cust	$18.26	$16.87	$19.32	$18.18	$21.32	$75.59
19	Ener Svcs Reqt	$ / Mo / Cust	$5.69	$5.44	$8.69	$6.50	$12.56	$1.70
20	Total Reqt	$ / Mo / Cust	$23.95	$22.31	$28.01	$24.68	$33.88	$77.29
	Prop Energy Component							
21	On Peak Rev Reqt		913,205	283,909	627,816	25,318	602,498	1,480
22	Off Peak Rev Reqt		915,785	298,193	612,986	23,593	589,392	4,606
23	Total Ener Rev Reqt		1,828,990	582,102	1,240,802	48,912	1,191,890	6,086
24	Annual MWh Sales		29,392,644	9,082,285	20,195,239	771,624	19,423,615	115,120
25	On Pk Reqt	Mills / kWh	31.069	31.260	31.087	32.812	31.019	12.854
26	Off Pk Reqt	Mills / kWh	31.157	32.832	30.353	30.576	30.344	40.012
27	Total Reqt	Mills / kWh	62.226	64.092	61.440	63.388	61.363	52.865
	Prop Demand Component							
28	Energy-Related Prod		425,613	122,115	302,570	11,669	290,901	928
29	Capacity-Related Summer Peak Prod		400,573	157,060	243,513	9,197	234,316	0
30	Capacity-Related Winter Peak Prod		126,707	49,680	77,026	2,909	74,117	0
31	Total Capacity-Related Prod		527,280	206,740	320,539	12,106	308,433	0
32	Total Production		952,892	328,856	623,109	23,775	599,334	928
33	Transmission **(Transco)**		552,688	174,721	376,169	14,930	361,239	1,798
34	Primary Dist Subs		113,440	42,476	70,483	3,407	67,076	481
35	Prim Dist Lines		286,051	153,108	131,322	9,186	122,136	1,622
36	Second Dist, Trans		65,537	37,087	28,275	2,185	26,090	176
37	Total Distribution **(Disco)**		465,028	232,671	230,080	14,778	215,302	2,278
38	Total Demand Rev Reqt		1,970,609	736,248	1,229,357	53,483	1,175,874	5,004
39	Annual Billing kW		50,438,651	0	50,438,651	0	50,438,651	0
40	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.77	$0.00
41	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.65	$0.00
42	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.47	$0.00
43	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$11.88	$0.00
44	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$7.16	$0.00
45	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.27	$0.00
46	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$23.31	$0.00
47	Tot Dmd Rev Reqt	Mills / kWh	67.044	81.064	60.874	69.312	60.538	43.468
48	Summer Billing kW		18,795,390	0	18,795,390	0	18,795,390	0
49	Winter Billing kW		31,643,261	0	31,643,261	0	31,643,261	0
50	Tot Summer Reqt	$ / kW	$0.00	$0.00	$30.97	$0.00	$29.66	$0.00
51	Tot Winter Reqt	$ / kW	$0.00	$0.00	$20.45	$0.00	$19.54	$0.00
52	Energy + Production **(Genco)**		2,781,882	910,958	1,863,911	72,687	1,791,224	7,014
53	Prop Rev - Pres Rev (Pg 2)		488,390	209,940	273,050	14,602	258,448	5,400
54	Difference / Present		13.11%	14.50%	12.17%	12.76%	12.13%	16.89%

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Original Plant in Service

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Summer Peak	D10S		2,817,006	1,159,676	1,657,330	62,605	1,594,725	0
2	WInter Peak	D10S		891,057	366,821	524,236	19,803	504,433	0
3	Total Peak	D10S		3,708,063	1,526,497	2,181,567	82,408	2,099,158	0
4	Base Load	E8760		6,809,663	2,168,526	4,619,045	181,356	4,437,689	22,091
5	Nuclear Fuel	E8760		3,055,122	972,899	2,072,312	81,365	1,990,947	9,911
6	Total	35.26%	120, 310-346	13,572,848	4,667,922	8,872,923	345,129	8,527,795	32,003
	Transmission								
7	Gen Step Up Base	E8760		138,431	44,083	93,899	3,687	90,212	449
8	Gen Step Up Peak	D10S		41,416	17,050	24,366	920	23,446	0
9	Total Gen Step Up			179,846	61,133	118,265	4,607	113,658	449
10	Bulk Transmission	D10T		4,325,433	1,475,943	2,832,760	113,958	2,718,802	16,731
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		10,127	0	10,127	0	10,127	0
13	Total		350-359	4,515,407	1,537,075	2,961,152	118,565	2,842,587	17,180
	Distribution:								
	Substations								
14	Generat Step Up	STRATH		2,811	944	1,859	73	1,787	7
15	Bulk Transmission	D10T		0	0	0	0	0	0
16	Distrib Function	D60Sub		1,016,495	434,301	576,639	30,717	545,922	5,555
17	Direct Assign	Dir Assign		23,574	0	23,574	0	23,574	0
18	Total		360-363	1,042,880	435,245	602,073	30,789	571,284	5,562
	Overhead Lines								
19	Primary Capacity 1 Phase	D61PS1Ph		281,134	234,044	44,691	9,092	35,599	2,399
20	Primary Capacity Multi Phase	D61PS		617,235	268,312	345,491	18,977	326,514	3,432
21	Primary Customer 1 Phase	C61PS1Ph		88,849	84,721	3,794	3,305	489	335
22	Primary Customer Multi Phase	C61PS		195,070	174,746	19,462	12,409	7,053	862
23	Total Primary			1,182,288	761,823	413,438	43,783	369,655	7,027
24	Second Capacity	D62SecL		95,806	52,707	42,688	3,476	39,212	412
25	Second Customer	C62Sec		380,619	341,084	37,853	24,222	13,632	1,682
26	Total Secondary			476,425	393,790	80,541	27,697	52,844	2,094
27	Street Lighting	DASL		72,646	0	0	0	0	72,646
28	Total		364,365	1,731,360	1,155,614	493,980	71,480	422,500	81,766
	Underground Lines								
29	Primary Capacity 1 Phase	D61PS1Ph		416,934	347,097	66,279	13,484	52,795	3,557
30	Primary Capacity Multi Phase	D61PS		601,744	261,578	336,820	18,501	318,320	3,346
31	Primary Customer 1 Phase	C61PS1Ph		221,323	211,039	9,450	8,232	1,218	834
32	Primary Customer Multi Phase	C61PS		319,427	286,147	31,869	20,320	11,549	1,411
33	Total Primary			1,559,428	1,105,861	444,419	60,536	383,882	9,148
34	Second Capacity	D62SecL		172,511	94,905	76,865	6,258	70,607	741
35	Second Customer	C62Sec		243,633	218,326	24,230	15,504	8,726	1,077
36	Total Secondary			416,144	313,231	101,095	21,763	79,332	1,818
37	Street Lighting	DASL		0	0	0	0	0	0
38	Total		366,367	1,975,571	1,419,092	545,513	82,299	463,214	10,966
	Line Transformers								
39	Primary	D61PS		92,347	40,143	51,690	2,839	48,851	513
40	Second Capacity	D62SecL		136,683	75,194	60,901	4,959	55,943	587
41	Second Customer	C62Sec		291,157	260,914	28,956	18,528	10,428	1,287
42	Total		368	520,186	376,251	141,548	26,326	115,221	2,387
	Services								
43	Second Capacity	D62NLL		161,823	126,944	34,879	3,563	31,316	0
44	Second Customer	C62NL		263,491	250,931	12,559	8,037	4,523	0
43	Total Services	C62NL	369	425,314	377,876	47,439	11,600	35,839	0
44	Meters	C12WM	370	305,288	248,497	56,208	29,505	26,703	583
45	Street Lighting	Dir Assign	373	92,249	0	0	0	0	92,249
46	**Total Distribution**			6,092,849	4,012,575	1,886,761	251,999	1,634,761	193,514
47	**General & Common Plant**	PTD	303, 389-399	3,088,305	1,304,944	1,752,365	91,405	1,660,960	30,996
48	Prelim Elec Plant			27,269,409	11,522,515	15,473,201	807,099	14,666,103	273,692
49	TBT Investment	NEPIS		0	0	0	0	0	0
50	**Elec Plant in Serv**			27,269,409	11,522,515	15,473,201	807,099	14,666,103	273,692

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Accum Deprec; Net Plant

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		1,660,625	683,629	976,996	36,906	940,090	0
2	Decom Int Peaking	D10S		0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0
4	Nuclear Fuel	E8760		2,861,297	911,175	1,940,839	76,203	1,864,637	9,282
5	Base Load	E8760		3,308,172	1,053,482	2,243,958	88,104	2,155,854	10,732
6	Total		108,111,115,120.5	7,830,094	2,648,286	5,161,793	201,212	4,960,581	20,015
	Transmission								
7	Gen Step Up Base	E8760		23,474	7,475	15,922	625	15,297	76
8	Gen Step Up Peak	D10S		18,573	7,646	10,927	413	10,514	0
9	Total Gen Step Up			42,046	15,121	26,849	1,038	25,811	76
10	Bulk Transmission	D10T		1,018,159	347,421	666,800	26,825	639,976	3,938
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		2,986	0	2,986	0	2,986	0
13	Total		108,111,115,120.5	1,063,192	362,542	696,636	27,862	668,773	4,014
	Distribution								
14	Generat Step Up	STRATH		1,928	647	1,275	50	1,226	5
15	Bulk Transmission	D10T		0	0	0	0	0	0
16	Distrib Function	D60Sub		272,001	116,213	154,301	8,219	146,082	1,486
17	Direct Assign	Dir Assign		6,662	0	6,662	0	6,662	0
18	Total Substations			280,591	116,861	162,238	8,269	153,969	1,492
19	Overhead Lines	POL		533,028	355,775	152,080	22,006	130,074	25,173
20	Underground	PUL		627,243	450,561	173,200	26,130	147,070	3,482
21	Line Transformers	P68		210,684	152,388	57,329	10,663	46,667	967
22	Services	P69		214,929	190,956	23,973	5,862	18,111	0
23	Meters	C12WM		49,507	40,297	9,115	4,785	4,330	95
24	Street Lighting	P73		35,000	0	0	0	0	35,000
25	Total		108,111,115,120.5	1,950,982	1,306,838	577,936	77,714	500,221	66,208
26	**General & CommonPlant**	PTD	108,111,115,120.5	1,496,150	632,189	848,945	44,282	804,663	15,016
27	**Total Accum Depr**			12,340,417	4,949,855	7,285,309	351,071	6,934,238	105,253
28	**Net Elec Plant**			14,928,992	6,572,660	8,187,892	456,028	7,731,864	168,439
29	**Net Plant w/ TBT**			14,928,992	6,572,660	8,187,892	456,028	7,731,864	168,439

Subtractions: Accum Defer Inc Tax

				1	2	3	4	5	6
	Production								
30	Peaking Plant	D10S		362,804	149,355	213,448	8,063	205,385	0
31	Base Load	E8760		1,040,921	331,480	706,065	27,722	678,343	3,377
32	Nuclear Fuel	E8760		(5,564)	(1,772)	(3,774)	(148)	(3,626)	(18)
33	Total		190,281,282,283	1,398,162	479,063	915,739	35,637	880,103	3,359
	Transmission								
34	Gen Step Up Base	E8760		22,741	7,242	15,426	606	14,820	74
35	Gen Step Up Peak	D10S		5,162	2,125	3,037	115	2,922	0
36	Total Gen Step Up			27,903	9,367	18,462	720	17,742	74
37	Bulk Transmission	D10T		774,263	264,197	507,071	20,399	486,672	2,995
38	Distrib Function	D60Sub		0	0	0	0	0	0
39	Direct Assign	Dir Assign		1,731	0	1,731	0	1,731	0
40	Total		281,282,283	803,897	273,564	527,264	21,119	506,145	3,069
	Distribution								
41	Generat Step Up	STRATH		189	63	125	5	120	0
42	Bulk Transmission	D10T		0	0	0	0	0	0
43	Distrib Function	D60Sub		123,901	52,937	70,287	3,744	66,543	677
44	Direct Assign	Dir Assign		2,927	0	2,927	0	2,927	0
45	Total Substations			127,017	53,001	73,339	3,749	69,590	678
46	Overhead Lines	POL		170,556	113,839	48,662	7,041	41,620	8,055
47	Underground	PUL		184,367	132,435	50,909	7,680	43,229	1,023
48	Line Transformers	P68		54,991	39,775	14,964	2,783	12,181	252
49	Services	P69		22,486	19,978	2,508	613	1,895	0
50	Meters	C12WM		18,126	14,754	3,337	1,752	1,585	35
51	Street Lighting	P73		8,185	0	0	0	0	8,185
52	Total		281,282,283	585,728	373,782	193,719	23,619	170,100	18,228
53	**General & Common Plant**	PTD	281,282,283	179,315	75,769	101,747	5,307	96,440	1,800
54	**Total Deferred Tax**			2,967,102	1,202,178	1,738,470	85,682	1,652,787	26,455
55	Net Operating Loss (NOL) Carry F	NEPIS		(631,129)	(277,862)	(346,146)	(19,279)	(326,868)	(7,121)
56	Non-Plant Related	LABOR		10,492	4,507	5,896	323	5,573	90
57	**Accum Def W/ Adj**			2,346,466	928,823	1,398,219	66,726	1,331,493	19,424

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Additions: CWIP, Etc; Rate Base

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		279,285	114,973	164,312	6,207	158,105	0
2	Base Load	E8760		19,505	6,211	13,230	519	12,711	63
3	Nuclear Fuel	E8760		187,428	59,686	127,134	4,992	122,142	608
4	Total		107	486,218	180,871	304,676	11,718	292,958	671
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		22,567	9,290	13,277	502	12,775	0
7	Total Gen Step Up			22,567	9,290	13,277	502	12,775	0
8	Bulk Transmission	D10T		134,601	45,929	88,151	3,546	84,605	521
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		107	157,167	55,219	101,428	4,048	97,380	521
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		39,967	17,076	22,673	1,208	21,465	218
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			39,967	17,076	22,673	1,208	21,465	218
17	Overhead Lines	POL		38,199	25,496	10,899	1,577	9,322	1,804
18	Underground	PUL		40,673	29,216	11,231	1,694	9,537	226
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		1,645	1,461	183	45	139	0
21	Meters	C12WM		2,003	1,630	369	194	175	4
22	Street Lighting	P73		157	0	0	0	0	157
23	Total		107	122,644	74,880	45,355	4,718	40,637	2,409
24	**General & Common Plant**	PTD	107	322,193	136,141	182,819	9,536	173,283	3,234
25	**Total CWIP**			1,088,222	447,111	634,277	30,019	604,258	6,834
26	Fuel Inventory	E8760	151,152	85,634	27,270	58,086	2,281	55,805	278
	Materials & Supplies								
27	Production	P10		151,420	52,076	98,987	3,850	95,137	357
28	Trans & Distr	TD		34,419	18,006	15,729	1,202	14,527	684
29	Total		154	185,838	70,082	114,716	5,053	109,664	1,041
	Prepayments								
30	Miscellaneous	NEPIS		88,520	38,972	48,549	2,704	45,845	999
	LED Deferral	DASLED		0	0	0	0	0	0
31	Fuel	E8760		0	0	0	0	0	0
32	Insurance	NEPIS	135,143,184,186,232	0	0	0	0	0	0
33	Total		235,252,165	88,520	38,972	48,549	2,704	45,845	999
34	Non-Plant Assets & Liab	LABOR	190,283,	99,107	42,571	55,691	3,047	52,644	846
35	Working Cash	PT0	calculated	(96,584)	(43,491)	(51,906)	(2,968)	(48,938)	(1,187)
36	**Total Additions**			1,450,736	582,513	859,413	40,135	819,278	8,810
37	**Total Rate Base**			14,033,262	6,226,351	7,649,086	429,437	7,219,649	157,825
38	**Common Rate Base (@ 52.50%)**			7,367,462.7	3,268,834	4,015,770	225,454	3,790,316	82,858

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Operating Rev (Cal Month)

				1	2	3	4	5	6
	Retail Revenue	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	3,724,454	1,447,977	2,244,516	114,442	2,130,075	31,961
2	Proposed Rate Revenue	PROREV; (calc)		4,212,844	1,657,917	2,517,566	129,043	2,388,523	37,361
3	Equal Rate Revenue			4,212,844	1,728,144	2,442,655	126,708	2,315,947	42,045
	Other Retail Revenue								
4	Interdepartmental	R01; R02	448	667	259	402	20	381	6
5	Gross Earnings Tax	R01; R02	408	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	E99XCIP	456	0	0	0	0	0	0
7	**Tot Other Retail Rev**			667	259	402	20	381	6
	Other Operating Revenue								
8	Interchg Prod Capacity	P10	456	439,888	151,285	287,566	11,185	276,381	1,037
9	Interchg Prod Energy	E8760	456	0	0	0	0	0	0
10	Interchg Tr Bulk Supply	D10T	456	0	0	0	0	0	0
11	Dist Int Sales; Oth Serv	E8760	412,451,456	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	454	4,786	3,194	1,365	198	1,168	226
13	Connection Charges	C11	451	0	0	0	0	0	0
14	Sales For Resale	E8760	447	247,354	78,770	167,782	6,588	161,195	802
15	Joint Op Agree-Other PSCo Rev	D10T	456	(2,673)	(912)	(1,751)	(70)	(1,680)	(10)
16	Misc Ancillary Trans Rev	D10T		257,694	87,931	168,766	6,789	161,977	997
17	MISO	D10T	456	(98,327)	(33,551)	(64,395)	(2,591)	(61,804)	(380)
18	Other	D10T	451,456,457	405	138	266	11	255	2
19	Late Pay Chg - Pres	R16C; R02		7,052	5,804	1,037	221	816	211
20	**Tot Other Op - Pres**		450	856,179	292,659	560,636	22,330	538,306	2,884
21	Incr Misc Serv - Prop	C62NL		1,338	1,274	64	41	23	0
22	Incr Inter-Dept'l - Prop	R01; R02		89	34	53	3	51	1
23	Incr Late Pay - Prop	(R16C); R02		925	761	136	29	107	28
	Tot Incr Other Op			2,351	2,069	253	72	181	28
24	**Tot Other Op - Prop**			858,530	294,728	560,889	22,403	538,486	2,913
25	**Tot Oper Rev - Pres**			4,581,300	1,740,895	2,805,554	136,792	2,668,762	34,851
26	**Tot Oper Rev - Prop**			5,072,041	1,952,904	3,078,857	151,467	2,927,391	40,279
	Tot Oper Rev - Eql			5,072,041	2,023,131	3,003,946	149,131	2,854,815	44,963

