EXHIBIT

12

Direct Testimony and Schedules
Christopher J. Barthol

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-24-___
Exhibit___(CJB-1)

Class Cost of Service Study

December 2, 2024

85 PU-24-376 Filed 01/16/2026 Pages: 104
NSP Exhibit 12 - Direct Testimony of Christopher
J. Berthol (Class Cost of Service Study)

Northern States Power Company

Table of Contents

Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Barthol. I am a Rate Consultant.

Q. PLEASE DESCRIBE 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. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy.

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

A. The purpose of my testimony is to present the Company's proposed Class Cost of Service Study (CCOSS) and sponsor Exhibit___(NSP-1), Statement I and Exhibit___(NSP-1), Statement O located in Volume 1 of our Application.

II. CLASS COST OF SERVICE STUDY

A. Overview of Proposed Class Cost of Service Study

Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT APPROVED BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE, CASE NO. PU-20-441?

A. We updated the Company's proposed CCOSS to reflect 2025 forecast data. Specifically, all costs have been updated to reflect 2025 weather normalized costs. The hourly load data, energy use data, and customer-related data have also been updated to reflect forecast weather normalized sales data for 2025 and have been used to update class cost allocation factors. All cost classification and allocation methods are the same as those approved by the Commission in the Company's last rate case, except that we are now proposing to remove the demand adjustment from the Zero Intercept Study. The reason for this refinement will be discussed later in my testimony. Other than this one refinement, all cost allocation methods are the same as those approved by the Commission in the Company's 2020[1] rate case.

Q. HAS THERE BEEN ANY CHANGE TO HOW CUSTOMER CLASSES ARE DEFINED SINCE THE COMPANY'S LAST RATE CASE?

A. No, the basic classes of service employed in the Company's CCOSS are the same class definitions consistently used by the Company in past rate cases. The basic rate classes in the class cost of service study are:

- Residential;
- Commercial Non-Demand Billed;
- Commercial and Industrial (C&I) Demand Billed; and
- Street Lighting.

In the CCOSS, the C&I Demand Billed class is further separated by voltage level.

[1] Case No. PU-20-441

Q. HAS THE COMPANY PROVIDED ANY OTHER DOCUMENTS EXPLAINING HOW ITS CCOSS IS DEVELOPED?

A. Yes. The Company has provided a document titled "Guide to Class Cost of Service Study." This document is included with my testimony as Exhibit___(CJB-1), Schedule 2. It provides a primer on how the CCOSS was conducted, including the processes of cost functionalization, classification, and allocation. These basic processes are common to all embedded cost studies. This Guide also describes how each of the cost allocation factors was developed and identifies the cost items to which each allocator is applied.

Q. WHAT IS THE ROLE OF THE CCOSS IN THE RATEMAKING PROCESS?

A. The CCOSS allocates jurisdictional costs (in this case, costs of the Company's State of North Dakota 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 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. IS THE COMPANY'S CCOSS THE APPROPRIATE TOOL FOR EVALUATING THE RATE DESIGN IN THIS CASE?

A. Yes. As discussed by Company witness Paluck, a CCOSS is the appropriate starting point for evaluating a given rate design. The Company's proposed CCOSS is appropriate because it:

- Properly recognizes that our investments in baseload generation facilities provide value to all customers, particularly our energy-intensive users;
- Accurately reflects the value of our investments in peaking capacity, transmission and distribution facilities used to meet system peak requirements;
- Recognizes the differing impact that seasonal and time usage patterns can have on the cost of service; and
- Recognizes that certain distribution costs are incurred simply to supply service to customers regardless of the kW load they demand.

B. CCOSS Results

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2025 CCOSS.

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

Table 1
Summary of 2025 Class Cost of Service Study
State of North Dakota Electric Jurisdiction
($ Thousands)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	274,817	118,528	13,763	140,091	2,434
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	114	96	6	12	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	274,931	118,625	13,769	140,103	2,434
[4]	Present Rates (CCOSS page 2, line 2)	230,375	92,694	12,098	123,554	2,028
[5]	Unadjusted Deficiency (line 3 - line 4)	44,556	25,930	1,671	16,549	406
[6]	Defic / Pres (line 5 / line 4)	19.3%	28.0%	13.8%	13.4%	20.0%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.45**	**0.71**	**0.69**	**1.04**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)	2,912	65	26	2,821	0
[9]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)	2,912	1,140	122	1,642	8
[10]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	1,075	96	(1,180)	8

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	274,817	119,604	13,859	138,912	2,442
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	114	96	6	12	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	274,931	119,700	13,865	138,924	2,442
[14]	Present Rates (line 4)	230,375	92,694	12,098	123,554	2,028
[15]	Adjusted Deficiency (line 13 - line 14)	44,556	27,005	1,767	15,369	414
[16]	Defic / Pres Rates (line 15 / line 14)	19.3%	29.1%	14.6%	12.4%	20.4%
[17]	**Ratio: Class % / Total %**	**1.00**	**1.51**	**0.76**	**0.64**	**1.06**

Q. IN TABLE 1, YOU SHOW "UNADJUSTED" AND "ADJUSTED" COST RESPONSIBILITIES. PLEASE SUMMARIZE THIS DISTINCTION.

A. The distinction between "unadjusted" and "adjusted" cost responsibilities relates to how the cost of interruptible rate 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 five 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 or uninterrupted loads. As explained in previous 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 capacity-related power supply costs and they need to be recognized as such in the CCOSS.

Q. HOW ARE INTERRUPTIBLE RATE DISCOUNTS ALLOCATED IN THE CCOSS?

A. The Company has specific line items in the CCOSS model to address the allocation of interruptible rate discounts:

1. Line 8 on Table 1 above and Schedule 3, labeled "Interruptible Rate Discounts" shows the amount of the total interruptible rate 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. Line 9 on Table 1 above and Schedule 3, labeled "Interruptible Rate Disc. Cost Allocation" shows how the cost of interruptible rate discounts are allocated to the classes. Interruptible rate discounts are allocated using the applicable generation capacity cost allocation factor.
3. Line 10 on Table 1 above and Schedule 3, labeled "Revenue Requirement Change" shows the net change in the revenue requirement for each customer class.

4. The resulting Line 11 on Table 1 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 15 and 16, respectively.

Q. HOW DO THE CCOSS RESULTS COMPARE WITH THOSE IN THE COMPANY'S LAST RATE CASE?

A. Table 2 below compares the class deficiencies in this case with those in the Company's last rate case.

Table 2
CCOSS Results: 2021 TY vs 2025 TY

Year	Residential	Commercial Non Demand	C&I Demand	Lighting	Overall Increase
2021	10.4%	4.3%	11.1%	39.7%	10.8%
2025	29.1%	14.6%	12.4%	20.4%	19.3%

Q. PLEASE EXPLAIN THE CCOSS INDICATED INCREASE FOR THE RESIDENTIAL AND C&I DEMAND CLASSES.

A. As Table 2 illustrates, in the last rate case, the CCOSS results indicated that the Residential and C&I Demand class were to receive a rate increase consistent with the overall retail increase. In this rate case, the CCOSS indicates an increase in rates of approximately 151 and 64 percent for the Residential and C&I Demand class, respectively. These results are driven by the percentage changes in the Company's proposed D10C and D10T allocators.

Q. PLEASE EXPLAIN THE D10C AND D10T ALLOCATORS.

A. The D10C and D10T allocators are based on the loads for each class at the time of the Company's system summer and winter peak loads. These allocators are used to allocate capacity-related generation costs and transmission costs.

Q. HOW DO THE D10C AND D10T ALLOCATORS COMPARE TO THOSE IN THE COMPANY'S LAST RATE CASE?

A. Table 3 below compares the D10C and D10T cost allocators between this rate case and the last rate case.

Table 3
D10C and D10T Allocators: 2021 TY vs 2025 TY

Year	Residential	Commercial Non Demand	C&I Demand	Lighting	Total
D10C - 2021	33.6%	4.5%	61.6%	0.3%	100.0%
D10C - 2025	39.1%	4.2%	56.4%	0.3%	100.0%
D10T - 2021	35.6%	4.7%	59.1%	0.6%	100.0%
D10T - 2025	40.8%	4.6%	54.1%	0.5%	100.0%

Q. WHAT IS DRIVING THE INCREASE IN ALLOCATORS FOR THE RESIDENTIAL CLASS AND DECREASE FOR THE C&I DEMAND CLASS?

A. There are a couple of reasons for the increase in the percentage cost allocation for the Residential class and decrease for the C&I Demand class. First, the summer system peak for the 2021 test year in the Company's last rate case was forecasted to occur at 3:00 p.m. In this rate case, the summer system peak has shifted an hour later to 4:00 p.m. when the Residential class is more likely to have a higher load. Second, the winter system peak in the last case was forecasted to occur on December 22. In this rate case, the winter system peak is forecasted to occur on January 2, the day after a holiday. The winter C&I Demand load at the time of the winter system peak is a lower percentage of the total load in this case compared to the last one because the winter system peak falls on the day after a holiday, when commercial loads are still impacted by the holiday timeframe.

C. Production Plant Stratification

Q. A SIGNIFICANT PORTION OF THE COMPANY'S TOTAL COSTS ARE DRIVEN BY FIXED PRODUCTION PLANT. DESCRIBE THE PROCESS THE COMPANY USES FOR ALLOCATING FIXED PRODUCTION PLANT COSTS.

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. This process has also been referred to in the NARUC manual as the Equivalent Peaker method. This allocation method is also supported by the Commissions in Minnesota and South Dakota.

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 the amount less than or equivalent to the cost of a comparable combustion turbine (CT) peaking plant (the generation source with the lowest capital cost and the highest operating cost). Since CTs are only used at peak times they are classified as 100 percent capacity-related. The fixed generation costs that exceed the cost of a comparable CT peaking plant are sub-functionalized as energy-related. Since these costs are in excess of the CT costs, they were not theoretically incurred to obtain capacity, but rather to obtain the lower-cost energy that such plants can produce. The capacity- and energy-related portions are expressed as percentages of total fixed production plant costs.

Q. HAS THE COMPANY UPDATED ITS PLANT STRATIFICATION ANALYSIS FOR THE CURRENT CASE?

A. Yes. As shown in Table 4 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 4 below. Table 4 compares the current-dollar replacement costs of each plant type towards developing stratification percentages.

Table 4
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	$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%

Q. ARE THE STRATIFICATION PERCENTAGES APPLIED TO EACH COMPONENT OF THE REVENUE REQUIREMENT?

A. Yes. The process of "stratifying" the revenue requirements of fixed production plant is accomplished by applying these stratification percentages to each rate base component (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. From a cost perspective, this method appropriately recognizes that a significant portion of the fixed capital costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs, thereby minimizing total costs.

D. Classification and Allocation of Distribution Plant Costs

1. *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 past rate cases, the Company has directly assigned all the costs in FERC Account 373. 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 distribution 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 47 of Schedule 4, we directly assigned $3.9 million of 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 OTHER DISTRIBUTION COSTS ARE ATTRIBUTABLE TO THE STREET LIGHTING CLASS?

A. As was done in the Company's last rate case, the Company has conducted an analysis to determine if there are costs in FERC Account 364 that should be assigned to the Street Lighting class.

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. Many of these poles have street lights attached and the cost of poles that only have street lights attached is not included in FERC Account 373.

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

A. Yes. FERC Account 364 includes the cost of 21,220 wooden poles. Company-owned street lights are attached to 2,941 of these poles, meaning 13.86 percent of the Account 364 costs are at least partially 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 facilities attached that serve other customer classes). Since these poles are only used for street lighting, it's appropriate to assign the cost of these poles to the Street Lighting Class. Line 7 of Table 5 below estimates lighting pole costs that should be direct assigned to the Street Lighting class. This direct assignment is also shown in Schedule 4 on page 4, line 27.

Table 5
Calculation of FERC Account 364 Direct Assignment
State of North Dakota Electric Jurisdiction
($ Thousands)

Line No.		
1	FERC 364	$30,583
2	ND Company-Owned Street Lights on Wooden Poles	2,941
3	Total ND Poles	21,220
4	Lighting Poles as % of Total Poles (line 2 / line 3)	13.86%
5	Lighting % x FERC 364 (line 1 x line 4)	$4,239
6	Percent of Lighting Poles that only Serve Lighting	60%
7	FERC Acct 364 Direct Assignment to Lighting (line 5 x line 6)	$2,543

*See Schedule 4 at page 4, line 27.

2. *Adjustment for Percent of Customers Served by Multi-Phase versus Single-Phase Primary Distribution Lines*

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN SINGLE-PHASE AND MULTI-PHASE PRIMARY DISTRIBUTION 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 (GIS), the Company's Distribution staff determined 69.9 percent of North Dakota Residential customers receive service off the single-phase primary distribution system. Table 6 also shows that significantly fewer C&I customers receive service from the single-phase primary distribution system.

Table 6
Percent of Customers Served by Single-Phase and Multi-Phase Primary Distribution Lines

Primary Distribution Line Serving the Customer Premise	Customer Class			
	Residential Customers	C&I Non-Demand	C&I Demand	Lighting Customers
Single-Phase	69.9%	40.2%	13.0%	48.1%
Multi-Phase	31.1%	59.8%	87.0%	51.9%
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 Guide to Class Cost of Service Study. In the current rate case, we included an additional step to 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 5 shows how these allocators were developed.

3. Separation of Distribution Plant Costs into Capacity and Customer-Related Components

Q. IN THE COMPANY'S CCOSS, HOW HAVE THE COSTS FOR DISTRIBUTION PLANT BEEN CLASSIFIED?

A. Table 7 below shows how the Company has classified costs for the various distribution property units. This classification is consistent with past rate cases.

Table 7
Classification of Distribution Plant Investment

Distribution Plant Property Unit	TY 2025 ND Plant Investment ($000)	Demand Component	Capacity Component
Distribution Substations	$50,857	X	
Primary Voltage Transformers	$6,604	X	
Primary Voltage Distribution Lines	$133,033	X	X
Secondary Voltage Distribution Lines	$41,919	X	X
Secondary Voltage Transformers	$30,596	X	X
Services	$20,287	X	X

Q. WHAT ANALYSIS DID THE COMPANY PERFORM TO DO THIS SEPARATION OF COSTS?

A. Since the 1990s, the Company has used a Minimum System Study to do this separation. Consistent with our last rate case, we updated the Minimum System Study, performed an extensive review of what equipment would be considered "minimum," performed an extensive review of the installed cost of distribution equipment, and conducted a Zero Intercept Study in addition to the Minimum System Study. A Zero Intercept Study is the alternative method to determine the customer component of distribution costs.

Q. WHAT ARE THE ANALYSIS STEPS THAT ARE TAKEN TO COMPLETE A MINIMUM SYSTEM STUDY?

A. The following steps are taken to complete a Minimum System Study (these steps are also described on pages 90 to 92 of the NARUC manual):

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.

Q. WHAT ARE THE ANALYSIS STEPS THAT ARE TAKEN TO COMPLETE A ZERO INTERCEPT STUDY?

A. The steps for completing a Zero or Minimum Intercept are described on pages 92 to 94 of the NARUC manual. A Zero Intercept Study requires considerably 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 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.

Q. AFTER THE DATA IS ACQUIRED FOR THE ZERO INTERCEPT STUDY, WHAT IS THE NEXT STEP IN THE ANALYSIS?

A. After the data is acquired, the following 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.

Q. AS DESCRIBED ABOVE, BOTH MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES REQUIRE DATA ON THE INVENTORY OF DIFFERENT DISTRIBUTION PROPERTY UNIT CONFIGURATIONS, THE MINIMUM SIZE OF DISTRIBUTION EQUIPMENT CURRENTLY INSTALLED, AND THE PER UNIT INSTALLED COSTS OF

DIFFERENT CONFIGURATIONS AND ASSOCIATED LOAD CARRYING CAPACITIES. HOW DID THE COMPANY ACQUIRE THIS INFORMATION?

A. 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 of nearly 43,000 distribution work orders that were completed over a 13-year period. The goal in this data gathering step was to obtain installed costs for equipment configuration that comprise 90 percent of the population for a given property unit (i.e., underground primary conductor). More detail on the specific data sources is provided in Exhibit___(CJB-1), Schedule 6.

Q. HOW WAS THE ABOVE-MENTIONED DATA UTILIZED TO CONDUCT MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES?

A. The analyses methods, data, and results of the Minimum System and Zero Intercept Studies are shown in Schedule 6 of my testimony. Attachments A through G of Schedule 6 show the inventory of the different equipment configurations for each property unit. Attachments H through M of Schedule 6 show the graphical results of the Zero Intercept linear regression analysis for each property unit. Attachment N of Schedule 6 shows the detailed Minimum System and Zero Intercept calculations.

Q. ARE YOU PROPOSING ANY CHANGES TO THE MINIMUM SYSTEM AND/OR ZERO INTERCEPT STUDIES?

A. Yes. I am proposing to remove the demand adjustment from the Zero Intercept Study.

Q. PLEASE EXPLAIN THE DEMAND ADJUSTMENT.

A. In past rate cases, the Company assumed a 1.5 kW per customer demand adjustment for the load carrying capacity of a minimum system and applied this 1.5 kW per customer to the distribution capacity cost allocation factors.

Q. WHY ARE YOU PROPOSING TO REMOVE THE 1.5 KW PER CUSTOMER DEMAND ADJUSTMENT FROM THE ZERO INTERCEPT STUDY?

A. The 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 is appropriate to remove the demand adjustment for allocating costs based on the Zero Intercept Study.

Q. HOW DO THE RESULTS OF THE ZERO INTERCEPT AND MINIMUM SYSTEM APPROACHES COMPARE?

A. For each property unit, the table below shows the percent of costs that would be classified as customer-related using the Zero Intercept method compared to the Minimum System method. As shown in Table 8 below, for five of the six property units the Zero Intercept provides a lower customer component.

Table 8
Percent of Distribution Investment Classified as Customer Related
Zero Intercept Method vs. Minimum System Method

Property Unit	Percent of Costs Classified as Customer-Related	
	Zero Intercept Method	Minimum System Method
Overhead Primary	24.0%	63.2%
Overhead Secondary	79.9%	96.0%
Overhead Transformers	69.1%	78.0%
Underground Primary	34.7%	63.8%
Underground Secondary	58.6%	100%
Underground Transformers	70.2%	66.7%

Q. WHICH RESULTS WERE USED IN THE COMPANY'S PROPOSED CCOSS?

A. For a given property unit a "hybrid" of the two methods was used, in that the Company used the method that provided the lower customer component as shown in Table 9 below.

Table 9
Customer versus Capacity Classification
Applied to Distribution Plant Investment

Property Unit	% Classified as Customer-Related	% Classified as Capacity-Related
Overhead Primary (used Zero Intercept result)	24.0%	76.0%
Overhead Secondary (used Zero Intercept result)	79.9%	20.1%
Underground Primary (used Zero Intercept result)	34.7%	65.3%
Underground Secondary (used Zero Intercept result)	58.6%	41.4%
Weighted Average for Overhead and Underground Transformers*	68.1%	31.9%

* used Zero Intercept for OH Transformers; used Minimum System for UG Transformers

Q. HOW ARE THE RESULTS USED TO SEPARATE DISTRIBUTION PLANT INVESTMENT INTO SUB-FUNCTION AND COST CLASSIFICATION?

A. Attachment O shows how the results of the Minimum System and Zero Intercept analyses are used to provide the needed cost separation. The results as shown in column 7 are the inputs to the CCOSS model for the 2025 test year as shown in Schedule 4, page 4, column 1, lines 19 – 42.

Q. WHY IS IT REASONABLE TO CLASSIFY THE CUSTOMER/CAPACITY COMPONENT OF DISTRIBUTION COSTS BASED ON A HYBRID OF APPROACHES?

A. As stated earlier, the purpose of the study is to establish the cost of a minimally sized distribution property unit, and then classify that minimum cost as customer related. Evaluating the two separate studies and selecting the result which provided the lowest minimum cost provides a reasonable way to ensure we are not overstating the customer classification.

4. *Classification and Allocation of Other Production O&M Costs*

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

A. Yes. 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 $0.337 million and make up only 1.1

percent of total Other Production O&M costs. The remaining $31.6 million of Other Production O&M does not vary directly with energy output.

Q. HOW DOES THE COMPANY CLASSIFY OTHER PRODUCTION O&M COSTS THAT VARY DIRECTLY WITH ENERGY?

A. The Company has classified the Other Production O&M costs that vary directly with energy usage as energy-related. This is consistent with the Company's approach in the last rate case.

Q. HOW DOES THE COMPANY CLASSIFY THE REMAINING OTHER PRODUCTION O&M COSTS?

A. Consistent with the Company's approach in the last rate case, Other Production O&M costs that originate from a specific generator are classified as capacity or energy related based on the Production plant investment (excluding nuclear fuel) split from the Company's plant stratification analysis, as shown on Lines 3 and 4 on page 4 of Schedule 4. For those production expenses that do not apply to a particular generation type, the Company applies the weighted average Capacity versus Energy percentage splits. I note that there are $0.827 million in costs that are not specific to a generator type and $0.686 million of Regional Markets expenses that are split into demand and energy components based on the total plant-specific expense split. Table 10 below shows the resulting classification of Other Production O&M expenses. As shown below, 78.58 percent of costs are classified as energy-related while 21.42 percent of costs are classified as capacity-related.

Table 10
Classification of Other Production O&M Costs
State of North Dakota Electric Jurisdiction

Plant Type or Expense Type	2025 Other Prod O&M	Percent Energy	Percent Capacity	Energy-Related	Capacity-Related
Variable (Chemicals & Water Use)	$337,412	100.00%	0.00%	$337,412	$0.0
Fossil	$2,415,208	65.08%	34.92%	$1,571,832	$843,376
Combustion Turbine	$145,856	0.00%	100.00%	$0.0	$145,856
Nuclear	$20,716,143	79.71%	20.29%	$16,513,452	$4,202,691
Combined Cycle	$900,010	34.15%	65.85%	$307,322	$592,688
Hydro	$53,719	81.35%	18.65%	$43,700	$10,019
Wind	$5,901,981	87.61%	12.39%	$5,170,869	$731,112
Total Generation-Related Other Production O&M	$30,470,329	**78.58%**	**21.42%**	$23,944,586	$6,525,742
Corporate Other Production O&M not Assigned to Generation Type	$826,615	**78.58%**	**21.42%**	$649,582	$177,034
Regional Market Expense (FERC Codes 575.1 – 575.8)	$686,199	**78.58%**	**21.42%**	$539,238	$146,961
Total Other Production O&M	$31,983,143	**78.58%**	**21.42%**	$25,133,406	$6,849,737

III. TARIFF CHANGES: SECTION NO. 6 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 where the Company is proposing revisions:

- Excess Footage Charges Section 6.5.1.A.1
  (cost last updated in rate case 10/1/2021)
- Winter Construction Charges Section 6.5.1.A.2
  (cost last updated in rate case 10/1/2021)
- Dedicated Switching Section 6.5.1.8-7

(cost last updated in 2010 rate case)

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 tariff Sheet No. 6-23 of the General Rules and Regulations. Based on current material, labor, and equipment costs, the Company is proposing decreases in each, as shown in Table 11 below.

Table 11
Excess Footage Charges (Per Foot)

Type	Present	Proposed
Service Line	$12.50	$10.00
Single Phase Sec or Prim	$13.20	$10.50
Three Phase Sec or Prim	$20.80	$17.00

The cost analysis supporting these decreases in charges is provided on page 2 of Exhibit___(CJB-1), Schedule 7.

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 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 12 below.

Table 12
Winter Construction Charges

Type	Present	Proposed
Thawing (Per Frost Burner)	$685.00	$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 Exhibit___(CJB-1), Schedule 7.

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 Exhibit___(CJB-1), Schedule 7.

D. Revenue Impact of the Proposed Excess Footage, Winter Construction, and Dedicated Switching Rate Changes

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 increases in these rates is $15,043 as shown on page 1 of Exhibit___(CJB-1), Schedule 7. This increase in revenues is shown with the increase in late payment charges on lines 2 and 12 of Schedule 3 to my testimony. It is also shown on page 7, row 21 of Schedule 4 to my testimony. The proposed increase in these charges reduces the increase in retail revenues proposed by Company witness Paluck.

IV. CONCLUSION

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

A. Yes.

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. <u>Functionalization</u> – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution and customer).
2. <u>Classification</u> – 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. <u>Allocation</u> – 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 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 percents 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 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		
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 (MDS) 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 system method. The 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 zero-intercept method compared to the minimum system method. As shown below, for 5 of the 6 property units the zero intercept provides a lower customer component, while 1 of the 6 have a lower customer component using the minimum system method.

	% of Costs Classified as "Customer" Related	
Equipment Type	**Zero Intercept Method**	**Minimum System Method**
Overhead Lines Primary	24.01%	63.15%
Overhead Lines Secondary	79.89%	95.97%
Overhead Transformers	69.09%	77.97%
Underground Lines Primary	34.68%	63.81%
Underground Lines Secondary	58.55%	100%
Underground Transformers	70.18%	66.72%

In applying the zero intercept and minimum system results 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)	24.01%	75.99%
Overhead Lines Secondary (used Zero Intercept Result)	79.89%	20.11%
Underground Lines Primary (used Zero Intercept Result)	34.68%	65.32%
Underground Lines Secondary (used Zero Intercept Result)	58.55%	41.45%
Weighted Average for Overhead & Underground Transformers (used Zero Intercept for OH Transformers; used Minimum System for UG Transformers)	68.05%	31.95%

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 2 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
  - 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 3 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
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy in the hour it's used
      - Customer-related allocators
        - Number of customers
        - 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
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 Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-49
	3	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-52
Rate Base Detail	4	Original Plant in Service	1-52
	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	31-36
		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	D01, D02, D03, D04, D05 (if residential), D10 (if residential)			• 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	D05 (if C&I), D10 (if C&I), D12, D14, D15, D18, D19, D34, D40, D42	< 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	D16, D17, D20, D21, D22, D41	> 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	D16, D17, D20, D21, D22, D41	> 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	D16, D17, D20, D21, D22, D41	> 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	D16, D17, D20, D21, D22, D41	> 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	D11, D30, D31, D32, D33			• 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.

The table below lists and describes the external allocators used in the Class Cost of Service (CCOSS) model.

Code	Allocator for:	Description	Allocator Rationale & Background
C11	Connection charge revenues	Average monthly customers for the Test Year	Customer connection revenues are driven by number of customer services.
C10	Used to calculate C11	C11 less automatic protective lighting and load management services. C11 less number of customers with a second service.	
C11WAF	Used to calculate C11WA allocator	Customer accounting cost weighting factors. The weighting factor for residential customers is set at 1.0. The weighting factors for other classes are defined relative to costs for residential. E.g., if a class were three times costlier, its factor would be 3.0.	Weighting factors are set so as to reflect the relative costs of meter reading, billing and providing customer service for different classes of customers. For example some rate schedules are significantly more complex requiring more sophisticated meter reading capabilities, billing systems and customer service staff.
C11WA	Customer accounting costs	Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF	Customer accounting costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.
C12	Used to calculate C12WM allocator	Reflects actual number of meters. C11 with an adjusted street lighting customer count. Only selected street lighting rates are metered	
C12WMF	Used to calculate C12WM allocator	Average meter cost for each customer type	
C12WM	Meter costs	Number of meters multiplied by each class' average meter costs: C12 X C12WMF	Metering costs are driven by the number of customers in each class and the respective metering costs.
C61PS	The "customer" (minimum system) portion of primary distribution line costs	Average monthly customers served at primary or secondary voltage. C11 less transmission transformed and transmission voltage customers	The number of customers served at secondary and primary voltages drives the customer related portion of primary distribution line costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system.

Code	Allocator for:	Derivation	Allocator Rationale & Background
C62Sec	The "customer" (minimum system) portion of secondary (not primary) distribution line costs	Average monthly customers served at secondary voltage. C61PS less primary voltage customers	The number of customers served at secondary voltage drives the customer related portion of secondary distribution line costs. Transmission and primary voltage customers are excluded since they do not use the secondary distribution system.
C62NL	The "customer" (minimum system) portion of service-line costs.	Adjusted average monthly secondary voltage customers. C62Sec less street lighting and C&I underground customers	The number of secondary customers drives the customer portion of service line costs. C&I underground secondary customers are excluded since they own their services. Lighting customers are excluded since they do not have services.
D60Sub	Distribution substation costs	Class Coincident peak measured at the high voltage side of the Distribution Substation less Class Coincident peak of Transmission Voltage customers	Distribution substation costs are driven by class peak demands, whenever they occur which is generally at times other than the total system peak. Transmission voltage customers are excluded since they do not use the distribution substation.
D61PS	The capacity portion of primary distribution line costs.	D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect the fact that their summer peak is less than their winter peak.	The driver of primary distribution line costs is the class coincident demands less the minimum system demand of each class. The minimum demand is classified as a customer related cost. Also, transmission and transmission transformed voltage customers are excluded since they do not use the distribution system.
D62Sec	Used to calculate the D62SecL allocator	D61PS less class coincident demands of primary voltage customers	
D62SecL	The capacity portion of secondary distribution line costs	D62SecL equals the average of D62Sec percent and non-coincident (or "individual customer peak") secondary voltage percent.	Capacity related secondary distribution line costs are driven by both class coincident peak demand and individual customer maximum demand, less the minimum system demand of each class. (The minimum system demand is classified as customer related.) Also, transmission and primary voltage customers are excluded since they do not use the secondary distribution system.

Code	Allocator For:	Derivation	Allocator Rationale
D62NLL	The capacity portion of service-line costs	Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground	Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service-related costs. Also excluded are C&I underground customers since they install their own services.
D10S	Summer season portion of capacity-related generation costs	Each class' % contribution to the single summer system peak. Summer months are June through September.	The class contribution to the system summer peak drives the summer portion of capacity-related generation costs.
D10W	Winter season portion of capacity-related generation costs	Each class' % contribution to the single winter system peak. Winter months are October through May.	The class contribution to the system winter peak drives the winter portion of capacity-related generation costs.
D10T	Transmission plant costs.	Weighted Class Contributions to Summer and Winter Peak loads. Allocator equals (D10W% plus (D10S% times 1.3952)) divided by (1 + 1.3952). The 1.3952 ratio is the ratio of the average summer and winter seasonal system peaks.	The driver for transmission costs is class contribution to the summer & winter system peaks. To reflect the fact that summer peaks have more impact, the summer peak contribution for each class is weighted by the ratio of average monthly summer and average monthly winter system peaks.
D10C	Capacity-related generation costs.	Weighted of Class Contributions to Summer and Winter system peak loads. Allocator equals (D10W% plus (D10S% times 3.2172) divided by (1 + 3.2172). The 3.2172 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.	Capacity- related generation costs are driven by class contribution to summer & winter system peaks. To reflect the fact that summer peaks have a disproportionate impact on capacity-related generation costs, the summer peak is weighted by the ratio of average monthly summer and winter system peaks, which are in excess of average annual demand.

Code	Allocator For:	Derivation	Allocator Rationale
E8760	Energy-related portion of generation, nuclear fuel capital and generation step-up costs. Also allocator for fuel, purchased energy and energy-related fixed generation costs.	Class hourly energy (MWH) requirements multiplied by the corresponding hourly marginal energy cost.	The driver of these costs is energy requirements, which is measured by hourly energy requirements weighted by hourly marginal energy costs.

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.

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 47 less A&G Labor on Page 12 line 45. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance	Electric plant in service less accumulated provision for depreciation	Property insurance is 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.
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.

Code	Allocator for:	Description	Allocator Justification
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.
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 Wisc. 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 40 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.