Operating & Maint (Pg 1 of 2)

	Production Expen								
27	**Fuel**	E8760	501,518,547	790,932	251,871	536,495	21,064	515,431	2,566
	Purchased Power								
28	Purchases: Cap Peak	D10S		79,667	32,796	46,871	1,771	45,100	0
29	Purchases: Cap Base	D10S		29,645	12,204	17,441	659	16,783	0
30	Purchases: Demand		555	109,312	45,001	64,312	2,429	61,883	0
31	Purchases: Other Energy	E8760	555	491,235	156,433	333,208	13,083	320,125	1,594
32	Tot Non-Assoc Purch			600,547	201,433	397,520	15,512	382,008	1,594
33	Interchg Agr Capacity	P10WoN	557	78,662	27,635	50,862	1,973	48,889	165
34	Interchg Agr Energy	E8760	557	16,993	5,411	11,527	453	11,074	55
35	Tot Wis Interchg Purch			95,655	33,047	62,388	2,425	59,963	220
36	**Tot Purchased Power**			696,202	234,480	459,908	17,937	441,971	1,814
	Other Production		500,502,505-507 509-514,517-519,520,						
37	Capacity Related	D10S	523-525,528-532,535,	102,572	42,226	60,346	2,280	58,067	0
38	Energy Related	E8760	539,543-546,548-550	359,453	114,467	243,819	9,573	234,246	1,166
39	Total Other Produc	22.20%	552-554,556,557 575.1-575.8	462,024	156,693	304,166	11,853	292,313	1,166
40	**Total Production**			1,949,158	643,044	1,300,569	50,854	1,249,715	5,546
41	**Transmission Exp**	D10T	560-563, 565-568 570-573	291,923	99,611	191,183	7,691	183,492	1,129

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Operating & Maint (Pg 2 of 2)

				1	2	3	4	5	6
	Distribution Expen	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	16,181	10,727	4,836	709	4,127	618
2	Load Dispatching	T20D80	581	411	174	235	12	223	2
3	Substations	P61	582,591,592	4,361	1,820	2,518	129	2,389	23
4	Overhead Lines	POL	583,593	88,845	59,301	25,349	3,668	21,681	4,196
5	Underground Lines	PUL	584, 594	18,736	13,458	5,174	781	4,393	104
6	Line Transformers	P68	595	0	0	0	0	0	0
7	Meters	C12WM	586,597,598	1,411	1,149	260	136	123	3
8	Customer Install'n	OXDTS	587	(926)	(602)	(266)	(38)	(228)	(57)
9	Street Lighting	Dir Assign	585,596	2,936	0	0	0	0	2,936
10	Miscellaneous	OXDTS	588	(568)	(370)	(163)	(23)	(140)	(35)
11	Rents (Pole Attachmts)	POL	589	3,748	2,502	1,069	155	915	177
12	**Total Distribution**			135,135	88,158	39,011	5,529	33,482	7,966
13	**Customer Accounting**	C11WA	901-905	76,805	64,747	11,655	5,512	6,143	404
14	**Sales, Econ Dvlp & Other**	R01	912	8,608	3,347	5,188	265	4,923	74
	Admin & General								
15	Salaries	LABOR	920	111,196	47,763	62,484	3,418	59,065	949
16	Office Supplies	OXTS	921	68,420	25,308	42,681	1,957	40,724	430
17	Admin Transfer Credit	OXTS	922	(91,374)	(33,799)	(57,000)	(2,613)	(54,387)	(575)
18	Outside Services	LABOR	923	25,882	11,117	14,544	796	13,748	221
19	Property Insurance	NEPIS	924	9,278	4,085	5,089	283	4,805	105
20	Pensions & Benefits	LABOR	926	74,258	31,897	41,727	2,283	39,445	634
21	Injuries & Claims	LABOR	925	30,069	12,916	16,896	924	15,972	257
22	Regulatory Exp	R01; R02	928	8,483	3,298	5,112	261	4,851	73
23	General Advertising	OXTS	930.1	1,133	419	707	32	674	7
24	Contributions	OXTS		0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	(374)	(138)	(233)	(11)	(223)	(2)
26	Rents	OXTS	931	62,281	23,038	38,852	1,781	37,071	392
27	Maint of General Plant	OXTS	935	416	154	259	12	248	3
28	Total			299,667	126,058	171,117	9,124	161,994	2,492
	Cust Service & Info								
29	Cust Assist Exp - Non-CIP	C11P10	908	3,363	2,062	1,264	148	1,116	37
30	CIP Total	E99XCIP	908	170,410	55,399	114,309	4,706	109,603	702
31	Instructional Advertising	C11P10	909	769	472	289	34	255	8
32	Total			174,543	57,932	115,863	4,888	110,975	748
33	Amortizations	LABOR		54,152	23,261	30,429	1,665	28,765	462
	Amortizations LED Deferral	DASLED		0	0	0	0	0	0
34	**Total O&M Expense**			2,989,992	1,106,157	1,865,014	85,527	1,779,488	18,821

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Exhibit___(CJB-1), Schedule 6

Book Depreciation

		Alloc	FERC Accounts	1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
1	Peaking Plant	D10S		136,044	56,005	80,039	3,023	77,015	0
2	Base Load	E8760		292,385	93,110	198,327	7,787	190,540	949
3	Total		403,413	428,429	149,115	278,366	10,810	267,555	949
	Transmission								
4	Gen Step Up Base	E8760		2,464	785	1,671	66	1,606	8
5	Gen Step Up Peak	D10S		1,433	590	843	32	811	0
6	Total Gen Step Up			3,897	1,374	2,514	97	2,417	8
7	Bulk Transmission	D10T		95,454	32,571	62,513	2,515	59,999	369
8	Distrib Function	D60Sub		0	0	0	0	0	0
9	Direct Assign	Dir Assign		224	0	224	0	224	0
10	Total		403,413	99,574	33,946	65,251	2,612	62,639	377
	Distribution								
11	Generat Step Up	STRATH		73	24	48	2	46	0
12	Bulk Transmission	D10T		0	0	0	0	0	0
13	Distrib Function	D60Sub		24,954	10,662	14,156	754	13,402	136
14	Direct Assign	Dir Assign		567	0	567	0	567	0
15	Total Substations		403,413	25,594	10,686	14,771	756	14,015	137
16	Overhead Lines	POL		62,384	41,639	17,799	2,576	15,223	2,946
17	Underground	PUL		59,186	42,514	16,343	2,466	13,877	329
18	Line Transformers	P68		16,144	11,677	4,393	817	3,576	74
19	Services	P69		17,982	15,976	2,006	490	1,515	0
20	Meters	C12WM		14,204	11,562	2,615	1,373	1,242	27
21	Street Lighting	P73		4,878	0	0	0	0	4,878
22	Total		403,413	200,371	134,054	57,927	8,477	49,450	8,390
23	**General & Common Plant**	PTD	403,413	201,861	85,295	114,540	5,975	108,566	2,026
24	**Total Book Deprec**		403,404	930,236	402,410	516,084	27,874	488,210	11,742

Real Estate & Property Tax

		Alloc	FERC Accounts	1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Production								
25	Peaking Plant	D10S		29,471	12,133	17,339	655	16,684	0
26	Base Load	E8760		54,123	17,235	36,712	1,441	35,271	176
27	Total		408.1	83,594	29,368	54,051	2,096	51,954	176
	Transmission								
28	Gen Step Up Base	E8760		1,358	433	921	36	885	4
29	Gen Step Up Peak	D10S		406	167	239	9	230	0
30	Total Gen Step Up			1,765	600	1,160	45	1,115	4
31	Bulk Transmission	D10T		42,440	14,481	27,794	1,118	26,676	164
32	Distrib Function	D60Sub		0	0	0	0	0	0
33	Direct Assign	Dir Assign		99	0	99	0	99	0
34	Total		408.1	44,304	15,081	29,054	1,163	27,891	169
	Distribution								
35	Generat Step Up	STRATH		29	10	19	1	19	0
36	Bulk Transmission	D10T		0	0	0	0	0	0
37	Distrib Function	D60Sub		10,527	4,498	5,972	318	5,654	58
38	Direct Assign	Dir Assign		244	0	244	0	244	0
39	Total Substations			10,800	4,508	6,235	319	5,916	58
40	Overhead Lines	POL		17,931	11,968	5,116	740	4,376	847
41	Underground	PUL		20,460	14,697	5,650	852	4,797	114
42	Line Transformers	P68		5,387	3,897	1,466	273	1,193	25
43	Services	P69		4,405	3,913	491	120	371	0
44	Meters	C12WM		3,162	2,574	582	306	277	6
45	Street Lighting	P73		955	0	0	0	0	955
46	Total		408.1	63,100	41,556	19,540	2,610	16,930	2,004
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			190,998	86,005	102,645	5,870	96,775	2,348
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0
50	Payroll Taxes	LABOR		29,174	12,531	16,393	897	15,497	249
51	**Tot Non-Inc Taxes**			220,171	98,536	119,038	6,766	112,272	2,597

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Provision For Defer Inc Tax

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		45,951	18,917	27,035	1,021	26,013	0
2	Nuclear Fuel	E8760		(418)	(133)	(284)	(11)	(273)	(1)
3	Base Load	E8760		(36,653)	(11,672)	(24,862)	(976)	(23,886)	(119)
4	Total		410, 411	8,880	7,111	1,889	34	1,855	(120)
	Transmission								
5	Gen Step Up Base	E8760		385	122	261	10	251	1
6	Gen Step Up Peak	D10S		185	76	109	4	105	0
7	Total Gen Step Up			570	199	370	14	355	1
8	Bulk Transmission	D10T		20,716	7,069	13,567	546	13,021	80
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		33	0	33	0	33	0
11	Total		410, 411	21,319	7,267	13,970	560	13,410	81
	Distribution								
12	Generat Step Up	STRATH		(34)	(11)	(23)	(1)	(22)	(0)
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		1,975	844	1,120	60	1,061	11
15	Direct Assign	Dir Assign		(24)	0	(24)	0	(24)	0
16	Total Substations			1,917	832	1,074	59	1,015	11
17	Overhead Lines	POL		9,658	6,447	2,756	399	2,357	456
18	Underground	PUL		(6,498)	(4,668)	(1,794)	(271)	(1,524)	(36)
19	Line Transformers	P68		(1,942)	(1,405)	(528)	(98)	(430)	(9)
20	Services	P69		56	50	6	2	5	0
21	Meters	C12WM		3,479	2,832	641	336	304	7
22	Street Lighting	P73		(439)	0	0	0	0	(439)
23	Total		410, 411	6,232	4,088	2,154	426	1,727	(10)
24	**General & Common Plant**	PTD	410, 411	3,374	1,426	1,914	100	1,815	34
25	**Net Operating Loss (NOL) Carry**	NEPIS		(227,036)	(99,955)	(124,519)	(6,935)	(117,584)	(2,562)
26	**Non - Plant Related**	LABOR	410, 411	(1,929)	(829)	(1,084)	(59)	(1,025)	(16)
27	**Tot Prov For Defer**			(189,161)	(80,891)	(105,677)	(5,874)	(99,802)	(2,593)
	Inv Tax Credit; Total Oper Exp								
	Production								
28	Peaking Plant	D10S		(236)	(97)	(139)	(5)	(133)	0
29	Base Load	E8760		(825)	(263)	(559)	(22)	(537)	(3)
30	Total		411	(1,061)	(360)	(698)	(27)	(671)	(3)
	Transmission								
31	Gen Step Up Base	E8760		0	0	0	0	0	0
32	Gen Step Up Peak	D10S		0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0
34	Bulk Transmission	D10T		(150)	(51)	(98)	(4)	(94)	(1)
35	Distrib Function	D60Sub		0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0
37	Total		411	(150)	(51)	(98)	(4)	(94)	(1)
	Distribution								
38	Generat Step Up	STRATH		0	0	0	0	0	0
39	Bulk Transmission	D10T		0	0	0	0	0	0
40	Distrib Function	D60Sub		0	0	0	0	0	0
41	Direct Assign	Dir Assign		0	0	0	0	0	0
42	Total Substations			0	0	0	0	0	0
43	Overhead Lines	POL		(292)	(195)	(83)	(12)	(71)	(14)
44	Underground	PUL		0	0	0	0	0	0
45	Line Transformers	P68		0	0	0	0	0	0
46	Services	P69		0	0	0	0	0	0
47	Meters	C12WM		0	0	0	0	0	0
48	Street Lighting	P73		0	0	0	0	0	0
49	Total		411	(292)	(195)	(83)	(12)	(71)	(14)
50	**General & Common Plant**	PTD	411	(5)	(2)	(3)	(0)	(3)	(0)
51	**Net Inv Tax Credit**			(1,508)	(608)	(883)	(43)	(839)	(17)
28	TBT Misc Net Exp	NEPIS		0	0	0	0	0	0
52	**Total Operating Exp**			**3,949,730**	**1,525,603**	**2,393,578**	**114,250**	**2,279,328**	**30,549**
53A	**Pres Op Inc Before Inc Tax**			**631,570**	**215,291**	**411,976**	**22,543**	**389,434**	**4,302**
53B	**Prop Op Inc Before Inc Tax**			**1,122,310**	**427,300**	**685,280**	**37,217**	**648,063**	**9,730**

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Tax Deprec; Inc Tax & Return

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		363,997	149,847	214,151	8,090	206,061	0
2	Nuclear Fuel	E8760		105,933	33,734	71,855	2,821	69,034	344
3	Base Load	E8760		211,517	67,357	143,474	5,633	137,840	686
4	Total		tax books	681,447	250,938	429,479	16,544	412,935	1,030
	Transmission								
5	Gen Step Up Base	E8760		7,541	2,401	5,115	201	4,914	24
6	Gen Step Up Peak	D10S		1,874	772	1,103	42	1,061	0
7	Total Gen Step Up			9,415	3,173	6,218	242	5,975	24
8	Bulk Transmission	D10T		182,195	62,169	119,321	4,800	114,521	705
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		330	0	330	0	330	0
11	Total		tax books	191,940	65,342	125,868	5,043	120,826	729
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		35,750	15,274	20,280	1,080	19,200	195
15	Direct Assign	Dir Assign		343	0	343	0	343	0
16	Total Substations			36,092	15,274	20,623	1,080	19,543	195
17	Overhead Lines	POL		83,203	55,535	23,739	3,435	20,304	3,929
18	Underground	PUL		90,684	65,140	25,040	3,778	21,263	503
19	Line Transformers	P68		17,082	12,355	4,648	865	3,784	78
20	Services	P69		15,199	13,504	1,695	415	1,281	0
21	Meters	C12WM		27,041	22,010	4,979	2,613	2,365	52
22	Street Lighting	P73		3,646	0	0	0	0	3,646
23	Total		tax books	272,947	183,819	80,724	12,186	68,539	8,404
24	**General & Common Plant**	PTD	tax books	212,504	89,792	120,579	6,290	114,289	2,133
25	Net Operating Loss (NOL) Carry F	NEPIS		(3,274)	(1,441)	(1,796)	(100)	(1,696)	(37)
26	**Total Tax Deprec**			1,355,563	588,449	754,855	39,962	714,893	12,259
27	Interest Expense		427,431	300,311.81	133,244	163,690	9,190	154,500	3,377
28	Other Tax Timing Differ	LABOR		(25,919)	(11,133)	(14,565)	(797)	(13,768)	(221)
29	Meals & Enter	LABOR		1,582	679	889	49	840	13
30	Total Tax Deductions			1,631,538	711,239	904,869	48,403	856,466	15,429
	Inc Tax Additions								
31	Book Depreciation			930,236	402,410	516,084	27,874	488,210	11,742
32	Deferred Inc Tax & ITC			(190,668.55)	(81,499)	(106,559)	(5,918)	(100,642)	(2,610)
33	Nuclear Fuel Book Burn	E8760		114,483	36,457	77,655	3,049	74,606	371
34	Tax Capitalized Leases	PTD		46,357	19,588	26,304	1,372	24,932	465
35	Avoided Tax Interest	RTBASE		54,641	24,244	29,783	1,672	28,111	615
36	Total Tax Additions			955,048	401,199	543,267	28,050	515,217	10,583
37	**Total Inc Tax Adjustments**			(676,489)	(310,041)	(361,602)	(20,353)	(341,249)	(4,846)
38A	**Pres Taxable Net Income**			(44,919)	(94,749)	50,374	2,189	48,185	(544)
38B	**Prop Taxable Net Income**			445,821	117,260	323,677	16,863	306,814	4,884
39A	Pres Fed & State Inc Tax			7,187	(18,316)	25,433	1,244	24,189	70
38A	Exp Fed & State Inc Tax			148,236	36,853	110,101	5,578	104,522	1,282
39B	Prop Fed & State Inc Tax			148,236	42,620	103,986	5,462	98,524	1,630
38C	Equal Fed & State Inc Tax			148,236	62,805	82,455	4,791	77,664	2,976
40A	Pres Preliminary Return	(total); BASE		624,383	233,607	386,543	21,298	365,245	4,232
40B	Prop Preliminary Return	(total); BASE		974,075	384,680	581,294	31,755	549,539	8,100
41	Total AFUDC			85,437	35,366	49,593	2,332	47,261	478
42A	**Present Total Return**			709,819	268,973	436,136	23,630	412,506	4,710
42B	**Proposed Total Return**			1,059,511	420,047	630,886	34,086	596,800	8,578
42C	**Equal Total Return**			1,059,511	470,089	577,506	32,422	545,084	11,916
43A	**Pres % Return on Rate Base**			5.06%	4.32%	5.70%	5.50%	5.71%	2.98%
43B	**Prop % Return on Rate Base**			7.55%	6.75%	8.25%	7.94%	8.27%	5.44%
44A	**Present Common Return**			409,508	135,729	272,445	14,440	258,005	1,333
44B	**Proposed Common Return**			759,199	286,803	467,196	24,897	442,299	5,201
45A	**Pres % Ret on Common Rt Base**			5.56%	4.15%	6.78%	6.40%	6.81%	1.61%
45B	**Prop % Ret on Common Rt Base**			10.30%	8.77%	11.63%	11.04%	11.67%	6.28%

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Allow For Funds Used During Constr

				1	2	3	4	5	6
	Production	**Alloc**	**FERC Accounts**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10S		26,145	10,763	15,382	581	14,801	0
2	Nuclear Fuel	E8760		13,496	4,298	9,154	359	8,795	44
3	Base Load	E8760		(2,320)	(739)	(1,574)	(62)	(1,512)	(8)
4	Total		419.1,432	37,321	14,322	22,963	879	22,084	36
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10S		1,395	574	821	31	790	0
7	Total Gen Step Up			1,395	574	821	31	790	0
8	Bulk Transmission	D10T		10,662	3,638	6,983	281	6,702	41
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		419.1,432	12,058	4,213	7,804	312	7,492	41
	Distribution								
12	Generat Step Up	STRATH		0	0	0	0	0	0
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		7,318	3,127	4,151	221	3,930	40
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			7,318	3,127	4,151	221	3,930	40
17	Overhead Lines	POL		2,334	1,558	666	96	570	110
18	Underground	PUL		3,297	2,368	910	137	773	18
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		3	3	0	0	0	0
21	Meters	C12WM		33	27	6	3	3	0
22	Street Lighting	P73		0	0	0	0	0	0
23	Total		419.1,432	12,985	7,082	5,734	458	5,276	169
24	**General & Common Plant**	PTD	419.1,432	23,073	9,749	13,092	683	12,409	232
25	**Total AFUDC**			85,437	35,366	49,593	2,332	47,261	478
	Labor Allocator								
	Production								
26	Other Prod - Cap	D10S		73,807	30,384	43,423	1,640	41,783	0
27	Other Prod - Ene	E8760		135,543	43,163	91,940	3,610	88,330	440
28	Total		500 through 557	209,350	73,547	135,362	5,250	130,112	440
	Transmission								
29	Stepup Subtrans	P5161A		706	240	464	18	446	2
30	Bulk Power Subs	D10T		16,978	5,793	11,119	447	10,672	66
31	Total		560 through 571	17,684	6,033	11,584	465	11,118	67
	Distribution								
32	Superv & Eng	ZDTS	580, 590	10,799	7,159	3,227	473	2,754	413
33	Load Dispatch	D10T	581	186	63	122	5	117	1
34	Substation	P61	582, 592	2,537	1,059	1,464	75	1,390	14
35	Overhead Lines	POL	583, 593	14,893	9,940	4,249	615	3,634	703
36	Underground Lines	PUL	584, 594	6,968	5,005	1,924	290	1,634	39
37	Line Transformer	P68	595	0	0	0	0	0	0
38	Meter	C12WM	586, 597	2,455	1,998	452	237	215	5
39	Cust Installation	ZDTS	587	743	492	222	33	189	28
40	Street Lighting	P73	585, 596	19	0	0	0	0	19
41	Miscellaneous	OXDTS	588	10,779	7,017	3,097	437	2,660	666
42	Total			49,378	32,734	14,758	2,165	12,593	1,886
43	**Cust Accounting**	C11WA	901,902,903,904,905	13,772	11,610	2,090	988	1,102	72
44	**Sales Expense**	C11P10	912	2,922	1,791	1,098	129	970	32
45	**Admin & General**	LABOR	920,921,922,923,924,	185,185	79,545	104,060	5,693	98,367	1,580
46	**Service & Inform**	C11P10	908, 909	1,011	620	380	44	335	11
47	**Labor**			479,302	205,880	269,332	14,735	254,597	4,089

PUBLIC DOCUMENT
HIGHLY CONFIDENTIAL DATA EXCISED

Highly Confidential data is shaded.

			1	2	3	4	5	
INTERNAL ALLOCATORS		Intern:	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	61.31%	37.59%	4.40%	33.19%	1.10%
2	Peaking Plant Capacity	D10S	100.00%	41.17%	58.83%	2.22%	56.61%	0.00%
3	57% Dmd; 43% Energy: Sales & I	D57E43	100.00%	31.84%	67.83%	2.66%	65.17%	0.32%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	31.84%	67.83%	2.66%	65.17%	0.32%
5	20%D10T; 80%D60Sub	T20D80	100.00%	42.41%	57.15%	2.86%	54.29%	0.44%
6	Labor w/o (or w/) A&G	LABOR	100.00%	42.95%	56.19%	3.07%	53.12%	0.85%
7	Net Plant In Service	NEPIS	100.00%	44.03%	54.85%	3.05%	51.79%	1.13%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	65.09%	28.73%	4.05%	24.68%	6.18%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	36.99%	62.38%	2.86%	59.52%	0.63%
10	Production Plant	P10	100.00%	34.39%	65.37%	2.54%	62.83%	0.24%
11	Production Plant Wo Nuclear	P10WoN	100.00%	35.13%	64.66%	2.51%	62.15%	0.21%
12	Total P51 & P61A	P5161A	100.00%	33.99%	65.76%	2.56%	63.20%	0.25%
13	Distribution Plant	P60	100.00%	65.86%	30.97%	4.14%	26.83%	3.18%
14	Distr Substn Plant	P61	100.00%	41.73%	57.73%	2.95%	54.78%	0.53%
15	Line Transformer Plant	P68	100.00%	72.33%	27.21%	5.06%	22.15%	0.46%
16	Services Plant	P69	100.00%	88.85%	11.15%	2.73%	8.43%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	66.75%	28.53%	4.13%	24.40%	4.72%
18	Real Est & Property Tax	PT0	100.00%	45.03%	53.74%	3.07%	50.67%	1.23%
19	Produc, Trans & Distrib	PTD	100.00%	42.25%	56.74%	2.96%	53.78%	1.00%
20	Dist Plt Undground Lines	PUL	100.00%	71.83%	27.61%	4.17%	23.45%	0.56%
21	Rate Base (Non-Column)	RTBASE	100.00%	44.37%	54.51%	3.06%	51.45%	1.12%
22	Stratified Hydro Baseload	STRATH	100.00%	33.58%	66.15%	2.58%	63.57%	0.26%
23	Transmission & Distrib	TD	100.00%	52.31%	45.70%	3.49%	42.21%	1.99%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	66.29%	29.89%	4.38%	25.50%	3.82%

			1	2	3	4	5	6
INTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	294,117	126,336	165,272	9,042	156,230	2,509
26	Dis O&M w/o Sup, Cust Install & I	OXDTS	120,448	78,404	34,604	4,880	29,724	7,440
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	2,941,007	1,087,877	1,834,637	84,108	1,750,529	18,493
28	Total P51 & P61A	P5161A	182,657	62,077	120,124	4,680	115,444	457
29	Produc, Trans & Distrib	PTD	24,181,104	10,217,571	13,720,836	715,694	13,005,143	242,696
30	Transmission & Distrib	TD	10,608,256	5,549,650	4,847,913	370,565	4,477,348	210,694
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	37,836	25,083	11,308	1,659	9,649	1,446

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34.12%

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	EXTERNAL ALLOCATORS	Extern:	1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
1	Customers - Ave Monthly	C11	100.00%	88.22%	9.81%	6.26%	3.55%	1.97%
2	Cust Acctg Wtg Factor	C11WA	100.00%	84.30%	15.17%	7.18%	8.00%	0.53%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	81.40%	18.41%	9.66%	8.75%	0.19%
4	Sec & Pri Customers	C61PS	100.00%	89.58%	9.98%	6.36%	3.62%	0.44%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	95.35%	4.27%	3.72%	0.55%	0.38%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	95.23%	4.77%	3.05%	1.72%	0.00%
7	Secondary Customers	C62Sec	100.00%	89.61%	9.95%	6.36%	3.58%	0.44%
8	Summer Peak Resp KW	D10S	100.00%	41.17%	58.83%	2.22%	56.61%	0.00%
9	Transmission Demand %	D10T	100.00%	34.12%	65.49%	2.63%	62.86%	0.39%
10	Winter Peak Resp KW	D10W	100.00%	34.24%	65.12%	2.78%	62.34%	0.64%
11	Alternative Production Allocator	12CP	100.00%	35.09%	64.49%	2.62%	61.87%	0.41%
12	Sec, Pri & TT, Class Coin kW @ :	D60Sub	100.00%	42.73%	56.73%	3.02%	53.71%	0.55%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	43.47%	55.97%	3.07%	52.90%	0.56%
14	Pri & Sec Coin kW Served w/ 1 P	D61PS1Ph	100.00%	83.25%	15.90%	3.23%	12.66%	0.85%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	78.45%	21.55%	2.20%	19.35%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	55.01%	44.56%	3.63%	40.93%	0.43%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
	Direct Assign LED Lighting Defer	DASLED	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	31.84%	67.83%	2.66%	65.17%	0.32%
19	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20	MWh Sales Excl CIP Exempt	E99XCIP	100.00%	32.51%	67.08%	2.76%	64.32%	0.41%
21	Present Rev	R01	100.00%	38.88%	60.26%	3.07%	57.19%	0.86%
22	Base Rev	R02	100.00%	41.54%	57.41%	3.21%	54.20%	1.05%
23	Late Fee Revenue Allocator	LateFee	100.00%	82.31%	14.70%	3.13%	11.57%	2.99%

	EXTERNAL DATA		1 MN	2 Res	3 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
23	Customers - B Basis	C10	1,411,455	1,264,372	140,848	89,788	51,061	6,235
24	Cust - Ave Monthly (C10-Area Lt)	C11	1,437,828	1,268,459	141,043	89,982	51,061	28,326
25	Mo Cus Wtd By Cus Acct	C11WA	1,504,701	1,268,459	228,330	107,979	120,351	7,911
26	Cust Acctg Wtg Factor	C11WAF	30.26	1.00	29.26	1.20	28.06	N/A
27	Cust-Ave Mo (C11 w/ Dir Assign :	C12	1,412,780	1,268,459	141,043	89,982	51,061	3,277
28	Mo Cus Wtd By Mtr Invest	C12WM	297,386,508	242,064,796	54,753,355	28,741,126	26,012,229	568,358
29	Meter Invest / Cust Factor	C12WMF	25,034	191	24,670	319	24,350	173
30	Sec & Pri Customers	C61PS	1,411,423	1,264,372	140,816	89,788	51,029	6,235
31	% Served by Primary Single Phase		0.0%	71.59%	0.00%	39.32%	0.00%	57.36%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	949,273	905,165	40,532	35,306	5,225	3,576
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	1,327,655	1,264,372	63,283	40,494	22,789	0
34	Secondary Customers	C62Sec	1,410,926	1,264,372	140,319	89,788	50,532	6,235
35	Summer Peak Resp KW	D10S	4,083	1,681	2,402	91	2,311	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,825,962	6,147,118	245,540	5,901,577	26,920
37	Winter Peak Resp KW	D10W	4,235	1,450	2,758	118	2,640	27
38	Alternative Production Allocator	12CP	4,250	1,492	2,741	111	2,630	18
39	Sec, Pri & TT, Class Coin kW @ :	D60Sub	6,288,154	2,686,635	3,567,155	190,017	3,377,138	34,364
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	6,180,437	2,686,635	3,459,439	190,017	3,269,422	34,364
41	Pri & Sec Coin kW Served w/ 1 P	D61PS1Ph	2,310,348	1,923,364	367,273	74,718	292,555	19,711
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	11,095,094	8,703,660	2,391,433	244,303	2,147,130	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,501,374	4,455,667	362,784	4,092,884	42,959
44	Annual Billing kW	D99	50,438.651	0	50,439	0	50,439	0
45	Summer Billing kW	D99S	18,795.390	0	18,795	0	18,795	0
46	Winter Billing kW	D99W	31,643.261	0	31,643	0	31,643	0
47	Non-Coinc Pk Second	DN-Sec	14,040,608	8,703,660	5,302,584	541,698	4,760,885	34,364
48	MWh Sales	E99	29,392,644	9,082,285	20,195,239	771,624	19,423,615	115,120
49	MWh Sales Excl CIP Exempt	E99XCIP	27,937,770	9,082,285	18,740,364	771,522	17,968,842	115,120
50	Late Fee Revenue Allocation	LateFee	100.00%	82.31%	14.70%	3.13%	11.57%	2.99%
	Base Revenues		$2,741,167	$1,138,705	$1,573,651	$87,889	$1,485,762	$28,812

CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
Allocator Comparison	Shows a comparison of allocators from this case and previous rate cases.
Results Comparison	Shows a comparison of CCOSS results from this case and previous rate cases.
CCOSS Summary	Shows a summary of CCOSS results; specifically Unadjusted Revenue Requirement, Adjusted Revenue Requirements and Revenue Deficiency are shown by Customer Class.
Err_Chk	Conducts error checking to insure costs and revenues are appropriately allocated to Cost Classification, Function, Subfunction and Customer Classes. Also insures the class subtotals are correct.
RR-TOT	Shows detailed revenue requirement calculations for all functions and cost classifications combined.
RR-CUS	Shows detailed revenue requirement calculations for costs that have been classified as Customer-Related. It includes the customer-related portion of primary and secondary distribution lines/transformers, service line costs, metering, meter reading, billing, customer service costs and costs of back office support. RR-Cus = RR-Svc_Drop + RR-En_Svc
RR-DMD	Shows detailed revenue requirement calculations for costs that have been classified as Demand-Related.
RR-ENE	Shows detailed revenue requirement calculations for costs that have been classified as Energy-Related. RR-ENE = RR-On + RR-Off
RR-Genco	Shows detailed revenue requirement calculations for costs that have been functionalized as being generation related. This includes all energy-related costs and all fixed production costs. RR-Genco = RR-ENE + RR-G_Dmd
RR-G_Dmd	Shows detailed revenue requirement calculations for all generation costs except those that are classified as Energy-Related. RR-G_Dmd = RR-Base + RR_Summ + RR_Wint
RR-Base	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Energy-Related.
RR-Summ	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Capacity-Related and are associated with the summer system peak load requirements.
RR-Wint	Shows detailed revenue requirement calculations for the fixed cost of generation plant investment and purchased capacity costs which have been stratified as Capacity-Related and are associated with the winter system peak load requirements.
RR-On	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for on-peal hours.
RR-Off	Shows detailed revenue requirement calculations for costs of fuel and purchases of energy for off-peal hours.
RR-Transco	Shows detailed revenue requirement calculations for the transmission function. It includes costs of transmission lines used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
RR-Disco	Shows detailed revenue requirement calculations for the Distribution function. It includes costs of distribution substations and the capacity-related portion of primary and secondary distribution lines and transformers. RR-Disco = RR-Psub + RR-Prim + RR_Sec
RR-Psub	Shows detailed revenue requirement calculations for Distribution substations.
RR-Prim	Shows detailed revenue requirement calculations for the capacity-related portion of primary voltage conductors, transformers and related facilities.
RR-Sec	Shows detailed revenue requirement calculations for the capacity-related portion of secondary voltage conductors, transformers and related facilities.
RR-Svc_Drop	Shows detailed revenue requirement calculations for the customer-related portion of primary and secondary distribution lines/transformers, service line costs and metering.
RR_En_Svc	Shows detailed revenue requirement calculations for costs of meter reading, billing, customer service and costs of back office support.

CCOSS Spreadsheet Tab Label	**Spreadsheet Tab Description**
JCOSS-Basic Inputs	Provides basic financial inputs from the Jurisdictional Cost of Service Study. Inputs include state and federal tax rates and capital structure inputs. Calculations are also included to insure JCOSS and CCOSS revenue requirement and deficiency results tie-out.
JCOSS Inputs	Provides detailed JCOSS line item FERC code level inputs to the CCOSS model. All detailed rate base and expense related line items are provided in this tab.
Jurisdictional Financial Details	Provides the derivation of line item details including base level data and all adjustments applied to derive the final JCOSS detailed inputs
MenuOpts	Shows JCOSS line-item labels used in the Revenue Analysis RIS System
NSPM-00 Complete Revenue Req	Shows overall JCOSS cost of service results. Also shows a line-item comparison of selected revenue and cost items between the JCOSS and CCOSS models
NSPM_00_ Complete Revenue Requi	Shows overall JCOSS cost of service results. Also shows a line-item comparison of selected revenue and cost items between the JCOSS and CCOSS models
Reconcile	CCOSS and JCOSS Comparison
Labor O&M	Has JCOSS O&M data for calculating the LABOR internal allocation factor that is used for allocating several cost items to customer class
Plant Stratified	Shows the results of the plant stratification analysis. Based on the Plant Stratification results, baseload versus peaking ratios are applied to various cost items that stratified
Alloc-Input Data	Provides external allocator data for input to the CCOSS model. Data is provided for all external allocators including production and transmission allocators, distribution capacity allocators and customer allocators.
Alloc-Prod Trans	Provides allocator calculations for all fixed production and transmission cost allocators. Note calculation of the D10S allocator is based on class hourly loads that are coincident with the forecasted MISO 2016 peak hour for Local Resource Zone 1.
Alloc-Dist Cap	Provides allocator calculations for all distribution costs that are capacity-related.
Alloc-Cust	Provides allocator calculations for all allocators that are used to allocate customer-related costs.
Alloc-E8760	Has the calculations for the E8760 energy allocation factor.
InputData-NSP Syst Peaks	Has the TY forecasted hourly loads for the NSP System. Also calculates the NSP System Load Factor
InputData-NSP Syst Peaks D10S	Has a ranking of the peak hours
InputData-8760 Loads	Has TY Minnesota forecasted hourly loads by customer class. Hourly loads are shown with and without load management. This tab also shows monthly system coincident and class coincident peaks by customer class. Summaries are shown with and without load management.
InputData-E8760	Has the hourly load data and hourly marginal energy costs for calculating the E8760 allocator. The hourly loads used in the calcultion of the E8760 allocator assume no load management
InputData-Cust Max kW	Based on the sum of individual customer maximum actual demands by customer class for demand billed customers. Loss factors are applied to these quantities. The data is provided by the Load Research Dept. These quanitites are used in calculating certain distribution capacity allocators.
InputData-Cust Fcst	Has the results of the customer forecast by customer class. These results were used in calculation allocation factors for customer-related costs.
InputData-kWh Sales Fcst	Has the results of the kWh sales forecast by customer class.
InputData-kWh Fcst CIP Exmpt	Has the sales forecast for CIP exempt customers. When allocating CIP costs these sales are excluded when calculating the CIP cost allocation factor.
InputData-Summ Wint	Has the NSP System monthly peaks that are used to are used to split Production Capacity costs into summer and winter seasons.
InputData-OthProdOM	Has the split of Other Production O&M costs into energy-related and capacity-related components using the "Location" method.