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 48 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 and economic development expenses	Present revenues for the test year	Economic Development expenses are used to retain or enhance the Company's revenues.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 37 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 D10C 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. (Line 42 on page 12, less lines 32 and 39)	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 Test Year. 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 forecast for the 2025 Test Year. 2. Hourly system marginal energy costs are based on the 2025 Test Year forecast 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 2023 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 2023 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 2025 actuals 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 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. In 2015 and 2021 the Company conducted a Minimum System study that was updated to 2025 using the Handy Whitman Indices. 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 Company 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.
Classification of Other Production O&M Costs	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 budget detail of Other Production O&M expenses and 2024 Plant Stratification Analysis.

Analysis	**Analysis Description**	**Data Sources and Associated Vintage**
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 only.	• TY2025 plant investment in FERC code 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 distribution system.	2024 listing from the GIS system of all customer premises in MN and whether they receive service off the 3 phase or 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 MNCO and whether they are served from an overhead or underground transformer.

Summary of 2025 Proposed Class Cost of Service Study ($000)

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	274,817	118,528	13,763	140,091	2,434
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	114	96	6	12	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	274,931	118,625	13,769	140,103	2,434
[4]	Present Rates (CCOSS page 2, line 2)	230,375	92,694	12,098	123,554	2,028
[5]	Unadjusted Deficiency (line 3 - line 4)	44,556	25,930	1,671	16,549	406
[6]	Defic / Pres (line 5 / line 4)	19.3%	28.0%	13.8%	13.4%	20.0%
[7]	**Ratio: Class % / Total %**	**1.00**	**1.45**	**0.71**	**0.69**	**1.04**

COST RESPONSIBILITIES FOR RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruptible Rate Discounts (CCOSS page 2, line 5)	2,912	65	26	2,821	0
[9]	Interruptible Rate Disc Cost Allocation (CCOSS page 2, line 7)	2,912	1,140	122	1,642	8
[10]	Revenue Requirement Change (lines 10 & 11 - lines 8 & 9)	0	1,075	96	(1,180)	8

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	274,817	119,604	13,859	138,912	2,442
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	114	96	6	12	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	274,931	119,700	13,865	138,924	2,442
[14]	Present Rates (line 4)	230,375	92,694	12,098	123,554	2,028
[15]	Adjusted Deficiency (line 13 - line 14)	44,556	27,005	1,767	15,369	414
[16]	Defic / Pres Rates (line 15 / line 14)	19.3%	29.1%	14.6%	12.4%	20.4%
[17]	**Ratio: Class % / Total %**	**1.00**	**1.51**	**0.76**	**0.64**	**1.06**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[18]	Proposed Rates (CCOSS page 3, line 3)	274,817	115,090	14,145	143,150	2,431
[19]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	114	96	6	12	0
[20]	Proposed Operating Revenues (line 18 + line 19)	274,931	115,186	14,151	143,163	2,431
[21]	Proposed Increase (line 20 - line 14)	44,556	22,492	2,053	19,608	403
[22]	Difference / Pres (line 21 / line 14)	19.3%	24.3%	17.0%	15.9%	19.9%
[23]	**Ratio: Class % / Total %**	**1.00**	**1.25**	**0.88**	**0.82**	**1.03**

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

Rate Base

	Plant In Service	Alloc	1=2+3+6 ND	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
1	Production		983,646	371,727	606,697	45,022	561,675	5,223
2	Transmission		287,276	116,773	169,048	13,118	155,930	1,455
3	Distribution		309,517	195,226	105,428	18,589	86,839	8,864
4	General		198,129	85,714	110,467	9,619	100,848	1,948
5	Common		0	0	0	0	0	0
6	Total Plant In Service		1,778,568	769,440	991,639	86,348	905,291	17,489
7	Production		546,266	206,064	337,234	25,108	312,126	2,968
8	Transmission		73,738	29,992	43,374	3,365	40,009	372
9	Distribution		97,318	63,958	30,142	5,678	24,464	3,218
10	General		92,913	40,196	51,804	4,511	47,293	914
11	Common		0	0	0	0	0	0
12	Total Depreciation Reserve		810,236	340,210	462,554	38,662	423,893	7,471
13	**Net Plant In Service**		968,333	429,231	529,084	47,687	481,398	10,018
14	Deducts: Accum Defer Inc Tax		150,287	62,521	86,468	7,101	79,367	1,298
15	Constr Work In Progress		4,722	1,964	2,726	219	2,507	32
16	Fuel Inventory		6,413	2,395	3,979	302	3,677	39
17	Materials & Supplies		13,075	5,291	7,685	616	7,069	98
18	Prepayments		(27,605)	(12,237)	(15,083)	(1,359)	(13,724)	(286)
19	Non-Plant & Work Cash		2,326	990	1,332	138	1,193	5
20	Total Additions		(1,069)	(1,597)	638	(84)	723	(111)
21	**Rate Base**		816,976	365,113	443,254	40,501	402,753	8,609

Income Statement

		ND	Res	C&I Tot	Sm Non-D	Demand	St Ltg
22A	**Tot Oper Rev - Pres**	292,912	116,861	173,667	14,991	158,676	2,385
22B	**Tot Oper Rev - Prop**	337,468	139,353	195,328	17,044	178,284	2,788
23	Oper & Maint	194,731	80,274	113,089	9,701	103,388	1,368
24	Book Depr + IRS Int	75,002	32,160	42,135	3,598	38,537	708
25	Payroll, RI Est & Prop Tax	13,200	5,911	7,150	655	6,495	140
26	Deferred Inc Tax & Net ITC	(11,319)	(4,930)	(6,251)	(545)	(5,707)	(138)
27A	Present Income Tax	(6,783)	(4,553)	(2,193)	(217)	(1,976)	(36)
27B	Proposed Income Tax	4,091	936	3,093	284	2,810	62
28	Allow Funds Dur Const	0	0	0	0	0	0
29A	**Present Return**	28,081	8,000	19,737	1,799	17,938	344
29B	**Proposed Return**	61,763	25,003	36,112	3,351	32,761	648
30A	**Pres Ret on Rt Base**	3.44%	2.19%	4.45%	4.44%	4.45%	3.99%
30B	**Prop Ret on Rt Base**	**7.56%**	6.85%	8.15%	8.27%	8.13%	7.53%
31A	**Pres Ret on Common**	2.45%	0.08%	4.39%	4.37%	4.39%	3.51%
31B	**Prop Ret on Common**	**10.30%**	8.95%	11.42%	11.66%	11.40%	10.25%

North Dakota 2025 Proposed CCOSS ($000)

PRES vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**UnAdj Equal Rev Reqt @ 7.56%**		**274,817**	**118,528**	**153,854**	**13,763**	**140,091**	**2,434**
2	**Present Revenue**		**230,375**	**92,694**	**135,652**	**12,098**	**123,554**	**2,028**
3	**UnAdj Revenue Deficiency**		**44,442**	**25,834**	**18,202**	**1,665**	**16,537**	**406**
4	**UnAdj Deficiency / Present**		**19.29%**	**27.87%**	**13.42%**	**13.76%**	**13.38%**	**20.02%**
5	**Pres Int Rate Discounts**		**2,912**	**64.774**	**2,847**	**26**	**2,821**	**0**
6	**Pres Int Rate Disc Cost Alloc**	**D10C**	**2,912**	**1,140**	**1,764**	**122**	**1,642**	**8**
7	**Revenue Requirement Shift**		**0**	**1,075**	**(1,083)**	**96**	**(1,180)**	**8**
8	**Adj Equal Rev Reqt (Rows 1+7)**		**274,817**	**119,604**	**152,771**	**13,859**	**138,912**	**2,442**
9	**Adj Rev Defic vs Pres Rev (Row 2)**		**44,442**	**26,909**	**17,118**	**1,761**	**15,357**	**414**
10	**Adj Deficiency / Adj Present**		**19.29%**	**29.03%**	**12.62%**	**14.56%**	**12.43%**	**20.43%**
	Equal Customer Classification							
11	Min Sys & Service Drop		19,211	15,695	2,525	1,531	994	990
12	Energy Services		7,349	5,974	1,356	820	537	19
13	Total Customer **(Cusco)**		26,560	21,669	3,881	2,351	1,531	1,009
14	Ave Monthly Customers		98,841	83,542	13,224	8,859	4,366	2,074
15	Svc Drop Reqt	$ / Mo / Cust	$16.20	$15.66	$15.91	$14.40	$18.98	$39.78
16	Ener Svcs Reqt	$ / Mo / Cust	$6.20	$5.96	$8.55	$7.71	$10.24	$0.76
17	Total Reqt	$ / Mo / Cust	$22.39	$21.62	$24.46	$22.11	$29.22	$40.54
	Equal Energy Classification							
18	On Peak Rev Reqt		52,818	19,513	33,171	2,674	30,497	135
19	Off Peak Rev Reqt		59,380	22,274	36,552	2,604	33,947	554
20	Total Ener Rev Reqt		112,198	41,787	69,722	5,278	64,444	689
21	Annual MWh Sales		2,131,650.436	776,035	1,339,754	98,552	1,241,203	15,861
22	On Pk Reqt	Mills / kWh	24.778	25.144	24.759	27.134	24.570	8.496
23	Off Pk Reqt	Mills / kWh	27.856	28.702	27.282	26.425	27.350	34.946
24	Total Reqt	Mills / kWh	52.634	53.846	52.041	53.558	51.921	43.442
	Equal Demand Classification							
25	Energy-Related Prod		39,861	14,902	24,723	1,863	22,860	237
26	Capacity-Related Summer Peak Prod		31,282	12,217	18,975	1,313	17,663	90
27	Capacity-Related Winter Peak Prod		9,723	3,797	5,898	408	5,490	28
28	Total Capacity-Related Prod		41,005	16,014	24,873	1,721	23,152	118
29	Total Production		80,866	30,915	49,596	3,584	46,012	355
30	Transmission **(Transco)**		33,705	13,725	19,809	1,538	18,271	170
31	Primary Dist Subs		5,510	2,153	3,299	251	3,048	57
32	Prim Dist Lines		12,992	6,637	6,221	611	5,610	135
33	Second Dist, Trans		2,986	1,642	1,325	149	1,176	20
34	Total Distribution **(Disco)**		21,488	10,432	10,846	1,012	9,834	211
35	Total Demand Rev Reqt		136,059	55,073	80,250	6,134	74,116	736
36	Annual Billing kW		3,197,012	0	3,197,012	0	3,197,012	0
37	Base Rev Reqt	$ / kW	$0.00	$0.00	$7.73	$0.00	$7.15	$0.00
38	Summer Rev Reqt	$ / kW	$0.00	$0.00	$5.94	$0.00	$5.52	$0.00
39	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.84	$0.00	$1.72	$0.00
40	Prod Rev Reqt	$ / kW	$0.00	$0.00	$15.51	$0.00	$14.39	$0.00
41	Tran Rev Reqt	$ / kW	$0.00	$0.00	$6.20	$0.00	$5.71	$0.00
42	Dist Rev Reqt	$ / kW	$0.00	$0.00	$3.39	$0.00	$3.08	$0.00
43	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$25.10	$0.00	$23.18	$0.00
44	Tot Dmd Rev Reqt	Mills / kWh	63.828	70.967	59.899	62.242	59.713	46.408
45	Summer Billing kW		1,148,948	0	1,148,948	0	1,148,948	0
46	Winter Billing kW		2,048,064	0	2,048,064	0	2,048,064	0
47	Tot Summer Reqt	$ / kW	$0.00	$0.00	$33.84	$0.00	$31.31	$0.00
48	Tot Winter Reqt	$ / kW	$0.00	$0.00	$20.20	$0.00	$18.62	$0.00
49	Energy + Production **(Genco)**		193,064	72,702	119,318	8,862	110,456	1,044

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

PROP vs Equal Rev Reqts

			1=2+3+6	2	3=4+5	4	5	6
	Total Retail Rev Reqt	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	**Proposed Ret On Rt Base**		**7.56%**	**6.85%**	**8.15%**	**8.27%**	**8.13%**	**7.53%**
2	**UnAdj Equalized Rev Reqt**		**274,817**	**118,528**	**153,854**	**13,763**	**140,091**	**2,434**
3	**Proposed Revenue**		**274,817**	**115,090**	**157,296**	**14,145**	**143,150**	**2,431**
4	**UnAdj Revenue Deficiency**		**0**	**3,439**	**(3,442)**	**(382)**	**(3,059)**	**3**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**2.99%**	**-2.19%**	**-2.70%**	**-2.14%**	**0.14%**
6	**Prop Interrupt Rate Discounts**		**3,175**	**63**	**3,112**	**50**	**3,061**	**0**
7	**Prop Int Rate Disc Cost Alloc**	**D10C**	**3,175**	**1,243**	**1,923**	**133**	**1,790**	**9**
8	**Revenue Requirement Shift**		**0**	**1,180**	**(1,189)**	**83**	**(1,272)**	**9**
9	**Adj Equal Rev (Rows 2+8)**		**274,817**	**119,708**	**152,665**	**13,846**	**138,819**	**2,443**
10	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**4,618**	**(4,630)**	**(299)**	**(4,331)**	**12**
11	**Adj Deficiency / Adj Prop**		**0.00%**	**4.01%**	**-2.94%**	**-2.12%**	**-3.03%**	**0.51%**
	Prop Customer Component							
12	Min Sys & Service Drop		18,679	15,018	2,673	1,597	1,075	988
13	Energy Services		7,348	5,972	1,357	820	537	19
14	Total Customer **(Cusco)**		26,027	20,990	4,030	2,417	1,612	1,007
15	Ave Monthly Customers		98,841	83,542	13,224	8,859	4,366	2,074
16	Svc Drop Reqt	$ / Mo / Cust	$15.75	$14.98	$16.84	$15.03	$20.53	$39.71
17	Ener Svcs Reqt	$ / Mo / Cust	$6.19	$5.96	$8.55	$7.71	$10.25	$0.76
18	Total Reqt	$ / Mo / Cust	$21.94	$20.94	$25.39	$22.74	$30.78	$40.47
	Prop Energy Component							
19	On Peak Rev Reqt		52,831	19,498	33,198	2,676	30,522	135
20	Off Peak Rev Reqt		59,391	22,256	36,581	2,606	33,975	554
21	Total Ener Rev Reqt		112,222	41,754	69,779	5,282	64,497	689
22	Annual MWh Sales		2,131,650	776,035	1,339,754	98,552	1,241,203	15,861
23	On Pk Reqt	Mills / kWh	24.784	25.125	24.779	27.155	24.591	8.496
24	Off Pk Reqt	Mills / kWh	27.862	28.679	27.304	26.445	27.372	34.945
25	Total Reqt	Mills / kWh	52.646	53.804	52.084	53.600	51.963	43.441
	Prop Demand Component							
26	Energy-Related Prod		40,650	13,851	26,563	1,996	24,567	236
27	Capacity-Related Summer Peak Prod		31,207	11,853	19,264	1,352	17,913	90
28	Capacity-Related Winter Peak Prod		9,700	3,684	5,988	420	5,568	28
29	Total Capacity-Related Prod		40,907	15,537	25,252	1,772	23,480	118
30	Total Production		81,557	29,388	51,815	3,768	48,047	354
31	Transmission **(Transco)**		33,672	13,061	20,441	1,613	18,828	170
32	Primary Dist Subs		5,465	2,016	3,392	267	3,125	57
33	Prim Dist Lines		12,806	6,326	6,346	640	5,706	134
34	Second Dist, Trans		3,068	1,556	1,493	158	1,336	20
35	Total Distribution **(Disco)**		21,339	9,897	11,231	1,065	10,166	210
36	Total Demand Rev Reqt		136,567	52,346	83,487	6,446	77,041	734
37	Annual Billing kW		3,197,012	0	3,197,012	0	3,197,012	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$7.68	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.60	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.74	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$15.03	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$5.89	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.18	$0.00
44	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$24.10	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	64.066	67.453	62.315	65.404	62.070	46.306
46	Summer Billing kW		1,148,948	0	1,148,948	0	1,148,948	0
47	Winter Billing kW		2,048,064	0	2,048,064	0	2,048,064	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$34.98	$0.00	$32.34	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$21.14	$0.00	$19.47	$0.00
50	Energy + Production **(Genco)**		193,779	71,142	121,594	9,050	112,544	1,043
51	Prop Rev - Pres Rev (Pg 2)		44,442	22,396	21,643	2,047	19,596	403
52	Difference / Present		19.29%	24.16%	15.96%	16.92%	15.86%	19.86%

North Dakota 2025 Proposed CCOSS ($000)

Original Plant in Service

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Summer Peak	D10C		186,374	72,953	112,886	7,822	105,065	534
2	Winter Peak	D10C		57,930	22,676	35,088	2,431	32,657	166
3	Total Peak	D10C		244,304	95,629	147,974	10,253	137,722	700
4	Base Load	E8760		532,713	198,935	330,519	25,052	305,467	3,259
5	Nuclear Fuel	E8760		206,630	77,163	128,203	9,717	118,486	1,264
6	Total	31.44%	120, 310-346	983,646	371,727	606,697	45,022	561,675	5,223
	Transmission								
7	Gen Step Up Base	E8760		11,133	4,158	6,908	524	6,384	68
8	Gen Step Up Peak	D10C		2,983	1,168	1,807	125	1,681	9
9	Total Gen Step Up			14,116	5,325	8,714	649	8,065	77
10	Bulk Transmission	D10T		273,160	111,448	160,334	12,470	147,864	1,378
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		0	0	0	0	0	0
13	Total		350-359	287,276	116,773	169,048	13,118	155,930	1,455
	Distribution:								
	Substations								
14	Generat Step Up	STRATH		214	81	132	10	123	1
15	Bulk Transmission	D10T		0	0	0	0	0	0
16	Distrib Function	D60Sub		50,857	19,909	30,424	2,321	28,103	523
17	Direct Assign	Dir Assign		0.000	0	0	0	0	0
18	Total		360-363	51,071	19,990	30,557	2,331	28,226	524
	Overhead Lines								
19	Primary Capacity 1 Phase	D61PS1Ph		11,213	8,319	2,778	558	2,220	117
20	Primary Capacity Multi Phase	D61PS		24,619	9,638	14,728	1,124	13,604	253
21	Primary Customer 1 Phase	C61PS1Ph		3,544	3,224	227	196	31	93
22	Primary Customer Multi Phase	C61PS		7,781	6,699	1,059	707	352	23
23	Total Primary			47,157	27,879	18,791	2,584	16,208	486
24	Second Capacity	D62SecL		3,821	1,970	1,822	202	1,620	29
25	Second Customer	C62Sec		15,181	13,076	2,061	1,380	681	44
26	Total Secondary			19,003	15,046	3,883	1,582	2,301	73
27	Street Lighting	DASL		2,543	0	0	0	0	2,543
28	Total		364,365	68,702	42,926	22,674	4,165	18,509	3,102
	Underground Lines								
29	Primary Capacity 1 Phase	D61PS1Ph		22,960	17,033	5,688	1,142	4,546	239
30	Primary Capacity Multi Phase	D61PS		33,138	12,973	19,824	1,512	18,312	341
31	Primary Customer 1 Phase	C61PS1Ph		12,188	11,087	781	673	108	320
32	Primary Customer Multi Phase	C61PS		17,591	15,146	2,393	1,598	795	51
33	Total Primary			85,877	56,239	28,686	4,925	23,761	952
34	Second Capacity	D62SecL		9,500	4,898	4,530	503	4,027	72
35	Second Customer	C62Sec		13,417	11,556	1,821	1,219	602	39
36	Total Secondary			22,917	16,454	6,351	1,722	4,629	111
37	Street Lighting	DASL		0	0	0	0	0	0
38	Total		366,367	108,793	72,693	35,037	6,647	28,390	1,063
	Line Transformers								
39	Primary	D61PS		6,604	2,585	3,951	301	3,649	68
40	Second Capacity	D62SecL		9,774	5,040	4,661	518	4,143	74
41	Second Customer	C62Sec		20,821	17,934	2,826	1,892	934	61
42	Total		368	37,199	25,559	11,438	2,711	8,727	203
	Services								
43	Second Capacity	D62NLL		3,249	2,521	728	100	628	0
44	Second Customer	C62NL		17,038	15,956	1,082	724	358	0
45	Total Services	C62NL	369	20,287	18,477	1,810	824	985	0
46	Meters	C12WM	370	19,520	15,581	3,912	1,911	2,001	27
47	Street Lighting	Dir Assign	373	3,944	0	0	0	0	3,944
48	**Total Distribution**			309,517	195,226	105,428	18,589	86,839	8,864
49	**General & Common Plant**	PTD	303, 389-399	198,129	85,714	110,467	9,619	100,848	1,948
50	Prelim Elec Plant			1,778,568	769,440	991,639	86,348	905,291	17,489
51	TBT Investment	NEPIS		0	0	0	0	0	0
52	**Elec Plant in Serv**			1,778,568	769,440	991,639	86,348	905,291	17,489

North Dakota 2025 Proposed CCOSS ($000)

Accum Deprec; Net Plant

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10C		114,879	44,968	69,582	4,821	64,761	329
2	Decom Int Peaking	D10C		0	0	0	0	0	0
3	Decom Int Baseload	E8760		0	0	0	0	0	0
4	Nuclear Fuel	E8760		193,544	72,276	120,083	9,102	110,982	1,184
5	Base Load	E8760		237,843	88,819	147,569	11,185	136,384	1,455
6	Total		108,111,115,120.5	546,266	206,064	337,234	25,108	312,126	2,968
	Transmission								
7	Gen Step Up Base	E8760		2,141	799	1,328	101	1,227	13
8	Gen Step Up Peak	D10C		1,139	446	690	48	642	3
9	Total Gen Step Up			3,280	1,245	2,018	148	1,870	16
10	Bulk Transmission	D10T		70,459	28,747	41,356	3,216	38,140	355
11	Distrib Function	D60Sub		0	0	0	0	0	0
12	Direct Assign	Dir Assign		0	0	0	0	0	0
13	Total		108,111,115,120.5	73,738	29,992	43,374	3,365	40,009	372
	Distribution								
14	Generat Step Up	STRATH		131	49	81	6	75	1
15	Bulk Transmission	D10T		0	0	0	0	0	0
16	Distrib Function	D60Sub		9,609	3,762	5,749	439	5,310	99
17	Direct Assign	Dir Assign		0	0	0	0	0	0
18	Total Substations			9,740	3,811	5,829	445	5,385	100
19	Overhead Lines	POL		25,339	15,832	8,363	1,536	6,827	1,144
20	Underground	PUL		33,742	22,545	10,867	2,061	8,805	330
21	Line Transformers	P68		10,471	7,194	3,220	763	2,456	57
22	Services	P69		12,877	11,728	1,149	523	626	0
23	Meters	C12WM		3,567	2,847	715	349	366	5
24	Street Lighting	P73		1,582	0	0	0	0	1,582
25	Total		108,111,115,120.5	97,318	63,958	30,142	5,678	24,464	3,218
26	**General & CommonPlant**	PTD	108,111,115,120.5	92,913	40,196	51,804	4,511	47,293	914
27	**Total Accum Depr**			810,236	340,210	462,554	38,662	423,893	7,471
28	**Net Elec Plant**			968,333	429,231	529,084	47,687	481,398	10,018
29	**Net Plant w/ TBT**			968,333	429,231	529,084	47,687	481,398	10,018

Subtractions: Accum Defer Inc Tax

	Production								
30	Peaking Plant	D10C		24,053	9,415	14,569	1,009	13,560	69
31	Base Load	E8760		76,296	28,492	47,338	3,588	43,750	467
32	Nuclear Fuel	E8760		(376)	(140)	(233)	(18)	(215)	(2)
33	Total		190,281,282,283	99,974	37,767	61,674	4,580	57,094	533
	Transmission								
34	Gen Step Up Base	D10C		1,279	500	774	54	721	4
35	Gen Step Up Peak	D10C		366	143	222	15	207	1
36	Total Gen Step Up			1,645	644	996	69	927	5
37	Bulk Transmission	D10T		50,929	20,779	29,893	2,325	27,568	257
38	Distrib Function	D60Sub		0	0	0	0	0	0
39	Direct Assign	Dir Assign		0	0	0	0	0	0
40	Total		281,282,283	52,574	21,423	30,889	2,394	28,495	262
	Distribution								
41	Generat Step Up	STRATH		16	6	10	1	9	0
42	Bulk Transmission	D10T		0	0	0	0	0	0
43	Distrib Function	D60Sub		7,865	3,079	4,705	359	4,346	81
44	Direct Assign	Dir Assign		0	0	0	0	0	0
45	Total Substations			7,881	3,085	4,715	360	4,355	81
46	Overhead Lines	POL		6,416	4,009	2,118	389	1,729	290
47	Underground	PUL		10,891	7,277	3,507	665	2,842	106
48	Line Transformers	P68		1,915	1,316	589	140	449	10
49	Services	P69		1,251	1,140	112	51	61	0
50	Meters	C12WM		1,034	825	207	101	106	1
51	Street Lighting	P73		356	0	0	0	0	356
52	Total		281,282,283	29,744	17,651	11,247	1,706	9,542	845
53	**General & Common Plant**	PTD	281,282,283	12,264	5,306	6,838	595	6,242	121
54	**Total Deferred Tax**			194,555	82,146	110,648	9,275	101,374	1,761
55	Net Operating Loss (NOL) Carry F	NEPIS		(46,317)	(20,531)	(25,307)	(2,281)	(23,026)	(479)
56	Non-Plant Related	LABOR		2,049	905	1,127	107	1,020	17
57	**Accum Def W/ Adj**			150,287	62,521	86,468	7,101	79,367	1,298

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

Additions: CWIP, Etc; Rate Base

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10C		1,600	626	969	67	902	5
2	Base Load	E8760		448	167	278	21	257	3
3	Nuclear Fuel	E8760		668	249	414	31	383	4
4	Total		107	2,715	1,043	1,661	120	1,541	11
	Transmission								
5	Gen Step Up Base	E8760		7	3	4	0	4	0
6	Gen Step Up Peak	D10C		39	15	23	2	22	0
7	Total Gen Step Up			46	18	28	2	26	0
8	Bulk Transmission	D10T		500	204	293	23	271	3
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		107	545	222	321	25	296	3
	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		26	10	16	1	15	0
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			26	10	16	1	15	0
17	Overhead Lines	POL		111	69	37	7	30	5
18	Underground	PUL		175	117	56	11	46	2
19	Line Transformers	P68		11	7	3	1	2	0
20	Services	P69		6	5	1	0	0	0
21	Meters	C12WM		1	1	0	0	0	0
22	Street Lighting	P73		0	0	0	0	0	0
23	Total		107	330	210	113	20	93	7
24	**General & Common Plant**	PTD	107	1,131	489	631	55	576	11
25	**Total CWIP**			4,722	1,964	2,726	219	2,507	32
26	Fuel Inventory	E8760	151,152	6,413	2,395	3,979	302	3,677	39
	Materials & Supplies								
27	Production	P10		10,659	4,028	6,575	488	6,087	57
28	Trans & Distr	TD		2,415	1,263	1,111	128	983	42
29	Total		154	13,075	5,291	7,685	616	7,069	98
	Prepayments								
30	Miscellaneous	NEPIS		(27,605)	(12,237)	(15,083)	(1,359)	(13,724)	(286)
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	(27,605)	(12,237)	(15,083)	(1,359)	(13,724)	(286)
34	Non-Plant Assets & Liab	LABOR	190,283,	7,655	3,382	4,210	400	3,810	63
35	Working Cash	PTO	calculated	(5,329)	(2,392)	(2,879)	(262)	(2,617)	(58)
36	**Total Additions**			(1,069)	(1,597)	638	(84)	723	(111)
37	**Total Rate Base**			816,976	365,113	443,254	40,501	402,753	8,609
38	**Common Rate Base (@ 52.50%)**			428,912.4	191,684	232,709	21,263	211,445	4,520

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

Line	Operating Rev (Cal Month)	Alloc	FERC Accounts	1=2+3+6 ND	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5 Demand	6 St Ltg
	Retail Revenue								
1	Present Rate Revenue	R01; (calc)	440, 442,444,445	230,375	92,694	135,652	12,098	123,554	2,028
	Expanded Rate Revenue			**274,817**	**110,576**	161,821	14,432	147,390	2,419
2	Proposed Rate Revenue	PROREV; (calc)		274,817	115,090	157,296	14,145	143,150	2,431
3	Equal Rate Revenue			274,817	118,528	153,854	13,763	140,091	2,434
	Other Retail Revenue								
4	Interdepartmental	R01; R02	448	0	0	0	0	0	0
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**			0	0	0	0	0	0
	Other Operating Revenue								
8	Interchg Prod Capacity	P10	456	32,378	12,236	19,970	1,482	18,488	172
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	358	224	118	22	96	16
13	Connection Charges	C11	451	0	0	0	0	0	0
14	Sales For Resale	E8760	447	19,347	7,225	12,004	910	11,094	118
15	Joint Op Agree-Other PSCo Rev	D10T	456	(109)	(44)	(64)	(5)	(59)	(1)
16	Misc Ancillary Trans Rev	D10T		17,477	7,131	10,258	798	9,460	88
17	MISO	D10T	456	(7,544)	(3,078)	(4,428)	(344)	(4,083)	(38)
18	Other	D10T	451,456,457	117	48	69	5	63	1
19	Late Pay Chg - Pres	R16C; R02		514	426	87	26	62	0
20	**Tot Other Op - Pres**		450	62,538	24,166	38,015	2,893	35,121	357
21	Incr Misc Serv - Prop	C62NL		15	14	1	1	0	0
22	Incr Inter-Dept'l - Prop	R01; R02		0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02		99	82	17	5	12	0
	Tot Incr Other Op			114	96	18	6	12	0
24	**Tot Other Op - Prop**			62,652	24,263	38,032	2,899	35,134	357
25	**Tot Oper Rev - Pres**			292,912	116,861	173,667	14,991	158,676	2,385
26	**Tot Oper Rev - Prop**			337,468	139,353	195,328	17,044	178,284	2,788
	Tot Oper Rev - Eql			337,468	142,791	191,886	16,662	175,225	2,791
	Operating & Maint (Pg 1 of 2)								
	Production Expen								
27	**Fuel**	E8760	501,518,547	44,934	16,780	27,879	2,113	25,766	275
	Purchased Power								
28	Purchases: Cap Peak	D10C		5,997	2,347	3,632	252	3,381	17
29	Purchases: Cap Base	D10C		2,231	873	1,351	94	1,258	6
30	Purchases: Demand		555	8,228	3,221	4,984	345	4,638	24
31	Purchases: Other Energy	E8760	555	38,378	14,332	23,812	1,805	22,007	235
32	Tot Non-Assoc Purch			46,607	17,553	28,796	2,150	26,645	258
33	Interchg Agr Capacity	P10WoN	557	3,366	1,276	2,073	153	1,920	17
34	Interchg Agr Energy	E8760	557	1,190	444	738	56	682	7
35	Tot Wis Interchg Purch			4,557	1,721	2,811	209	2,603	24
36	**Tot Purchased Power**			51,163	19,273	31,607	2,359	29,248	283
	Other Production		500,502,505-507 509-514,517-519,520, 523-525,528-532,535, 539,543-546,548-550 552-554,556,557 575.1-575.8						
37	Capacity Related	D10C		6,850	2,681	4,149	287	3,861	20
38	Energy Related	E8760		25,133	9,386	15,594	1,182	14,412	154
39	Total Other Produc	21.42%		31,983	12,067	19,743	1,469	18,273	173
40	**Total Production**			128,080	48,120	79,229	5,942	73,287	731
41	**Transmission Exp**	D10T	560-563, 565-568 570-573	19,511	7,960	11,452	891	10,561	98