CCOSS Spreadsheet Tab Label	Spreadsheet Tab Description
InputData-PlantStrat	Has the plant stratification analysis results. These peaking versus baseload results were applied as shown on the "JCOSS-Plant Stratified" and "InputData-OthProdOM" tabs.
InputData-MeterCost	Has average metering costs by customer class. Metering costs include the cost of meters, current transformers and voltage transformers. These costs were used in calculating the meter cost allocation factor.
InputData-Dist1Ph3Ph	Shows the percent of customers that are served off 3 phase primary distribution lines versus 1 phase distribution lines.
InputData-OHUGSvc	Shows the results of the analysis that shows the percent of C&I customers that are served by an overhead versus underground service. C&I customers that are served by an underground service own the service and shouldn't be allocated these costs.
InputData-OHLtg	Shows the results of an analysis that quantifies the amount of pole p1ant investement that should be directly assigned to the lighting class.
InputData-PSHLMeters	Based on a query of the customer billing system, shows the number of street lighting meters that is used in the allocation of metering costs.
InputData-CustAcctgWt	Relative weighting by customer class for costs of meter reading, billing and collections and uncollectible accounts.
InputData-WriteOffs	Has the writeoff study that determines customer weightings related to writeoffs.
InputData-LateFees	Based on budgeted late fees for C&I versus Residential customers and a query of late fee revenues by customer class, provides an allocation factor for late fee revenues.
InputData-T&D Direct AssignMW	Based on the customers served by direct assignment distribution substations and transmission radials, provides loads to be removed from cost allocators
InputData-T&D Direct Assign $	Based on the customers served by direct assignment distribution substations and transmission radials, provides $ to be direct assigned to specific class.
InputData - Pres Prop Revenue	Has present revenues by customer class with and without load management discounts. Also has the amount of the economic development discounts by customer class.
InputData - Base Revenue	Has base revenues used for allocating economic development discounts.
InputData - Misc. Revenue	Shows the increases associated with miscellaneous revenues such as dedicated switching, winter construction, and excess footage.
InputData-Dist Cap Vs Cust	Based on the results of the Minimum System and Zero Intercept studies, shows how distribution plant investment should be split into capacity and customer-related components

Results of Xcel Energy

Minimum Distribution System & Zero Intercept Studies

1. Overview

An important step in the Class Cost of Service Study (CCOSS) process is to classify costs according to one of the following billing components based on the nature of the cost:

1. Demand – Costs that are driven by customers' maximum kilowatt (kW) demand.
2. Energy – Costs that are driven by customers' energy or kilowatt-hours (kWh) requirements.
3. Customer – Costs that are related to the number of customers served.

For Distribution Plant Investment, costs are classified as being capacity or customer-related. Page 87 of the NARUC Electric Utility Cost Allocation Manual and Table 1 below shows how FERC classifies distribution plant by function and sub-function.

Table 1
FERC Classification of Distribution Plant Investment

	Cost Classification	
Function/Sub-Function	**Demand**	**Customer**
Distribution Substations	X	
Primary Transformers	X	
Primary Lines	X	X
Secondary Lines	X	X
Secondary Transformers	X	X
Service Drops		X

As shown in the table above, primary lines, secondary lines and secondary transformers are classified as both "demand" and "customer" related costs. 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 Minimum System and Zero Intercept methods are two widely used methods for determining the percent of distribution plant investment that is customer-related and allocated to class with a customer based allocation factor, versus the percent of costs that are capacity-related and allocated to class with a demand based allocator. These methods are described on pages 86-96 of the NARUC Electric Utility Cost Allocation Manual.

The Company has used the Minimum System method to do this classification for distribution plant investment in its rate cases since the 1990s. As part of its order from the Company's 2013 rate case, the Commission ordered the Company to update its minimum system study, and attempt to conduct a zero intercept study providing it can obtain the necessary data. This exhibit describes the steps the Company has taken to fulfill this requirement.

2. Steps for Completing a Minimum System Study

The following steps are taken to complete a minimum system study (these steps are also described on pages 90-92 of the NARUC manual):

Step 1: Determine the minimum sized conductor, transformer and service that are installed on the distribution system.

Step 2: Determine the installed cost per unit for the minimum sized plant. Installed costs include material costs, labor costs and equipment costs.

Step 3: Multiply the cost per unit of the minimum sized plant by the total inventory of each plant type.

Step 4: The total cost of the minimum sized plat it divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the customer-related portion of distribution plant investment, with the balance being the capacity-related portion.

The assumed minimum property unit configurations used in the minimum system study are shown in Company witness Marty Mensen's testimony.

3. Steps for Completing a Zero Intercept Study

The steps for completing a zero or minimum intercept are described on pages 92-94 of the NARUC manual. A zero intercept study requires considerable more data and analysis than a minimum system study. A zero intercept study requires the following data:

- A listing of all the configurations of equipment installed for the following for the following distribution property units:
  - Overhead Primary Conductor
  - Overhead Secondary Conductor
  - Overhead Transformers
  - Underground Primary Conductor
  - Underground Secondary Conductor
  - Underground Transformers
  - Primary Voltage Stepdown Transformers

- For each of the above property units, the equipment inventory is obtained for each property unit configuration.
- The maximum capacity rating for each property unit configuration.
  - Ampacity for conductors
  - kVa for transformers

- The installed cost per unit for the most common property unit configurations.

After the above data is acquired, the following analysis steps are taken to complete a zero intercept study:

Step 1: The statistical analysis technique called linear regression is applied to the data acquired for each property unit. Specifically, the variable “cost per unit” as the dependent variable (Y axis) is regressed on the variable “maximum capacity” as the independent variable (X axis). The point where the regression line crosses the Y intercept is the theoretical “zero load” cost per unit.

Step 2: The zero load cost per unit is multiplied by the total inventory of the distribution property unit.

Step 3: The installed cost per unit for the most common property configurations is multiplied by the inventory of each configuration. The resulting product is then summed for each property unit.

Step 4: The result from step 2 is divided by the result from step 3. This ratio is classified as the customer component for each property unit.

4. Minimum System and Zero Intercept Data Sources

The data sources used to complete both studies are described in detail in Mr. Mensen’s direct testimony. In short, data on the types, configurations, sizes and quantities of distribution equipment were obtained by querying the Company’s Geographic Information System (GIS). Data on the installed unit costs for each equipment configuration were obtained by analyzing the costs distribution work orders that were completed from 2007-2020. The goal in this data gathering step was to obtain installed costs for equipment configuration that comprise 90% of the population for a given property unit (i.e. underground primary conductor).

5. Analysis Results

The data and results of the minimum system and zero intercept studies are shown in Attachments A to P of Schedule 8.

Attachments A to F show the inventory of the different equipment configurations for each property unit.

Attachment G shows the inventory of primary voltage distribution transformers. As shown in Table 1 above, there is no customer component to this property unit. Attachment G also shows the installed cost per unit and total replacement cost for primary voltage transformers so that transformer plant investment can be separated into primary and secondary voltages.

Attachments H through M show the graphical results of the zero intercept linear regression analysis for each property unit.

Attachment N shows the detailed minimum system and zero intercept calculations.

- Column 1: Lists the property unit.
- Column 2: For primary conductor, indicates if it's 1 phase or 3 phase.
- Column 3: Lists the specific configuration of the equipment.
- Column 4: Lists the inventory of the equipment configuration.
- Column 5: Shows the percent of total equipment total inventory that the specific configuration makes up.
- Column 6: Shows the cumulative percent of inventory that the configuration included in the study make up. As shown in Column 6, the Distribution Engineering area provided cost data for equipment configurations that make up 90% of the total inventory for a given property unit.
- Column 7: Shows the load carrying capacity of the given equipment configuration.
- Column 8: Shows the per unit installed cost as determined by the Distribution Engineering area.
- Column 9: Calculates the total cost of each equipment configuration by multiplying its equipment inventory in Column 4 by the per unit installed cost in Column 8. This result is summed across all equipment configurations to provide total installed costs for a given property unit.
- Column 10: Shows the cost per unit that was determined using the zero intercept method. This was determined by conducting a linear regression analysis using load carrying capacity (in Column 7) as the independent variable, with cost per unit (in Column 8) as the dependent variable.

- Column 11: Calculates total cost of each equipment configuration assuming the zero intercept cost is the cost per unit for all equipment configurations. The equipment inventory in Column 4 is multiplied by the zero intercept cost in Column 10. This result is summed across all equipment configurations to provide total cost for a given property unit, assuming the zero intercept cost is the cost for all equipment configurations. This total for a given property unit divided by the same total in Column 9 is the percent of costs that should be classified as customer-related using the zero intercept approach.
- Column 12: Shows the per unit installed cost of the minimum sized equipment configuration.
- Column 13: Calculates total cost of each equipment configuration assuming the cost of minimum system equipment configuration is the cost per unit for all equipment configurations. The equipment inventory in Column 4 is multiplied by the cost of the minimum system unit in Column 12. This result is summed across all equipment configurations to provide total cost for a given property unit assuming the cost of the minimum system unit is the cost for all equipment configurations. This total for a given property unit divided by the same total in Column 9 is the percent of costs that should be classified as customer-related using the minimum system approach.

Table 2 below shows the percent of costs that would be classified as customer related using the minimum system method compared to the zero intercept method. As shown in Table 2, the zero intercept method provided a lower customer component for all six property units.

Table 2
Percent of Distribution Plant Investment Classified as Customer-Related
Zero Intercept Method vs. the Minimum System Method

Equipment Type	% of Costs Classified as "Customer" Related	
	Minimum/Zero Intercept Method	Minimum Distribution System Method
Overhead Lines Primary	24.0%	63.2%
Overhead Lines Secondary	79.9%	96.0%
Overhead Transformers	69.1%	78.0%
Underground Lines Primary	34.7%	63.8%
Underground Lines Secondary	58.6%	100%
Underground Transformers	70.2%	66.7%

6. Application of Minimum System and Zero Intercept Results to Distribution Plant Investment

For a given property unit the Company used a "hybrid" of the two methods by applying the result that provided the lowest customer component as shown in Table 3 below.

Table 3
Customer vs. Capacity Classification Applied to Distribution Plant Investment

Property Unit	% Customer Related	% Capacity Related
Overhead Lines Primary (used Zero Intercept Result)	24.0%	76.0%
Overhead Lines Secondary (used Zero Intercept Result)	79.9%	20.1%
Underground Lines Primary (used Zero Intercept Result)	34.7%	65.3%
Underground Lines Secondary (used Zero Intercept Result)	58.6%	41.4%
Weighted Average for Overhead & Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	68.1%	31.9%

Attachment O of Schedule 8 shows how the above results from the minimum system and zero intercept analyses are used to provide the needed cost separations.

The first step is to multiply the total inventory of each property unit (shown in Column 1) by the overall cost per unit (shown in Column 2) to provide the total replacement cost (shown in Column 3). The total replacement costs for each property unit are shown in percentages in Column 4.

These percentages are then applied to the Total Test Year Plant in Service as provided from the Jurisdictional Cost of Service Study (JCOSS) to separate costs into sub-function. The Total Test Year Plant in Service from the JCOSS is shown in Attachment O on line 11, column 5 for Overhead Distribution Plant; on line 22, column 5 for Underground Distribution Plant; and on line 27, column 5 for transformers. (Note that the cost of Overhead Distribution Plant that is directly assigned to the Lighting class was quantified as shown on Table 12 on Page 32). For Overhead Distribution Line, the result as shown in Column 5 is a separation of Overhead Plant in Service costs into the following sub-functions:

- Overhead Primary Single Phase Lines (line 3)
- Overhead Primary Multi Phase Lines (line 6)

- Overhead Secondary Lines (line 9)
- Lighting (line 10)

For Underground Lines, there was no direct assignment to the Lighting class. The result as shown in Column 5 is a separation of Underground Plant in Service costs into the following sub-functions:

- Underground Primary Single Phase Lines (line 14)
- Underground Primary Multi Phase Lines (line 17)
- Underground Secondary Lines (line 20)

For Transformers, the result shown in Column 5 is a separation of Plant in Service costs into the following sub-functions:

- Primary Voltage Transformers (line 23)
- Secondary Voltage Transformers (line 26)

The final step as shown in Column 7 of Attachment O, was to apply the associated Customer & Capacity percentages as shown in Column 6 of Attachment O to the corresponding Plant in Service costs as shown in Column 5. The final result in Column 7 is a separation of distribution plant costs into sub-function and cost classification. These are the inputs to the CCOSS model for the 2025 test year as shown in Schedule 4, page 4, column 1, lines 19 – 42.

7. Distribution Service Drops

Although FERC (as shown in Table 1) and many utilities classify distribution services as only being customer-related, the Company has split these costs into capacity and customer-related components. The Company does not have detailed property records on the configuration or footage of distribution service drops. As such, it was not possible to conduct a detailed minimum system or zero intercept studies as described above. As a substitute a simplified minimum system analysis was conducted as shown in Attachment P.

Column 2 of Attachment P lists the minimum conductor configuration used by the Company in Overhead and Underground applications.

In column 3 we assumed a minimum footage per service of 50 feet.

In order to the get an estimated cost per foot for each conductor configuration, staff in the Distribution Design ran a number of service installation work orders through the Company's distribution design software. The resulting unit costs are shown in column 4.

The Total Installed Costs for minimum service drop configuration as shown in column 6 is obtained by multiplying the Minimum Service Footage (column 3) by the Unit Cost per Foot (column 4) by the number of customers with overhead or underground services (column 5). The total minimum installed cost (column 6 total) is divided by total plant investment for distribution services (column 7). This is percent of distribution service costs that was classified as customer-related as shown in column 8.

8. Load Carrying Capacity of Minimum System Design

The Company used the same 1.5 kW per customer for the load carrying capacity of the minimum system design. This is the same assumption that was made in the last rate case. This adjustment was applied to the distribution capacity cost allocation factors. For the Zero-Intercept Study, the demand adjustment is not needed because this study estimates the cost of a conductor and/or transformer with no load.

Inventory of Underground Primary by Conductor Configuration

Phase	Configuration Details Underground Primary	Footage	% of 1 Phase Footage	Cumulative % of 1 Phase Footage	% of All UG Primary	Cumulative % of All UG Primary
1 Phase	1/0 AL 1ph	16,024,349	50.84%	50.84%	28.67%	28.67%
	2 AL 1ph	14,788,376	46.92%	97.76%	26.46%	55.14%
	1 AL 1ph	284,143	0.90%	98.66%	0.51%	55.65%
	1/0 Unknown 1ph	214,004	0.68%	99.34%	0.38%	56.03%
	Unknown AL 1ph	77,809	0.25%	99.59%	0.14%	56.17%
	Unknown Unknown 1ph	46,349	0.15%	99.73%	0.08%	56.25%
	2 Unknown 1ph	31,174	0.10%	99.83%	0.06%	56.31%
	1/0 CU 1ph	16,095	0.05%	99.88%	0.03%	56.34%
	2/0 AL 1ph	13,610	0.04%	99.93%	0.02%	56.36%
	2 CU 1ph	4,767	0.02%	99.94%	0.01%	56.37%
	Unknown CU 1ph	4,504	0.01%	99.96%	0.01%	56.38%
	4/0 AL 1ph	3,999	0.01%	99.97%	0.01%	56.38%
	1/0 N/A 1ph	1,921	0.01%	99.97%	0.00%	56.39%
	Footage of 13 Remaining 1 Phase Underground Primary Conductor Configurations	8,015	0.03%	100.00%	0.01%	56.40%
	Total 1 Phase	**31,519,114**	**100.00%**		**56.40%**	

Phase	Config Details Underground Primary	Footage	% of 3 Phase Footage	Cumulative % of 3 Phase Footage	% of All UG Primary	Cumulative % of All UG Primary
3 Phase	1/0 AL 3ph	14,140,772	58.04%	58.04%	25.30%	25.30%
	750 AL 3ph	4,826,798	19.81%	77.85%	8.64%	33.94%
	2 AL 3ph	933,040	3.83%	81.68%	1.67%	35.61%
	600 CU 3ph	860,560	3.53%	85.21%	1.54%	37.15%
	500 CU 3ph	753,701	3.09%	88.30%	1.35%	38.50%
	1000 AL 3ph	534,454	2.19%	90.50%	0.96%	39.46%
	500 AL 3ph	459,969	1.89%	92.38%	0.82%	40.28%
	750 CU 3ph	436,689	1.79%	94.18%	0.78%	41.06%
	Footage of 32 Remaining 3 Phase Underground Primary Conductor Configurations	1,418,738	5.82%	100.00%	2.54%	43.60%
	Total 3 Phase	**24,364,721**	**100.00%**		**43.60%**	
	Total Underground Primary	**55,883,835**			**100.00%**	

Inventory of Underground Secondary by Conductor Configuration

Configuration Details Underground Secondary	Total Footage	% of UG Secondary	Cumulative % UG Secondary
6 AL Duplex	9,878,341	36.70%	36.70%
4/0 AL Triplex	8,355,002	31.04%	67.73%
2/0 AL Triplex	2,679,564	9.95%	77.69%
1/0 AL Triplex	1,460,657	5.43%	83.11%
6 CU Open Wire	1,206,909	4.48%	87.60%
350 AL Triplex	660,658	2.45%	90.05%
6 CU Triplex	285,950	1.06%	91.11%
2 AL Triplex	262,510	0.98%	92.09%
8 CU Open Wire	262,460	0.97%	93.06%
4 CU Open Wire	209,884	0.78%	93.84%
6 AL Triplex	208,881	0.78%	94.62%
8 CU Triplex	176,892	0.66%	95.28%
4 CU Triplex	108,269	0.40%	95.68%
4 AL Triplex	91,919	0.34%	96.02%
4 CU Duplex	77,412	0.29%	96.31%
Unknown Unknown Unknown	60,147	0.22%	96.53%
2 Unknown Triplex	59,507	0.22%	96.75%
4 CU N/A	55,480	0.21%	96.96%
2 Unknown Open Wire	49,863	0.19%	97.14%
Unknown Unknown Unknown	41,769	0.16%	97.30%
2 Unknown Duplex	33,248	0.12%	97.42%
4/0 AL Quadraplex	32,738	0.12%	97.54%
0 0 Unknown	32,072	0.12%	97.66%
8 AL Triplex	28,527	0.11%	97.77%
2 AL Duplex	26,950	0.10%	97.87%
6 CU Unknown	25,540	0.09%	97.96%
6 CU N/A	25,400	0.09%	98.06%
Unknown Unknown Triplex	24,459	0.09%	98.15%
6 CU Quadraplex	23,525	0.09%	98.24%
6 AL Open Wire	21,387	0.08%	98.32%
0 0 Duplex	20,947	0.08%	98.39%
500 CU Quadraplex	20,641	0.08%	98.47%
0 0 Triplex	18,279	0.07%	98.54%
Unknown Unknown Duplex	15,757	0.06%	98.60%
8 CU Duplex	15,372	0.06%	98.65%
6 CU Duplex	14,750	0.05%	98.71%
6 Unknown Duplex	12,764	0.05%	98.76%
4/0 AL Duplex	11,864	0.04%	98.80%
8 CU Duplex	11,130	0.04%	98.84%
350 AL Duplex	9,872	0.04%	98.88%
8 AL Duplex	9,563	0.04%	98.91%
Footage of 156 Remaining Underground Secondary Conductor Configurations	292,625	1.09%	100.00%
Total Underground Secondary	**26,919,485**	**100.00%**	