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

Operating & Maint (Pg 2 of 2)

				1=2+3+6	2	3=4+5	4	5	6
	Distribution Expen	**Alloc**	**FERC Accounts**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	580,590	1,228	801	391	85	306	36
2	Load Dispatching	T20D80	581	28	11	17	1	16	0
3	Substations	P61	582,591,592	267	105	160	12	148	3
4	Overhead Lines	POL	583,593	3,043	1,901	1,004	184	820	137
5	Underground Lines	PUL	584, 594	1,093	730	352	67	285	11
6	Line Transformers	P68	595	0	0	0	0	0	0
7	Meters	C12WM	586,597,598	504	402	101	49	52	1
8	Customer Install'n	OXDTS	587	(55)	(35)	(18)	(4)	(15)	(2)
9	Street Lighting	Dir Assign	585,596	13	0	0	0	0	13
10	Miscellaneous	OXDTS	588	1,040	661	343	66	278	35
11	Rents (Pole Attachmts)	POL	589	231	145	76	14	62	10
12	**Total Distribution**			7,391	4,721	2,426	476	1,950	244
13	**Customer Accounting**	C11WA	901-905	5,367	4,360	996	601	395	11
14	**Sales, Econ Dvlp & Other**	R01	912	395	159	232	21	212	3
	Admin & General								
15	Salaries	LABOR	920	7,816	3,453	4,299	409	3,890	65
16	Office Supplies	OXTS	921	4,610	1,901	2,677	230	2,448	32
17	Admin Transfer Credit	OXTS	922	(5,859)	(2,415)	(3,402)	(292)	(3,110)	(41)
18	Outside Services	LABOR	923	1,866	824	1,027	98	929	15
19	Property Insurance	NEPIS	924	597	265	326	29	297	6
20	Pensions & Benefits	LABOR	926	4,776	2,110	2,627	250	2,377	39
21	Injuries & Claims	LABOR	925	1,907	843	1,049	100	949	16
22	Regulatory Exp	R01; R02	928	410	165	241	22	220	4
23	General Advertising	OXTS	930.1	58	24	34	3	31	0
24	Contributions	OXTS		0	0	0	0	0	0
25	Misc General Exp	OXTS	929, 930.2	231	95	134	12	123	2
26	Rents	OXTS	931	4,450	1,834	2,584	222	2,363	31
27	Maint of General Plant	OXTS	935	50	21	29	3	27	0
28	Total			20,914	9,119	11,625	1,083	10,542	170
	Cust Service & Info								
29	Cust Assist Exp - Non-CIP	C11P10	908	281	172	105	19	86	4
30	CIP Total	E99XCIP	908	0	0	0	0	0	0
31	Instructional Advertising	C11P10	909	71	43	26	5	22	1
32	Total			351.182	215	132	24	108	5
33	Amortizations	LABOR		12,722	5,620	6,997	665	6,332	105
34	**Total O&M Expense**			194,731	80,274	113,089	9,701	103,388	1,368

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

Book Depreciation

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10C		15,069	5,899	9,127	632	8,495	43
2	Base Load	E8760		30,520	11,397	18,936	1,435	17,501	187
3	Total		403,413	45,589	17,296	28,063	2,068	25,995	230
	Transmission								
4	Gen Step Up Base	E8760		176	66	109	8	101	1
5	Gen Step Up Peak	D10C		87	34	53	4	49	0
6	Total Gen Step Up			263	100	162	12	150	1
7	Bulk Transmission	D10T		5,513	2,249	3,236	252	2,984	28
8	Distrib Function	D60Sub		0	0	0	0	0	0
9	Direct Assign	Dir Assign		0	0	0	0	0	0
10	Total		403,413	5,776	2,349	3,398	264	3,134	29
	Distribution								
11	Generat Step Up	STRATH		6	2	3	0	3	0
12	Bulk Transmission	D10T		0	0	0	0	0	0
13	Distrib Function	D60Sub		1,170	458	700	53	646	12
14	Direct Assign	Dir Assign		0	0	0	0	0	0
15	Total Substations		403,413	1,175	460	703	54	650	12
16	Overhead Lines	POL		2,003	1,252	661	121	540	90
17	Underground	PUL		2,698	1,803	869	165	704	26
18	Line Transformers	P68		1,158	796	356	84	272	6
19	Services	P69		1,424	1,297	127	58	69	0
20	Meters	C12WM		1,141	911	229	112	117	2
21	Street Lighting	P73		176	0	0	0	0	176
22	Total		403,413	9,775	6,517	2,945	594	2,351	312
23	**General & Common Plant**	PTD	403,413	13,863	5,997	7,729	673	7,056	136
24	**Total Book Deprec**		403,404	75,002	32,160	42,135	3,598	38,537	708

Real Estate & Property Tax

				ND	Res	C&I Tot	Sm Non-D	Demand	St Ltg
	Production								
25	Peaking Plant	D10C		1,774	694	1,074	74	1,000	5
26	Base Load	E8760		3,868	1,444	2,400	182	2,218	24
27	Total		408.1	5,642	2,139	3,474	256	3,218	29
	Transmission								
28	Gen Step Up Base	E8760		109.2499	41	68	5	63	1
29	Gen Step Up Peak	D10C		29.2690	11	18	1	16	0
30	Total Gen Step Up			138.5189	52	86	6	79	1
31	Bulk Transmission	D10T		2,680.5305	1,094	1,573	122	1,451	14
32	Distrib Function	D60Sub		0	0	0	0	0	0
33	Direct Assign	Dir Assign		0	0	0	0	0	0
34	Total		408.1	2,819.049	1,146	1,659	129	1,530	14
	Distribution								
35	Generat Step Up	STRATH		2	1	1	0	1	0
36	Bulk Transmission	D10T		0	0	0	0	0	0
37	Distrib Function	D60Sub		463	181	277	21	256	5
38	Direct Assign	Dir Assign		0	0	0	0	0	0
39	Total Substations			465	182	278	21	257	5
40	Overhead Lines	POL		625	391	206	38	168	28
41	Underground	PUL		990	662	319	61	258	10
42	Line Transformers	P68		339	233	104	25	79	2
43	Services	P69		185	168	16	8	9	0
44	Meters	C12WM		178	142	36	17	18	0
45	Street Lighting	P73		36	0	0	0	0	36
46	Total		408.1	2,818	1,777	960	169	791	81
47	**General & Common Plant**	PTD	408.1	0	0	0	0	0	0
48	**Tot Rl Est & Pr Tax**			11,279	5,062	6,093	554	5,539	124
49	Gross Earnings Tax	R01; R02		0	0	0	0	0	0
50	Payroll Taxes	LABOR		1,922	849	1,057	100	957	16
51	**Tot Non-Inc Taxes**			13,200	5,911	7,150	655	6,495	140

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

Provision For Defer Inc Tax

				1=2+3+6	2	3=4+5	4	5	6
	Production	Alloc	FERC Accounts	ND	Res	C&I Tot	Sm Non-D	Demand	St Ltg
1	Peaking Plant	D10C		863	338	523	36	486	2
2	Nuclear Fuel	E8760		(5)	(2)	(3)	(0)	(3)	(0)
3	Base Load	E8760		(1,691)	(631)	(1,049)	(80)	(970)	(10)
4	Total		410, 411	(833)	(296)	(530)	(44)	(486)	(8)
	Transmission								
5	Gen Step Up Base	E8760		75	28	47	4	43	0
6	Gen Step Up Peak	D10C		20	8	12	1	11	0
7	Total Gen Step Up			95	36	59	4	54	1
8	Bulk Transmission	D10T		805	328	472	37	436	4
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		410, 411	900	364	531	41	490	5
	Distribution								
12	Generat Step Up	STRATH		(2)	(1)	(1)	(0)	(1)	(0)
13	Bulk Transmission	D10T		0	0	0	0	0	0
14	Distrib Function	D60Sub		107	42	64	5	59	1
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			105	41	63	5	58	1
17	Overhead Lines	POL		289	181	96	18	78	13
18	Underground	PUL		173	115	56	11	45	2
19	Line Transformers	P68		(111)	(77)	(34)	(8)	(26)	(1)
20	Services	P69		(66)	(60)	(6)	(3)	(3)	0
21	Meters	C12WM		403	322	81	39	41	1
22	Street Lighting	P73		(17)	0	0	0	0	(17)
23	Total		410, 411	776	523	254	62	193	(1)
24	**General & Common Plant**	PTD	410, 411	840	363	468	41	427	8
25	**Net Operating Loss (NOL) Carry**	NEPIS		(14,510)	(6,432)	(7,928)	(715)	(7,214)	(150)
26	**Non - Plant Related**	LABOR	410, 411	(228)	(101)	(125)	(12)	(113)	(2)
27	**Tot Prov For Defer**			(13,056)	(5,578)	(7,330)	(627)	(6,703)	(148)

Inv Tax Credit; Total Oper Exp

				ND	Res	C&I Tot	Sm Non-D	Demand	St Ltg
	Production								
28	Peaking Plant	D10C		(18)	(7)	(11)	(1)	(10)	(0)
29	Base Load	E8760		1,765	659	1,095	83	1,012	11
30	Total		411	1,748	652	1,085	82	1,002	11
	Transmission								
31	Gen Step Up Base	E8760		0	0	0	0	0	0
32	Gen Step Up Peak	D10C		0	0	0	0	0	0
33	Total Gen Step Up			0	0	0	0	0	0
34	Bulk Transmission	D10T		(10)	(4)	(6)	(0)	(6)	(0)
35	Distrib Function	D60Sub		0	0	0	0	0	0
36	Direct Assign	Dir Assign		0	0	0	0	0	0
37	Total		411	(10)	(4)	(6)	(0)	(6)	(0)
	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		0	0	0	0	0	0
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	0	0	0	0	0	0
50	**General & Common Plant**	PTD	411	(0)	(0)	(0)	(0)	(0)	(0)
51	**Net Inv Tax Credit**			1,737	648	1,078	82	996	11
52	**Total Operating Exp**			**271,614**	**113,414**	**156,123**	**13,409**	**142,714**	**2,077**
53A	**Pres Op Inc Before Inc Tax**			**21,298.243**	**3,447**	**17,544**	**1,582**	**15,962**	**307**
53B	**Prop Op Inc Before Inc Tax**			**65,854**	**25,939**	**39,205**	**3,635**	**35,570**	**710**

North Dakota 2025 Proposed CCOSS ($000)

Tax Deprec; Inc Tax & Return

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10C		20,625	8,074	12,493	866	11,627	59
2	Nuclear Fuel	E8760		6,928	2,587	4,298	326	3,973	42
3	Base Load	E8760		30,371	11,342	18,844	1,428	17,415	186
4	Total		tax books	57,925	22,002	35,635	2,620	33,015	287
	Transmission								
5	Gen Step Up Base	E8760		537	200	333	25	308	3
6	Gen Step Up Peak	D10C		135	53	82	6	76	0
7	Total Gen Step Up			671	253	415	31	384	4
8	Bulk Transmission	D10T		9,097	3,712	5,340	415	4,924	46
9	Distrib Function	D60Sub		0	0	0	0	0	0
10	Direct Assign	Dir Assign		0	0	0	0	0	0
11	Total		tax books	9,768	3,965	5,754	446	5,308	50
	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		1,643	643	983	75	908	17
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			1,643	643	983	75	908	17
17	Overhead Lines	POL		2,909	1,818	960	176	784	131
18	Underground	PUL		4,240	2,833	1,365	259	1,106	41
19	Line Transformers	P68		1,859	1,277	572	135	436	10
20	Services	P69		540	492	48	22	26	0
21	Meters	C12WM		2,462	1,966	493	241	252	3
22	Street Lighting	P73		130	0	0	0	0	130
23	Total		tax books	13,783	9,029	4,422	909	3,513	333
24	**General & Common Plant**	PTD	tax books	18,499	8,003	10,314	898	9,416	182
25	Net Operating Loss (NOL) Carry F	NEPIS		243	108	133	12	121	3
26	**Total Tax Deprec**			100,219	43,107	56,258	4,885	51,373	855
27	Interest Expense		427,431	17,564.98	7,850	9,530	871	8,659	185
28	Other Tax Timing Differ	LABOR		(1,939)	(856)	(1,066)	(101)	(965)	(16)
29	Meals & Enter	LABOR		110	49	61	6	55	1
30	Total Tax Deductions			115,955	50,149	64,782	5,660	59,122	1,025
	Inc Tax Additions								
31	Book Depreciation			75,002	32,160	42,135	3,598	38,537	708
32	Deferred Inc Tax & ITC			(11,319.42)	(4,930)	(6,251)	(545)	(5,707)	(138)
33	Nuclear Fuel Book Burn	E8760		7,526	2,811	4,670	354	4,316	46
34	Tax Capitalized Leases	PTD		3,763	1,628	2,098	183	1,915	37
35	Avoided Tax Interest	RTBASE		4,045	1,808	2,194	201	1,994	43
36	Total Tax Additions			79,017	33,475	44,846	3,790	41,055	696
37	**Total Inc Tax Adjustments**			(36,938)	(16,673)	(19,936)	(1,870)	(18,066)	(329)
38A	**Pres Taxable Net Income**			(15,640)	(13,226)	(2,392)	(288)	(2,104)	(21)
38B	**Prop Taxable Net Income**			28,916	9,266	19,269	1,765	17,504	381
39A	Pres Fed & State Inc Tax			(6,783)	(4,553)	(2,193)	(217)	(1,976)	(36)
39B	Prop Fed & State Inc Tax			4,091	936	3,093	284	2,810	62
40A	Pres Preliminary Return	(total); BASE		28,081	8,000	19,737	1,799	17,938	344
40B	Prop Preliminary Return	(total); BASE		61,763	25,003	36,112	3,351	32,761	648
39C	Eql Preliminary Return	RTBASE		61,763	27,603	33,510	3,062	30,448	651
41	Total AFUDC			0	0	0	0	0	0
42A	**Present Total Return**			28,081	8,000	19,737	1,799	17,938	344
42B	**Proposed Total Return**			61,763	25,003	36,112	3,351	32,761	648
43A	**Pres % Return on Rate Base**			3.44%	2.19%	4.45%	4.44%	4.45%	3.99%
43B	**Prop % Return on Rate Base**			7.56%	6.85%	8.15%	8.27%	8.13%	7.53%
44A	**Present Common Return**			10,516	151	10,207	928	9,279	159
44B	**Proposed Common Return**			44,198	17,153	26,582	2,480	24,102	463
45A	**Pres % Ret on Common Rt Base**			2.45%	0.08%	4.39%	4.37%	4.39%	3.51%
45B	**Prop % Ret on Common Rt Base**			10.30%	8.95%	11.42%	11.66%	11.40%	10.25%

North Dakota 2025 Proposed CCOSS ($000)

Allow For Funds Used During Constr

				1=2+3+6	2	3=4+5	4	5	6
	Production	**Alloc**	**FERC Accounts**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Peaking Plant	D10C		0	0	0	0	0	0
2	Nuclear Fuel	E8760		0	0	0	0	0	0
3	Base Load	E8760		0	0	0	0	0	0
4	Total		419.1,432	0	0	0	0	0	0
	Transmission								
5	Gen Step Up Base	E8760		0	0	0	0	0	0
6	Gen Step Up Peak	D10C		0	0	0	0	0	0
7	Total Gen Step Up			0	0	0	0	0	0
8	Bulk Transmission	D10T		0	0	0	0	0	0
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	0	0	0	0	0	0
	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		0	0	0	0	0	0
15	Direct Assign	Dir Assign		0	0	0	0	0	0
16	Total Substations			0	0	0	0	0	0
17	Overhead Lines	POL		0	0	0	0	0	0
18	Underground	PUL		0	0	0	0	0	0
19	Line Transformers	P68		0	0	0	0	0	0
20	Services	P69		0	0	0	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	0	0	0	0	0	0
24	**General & Common Plant**	PTD	419.1,432	0	0	0	0	0	0
25	**Total AFUDC**			0	0	0	0	0	0