Inventory of Underground Transformers by Transformer Configuration

Configuration Details 1 Phase Underground Transformers	Number of Transformers	1 Phase %	Cumulative Percent of 1 Phase Transformers	% of All Underground Transformers	Cumulative Percent of All Transformers
1 Phase Wye 50 kVA	31,125	49.71%	49.71%	35.41%	35.41%
1 Phase Wye 25 kVA	17,418	27.82%	77.52%	19.81%	55.22%
1 Phase Wye 37.5 kVA	8,619	13.76%	91.29%	9.81%	65.03%
1 Phase Wye 15 kVA	2,258	3.61%	94.89%	2.57%	67.60%
1 Phase Wye 100 kVA	1,431	2.29%	97.18%	1.63%	69.22%
1 Phase Wye 75 kVA	1,226	1.96%	99.14%	1.39%	70.62%
1 Phase Wye 10 kVA	279	0.45%	99.58%	0.32%	70.94%
1 Phase Wye 167 kVA	214	0.34%	99.92%	0.24%	71.18%
1 Phase Wye 250 kVA	15	0.02%	99.95%	0.02%	71.20%
1 Phase Wye Unknown kVA	7	0.01%	99.96%	0.01%	71.20%
1 Phase Wye 35 kVA	6	0.01%	99.97%	0.01%	71.21%
Number of Transformers for 12 Remaining Single Phase Transformer Configurations	19	0.03%	100.00%	0.02%	71.23%
Total 1 Phase Transformers	**62,617**	**100.00%**		**71.23%**	

Configuration Details 2 Phase Underground Transformers	Number of Transformers	2 Phase %	Cumulative Percent of 2 Phase Transformers	% of All UG Transformers	Cumulative Percent of All Transformers
2 Phase Wye/Delta 75 kVA	274	31.49%	31.49%	0.31%	0.31%
2 Phase Wye/Delta 125 kVA	173	19.89%	51.38%	0.20%	0.51%
2 Phase Wye/Delta 204.5 kVA	106	12.18%	63.56%	0.12%	0.63%
2 Phase Wye/Delta 300 kVA	61	7.01%	70.57%	0.07%	0.70%
2 Phase Wye/Delta 50 kVA	57	6.55%	77.13%	0.06%	0.76%
2 Phase Wye/Delta 100 kVA	37	4.25%	81.38%	0.04%	0.81%
2 Phase Wye/Delta 62.5 kVA	28	3.22%	84.60%	0.03%	0.84%
2 Phase Wye/Delta 150 kVA	19	2.18%	86.78%	0.02%	0.86%
2 Phase Wye/Delta 30 kVA	15	1.72%	88.51%	0.02%	0.88%
2 Phase Wye/Delta 87.5 kVA	12	1.38%	89.89%	0.01%	0.89%
Number of Transformers for 26 Remaining 2 Phase Transformer Configurations	88	10.11%	100.00%	0.10%	0.99%
Total 2 Phase Transformers	**870**	**100.00%**		**0.99%**	

Inventory of Underground Transformers by Transformer Configuration

Configuration Details 3 Phase Underground Transformers	Number of Transformers	3 Phase %	Cumulative Percent of 3 Phase Transformers	% of All UG Transformers	Cumulative Percent of All Transformers
3 Phase Wye/Wye 150 kVA	3,986	16.32%	16.32%	4.53%	4.53%
3 Phase Wye/Wye 300 kVA	3,834	15.70%	32.03%	4.36%	8.90%
3 Phase Wye/Wye 75 kVA	3,656	14.97%	47.00%	4.16%	13.06%
3 Phase Wye/Wye 500 kVA	3,255	13.33%	60.33%	3.70%	16.76%
3 Phase Wye/Wye 750 kVA	1,954	8.00%	68.33%	2.22%	18.98%
3 Phase Wye/Wye 112 kVA	1,932	7.91%	76.25%	2.20%	21.18%
3 Phase Wye/Wye 225 kVA	1,752	7.18%	83.42%	1.99%	23.17%
3 Phase Wye/Wye 1000 kVA	1,452	5.95%	89.37%	1.65%	24.82%
3 Phase Wye/Wye 1500 kVA	1,151	4.71%	94.08%	1.31%	26.13%
3 Phase Wye/Wye 45 kVA	506	2.07%	96.15%	0.58%	26.71%
3 Phase Wye/Wye 2000 kVA	491	2.01%	98.17%	0.56%	27.27%
3 Phase Wye/Wye 2500 kVA	135	0.55%	98.72%	0.15%	27.42%
Number of Transformers for 72 Remaining 3 Phase Transformer Configurations	313	1.28%	100.00%	0.36%	27.78%
Total 3 Phase Transformers	**24,417**	**100.00%**		**27.78%**	
Total Underground Transformers	**87,904**			**100.00%**	

Phase	Configuration Details Overhead Primary	Footage	% of 1 Phase Footage	Cumulative % of 1 Phase Footage	% of All OH Primary	Cumulative % of All OH Primary
1 Phase	4 ACSR 1ph	10,698,423	26.59%	26.59%	15.28%	15.28%
	2 ACSR 1ph	10,139,492	25.20%	51.79%	14.49%	29.77%
	6A CUWD 1ph	7,459,455	18.54%	70.33%	10.66%	40.43%
	6 CU 1ph	6,943,615	17.26%	87.59%	9.92%	50.35%
	3/10 CU 1ph	1,564,708	3.89%	91.48%	2.24%	52.58%
	4 CU 1ph	764,837	1.90%	93.38%	1.09%	53.68%
	Unknown Unknown 1ph	753,427	1.87%	95.26%	1.08%	54.75%
	2/0 ACSR 1ph	239,332	0.59%	95.85%	0.34%	55.10%
	3/8 CU 1ph	201,915	0.50%	96.35%	0.29%	55.38%
	6 CUWD 1ph	173,814	0.43%	96.78%	0.25%	55.63%
	8A CUWD 1ph	164,182	0.41%	97.19%	0.23%	55.87%
	2 CU 1ph	145,776	0.36%	97.55%	0.21%	56.08%
	Unknown CU 1ph	135,674	0.34%	97.89%	0.19%	56.27%
	1/0 ACSR 1ph	135,210	0.34%	98.23%	0.19%	56.46%
	130 Steel 1ph	75,306	0.19%	98.42%	0.11%	56.57%
	4A CUWD 1ph	69,548	0.17%	98.59%	0.10%	56.67%
	1/0 CU 1ph	67,877	0.17%	98.76%	0.10%	56.77%
	336 ACSR 1ph	58,553	0.15%	98.90%	0.08%	56.85%
	336 AL 1ph	49,374	0.12%	99.02%	0.07%	56.92%
	3/6 CU 1ph	36,084	0.09%	99.11%	0.05%	56.97%
	Footage of 62 Remaining Single Phase Overhead Primary Conductor Configurations	356,241	0.89%	100.00%	0.51%	57.48%
	Total 1 Phase	**40,232,843**	**100.00%**		**57.48%**	

Phase	Config Details OH Primary	Footage	% of 3 Phase Footage	Cumulative % of 3 Phase Footage	% of All OH Primary	Cumulative % of All OH Primary
3 Phase	336 AL 3ph	6,449,212	21.67%	21.67%	9.21%	9.21%
	2 ACSR 3ph	5,828,121	19.58%	41.25%	8.33%	17.54%
	336 ACSR 3ph	5,187,129	17.43%	58.68%	7.41%	24.95%
	2/0 ACSR 3ph	2,335,697	7.85%	66.53%	3.34%	28.29%
	4 ACSR 3ph	1,756,872	5.90%	72.43%	2.51%	30.80%
	6 CU 3ph	1,294,407	4.35%	76.78%	1.85%	32.65%
	4/0 CU 3ph	820,787	2.76%	79.54%	1.17%	33.82%
	6A CUWD 3ph	733,392	2.46%	82.01%	1.05%	34.87%
	1/0 ACSR 3ph	719,893	2.42%	84.43%	1.03%	35.90%
	Footage of 85 Remaining 3 Phase Overhead Primary Conductor Configurations	4,635,222	15.57%	114.18%	6.62%	42.52%
	Total 3 Phase	**29,760,732**	**100.00%**		**42.52%**	
	Total Overhead Primary	**69,993,575**			**100.00%**	

Inventory of Overhead Secondary by Conductor Configuration

Configuration Details Overhead Secondary	Total Footage	% of Total Overhead Secondary	Cumulative % Overhead Secondary
2 ACSR Open Wire	20,338,802	14.90%	14.90%
1/0 ACSR Open Wire	18,334,359	13.43%	28.34%
4 CU Open Wire	15,181,580	11.12%	39.46%
2 CU Open Wire	14,916,284	10.93%	50.39%
6 CU Open Wire	9,845,756	7.21%	57.61%
4 ACSR Open Wire	9,718,445	7.12%	64.73%
1/0 AL Triplex	7,573,248	5.55%	70.28%
1/0 AL Triplex, Lashed	6,721,759	4.93%	75.21%
6A CUWD Open Wire	6,296,098	4.61%	79.82%
6 ACSR Duplex	4,852,695	3.56%	83.37%
2 AL Triplex	2,723,553	2.00%	85.37%
1/0 CU Open Wire	2,505,605	1.84%	87.21%
3/10 CU Open Wire	1,505,128	1.10%	88.31%
1/0 AL Open Wire	1,294,876	0.95%	89.26%
6 AL Duplex	1,292,144	0.95%	90.21%
2/0 ACSR Open Wire	915,530	0.67%	90.88%
2 ACSR N/A	790,708	0.58%	91.46%
Unknown CU Open Wire	785,058	0.58%	92.03%
2 AL Open Wire	725,975	0.53%	92.56%
3/8 CU Open Wire	688,413	0.50%	93.07%
6 AL Triplex	685,906	0.50%	93.57%
1/0 ACSR Quadraplex	495,596	0.36%	93.93%
2/0 ACSR Neutral	491,289	0.36%	94.29%
2 ACSR Neutral	486,200	0.36%	94.65%
2 ACSR Triplex	409,132	0.30%	94.95%
2 ACSR Triplex, Lashed	335,042	0.25%	95.19%
1/0 ACSR Triplex, Lashed	301,632	0.22%	95.42%
3/8 CU Open Wire	295,701	0.22%	95.63%
4 ACSR Triplex	213,935	0.16%	95.79%
4/0 ACSR Quadraplex	193,454	0.14%	95.93%
Unknown Unknown Unknown	185,375	0.14%	96.07%
4/0 AL Triplex	185,375	0.14%	96.20%
6 CUWD Open Wire	160,520	0.12%	96.32%
4 Unknown Open Wire	160,430	0.12%	96.44%
8A CUWD Open Wire	155,387	0.11%	96.55%
4 AL Open Wire	147,393	0.11%	96.66%
3/6 CU Open Wire	145,023	0.11%	96.77%
0 0 Open Wire	133,292	0.10%	96.86%
1/0 AL Quadraplex	126,111	0.09%	96.96%
4 ACSR Duplex	122,825	0.09%	97.05%
Footage of 494 Remaining Overhead Secondary Conductor Configurations	4,031,541	2.95%	100.00%
Total OH Secondary	**136,467,174**	**100.00%**	

Inventory of Overhead Transformers by Transformer Configuration

Config Details 1 Phase Overhead Transformers	Number of Transformers	1 Phase %	1 Phase Cumulative %	% of All Overhead Transformers	Cumulative Percent of All OH Transformers
1 Phase Wye 25 kVA	33,552	33.33%	33.33%	29.66%	29.66%
1 Phase Wye 10 kVA	17,527	17.41%	50.73%	15.50%	45.16%
1 Phase Wye 15 kVA	17,194	17.08%	67.81%	15.20%	60.36%
1 Phase Wye 37.5 kVA	15,358	15.25%	83.07%	13.58%	73.94%
1 Phase Wye 50 kVA	14,750	14.65%	97.72%	13.04%	86.98%
1 Phase Wye 75 kVA	773	0.77%	98.49%	0.68%	87.66%
1 Phase Wye 100 kVA	657	0.65%	99.14%	0.58%	88.24%
1 Phase Wye 5 kVA	368	0.37%	99.50%	0.33%	88.57%
1 Phase Wye 0.5 kVA	116	0.12%	99.62%	0.10%	88.67%
1 Phase Wye 3 kVA	101	0.10%	99.72%	0.09%	88.76%
1 Phase Wye 167 kVA	58	0.06%	99.78%	0.05%	88.81%
1 Phase Delta 25 kVA	42	0.04%	99.82%	0.04%	88.85%
Number of Transformers for 22 Remaining 1 Phase Transformer Configurations	183	0.18%	100.00%	0.16%	89.01%
Total 1 Phase Transformers	**100,679**	**100.00%**		**89.01%**	

Config Details 2 Phase Overhead Transformers	Number of Transformers	2 Phase %	2 Phase Cumulative %	% of All Overhead Transformers	Cumulative Percent of All OH Transformers
2 Phase Wye/Delta 75 kVA	24	30.77%	30.77%	0.02%	0.02%
2 Phase Wye/Delta 40 kVA	12	15.38%	46.15%	0.01%	0.03%
2 Phase Wye/Delta 50 kVA	7	8.97%	55.13%	0.01%	0.04%
2 Phase Wye/Delta 65 kVA	6	7.69%	62.82%	0.01%	0.04%
2 Phase Wye/Delta 100 kVA	5	6.41%	69.23%	0.00%	0.05%
2 Phase Wye/Delta 150 kVA	4	5.13%	74.36%	0.00%	0.05%
2 Phase Wye/Delta 25 kVA	4	5.13%	79.49%	0.00%	0.05%
2 Phase Wye/Delta 30 kVA	4	5.13%	84.62%	0.00%	0.06%
Number of Transformers for 9 Remaining 2 Phase Transformer Configurations	12	15.38%	100.00%	0.01%	0.07%
Total 2 Phase Transformers	**78**	**100.00%**		**0.07%**	

Config Details 3 Phase OH Transformers	Number of Transformers	3 Phase %	3 Phase Cumulative %	% of All OH Transformers	Cumulative Percent of All OH Transformers
3 Phase Wye/Wye 75 kVA	1,325	10.73%	10.73%	1.17%	1.17%
3 Phase Wye/Wye 150 kVA	1,068	8.65%	19.37%	0.94%	2.12%
3 Phase Wye/Wye 45 kVA	773	6.26%	25.63%	0.68%	2.80%
3 Phase Open Wye/Open Delta 75 kVA	735	5.95%	31.58%	0.65%	3.45%
3 Phase Wye/Wye 112 kVA	548	4.44%	36.02%	0.48%	3.93%
3 Phase Wye/Wye 300 kVA	515	4.17%	40.18%	0.46%	4.39%
3 Phase Open Wye/Open Delta 40 kVA	467	3.78%	43.97%	0.41%	4.80%
3 Phase Open Wye/Open Delta 35 kVA	364	2.95%	46.91%	0.32%	5.12%
3 Phase Open Wye/Open Delta 100 kVA	333	2.70%	49.61%	0.29%	5.42%
3 Phase Open Wye/Open Delta 62.5 kVA	314	2.54%	52.15%	0.28%	5.70%
3 Phase Open Wye/Open Delta 52.5 kVA	295	2.39%	54.54%	0.26%	5.96%
3 Phase Open Wye/Open Delta 65 kVA	293	2.37%	56.91%	0.26%	6.22%
3 Phase Open Wye/Open Delta 20 kVA	288	2.33%	59.24%	0.25%	6.47%
3 Phase Wye/Wye 225 kVA	282	2.28%	61.52%	0.25%	6.72%
3 Phase Open Wye/Open Delta 125 kVA	240	1.94%	63.47%	0.21%	6.93%
Number of Transformers for 155 Remaining 3 Phase Transformer Configurations	4,513	36.53%	100.00%	3.99%	10.92%
Total 3 Phase Transformers	**12,353**	**100.00%**		**10.92%**	
Total OH Transformers	**113,110**			**100.00%**	

Inventory of Primary Voltage Step-Down Transformers by Transformer Configuration

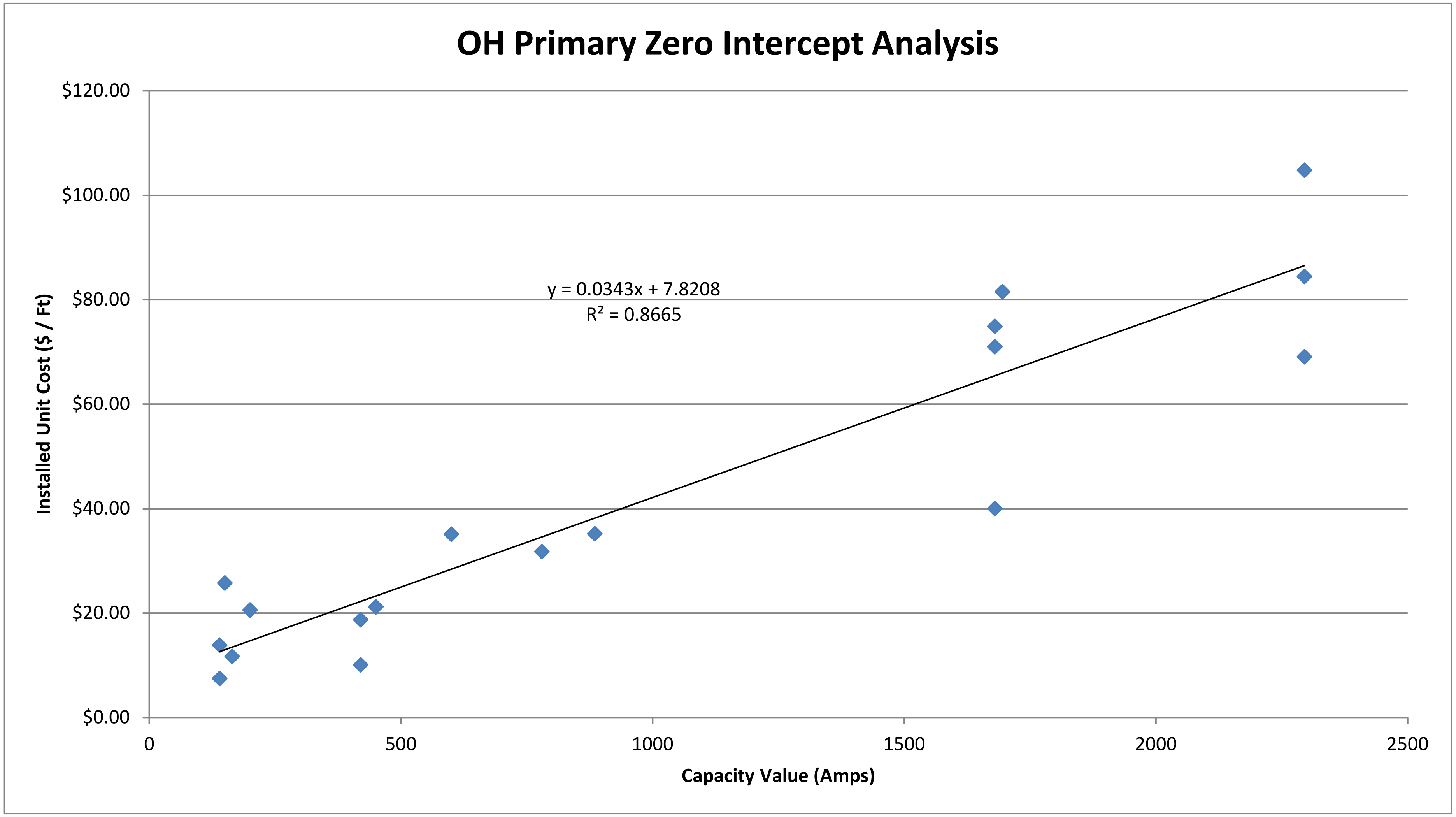
Overhead 1 Phase	Number OH 1 Phase	% of OH 1 Phase	Cumulative % of OH 1 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 1 phase 34.5/13.8 kV 500 kVA	240	23.90%	23.90%	18.66%	500	$102,886	$24,692,533
OH 1 phase 19.92/7.2 kV 167 kVA	131	13.05%	36.95%	10.19%	167	$53,067	$6,951,733
OH 1 phase 34.5/13.8 kV 333 kVA	126	12.55%	49.50%	9.80%	333	$88,233	$11,117,400
OH 1 phase 34.5/13.8 kV 250 kVA	121	12.05%	61.55%	9.41%	250	$72,404	$8,760,830
OH 1 phase 19.92/7.97 kV 50 kVA	120	11.95%	73.51%	9.33%	50	$23,489	$2,818,667
OH 1 phase 19.92/7.2 kV 100 kVA	103	10.26%	83.76%	8.01%	100	$46,678	$4,807,811
Number of Transformers and Cost of Transformers for 5 Remaining 1 Phase OH Transformer Configurations	**163**	**16.24%**		**11.91%**		$291,923.72	$47,583,567
Total OH 1 Phase	**1004**	**100.00%**		**78.07%**		$106,307.31	$106,732,541

Overhead 2 Phase	Number OH 2 Phase	% of OH 2 Phase	Cumulative % of OH 2 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 2 phase 13.8/4.16 kV 500 kVA	5	35.71%	35.71%	0.39%	500	$82,815	$414,077
OH 2 phase 34.5/13.8 kV 1000 kVA	2	14.29%	50.00%	0.16%	1000	$140,241	$280,482
Number of Transformers and Cost of Transformers for 5 Remaining 2 Phase OH Transformer Configurations	**7**	**50.00%**		**0.54%**		$58,950	$412,651
Total OH 2 Phase	**14**	**100.00%**		**1.09%**		$79,086	$1,107,210

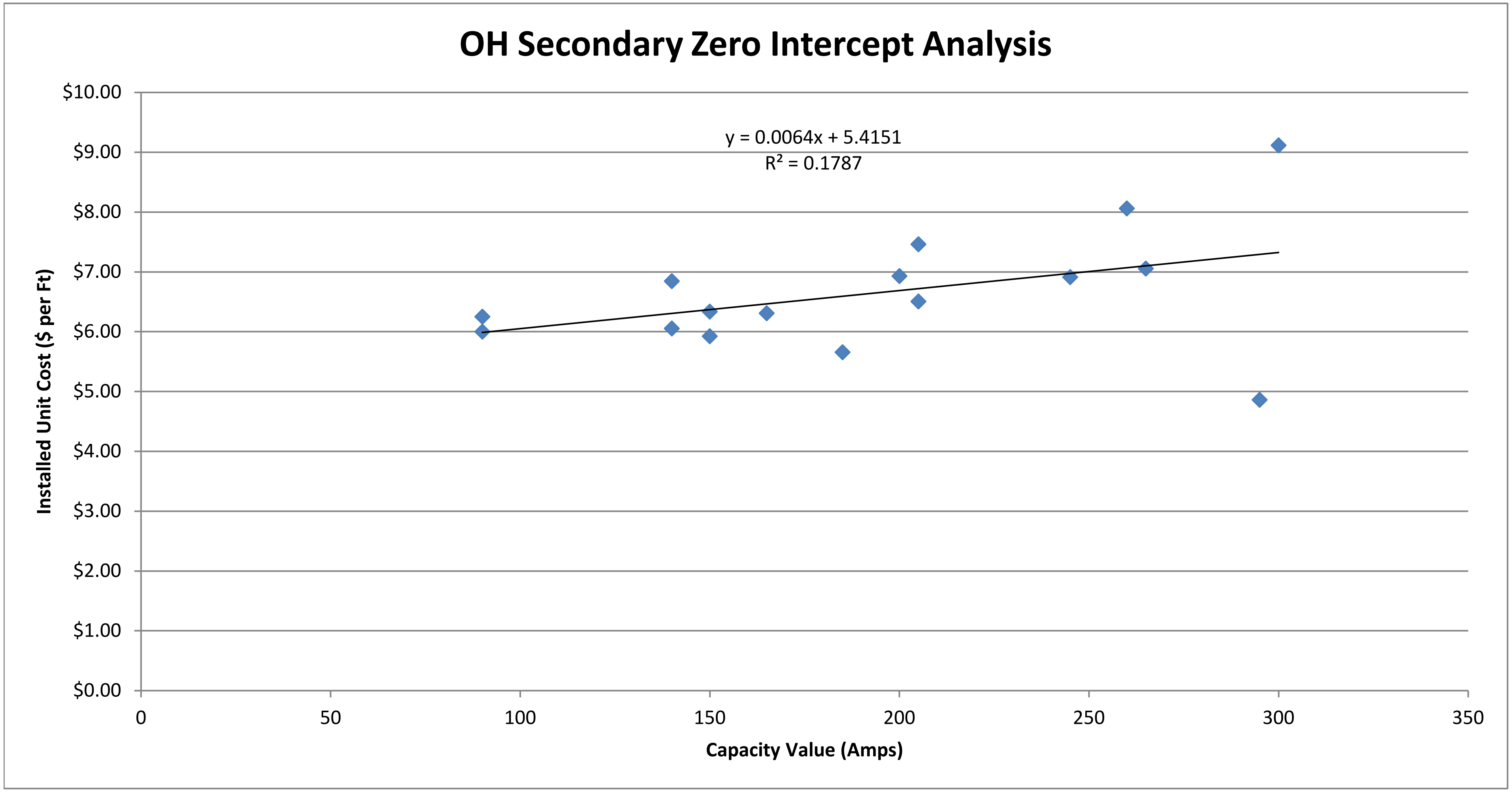
Overhead 3 Phase	Number OH 3 Phase	% of OH 3 Phase	Cumulative % of OH 3 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 3 phase 34.5/13.8 kV 1500 kVA	73	27.24%	27.24%	5.68%	1500	$209,763	$15,312,663
OH 3 phase 13.8/4.16 kV 1000 kVA	48	17.91%	45.15%	3.73%	1000	$122,672	$5,888,250
OH 3 phase 34.5/12.47 750 kVA	35	13.06%	58.21%	2.72%	750	$99,114	$3,468,974
OH 3 phase 13.8/4.16 kV 500 kVA	34	12.69%	70.90%	2.64%	500	$77,198	$2,624,715
OH 3 phase 34.5/13.8 300 kVA	21	7.84%	78.73%	1.63%	300	$62,295	$1,308,195
OH 3 phase 13.8/12.47 kV 5000 kVA	11	4.10%	82.84%	0.86%	5000	$649,719	$7,146,906
Number of Transformers and Cost of Transformers for 17 Remaining 3 Phase OH Transformer Configurations	**46**	**17.16%**		**3.58%**		$96,173	$4,423,969
Total OH 3 Phase	**268**	**100.00%**		**20.84%**		$149,902	**$40,173,672**
Total OH Step-Down Transformers	**1,286**					$115,096	$148,013,424

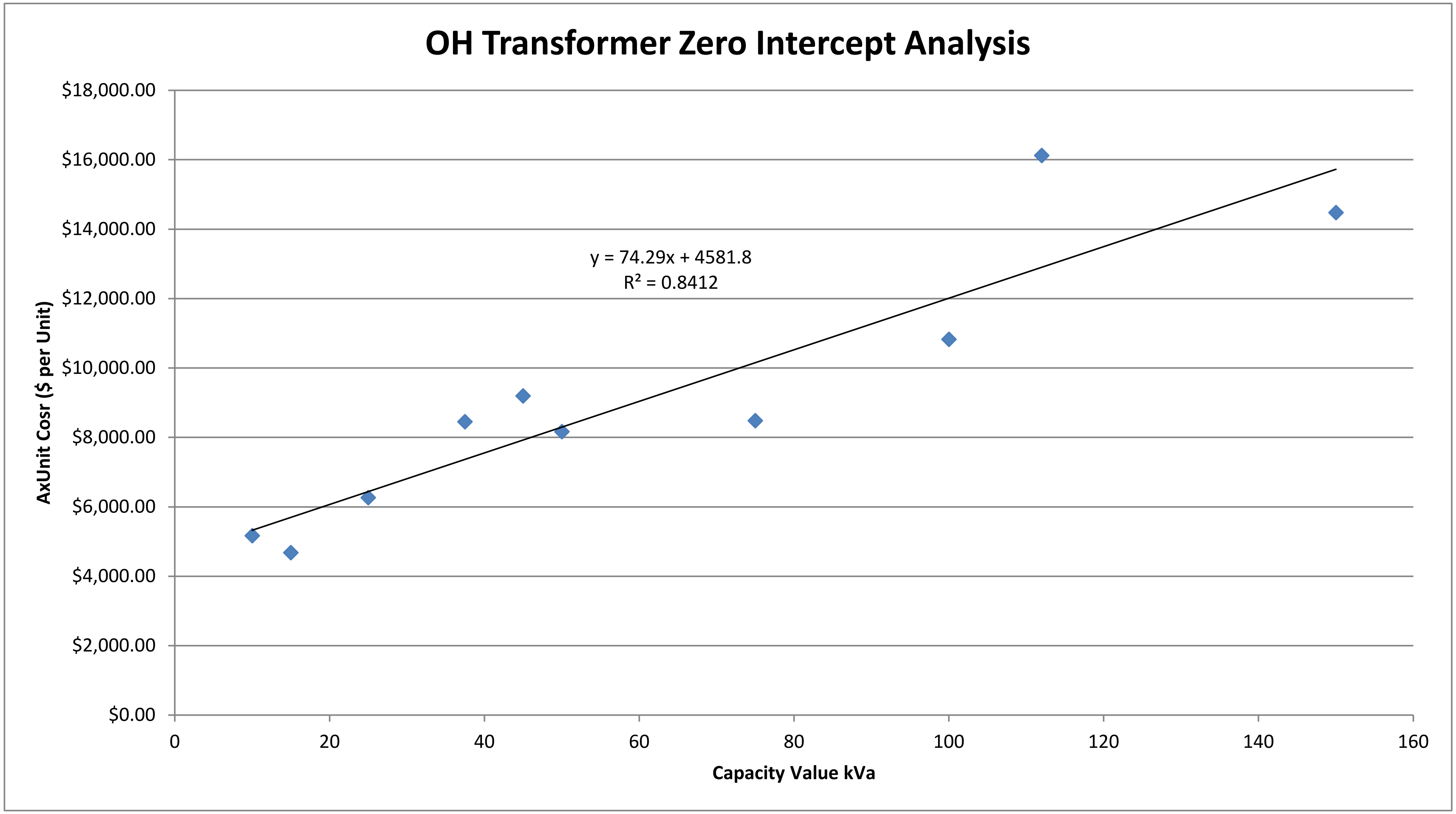
Underground 1 Phase	Number UG 1 Phase	% of UG 1 Phase	Cumulative % of UG 1 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 1 phase 19.92/7.97 kV 500 kVA	1	33.33%	33.33%	1.20%	500	$61,508	$61,508
UG 1 phase 19.92/7.2 333.0 kVA	1	33.33%	66.67%	1.20%	333	$42,473	$42,473
UG 1 phase 19.92/7.2 50.0 kVA	1	33.33%	100.00%	1.20%	50	$5,335	$5,335
Total UG 1 Phase	**3**	**100.00%**		**3.61%**		$36,438	**$109,315**

Underground 3 Phase	Number UG 3 Phase	% of UG 3 Phase	Cumulative % of UG 3 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 3 phase 34.5/13.8 kV 5000 kVA	48	60.00%	60.00%	57.83%	5000	$683,393	$32,802,844
UG 3 phase 34.5/13.8 kV 3750 kVA	20	25.00%	85.00%	24.10%	3750	$1,024,753	$20,495,056
UG 3 phase 34.5/4.16 kV 11250 kVA	4	5.00%	90.00%	4.82%	11250	$3,684,733	$14,738,933
Number of Transformers and Cost of Transformers for 4 Remaining 3 Phase UG Transformer Configurations	**8**	**10.00%**		**9.64%**		$641,233	$5,129,861
Total UG 3 Phase	**80**	**100.00%**		**96.39%**		$914,584	**$73,166,694**
Total UG Step-Down Transformers	**83**						**$73,276,010**
All OH & UG Primary Step-Down Transfo	**1,369**					$161,643	**$221,289,433**

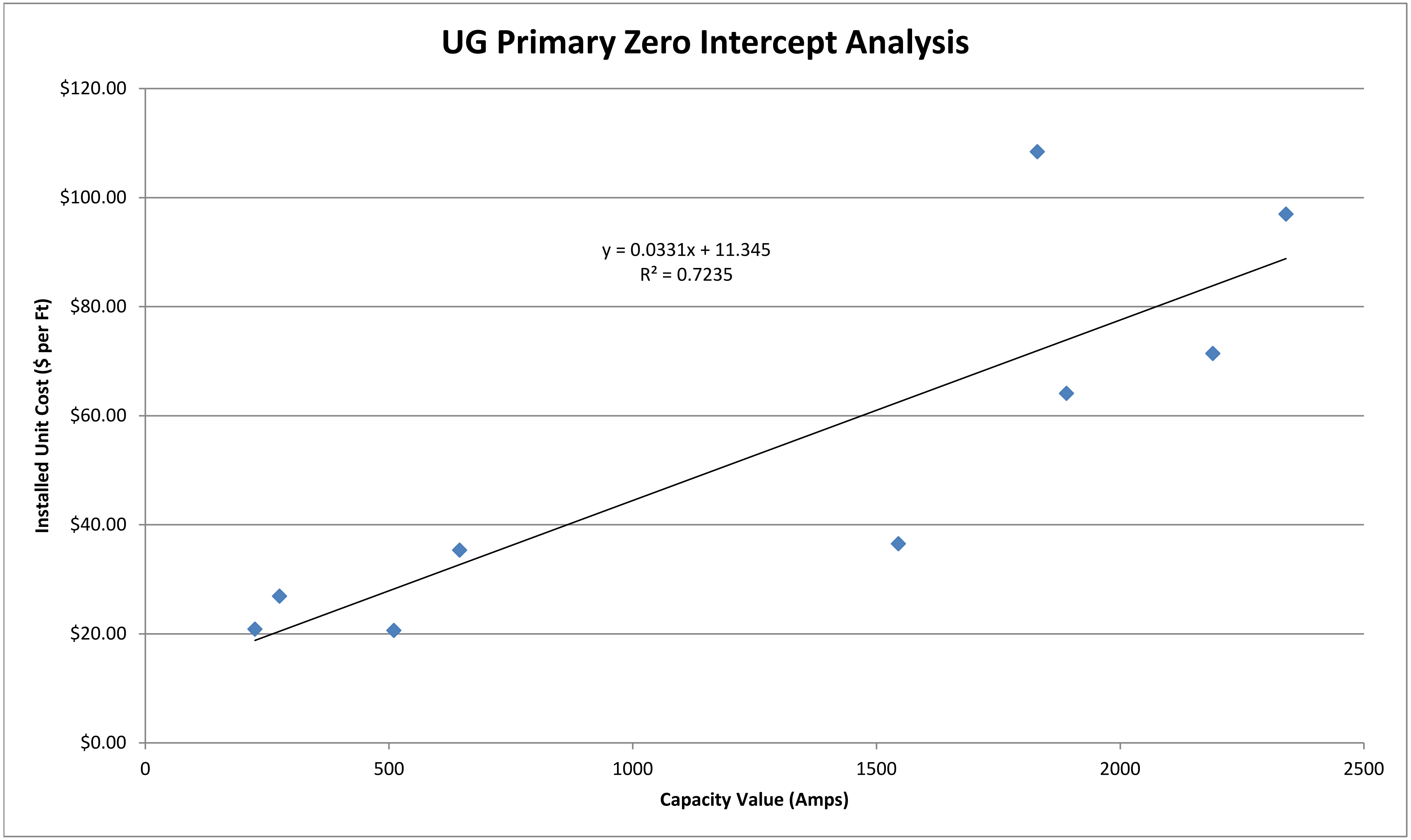

OH Primary Zero Intercept Analysis
Installed Unit Cost ($ / Ft)
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
0
500
1000
1500
2000
2500
Capacity Value (Amps)
y = 0.0343x + 7.8208
R² = 0.8665