Labor Allocator

	Production								
26	Other Prod - Cap	D10C		4,659	1,824	2,822	196	2,626	13
27	Other Prod - Ene	E8760		10,159	3,794	6,303	478	5,825	62
28	Total		500 through 557	14,818	5,617	9,125	673	8,452	75
	Transmission								
29	Stepup Subtrans	P5161A		59	22	36	3	34	0
30	Bulk Power Subs	D10T		1,142	466	670	52	618	6
31	Total		560 through 571	1,201	488	707	55	652	6
	Distribution								
32	Superv & Eng	ZDTS	580, 590	837	546	266	58	208	24
33	Load Dispatch	D10T	581	13	5	7	1	7	0
34	Substation	P61	582, 592	161	63	96	7	89	2
35	Overhead Lines	POL	583, 593	476	298	157	29	128	22
36	Underground Lines	PUL	584, 594	202	135	65	12	53	2
37	Line Transformer	P68	595	0	0	0	0	0	0
38	Meter	C12WM	586, 597	489	391	98	48	50	1
39	Cust Installation	ZDTS	587	30	19	9	2	7	1
40	Street Lighting	P73	585, 596	11	0	0	0	0	11
41	Miscellaneous	OXDTS	588	525	334	173	33	140	18
42	Total			2,744	1,791	873	190	683	80
43	**Cust Accounting**	C11WA	901,902,903,904,905	1,025	832	190	115	75	2
44	**Sales Expense**	C11P10	912	21	13	8	1	6	0
45	**Admin & General**	LABOR	920,921,922,923,924,	12,609	5,570	6,935	659	6,276	104
46	**Service & Inform**	C11P10	908, 909	49	30	18	3	15	1
47	**Labor**			32,466	14,341	17,856	1,697	16,159	268

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

			1=2+3+6	2	3=4+5	4	5	6
INTERNAL ALLOCATORS		Intern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.00%	61.16%	37.53%	6.77%	30.76%	1.31%
2	Peaking Plant Capacity	D10C	100.00%	39.14%	60.57%	4.20%	56.37%	0.29%
3	57% Dmd; 43% Energy; Sales & E	D57E43	100.00%	37.34%	62.04%	4.70%	57.34%	0.61%
4	40% Dmd; 60% Energy: CIP	D40E60	100.00%	37.34%	62.04%	4.70%	57.34%	0.61%
5	20%D10T; 80%D60Sub	T20D80	100.00%	38.71%	60.47%	4.39%	56.07%	0.82%
6	Labor w/o (or w/) A&G	LABOR	100.00%	44.17%	55.00%	5.23%	49.77%	0.83%
7	Net Plant In Service	NEPIS	100.00%	44.33%	54.64%	4.92%	49.71%	1.03%
8	Dis O&M w/o Sup & Misc	OXDTS	100.00%	63.59%	33.02%	6.33%	26.69%	3.39%
9	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	100.00%	41.22%	58.07%	4.98%	53.09%	0.70%
10	Production Plant	P10	100.00%	37.79%	61.68%	4.58%	57.10%	0.53%
11	Production Plant Wo Nuclear	P10WoN	100.00%	37.91%	61.58%	4.54%	57.04%	0.51%
12	Total P51 & P61A	P5161A	100.00%	37.72%	61.73%	4.60%	57.14%	0.54%
13	Distribution Plant	P60	100.00%	63.07%	34.06%	6.01%	28.06%	2.86%
14	Distr Substn Plant	P61	100.00%	39.14%	59.83%	4.56%	55.27%	1.03%
15	Line Transformer Plant	P68	100.00%	68.71%	30.75%	7.29%	23.46%	0.54%
16	Services Plant	P69	100.00%	91.08%	8.92%	4.06%	4.86%	0.00%
17	Dist Plt Overhead Lines	POL	100.00%	62.48%	33.00%	6.06%	26.94%	4.52%
18	Real Est & Property Tax	PT0	100.00%	44.88%	54.02%	4.91%	49.11%	1.10%
19	Produc, Trans & Distrib	PTD	100.00%	43.26%	55.75%	4.85%	50.90%	0.98%
20	Dist Plt Undground Lines	PUL	100.00%	66.82%	32.21%	6.11%	26.10%	0.98%
21	Rate Base (Non-Column)	RTBASE	100.00%	44.69%	54.26%	4.96%	49.30%	1.05%
22	Stratified Hydro Baseload	STRATH	100.00%	37.68%	61.77%	4.61%	57.16%	0.55%
23	Transmission & Distrib	TD	100.00%	52.28%	45.99%	5.31%	40.68%	1.73%
24	Labor Dis w/o Sup & Eng	ZDTS	100.00%	65.27%	31.83%	6.94%	24.88%	2.90%

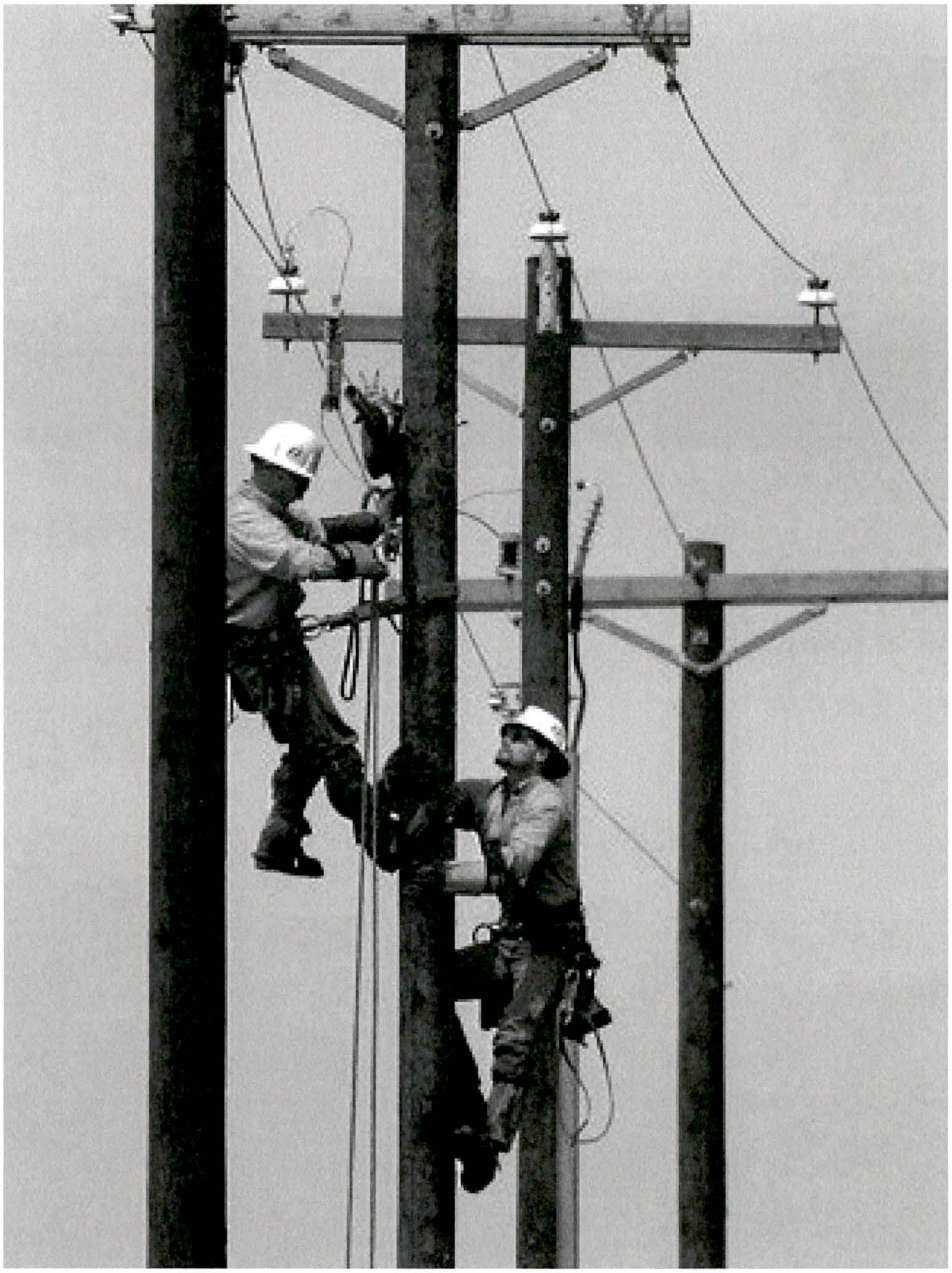
			1=2+3+6	2	3=4+5	4	5	6
INTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
25	Labor w/o A&G	LABOR(S)	19,856	8,771	10,921	1,038	9,883	164
26	Dis O&M w/o Sup, Cust Install & M	OXDTS	5,179	3,293	1,710	328	1,382	175
27	O&M w/o Reg Ex & OXTS-Alloc'd	OXTS	190,780	78,649	110,792	9,503	101,289	1,339
28	Total P51 & P61A	P5161A	14,330	5,406	8,847	659	8,188	78
29	Produc, Trans & Distrib	PTD	1,580,439	683,726	881,172	76,729	804,443	15,541
30	Transmission & Distrib	TD	596,793	311,999	274,476	31,707	242,768	10,318
31	Labor Dis w/o Sup & Eng, Cust In	ZDTS	1,877	1,225	597	130	467	55

Northern States Power Company
North Dakota 2025 Proposed CCOSS ($000)

			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL ALLOCATORS		Extern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	84.52%	13.38%	8.96%	4.42%	2.10%
2	Cust Acctg Wtg Factor	C11WA	100.00%	81.24%	18.56%	11.20%	7.36%	0.20%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	79.82%	20.04%	9.79%	10.25%	0.14%
4	Sec & Pri Customers	C61PS	100.00%	86.10%	13.60%	9.08%	4.52%	0.29%
5	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	100.00%	90.97%	6.41%	5.52%	0.89%	2.63%
6	C62Sec, w/o Ltg & C/I Undergrou	C62NL	100.00%	93.65%	6.35%	4.25%	2.10%	0.00%
7	Secondary Customers	C62Sec	100.00%	86.13%	13.57%	9.09%	4.49%	0.29%
8	Summer Peak Resp KW	D10S	100.00%	36.97%	63.03%	3.71%	59.32%	0.00%
9	Transmission Demand %	D10T	100.00%	40.80%	58.70%	4.56%	54.13%	0.50%
10	Winter Peak Resp KW	D10W	100.00%	46.15%	52.64%	5.75%	46.89%	1.21%
11	Alternative Production Allocator	D10C	100.00%	39.14%	60.57%	4.20%	56.37%	0.29%
12	Sec, Pri & TT, Class Coin kW @ !	D60Sub	100.00%	39.15%	59.82%	4.56%	55.26%	1.03%
13	Sec & Pri, Cl Coin kW (no Min Sy	D61PS	100.00%	39.15%	59.82%	4.56%	55.26%	1.03%
14	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	100.00%	74.19%	24.77%	4.97%	19.80%	1.04%
15	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	100.00%	77.59%	22.41%	3.09%	19.33%	0.00%
16	Sec, Class Coin kW (w/o Min Sys	D62SecL	100.00%	51.56%	47.68%	5.29%	42.39%	0.76%
17	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	On + Off Sales MWH	E8760	100.00%	37.34%	62.04%	4.70%	57.34%	0.61%
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%	36.41%	62.85%	4.62%	58.227%	0.74%
21	Present Rev	R01	100.00%	40.24%	58.88%	5.25%	53.63%	0.88%
22	Late Fee Revenue Allocator	LateFee	100.00%	82.95%	17.02%	5.03%	11.99%	0.03%

			6	**7**	**11**	**12**	**13**	**36**
			1=2+3+6	2	3=4+5	4	5	6
EXTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**St Ltg**
23	Customers - B Basis	C10	96,570	83,151	13,138	8,772	4,366	282
24	Cust - Ave Monthly (C10-Area Lt)	C11	98,841	83,542	13,224	8,859	4,366	2,074
25	Mo Cus Wtd By Cus Acct	C11WA	102,834	83,542	19,089	11,516	7,573	202
26	Cust Acctg Wtg Factor	C11WAF	6.55	1.00	5.46	1.30	4.16	0.10
27	Cust-Ave Mo (C11 w/ Dir Assign !	C12	96,919	83,542	13,224	8,859	4,366	152
28	Mo Cus Wtd By Mtr Invest	C12WM	17,064,231	13,620,995	3,419,377	1,670,140	1,749,237	23,859
29	Meter Invest / Cust Factor	C12WMF	4,998	163	4,678	189	4,490	157
30	Sec & Pri Customers	C61PS	96,570	83,151	13,138	8,772	4,366	282
31	% Served by Primary Single Phase		0.0%	69.85%	0.00%	40.17%	0.00%	48.08%
32	Pri & Sec Cust Served w/ 1 Ph	C61PS1Ph	63,852	58,083	4,090	3,524	567	1,679
33	C62Sec, w/o Ltg & C/I Undergrou	C62NL	88,788	83,151	5,637	3,774	1,864	0
34	Secondary Customers	C62Sec	96,537	83,151	13,105	8,772	4,332	282
35	Summer Peak Resp KW	D10S	385	142	242	14	228	0
36	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	4,079,962	5,869,587	456,494	5,413,093	50,452
37	Winter Peak Resp KW	D10W	325	150	171	19	153	4
38	Alternative Production Allocator	D10C	10,000,000	3,914,358	6,056,987	419,677	5,637,310	28,655
39	Sec, Pri & TT, Class Coin kW @ !	D60Sub	437,121	171,122	261,502	19,949	241,552	4,498
40	Sec & Pri, Class Coin kW (w/o Mi	D61PS	437,121	171,122	261,502	19,949	241,552	4,498
41	Pri & Sec Coin kW Served w/ 1 Pl	D61PS1Ph	161,128	119,534	39,916	8,013	31,903	1,679
42	D62Sec, w/o Ltg & C/I Undergrou	D62NLL	933,823	724,515	209,307	28,846	180,462	0
43	Sec, Class Coin kW (w/o Min Sys	D62SecL	10,000,000	5,155,831	4,768,482	529,466	4,239,015	75,688
44	Annual Billing kW	D99	3,197.012	0	3,197	0	3,197	0
45	Summer Billing kW	D99S	1,148.948	0	1,149	0	1,149	0
46	Winter Billing kW	D99W	2,048.064	0	2,048	0	2,048	0
47	Non-Coinc Pk Second	DN-Sec	1,215,588	724,515	486,575	67,058	419,518	4,498
48	MWh Sales	E99	2,131,650	776,035	1,339,754	98,552	1,241,203	15,861
49	MWh Sales Excl CIP Exempt	E99XCIP	2,131,650	776,035	1,339,754	98,552	1,241,203	15,861
50	Late Fee Revenue Allocation	LateFee	100.00%	82.95%	17.02%	5.03%	11.99%	0.03%

					Customer Class				
Line	**Primary Distribution Cost**	**Allocator Derivation**	**Allocator Label**	**ND**	**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	96,570	83,151	8,772	4,332	33	282
2	Capacity Portion of **Multi-Phase** Primary Lines	Class Coincident Peak Demands	D61PS	437,121	171,122	19,949	197,683	43,870	4,498
3	% of Customers Served by Primary **Single Phase** Lines				69.9%	40.2%	13.0%	14.3%	48.1%
4	Customer Portion of **Single-Phase** Primary Lines	line 1 x line 3	C61PS1Ph	63,852	58,083	3,524	562	5	1,679
5	Capacity Portion of Single-Phase Primary Lines	line 2 x line 3	D61PS1Ph	161,128	119,534	8,013	25,635	6,267	1,679
6	Customer Portion of **Multi-Phase** Primary Lines	Cost Allocator %	C61PS	100.0%	86.1%	9.1%	4.5%	0.0%	0.3%
7	Capacity Portion of **Multi-Phase** Primary Lines	Cost Allocator %	D61PS	100.0%	39.1%	4.6%	45.2%	10.0%	1.0%
8	Customer Portion of **Single-Phase** Primary Lines	Cost Allocator %	C61PS1Ph	100.0%	91.0%	5.5%	0.9%	0.0%	2.6%
9	Capacity Portion of **Single-Phase** Primary Lines	Cost Allocator %	D61PS1Ph	100.0%	74.2%	5.0%	15.9%	3.9%	1.0%



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 were determined by the Company's Distribution Engineering area according to its field experience and its evaluation of the smallest practical-sized equipment inventories held in the Company's inventory.

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

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 6.

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, for 5 of the 6 property units the zero intercept method provided a lower customer component, while 1 of the 6 have a lower customer component using the minimum system method.

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

	% 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%

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 3 of Christopher Barthol's Direct Testimony). 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.

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%**	

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%**	

Northern States Power Company

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%**	

Northern States Power Company

Inventory of Underground Transformers by Transformer Configuration

Case No. PU-24-___

Exhibit___(CJB-1), Schedule 6

Attachment C - Page 2 of 2

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%**	

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%**	

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%**	

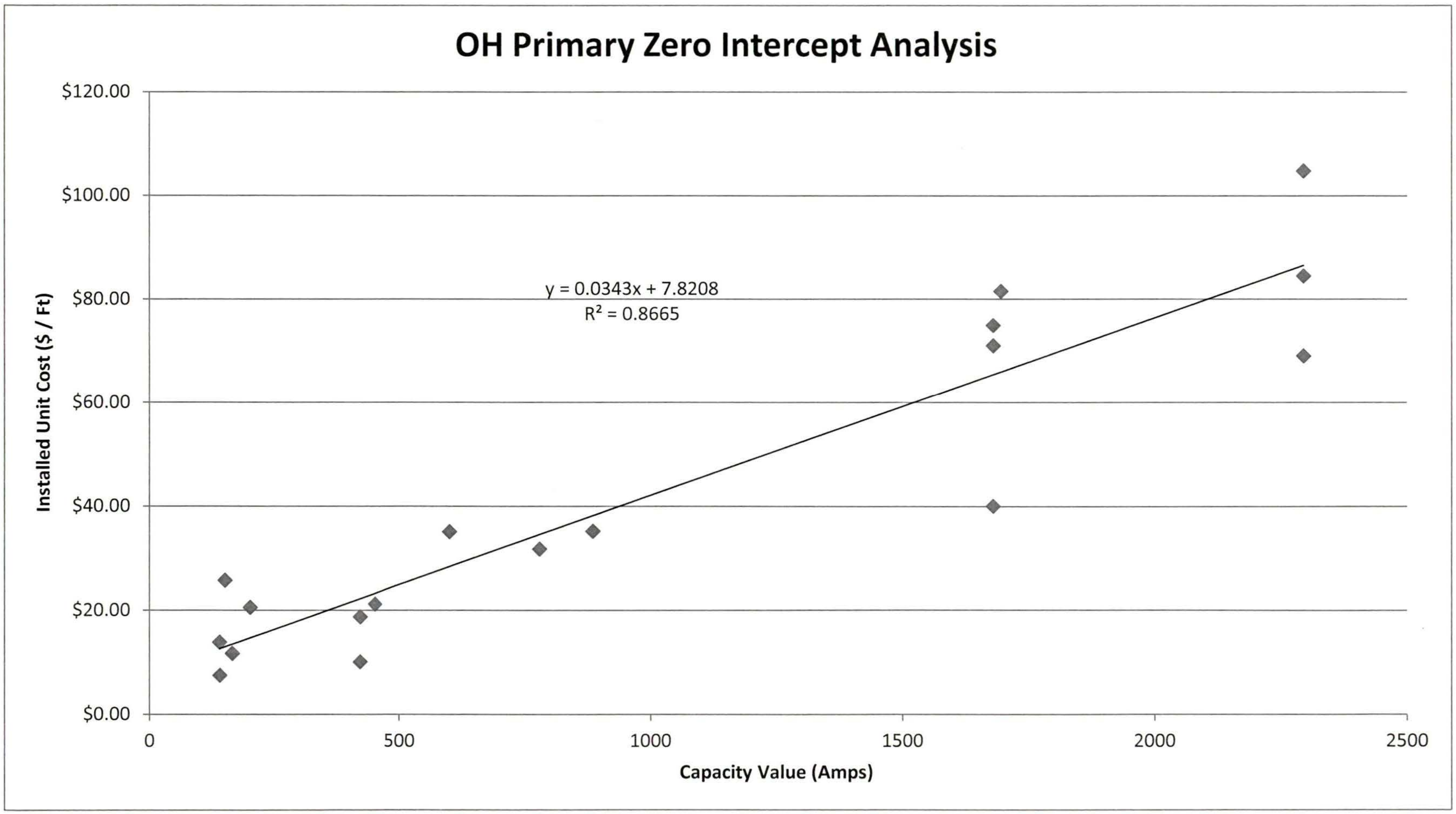
Overhead 1 Phase	Number OH 1 Phase	% of OH 1 Phase	Cumulative % of OH 1 Phase	% of All OH Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
OH 1 phase 34.5/13.8 kV 500 kVA	240	23.90%	23.90%	18.66%	500	$102,886	$24,692,533
OH 1 phase 19.92/7.2 kV 167 kVA	131	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

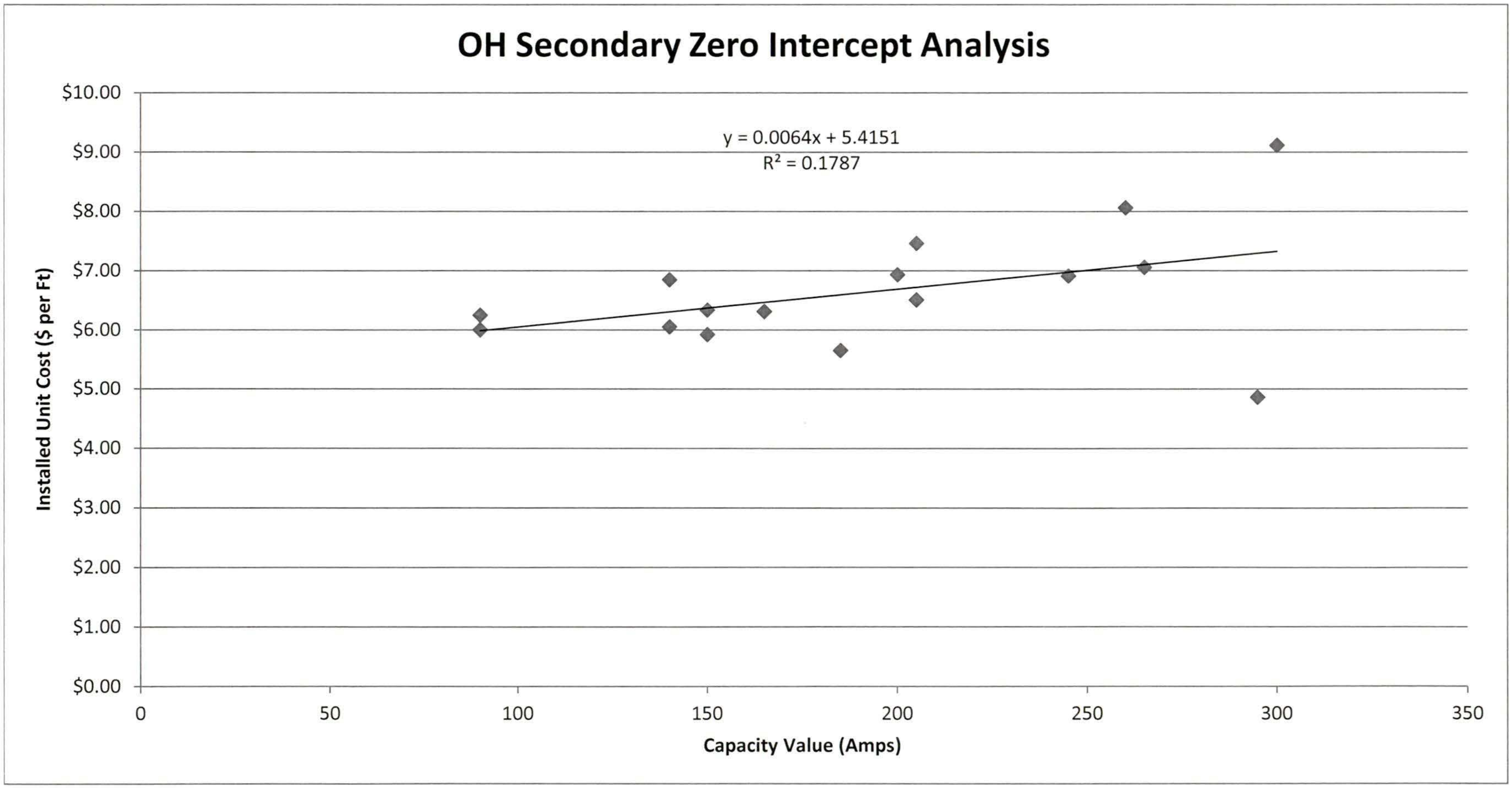
Underground 1 Phase	Number UG 1 Phase	% of UG 1 Phase	Cumulative % of UG 1 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 1 phase 19.92/7.97 kV 500 kVA	1	33.33%	33.33%	1.20%	500	$61,508	$61,508
UG 1 phase 19.92/7.2 333.0 kVA	1	33.33%	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**

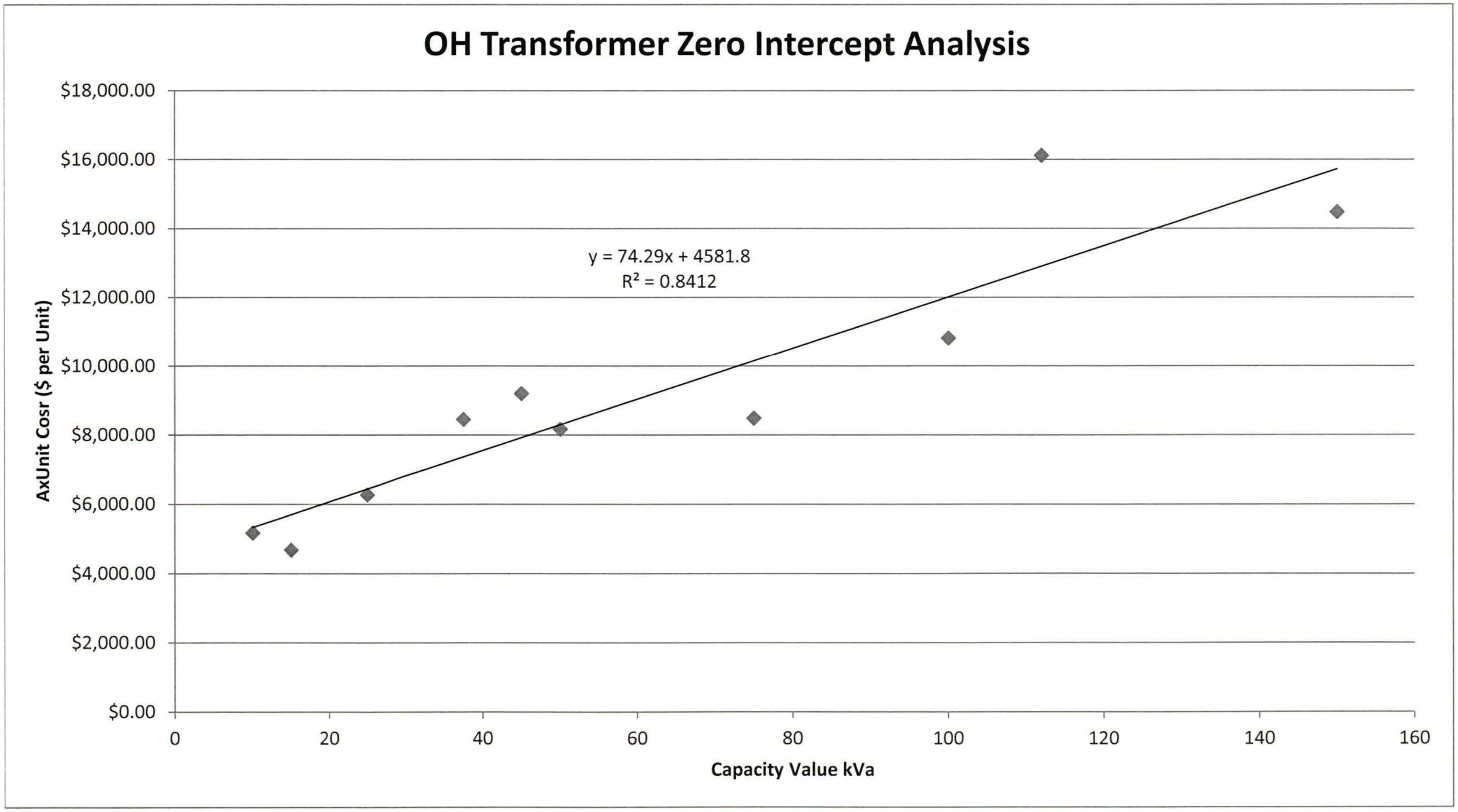
Underground 3 Phase	Number UG 3 Phase	% of UG 3 Phase	Cumulative % of UG 3 Phase	% of All UG Step-Down Transformers	Load Carrying Capacity (kVA)	Installed Unit Cost	Total Replacement Costs
UG 3 phase 34.5/13.8 kV 5000 kVA	48	60.00%	60.00%	57.83%	5000	$683,393	$32,802,844
UG 3 phase 34.5/13.8 kV 3750 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 Transf	**1,369**					$161,643	**$221,289,433**

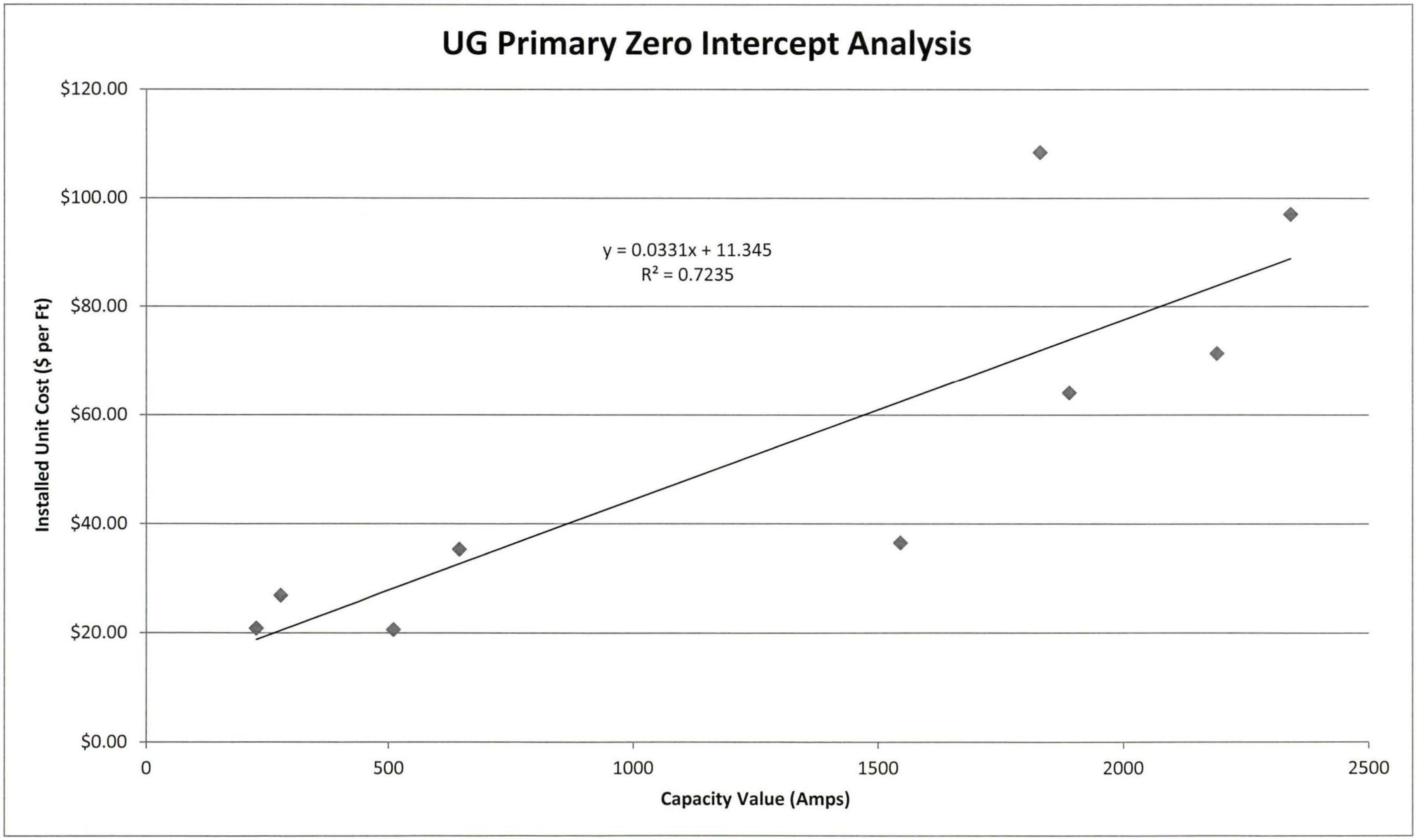

OH Primary Zero Intercept Analysis
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
Installed Unit Cost ($ / Ft)
y = 0.0343x + 7.8208
R² = 0.8665
0
500
1000
1500
2000
2500
Capacity Value (Amps)