Overhead Secondary Zero Intercept Analysis

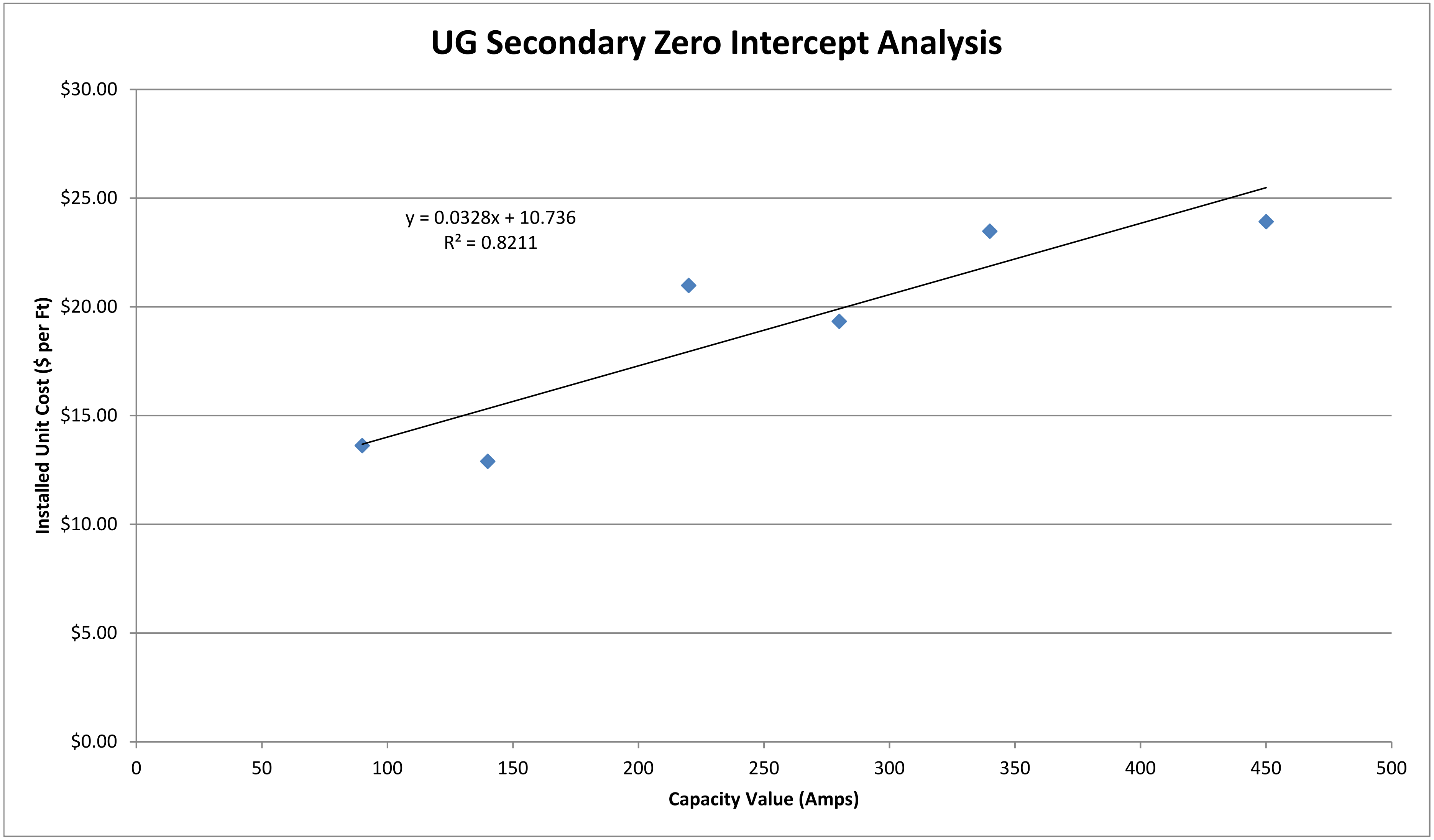



OH Transformer Zero Intercept Analysis
y = 74.29x + 4581.8
R² = 0.8412
$18,000.00
$16,000.00
$14,000.00
$12,000.00
$10,000.00
$8,000.00
$6,000.00
$4,000.00
$2,000.00
$0.00
AxUnit Cosr ($ per Unit)
0
20
40
60
80
100
120
140
160
Capacity Value kVa

Underground Primary Zero Intercept Analysis



Underground Secondary Zero Intercept Analysis



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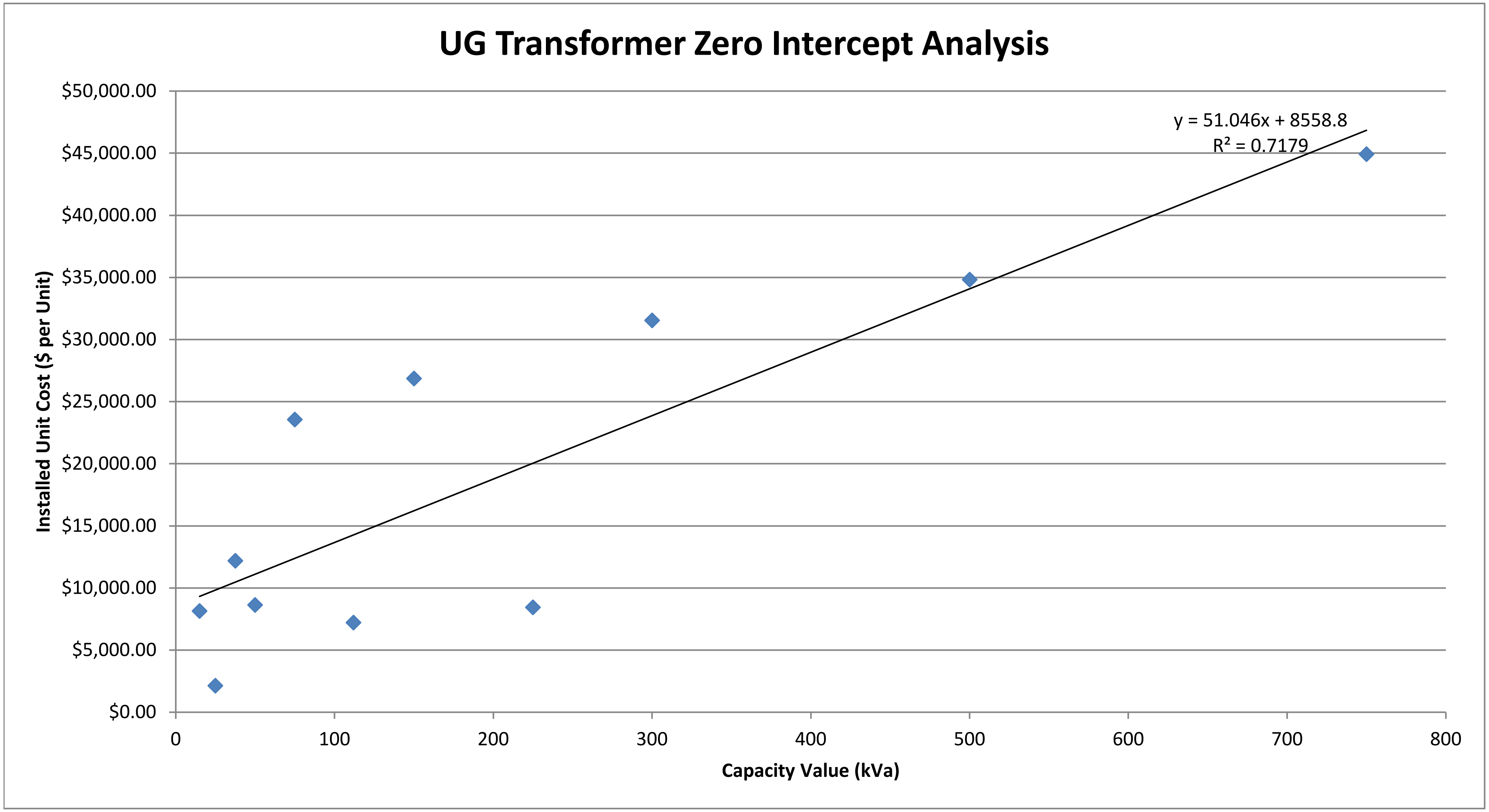
Underground Transformer Zero Intercept Analysis



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Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
1	OH Primary	1 ph	4 ACSR 1ph	10,698,423	15.3%	15.3%	150	$25.73	$275,322,293	$7.82	$83,670,230	$20.56	$220,009,945
2	OH Primary	1 ph	2 ACSR 1ph	10,139,492	14.5%	29.8%	200	$20.56	$208,515,678	$7.82	$79,298,937	$20.56	$208,515,678
3	OH Primary	1 ph	6A CUWD 1ph	7,459,455	10.7%	40.4%	140	$13.85	$103,293,832	$7.82	$58,338,902	$20.56	$153,401,499
4	OH Primary	1 ph	6 CU 1ph	6,943,615	9.9%	50.3%	140	$7.45	$51,729,929	$7.82	$54,304,621	$20.56	$142,793,401
5	OH Primary	1 ph	3/10 CU 1ph	1,564,708	2.2%	52.6%	165	$11.68	$18,282,341	$7.82	$12,237,267	$20.56	$32,177,759
6		**Total 1 Phase Primary in Sample**		36,805,692				**$17.85**	$657,144,073		$287,849,958		$756,898,281
7	OH Primary	3 ph	336 AL 3ph	6,449,212	9.2%	61.8%	1680	$71.01	$457,964,375	$7.82	$50,437,999	$20.56	$132,626,161
8	OH Primary	3 ph	2 ACSR 3ph	5,828,121	8.3%	70.1%	600	$35.10	$204,561,003	$7.82	$45,580,572	$20.56	$119,853,609
9	OH Primary	3 ph	336 ACSR 3ph	5,187,129	7.4%	77.5%	1695	$81.55	$422,985,909	$7.82	$40,567,501	$20.56	$106,671,795
10	OH Primary	3 ph	2/0 ACSR 3ph	2,335,697	3.3%	80.9%	885	$35.21	$82,231,022	$7.82	$18,267,017	$20.56	$48,032,919
11	OH Primary	3 ph	4 ACSR 3ph	1,756,872	2.5%	83.4%	450	$21.17	$37,192,973	$7.82	$13,740,142	$20.56	$36,129,551
12	OH Primary	3 ph	6 CU 3ph	1,294,407	1.8%	85.2%	420	$10.06	$13,021,730	$7.82	$10,123,295	$20.56	$26,619,093
13	OH Primary	3 ph	6A CUWD 3ph	733,392	1.0%	86.3%	420	$18.70	$13,713,937	$7.82	$5,735,715	$20.56	$15,081,999
14	OH Primary	3 ph	1/0 ACSR 3ph	719,893	1.0%	87.3%	780	$31.76	$22,864,737	$7.82	$5,630,136	$20.56	$14,804,379
15	OH Primary	3 ph	4/0 CU 3ph	820,787	1.2%	88.5%	1680	$40.01	$32,837,361	$7.82	$6,419,214	$20.56	$16,879,253
16	OH Primary	3 ph	556 AL 3ph	448,373	0.6%	89.1%	2295	$104.81	$46,995,605	$7.82	$3,506,634	$20.56	$9,220,655
17	OH Primary	3 ph	556 ACSR 3ph	340,521	0.5%	89.6%	2295	$69.07	$23,519,500	$7.82	$2,663,148	$20.56	$7,002,718
18	OH Primary	3 ph	336 AAC 3ph	352,504	0.5%	90.1%	1680	$74.90	$26,401,194	$7.82	$2,756,862	$20.56	$7,249,138
19	OH Primary	3 ph	556 AAC 3ph	244,006	0.3%	90.5%	2295	$84.45	$20,607,465	$7.82	$1,908,325	$20.56	$5,017,920
20	OH Primary	**Total 3 Phase Primary in Sample**		26,510,914				**$52.99**	$1,404,896,810		$207,336,559		$545,189,189
19	OH Primary	**Total 1 Ph & 3 Ph OH Primary in Sample**		63,316,607				**$32.57**	$2,062,040,882		$495,186,518		$1,302,087,470
20										**% Customer Related Costs Using Zero Intercept =**	**24.01%**	**% Customer Related Costs Using Minimum System =**	**63.15%**

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
21	OH Secondary		2 ACSR Open Wire	20,338,802	14.9%	14.9%	200	$6.93	$140,948,065	$5.42	$110,136,646	$6.51	$132,308,390
22	OH Secondary		4 ACSR Open Wire	9,718,445	7.1%	22.0%	150	$5.92	$57,561,156	$5.42	$52,626,352	$6.51	$63,220,627
23	OH Secondary		1/0 ACSR Open Wire	18,334,359	13.4%	35.5%	260	$8.06	$147,781,520	$5.42	$99,282,385	$6.51	$119,269,044
24	OH Secondary		6 CU Open Wire	9,845,756	7.2%	42.7%	140	$6.84	$67,392,455	$5.42	$53,315,751	$6.51	$64,048,810
25	OH Secondary		6A CUWD Open Wire	6,296,098	4.6%	47.3%	140	$6.05	$38,114,991	$5.42	$34,094,002	$6.51	$40,957,507
26	OH Secondary		4 CU Open Wire	15,181,580	11.1%	58.4%	185	$5.66	$85,909,751	$5.42	$82,209,774	$6.51	$98,759,525
27	OH Secondary		2 CU Open Wire	14,916,284	10.9%	69.3%	245	$6.91	$103,105,077	$5.42	$80,773,171	$6.51	$97,033,717
28	OH Secondary		1/0 AL Triplex	7,573,248	5.5%	74.9%	205	$6.51	$49,265,645	$5.42	$41,009,893	$6.51	$49,265,645
29	OH Secondary		6 ACSR Duplex	4,852,695	3.6%	78.4%	90	$6.00	$29,112,049	$5.42	$26,277,828	$6.51	$31,567,850
30	OH Secondary		1/0 AL Triplex, Lashed	6,721,759	4.9%	83.4%	205	$7.46	$50,146,651	$5.42	$36,398,996	$6.51	$43,726,522
31	OH Secondary		3/10 CU Open Wire	1,505,128	1.1%	84.5%	165	$6.31	$9,498,772	$5.42	$8,150,419	$6.51	$9,791,189
32	OH Secondary		1/0 CU Open Wire	2,505,605	1.8%	86.3%	300	$9.11	$22,837,129	$5.42	$13,568,102	$6.51	$16,299,513
33	OH Secondary		2 AL Triplex	2,723,553	2.0%	88.3%	150	$6.34	$17,260,627	$5.42	$14,748,310	$6.51	$17,717,310
34	OH Secondary		2/0 ACSR Open Wire	915,530	0.7%	89.0%	295	$4.86	$4,449,475	$5.42	$4,957,685	$6.51	$5,955,723
35	OH Secondary		6 AL Duplex	1,292,144	0.9%	89.9%	90	$6.25	$8,078,627	$5.42	$6,997,088	$6.51	$8,405,680
36	OH Secondary		1/0 AL Open Wire	1,294,876	0.9%	90.9%	265	$7.06	$9,135,603	$5.42	$7,011,880	$6.51	$8,423,451
37		**Total OH Secondary in Sample**		124,015,860				**$6.78**	$840,597,592		$671,558,283		$806,750,504
38										**% Customer Related Costs Using Zero Intercept =**	**79.89%**	**% Customer Related Costs Using Minimum System =**	**95.97%**

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
39	OH Transformers		1 Phase Wye 25 kVA	33,552	29.7%	29.7%	25	$6,268	$210,290,392	$4,582	$153,728,554	$5,171	$173,497,392
40	OH Transformers		1 Phase Wye 10 kVA	17,527	15.5%	45.2%	10	$5,171	$90,626,252	$4,582	$80,305,209	$5,171	$90,632,117
41	OH Transformers		1 Phase Wye 37.5 kVA	15,358	13.6%	58.7%	37.5	$8,449	$129,763,828	$4,582	$70,367,284	$5,171	$79,416,218
42	OH Transformers		1 Phase Wye 15 kVA	17,194	15.2%	73.9%	15	$4,683	$80,513,259	$4,582	$78,779,469	$5,171	$88,910,174
43	OH Transformers		1 Phase Wye 50 kVA	14,750	13.0%	87.0%	50	$8,169	$120,489,966	$4,582	$67,581,550	$5,171	$76,272,250
44	OH Transformers		3 Phase Wye/Wye 75 kVA	1,325	1.2%	88.1%	75	$8,483	$11,239,552	$4,582	$6,070,885	$5,171	$6,851,575
45	OH Transformers		3 Phase Wye/Wye 150 kVA	1,068	0.9%	89.1%	150	$14,478	$15,463,035	$4,582	$4,893,362	$5,171	$5,522,628
46	OH Transformers		3 Phase Wye/Wye 112 kVA	548	0.5%	89.6%	112	$16,120	$8,833,592	$4,582	$2,510,826	$5,171	$2,833,708
47	OH Transformers		3 Phase Wye/Wye 45 kVA	773	0.7%	90.3%	45	$9,192	$7,105,570	$4,582	$3,541,731	$5,171	$3,997,183
48	OH Transformers		1 Phase Wye 100 kVA	657	0.6%	90.8%	100	$10,829	$7,114,626	$4,582	$3,010,243	$5,171	$3,397,347
49			**Total OH Transformers in Sample**	102,752				**$6,631.89**	**$681,440,072**		**$470,789,114**		**$531,330,592**
50										**% Customer Related Costs Using Zero Intercept =**	**69.09%**	**% Customer Related Costs Using Minimum System =**	**77.97%**
51	UG Primary	1 ph	1/0 AL 1ph	16,024,349	28.7%	28.7%	275	$26.92	$431,436,628	$11.35	$181,796,240	$20.88	$334,525,622
52	UG Primary	1 ph	2 AL 1ph	14,788,376	26.5%	55.1%	225	$20.88	$308,723,338	$11.35	$167,774,120	$20.88	$308,723,338
53			**Total 1 Phase Primary in Sample**	30,812,725				**$24.02**	**$740,159,966**		**$349,570,360**		**$643,248,960**
54													
55	UG Primary	3 ph	1/0 AL 3ph	14,140,772	25.3%	80.4%	645	$35.34	$499,721,282	$11.35	$160,427,055	$20.88	$295,203,907
56	UG Primary	3 ph	750 AL 3ph	4,826,798	8.6%	89.1%	1890	$64.09	$309,330,428	$11.35	$54,760,018	$20.88	$100,764,620
57	UG Primary	3 ph	2 AL 3ph	933,040	1.7%	90.7%	510	$20.62	$19,239,291	$11.35	$10,585,342	$20.88	$19,478,226
58	UG Primary	3 ph	1000 AL 3ph	534,454	1.0%	91.7%	2190	$71.40	$38,161,254	$11.35	$6,063,383	$20.88	$11,157,309
59	UG Primary	3 ph	500 AL 3ph	459,969	0.8%	92.5%	1545	$36.51	$16,793,481	$11.35	$5,218,352	$20.88	$9,602,358
60	UG Primary	3 ph	500 CU 3ph	753,701	1.3%	93.9%	1830	$108.41	$81,709,846	$11.35	$8,550,735	$20.88	$15,734,319
61	UG Primary	3 ph	750 CU 3ph	436,689	0.8%	94.7%	2340	$96.97	$42,346,704	$11.35	$4,954,235	$20.88	$9,116,352
62			**Total 3 Phase Primary in Sample**	22,085,423				**$44.85**	**$990,508,805**		**$250,559,120**		**$461,057,091**
63													
64			**Total 1 Ph & 3 Ph UG Primary in Sample**	52,898,147					**$1,730,668,771**		**$600,129,480**		**$1,104,306,051**
65										**% Customer Related Costs Using Zero Intercept =**	**34.68%**	**% Customer Related Costs Using Minimum System =**	**63.81%**