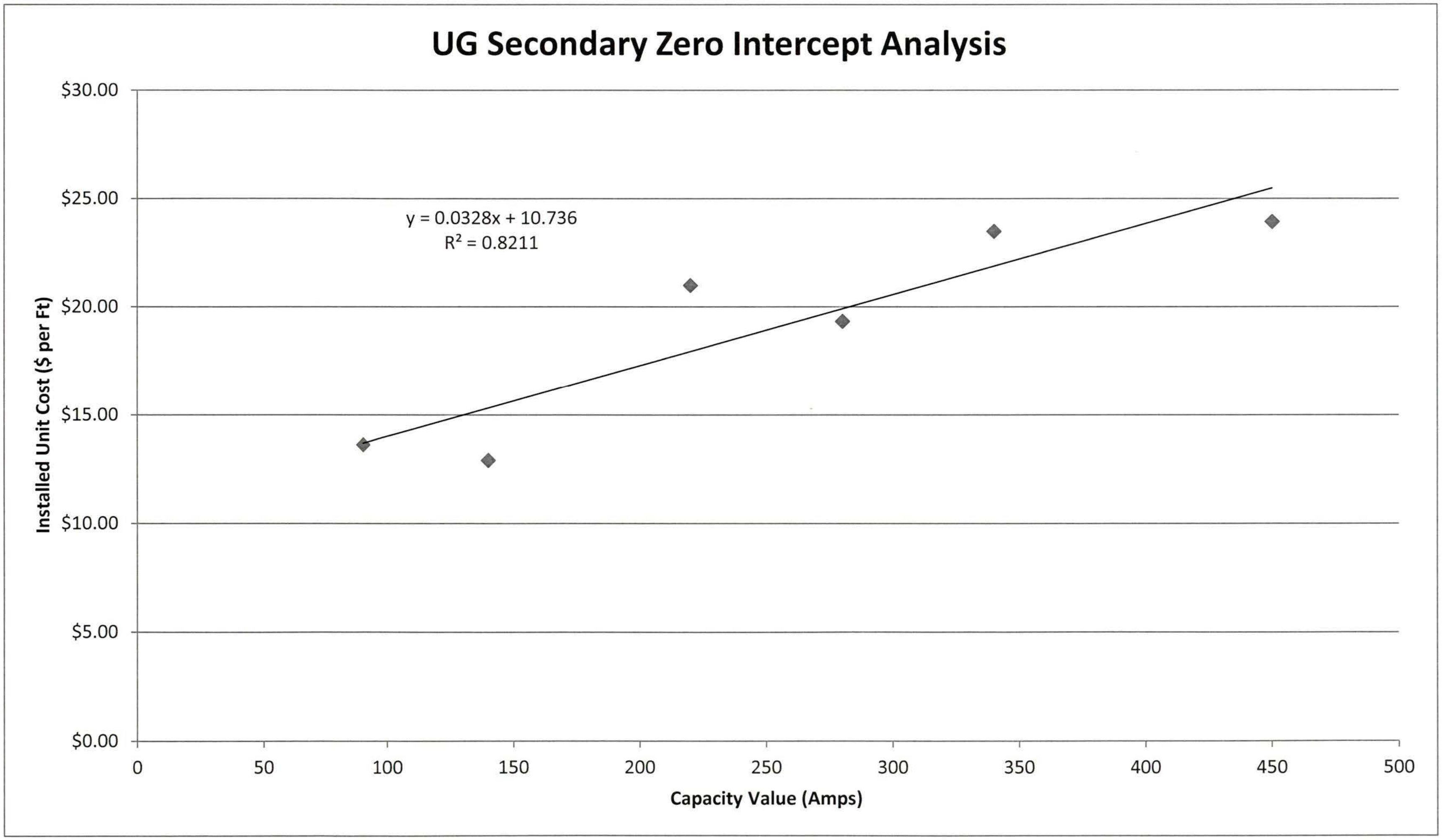
Northern States Power Company
Overhead Secondary Zero Intercept Analysis

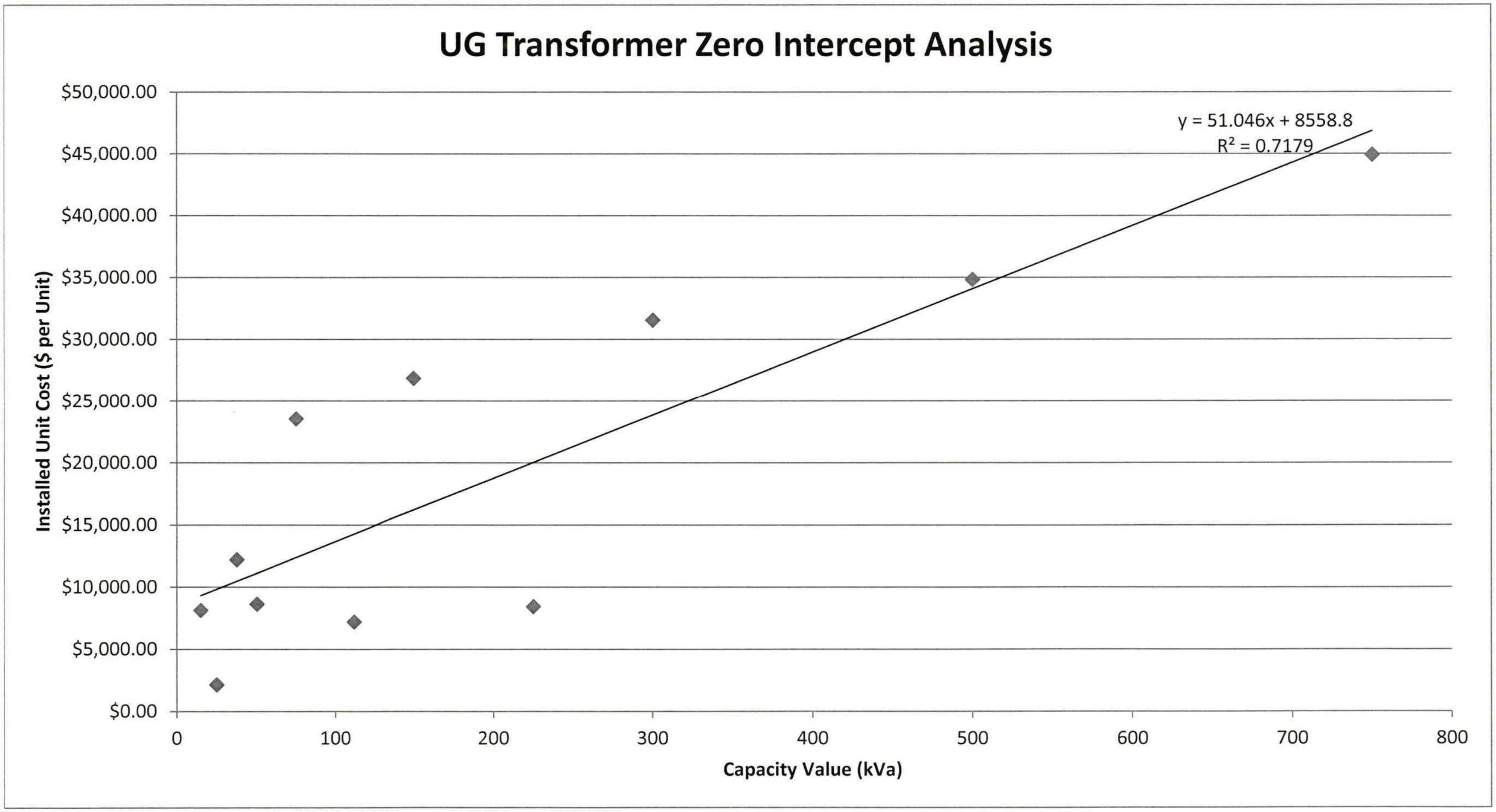
Case No. PU-24-___
Exhibit___(CJB-1), Schedule 6
Attachment I - Page 1 of 1




OH Transformer Zero Intercept Analysis
$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)
y = 74.29x + 4581.8
R² = 0.8412
0
20
40
60
80
100
120
140
160
Capacity Value kVa


UG Primary Zero Intercept Analysis
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
Installed Unit Cost ($ per Ft)
y = 0.0331x + 11.345
R² = 0.7235
0
500
1000
1500
2000
2500
Capacity Value (Amps)


UG Secondary Zero Intercept Analysis
y = 0.0328x + 10.736
R² = 0.8211
Installed Unit Cost ($ per Ft)
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
0
50
100
150
200
250
300
350
400
450
500
Capacity Value (Amps)


UG Transformer Zero Intercept Analysis
y = 51.046x + 8558.8
R² = 0.7179
Installed Unit Cost ($ per Unit)
$50,000.00
$45,000.00
$40,000.00
$35,000.00
$30,000.00
$25,000.00
$20,000.00
$15,000.00
$10,000.00
$5,000.00
$0.00
0
100
200
300
400
500
600
700
800
Capacity Value (kVa)

Northern States Power Company
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**
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%**

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]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9] = [4] x [8]	[10]	[11] = [4] x [10]	[12]	[13] = [4] x [12]
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%**

	[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 Transformers 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

Case No. PU-24-___
Exhibit___(CJB-1), Schedule 6
Attachment O - Page 1 of 1

		[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%	$11,213	16.32%
2	OH Primary Single Phase Customer						24.01%	$3,544	5.16%
3	Total OH Primary Single Phase	40,232,843	$17.85	$718,334	22.31%	$14,757	100.00%	$14,757	
4	OH Primary Multi Phase Capacity						75.99%	$24,619	35.83%
5	OH Primary Multi Phase Customer						24.01%	$7,781	11.32%
6	Total OH Primary Multi Phase	29,760,732	$52.99	$1,577,115	48.97%	$32,400	100.00%	$32,400	
7	OH Secondary Capacity						20.11%	$3,821	5.56%
8	OH Secondary Customer						79.89%	$15,181	22.10%
9	Total OH Secondary	136,467,174	$6.78	$924,994	28.72%	$19,003	100.00%	$19,003	
10	Street Lighting (see Line 9 of Schedule XX)					$2,543		$2,543	3.70%
11	Total Overhead (see Schedule X, Page 4, Column 1, Line XX)			$3,220,443	100.00%	$68,702		$68,702	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%	$22,960	21.10%
13	UG Primary Single Phase Customer						34.68%	$12,188	11.20%
14	Total UG Primary Single Phase	31,519,114	$24.02	$757,128	32.31%	$35,148	100.00%	$35,148	
15	UG Primary Multi Phase Capacity						65.32%	$33,138	30.46%
16	UG Primary Multi Phase Customer						34.68%	$17,591	16.17%
17	Total UG Primary Multi Phase	24,364,721	$44.85	$1,092,733	46.63%	$50,728	100.00%	$50,728	
18	UG Secondary Capacity						41.45%	$9,500	8.73%
19	UG Secondary Customer						58.55%	$13,417	12.33%
20	Total UG Secondary	26,919,485	$18.34	$493,648	21.06%	$22,917	100.00%	$22,917	
21	Street Lighting					$0		$0	0.00%
22	Total Underground			$2,343,509	100.00%	$108,793		$108,793	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%	$6,604	100% Capacity	$6,604	17.75%
24	Secondary Capacity						31.95%	$9,774	26.28%
25	Secondary Customer						68.05%	$20,821	55.97%
26	Total Secondary	113,110	$9,064	$1,025,230	82.25%	$30,596	100.00%	$30,596	82.25%
27	Total Transformers			$1,246,520	100.00%	$37,199		$37,199	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	74,808	$15,074			
2	UG Services	1/0 Triplex	50	$2.81	13,980	$1,964			
3	Total Services				88,788	$17,038	$20,287	83.98%	16.02%

Northern States Power Company
State of North Dakota Electric Jurisdiction
Test Year Ending December 31, 2025
Excess Footage and Winter Construction Revenue Impact

Tariff	Description	Present Price	Proposed Price	2023 Units	Present $	Proposed $	Difference
1.8	**Dedicated Switching Service**	Chg / trip	Chg / trip				
	Monday through Saturday	$300.00	$800.00	28	$8,400	$22,400	$14,000
	Sunday and Federal holidays	$400.00	$1,000.00	2	$800	$2,000	$1,200
5.1.A.1	**Standard Installation and Extension Rules**						
	Excess service charge - Services	$12.50	$10.00	536	$6,700	$5,360	-$1,340
	Excess service charge - Excess single phase primary	$13.20	$10.50	-	$0	$0	$0
	Excess service charge - Excess three phase primary	$20.80	$17.00	-	$0	$0	$0
5.1.A.2.	**Winter Construction**						
	Per Thaw Unit	$685.00	$870.00	0	$0	$0	$0
	Per Trench Foot	$8.90	$18.00	130	$1,157	$2,340	$1,183
			REVENUE IMPACT		**$17,057**	**$32,100**	**$15,043**

Section 6.5.1.A1.			
Excess Footage Charge	Current Electric tariff per circuit foot	Proposed Tariff Charge per circuit foot	Proposed Rate
Services	$12.50	**$10.12**	**$10.00**
Excess single phase primary or secondary extension	$13.20	**$10.65**	**$10.50**
Excess three phase primary or secondary extension	$20.80	**$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
Propane Cost					2.72	22.5	$61.20	$61.20
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 S	$30.61
Difference for Winter Construction	**$18.17**

2024 Updates to Charges

Tariff								
	Current Electric Charges		Updated Costs		Proposed Tarif Charge			
Winter Construction Service primary or secondary distribution	$685.00	per thaw unit	$870.27	per thaw unit	Thawing		$870.00	per thaw unit
	$8.90	plus per trench foot	$18.17	plus per trench foot	Service, Primary, or Secondary distribution extension		$18.00	per foot

	Normal		Overtime		Overtime	
	2023 $		Mon-Sat x 1.5%		Sun-Fed Holidays x 2.0%	
	$/hour		2023 $/hour		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

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY 2025 ELECTRIC RATE INCREASE APPLICATION	)))	Case No. PU-24-___

AFFIDAVIT OF
Christopher J. Barthol

I, the undersigned, being first duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Christopher J. Barthol

Subscribed and sworn to before me, this 21 day of November, 2024.

Notary Public
My Commission Expires: 1/31/2027

JODI LYNN YANZ
NOTARY PUBLIC
MINNESOTA
My Commission Expires 01/31/2027