Minimum System / Zero Intercept Distribution System Cost Analysis

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
Line	**Property Unit**	**Phase**	**Config Details**	**Conductor Footage/Number Transformers**	**% of Total Population Footage/ Transformers**	**Cumulative % of Total Population Footage/ Transformers**	**Load Carrying Capacity (A, or kVA)**	**Installed Unit Cost**	**Total Cost**	**Y Intercept Minimum Cost per Unit**	**Total Cost Using Y Intercept Unit Cost**	**Minimum System Cost per Unit**	**Total Cost Using Minimum System Cost per Unit**
66	UG Secondary		6 AL Duplex	9,878,341	36.7%	36.7%	90	$13.62	$134,523,954	$10.74	$106,053,871	$20.98	$207,265,507
67	UG Secondary		4/0 AL Triplex	8,355,002	31.0%	67.7%	340	$23.48	$196,188,727	$10.74	$89,699,304	$20.98	$175,303,093
68	UG Secondary		2/0 AL Triplex	2,679,564	10.0%	77.7%	280	$19.33	$51,808,384	$10.74	$28,767,803	$20.98	$56,222,119
69	UG Secondary		1/0 AL Triplex	1,460,657	5.4%	83.1%	220	$20.98	$30,647,236	$10.74	$15,681,615	$20.98	$30,647,236
70	UG Secondary		6 CU Open Wire	1,206,909	4.5%	87.6%	140	$12.90	$15,564,876	$10.74	$12,957,378	$20.98	$25,323,146
71	UG Secondary		350 AL Triplex	660,658	2.5%	90.1%	450	$23.91	$15,799,054	$10.74	$7,092,828	$20.98	$13,861,809
72		**Total UG Secondary in Sample**		24,241,133				**$18.34**	**$444,532,232**		**$260,252,800**		**$508,622,909**
73										**% Customer Related Costs Using Zero Intercept =**	**58.55%**	**% Customer Related Costs Using Minimum System =**	**100.00%**
74	UG Transformers		1 Phase Wye 50 kVA	31,125	35.4%	35.4%	50	$8,630	$268,614,731	$8,559	$266,392,650	$8,137	$253,272,440
75	UG Transformers		1 Phase Wye 25 kVA	17,418	19.8%	55.2%	25	$2,129	$37,087,596	$8,559	$149,077,178	$8,137	$141,734,919
76	UG Transformers		1 Phase Wye 37.5 kVA	8,619	9.8%	65.0%	37.5	$12,182	$104,994,055	$8,559	$73,768,297	$8,137	$70,135,106
77	UG Transformers		3 Phase Wye/Wye 150 kVA	3,986	4.5%	69.6%	150	$26,857	$107,053,066	$8,559	$34,115,377	$8,137	$32,435,147
78	UG Transformers		3 Phase Wye/Wye 300 kVA	3,834	4.4%	73.9%	300	$31,548	$120,955,892	$8,559	$32,814,439	$8,137	$31,198,282
79	UG Transformers		3 Phase Wye/Wye 75 kVA	3,656	4.2%	78.1%	75	$23,569	$86,170,049	$8,559	$31,290,973	$8,137	$29,749,849
80	UG Transformers		3 Phase Wye/Wye 500 kVA	3,255	3.7%	81.8%	500	$34,818	$113,331,005	$8,559	$27,858,894	$8,137	$26,486,805
81	UG Transformers		1 Phase Wye 15 kVA	2,258	2.6%	84.4%	15	$8,137	$18,373,949	$8,559	$19,325,770	$8,137	$18,373,949
82	UG Transformers		3 Phase Wye/Wye 112 kVA	1,932	2.2%	86.6%	112	$7,217	$13,942,448	$8,559	$16,535,602	$8,137	$15,721,200
83	UG Transformers		3 Phase Wye/Wye 225 kVA	1,752	2.0%	88.5%	225	$8,446	$14,798,075	$8,559	$14,995,018	$8,137	$14,256,492
84	UG Transformers		3 Phase Wye/Wye 750 kVA	1,954	2.2%	90.8%	750	$44,930	$87,792,569	$8,559	$16,723,895	$8,137	$15,900,220
85		**Total UG Transformers in Sample**		79,789				**$12,196.09**	**$973,113,435**		**$682,898,093**		**$649,264,409**
86													
										% Customer Related Costs Using Zero Intercept =	**70.18%**	**% Customer Related Costs Using Minimum System =**	**66.72%**
87		**Total OH and UG Transforners in Sample**		182,541				**$9,064**	**$1,654,553,506**		**$1,153,687,207**		**$1,180,595,001**
88										**% Customer Related Costs Using Zero Intercept =**	**69.73%**	**% Customer Related Costs Using Minimum System =**	**71.35%**

Northern States Power Company
Minimum System / Zero Intercept Analysis Results
Distribution Plant Cost Classification: Capacity Vs Customer Classification
Hybrid Method

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 11	[5] = [Col 5 Line 11 - Line 10] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
Line	**Overhead Distribution Plant**	**Total Footage**	**Average Cost per Foot**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Overhead Dist Costs**
1	OH Primary Single Phase Capacity						75.99%	$246,875	16.24%
2	OH Primary Single Phase Customer						24.01%	$78,022	5.13%
3	Total OH Primary Single Phase	40,232,843	$17.85	$718,334	22.31%	$324,897	100.00%	$324,897	
4	OH Primary Multi Phase Capacity						75.99%	$542,018	35.65%
5	OH Primary Multi Phase Customer						24.01%	$171,299	11.27%
6	Total OH Primary Multi Phase	29,760,732	$52.99	$1,577,115	48.97%	$713,316	100.00%	$713,316	
7	OH Secondary Capacity						20.11%	$84,131	5.53%
8	OH Secondary Customer						79.89%	$334,236	21.98%
9	Total OH Secondary	136,467,174	$6.78	$924,994	28.72%	$418,367	100.00%	$418,367	
10	Street Lighting (see Line 9 of Schedule XX)					$63,793		$63,793	4.20%
11	Total Overhead (see Schedule X, Page 4, Column 1, Line XX)			$3,220,443	100.00%	$1,520,374		$1,520,374	100.00%

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 22	[5] = [Col 5 Line 22 - Line 21] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
	Underground Distribution Plant	**Total Footage**	**Average Cost per Foot**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Underground Distr Costs**
12	UG Primary Single Phase Capacity						65.32%	$361,197	21.10%
13	UG Primary Single Phase Customer						34.68%	$191,736	11.20%
14	Total UG Primary Single Phase	31,519,114	$24.02	$757,128	32.31%	$552,933	100.00%	$552,933	
15	UG Primary Multi Phase Capacity						65.32%	$521,301	30.46%
16	UG Primary Multi Phase Customer						34.68%	$276,725	16.17%
17	Total UG Primary Multi Phase	24,364,721	$44.85	$1,092,733	46.63%	$798,026	100.00%	$798,026	
18	UG Secondary Capacity						41.45%	$149,449	8.73%
19	UG Secondary Customer						58.55%	$211,063	12.33%
20	Total UG Secondary	26,919,485	$18.34	$493,648	21.06%	$360,512	100.00%	$360,512	
21	Street Lighting					$0		$0	0.00%
22	Total Underground			$2,343,509	100.00%	$1,711,471		$1,711,471	100.00%

		[1]	[2]	[3] = [1] x [2]	[4] = % of Line 27	[5] = [Col 5 Line 27] x [4]	[6] = (Customer % from Attachment N)	[7]	[8]
	Transformers	**Number of Transformers**	**Average Cost Per Transformer**	**Total Replacement Cost ($000)**	**% of Total Replacement Cost**	**Test Year Plant in Service ($000)**	**% Customer or Capacity Related**	**Final Test Year Plant in Service ($000)**	**% of Total Transformer Costs**
23	Primary	1,369	$161,643	$221,289	17.75%	$94,136	100% Capacity	$94,136	17.75%
24	Secondary Capacity						31.95%	$139,331	26.28%
25	Secondary Customer						68.05%	$296,798	55.97%
26	Total Secondary	113,110	$9,064	$1,025,230	82.25%	$436,129	100.00%	$436,129	82.25%
27	Total Transformers			$1,246,520	100.00%	$530,265		$530,265	100.00%

	[1]	[2]	[3]	[4]	[5]	[6] = [3] x [4] x [5] / 1000	[7]	[8] = [6] / [7]	[9] = 1 - [8]
	Services	**Minimum Conductor Configuration**	**Minimum Footage per Service**	**Installed Cost per Foot**	**Number of Customers**	**Total Minimum Installed Cost ($000)**	**Test Year Plant Investment Distribution Services ($000)**	**Customer Component Distribution Services**	**Capacity Component Distribution Services**
1	OH Services	2 ACSR Triplex	50	$4.03	821,337	$165,499			
2	UG Services	1/0 Triplex	50	$2.81	431,035	$60,560			
3	Total Services				1,252,372	$226,060	$364,895	61.95%	38.05%

					Customer Class				
Line	**Primary Distribution Cost**	**Allocator Derivation**	**Allocator Label**	**MN**	**Resid**	**Commercial Non Demand**	**C&I Demand Secondary**	**C&I Demand Primary**	**Ltg**
1	Customer Portion of **Multi-Phase** Primary Lines	Number of Customers	C61PS	1,394,361	1,248,393	89,156	50,179	495	6,138
2	Capacity Portion of **Multi-Phase** Primary Lines	Class Coincident Peak Demands	D61PS	6,068,286	2,567,861	191,730	2,681,876	593,538	33,281
3	% of Customers Served by Primary **Single Phase** Lines				**71.6%**	**39.3%**	**10.3%**	**2.7%**	**57.4%**
4	Customer Portion of **Single-Phase** Primary Lines	line 1 x line 3	C61PS1Ph	937,493	893,725	35,058	5,175	13	3,521
5	Capacity Portion of Single-Phase Primary Lines	line 2 x line 3	D61PS1Ph	2,225,548	1,838,334	75,392	276,606	16,126	19,090
6	Customer Portion of **Multi-Phase** Primary Lines	Cost Allocator %	C61PS	100.0%	89.53%	6.39%	3.60%	0.04%	0.44%
7	Capacity Portion of **Multi-Phase** Primary Lines	Cost Allocator %	D61PS	100.0%	42.32%	3.16%	44.19%	9.78%	0.55%
8	Customer Portion of **Single-Phase** Primary Lines	Cost Allocator %	C61PS1Ph	100.0%	95.33%	3.74%	0.55%	0.00%	0.38%
9	Capacity Portion of **Single-Phase** Primary Lines	Cost Allocator %	D61PS1Ph	100.0%	82.60%	3.39%	12.43%	0.72%	0.86%

Conservation Improvement Program Conservation Cost Recovery Charge (CCRC) Computation

12 Months Ending December 31, 2025

TY25 CIP Expense DOC-Approved Spending		
2025 Approved CIP Budget	**$ 166,570,277**	
TY25 kWh		
TY 2025 MN kWh Sales	28,304,703,761	
TY 2025 CIP Exempt Cust Sales (Est.)	1,454,874,924	
Net CIP Sales	26,849,828,837	
CCRC = TY25 CIP Expense / TY2025 kWh Sales	**0.6204**	**¢ per kWh**

Northern States Power Company
State of Minnesota Electric Jurisdiction
Test Year Ending December 31, 2025
WORKPAPER: General Rules and Regulations Cost Analysis Overview

Tariff	Description	Pres Price	Prop Price	2023 Units	Pres $	Prop $	Differ
1.8	**Dedicated Switching Service**	Chg / trip	Chg / trip				
	Monday through Saturday	$300.00	$800.00	398	$119,400	$318,400	$199,000
	Sunday and Federal holidays	$400.00	$1,000.00	38	$15,200	$38,000	$22,800
5.1	**Standard Installation and Extension Rules**						
	Excess service charge - Services	$7.90	$10.00	16,143	$127,530	$161,430	$33,900
	Excess service charge - Excess single phase primary	$8.00	$10.50	-	$0	$0	$0
	Excess service charge - Excess three phase primary	$13.90	$17.00	-	$0	$0	$0
5.1.A.2.	**Winter Construction**						
	Per Frost Burner	$640.00	$870.00	782	$500,480	$680,340	$179,860
	Per Trench Foot	$8.90	$18.00	99,123	$882,195	$1,784,214	$902,019
			Total		**$1,644,804**	**$2,982,384**	**$1,337,580**

Section 6.5.1.A1.			
Excess Footage Charge	**Current Electric tariff per circuit foot**	**Proposed Tariff Charge per circuit foot**	**Proposed Rate**
Services	$7.90	**$10.12**	**$10.00**
Excess single phase primary or secondary extension	$8.00	**$10.65**	**$10.50**
Excess three phase primary or secondary extension	$13.90	**$17.03**	**$17.00**

Equipment Specifications

Assumptions - based off 100 ft service
Single Phase secondary = 4/0 alum tri w/ installation
Single Phase primary = #2 alum 1/0 primary w/ installation
3 Phase primary or secondary = 1/0 alum 3/0 primary w/ installation

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%				$235.92				
Labor w/ Loading				$535.92				$535.92
Vehicle & Equipment	2 Trucks (stafford truck and the leads truck	2	55	$110.00				$110.00
					2.72	22.5	$61.20	$61.20
Propane Cost								
Costs (before E&S)				$707.12				$707.12
E&S Cost @ 25.00%				$176.78				$176.78
Total Cost				$883.90				$883.90

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

	Before and after January Costs	Percentage	
	$635.01	10%	$63.50
	$883.90	90%	$795.51
			$859.01
Billing Labor			$10.00
Producing Bill			$0.53
Postage			$0.73
Total Cost of a Thaw Unit			**$870.27**

2024 Winter Construction Per foot Charge

Winter Construction billed for in Winter of 2023

Average Cost per Foot Winter 2023 Services =	$48.78
Average Cost per Foot Non-Winter Months Services =	$30.61
Difference for Winter Construction	**$18.17**

2024 Updates to Charges

<table>
<tr><th colspan="8">Tariff</th></tr>
<tr><th colspan="3">Current Electric Charges</th><th colspan="2">Updated Costs</th><th colspan="3">Proposed Tarif Charge</th></tr>
<tr><td rowspan="2">Winter Construction Service primary or secondary distribution</td><td>$640.00</td><td>per thaw unit</td><td>$870.27</td><td>per thaw unit</td><td>Thawing</td><td>$870.00</td><td>per thaw unit</td></tr>
<tr><td>$8.90</td><td>plus per trench foot</td><td>$18.17</td><td>plus per trench foot</td><td>Secondary distribution extension</td><td>$18.00</td><td>per foot</td></tr>
</table>

	Normal 2023 $ $/hour	Overtime Mon-Sat x 1.5% 2023 $/hour	Overtime Sun-Fed Holidays x 2.0% 2023 $/hour
Dispatching labor cost	$ 43.07	$ 64.61	$ 129.21
Troubleman labor	$ 554.59	$ 596.55	$ 795.40
Administrative @ 5% of Troubleman labor	$ 27.73	$ 29.83	$ 39.77
Sub total labor	**$ 625.39**	**$ 690.98**	**$ 964.38**
Trucks	$ 111.16	$ 111.16	$ 111.16
Total Trouble Costs	**$ 736.55**	**$ 802.14**	**$ 1,075.54**
Call Center labor cost per call	$ 2.06	$ 1.54	$ 1.54
Producing bill	$ 0.53	$ 0.53	$ 0.53
Postage for bill	$ 0.73	$ 0.73	$ 0.73
Total Billing Costs	**$ 3.32**	**$ 2.80**	**$ 2.80**
TOTAL COSTS	**$ 739.87**	**$ 804.94**	**$ 1,078.34**

TARIFF	Charge per hour		
Requested Appointment Date	**Tariff $**	**2023 $**	**Proposed 2024 $**
Monday through Saturday	$ 300.00	$ 804.94	**$ 800.00**
Sunday and federally observed holidays	$ 400.00	$ 1,078.34	**$ 1,000.00**

Labor	p/hour Loaded
Straight time/hour	**78.60%**
$ 72.45	$ 129.40
$ 80.97	$ 144.62
Troubleman Overtime @ 1.5%	
Hourly rate @ 1.5%	**$ 216.93**
Troubleman Overtime @ 2.0%	
Hourly rate @ 2.0%	$ 289.24

Time for Avg Dedicated Switch Call	
Task	Minutes
Dispatch tasks	
Scheduling	**20**
Troubleman tasks	
Drive to site	**40**
Drive from/to next site	**35**
Site work	**90**
Total	**165**

Trucks Analysis	
Monthly lease	**$ 6,992.80**
Monthly hours	**173**
Hourly cost	$ 40.42